TYNDP 2022

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Scenario Building Guidelines

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Disclaimer

In a rapidly changing energy landscape and impacts due to geopolitical influences, the energy policies of the EU and many Member States are continuously developing.

The invasion of Ukraine by Russia on 24 February 2022 has led to a major overhaul of energy policy objectives in terms of energy security and diversification of supply that the TYNDP 2022 scenarios do not currently reflect.

ENTSO-E and ENTSOG would like to explain that due to these recent events affecting the energy supply in Europe, some assumptions used in this report regarding gas supply may be impacted for the short and longer terms.

ENTSO-E and ENTSOG are committed to developing TYNDP scenarios that will support the European Union plans for energy infrastructure and to achieve the objectives of the EU Green Deal as well as the Paris Agreement, and to ensure a fair, affordable and secure transition towards a clean and decarbonised energy system. The TYNDP 2022 scenarios were developed over the last two years on this basis, and with extensive stakeholder engagement.

As for every TYNDP, the assessment of the EU's dependence on the main gas supply sources and impact on the infrastructure will continue in TYNDP 2022 and is planned to be published at the end of the 2022.

1 Introduction

The purpose of the Scenario Building guideline is to give insight in the methodologies used for developing the scenario and thereby both helping the reader to better comprehend figures, charts and results of the Scenarios Main Report by providing additional information as well as give an understanding of 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 and COP 21 scenarios being 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 appendixes aim to provide further details about the tools used, the modelling innovations embedded in this edition (district heating supply, P2G methodology and its possible configurations, EV and prosumer nodes and differentiated PECD) 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 lead to the modelling features implemented for this 2022 edition.

1.2 Decisional process for designing the methodology

The methodology guideline 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 deriving 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 2022 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 considering also 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.

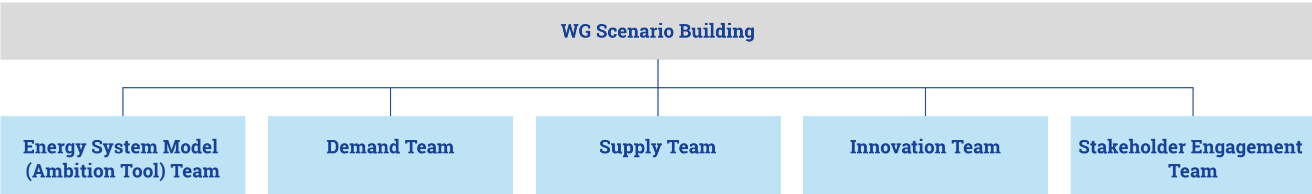

Figure 1: Decision making groups for the Scenario building methodology definition

1.3 Summarising the improvements

The evolution of TYNDP Scenarios produced by ENTSOG and ENTSO-E is two-fold. On the first hand the storylines are adapted to capture evolving stakeholders' expectations and the European policy and climatic ambition. Thereby the improvements of the TYNDP 2022 scenarios are to a large extend based upon the evaluation of the TYNDP 2020 scenarios and the feedback given by stakeholders. On the other hand, some modelling innovations are developed and implemented in order 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 previous edition, improvements cover many aspects of scenario development and offered the opportunity of closer interaction with the respective sectors. In particular the improvements achieved to model different sectors (among which electrolysis, prosumer and EV node, district heating) have benefited from both the expertise of those stakeholders that, being closer to certain sectors, have manifested their availability for bilateral exchanges and feedbacks received during the public consultations. More details on stakeholders' interactions and exchanges are provided in a dedicated section of the Updated TYNDP 2022 Scenario Report.

As WGSB responsible for the TYNDP 2022 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!

Electrolysis modelling

In the previous edition, electrolysis was modelled with dedicated Renewable Energy Sources (RES) (not connected to the electricity wholesale market) and "spilled" energy from the market. The intention was to provide some first insights on the amount of wind and solar necessary to produce renewable hydrogen in Europe.

Taking into account 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), 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.

For more information on the P2X modelling in the current TYNDP 2022 scenario, see Appendix III.

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 optimizing 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.

For this edition 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.

For more information on the modelling of the EV and prosumer node in the TYNDP 2022 scenarios, see Appendix II.

District heating

In the previous edition of the TYNDP scenarios, heating technologies connected to district heating grids were operating like their household equivalents. Such approach prevents to take into account the specific design and operation of district heating heat pumps and thus cannot capture its benefits.

As a result, an ex-ante modelling of district heating supply is carried out in order to define the design and load profile of heat pumps depending on climatic data and other available heat sources. Such electricity profile is then added to the rest of the electricity demand profile.

For more information on the modelling of district heating in the TYNDP 2022 scenarios, see Appendix I.

Climatic database

Wind and solar production depend on both weather conditions and generation technologies. Manufacturers are further improving wind turbine technologies in order to better harvest wind potential. In previous edition existing and newly build wind capacity at a given place used the same load factor.

In this edition, a separate load factor is applied for onshore wind farms build after 2025 ensuring a better consideration of wind potential.

A new climatic database is also progressively introduced to better capture global warming impact on energy demand.

For more information on climatic database see Appendix VII.

2 Overall Process

The aim of the Scenario Building Methodology is to enable the delivery of a set of scenarios in a sufficient level of detail to support infrastructure assessment at ENTSOG and ENTSO-E TYNDP level.

Such methodology should capture the evolving dynamics of the energy system (e.g., sector coupling) and be transparent to ensure stakeholders' understanding and support.

The nature of the methodology differs between:

- **National Trends** based on TSOs (bottom-up) data up to 2040 translating national policies and strategies as stated end of 2020 and focusing on the sole electricity, methane and hydrogen energy carriers.
- **Distributed Energy and Global Ambition** based on a holistic view of the European energy system up to 2050 factoring stakeholders' feedback collected during the Draft Storyline Report consultation process and bilateral engagement with a wide range of sectors. These scenarios are often referred to as COP21 scenarios, given their compliance with the 2015 Paris Agreement.

2.1 National Trends (bottom-up) Scenario Modelling Principles

A core element of the ENTSOs' scenario building process is the use of supply and demand data collected from both gas and electricity TSOs to build bottom-up scenarios. The 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. Bottom-up scenarios are an important feature of TYNDP scenarios as they show how National Plans come together from a European perspective.

For TYNDP 2022, National Trends is the bottom-up scenario. This scenario uses a simplified methodology compared to Distributed Energy and Global Ambition scenarios because it covers a focused scope (electricity, methane and hydrogen), as predefined demand and capacity figures resulting from TSO data collection are used.

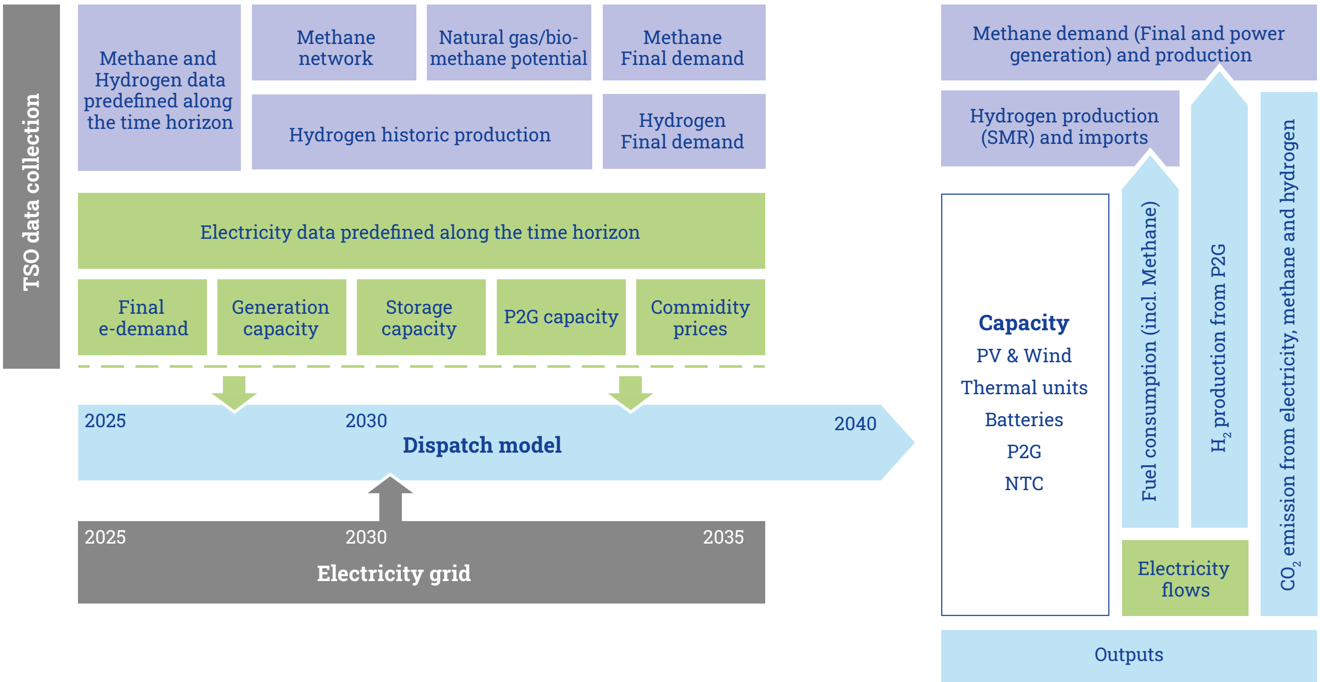

Figure 2: Building blocks for National Trends scenario

2.1.1 Data Collection Process

As written above, the National Trends scenario is based on data collected from gas and electricity TSOs, reflecting the latest policy- and market-driven developments discussed at national level as stated end of 2020. This may include, but is not limited to, the National Energy and Climate Plans, as there may be additional developments/ambitions (in particular but not limited to National Hydrogen Strategies). The scenario covers electricity, methane, and hydrogen energy carriers. The aim is to ensure that gas and electricity TYNDPs provide a consistent and aggregated view of the national scenarios and inform stakeholders about European energy dispatch.

Electricity and gas data were collected from TSOs respectively in January 2021 and April 2021 for the time horizons 2025, 2030 and 2040.

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.

Synchronised data
Gas-fired power generation capacity
Electrolyser capacity
Number of electric vehicles for passenger transport
Number of all-electric and hybrid heat pumps

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

Electricity	Gas
Number of Electric Vehicles for non-passenger transport	Number of Fuel Cell Electric Vehicles for passenger transport
Photovoltaic capacity for electrolysis	Conventional natural gas production
Offshore wind capacity for electrolysis	Natural gas production via unconventional technology, e.g., fracking etc.
Onshore wind capacity for electrolysis	Gas demand in all power plants (incl. CHP)
Hydro (reservoir, run-of-river and pump storage) capacity	Electrolyser (only connected to gas grid)
Thermal unit capacity and must-runs	
Nuclear unit capacity and must-runs	
Electrolyser (only connected to electricity grid)	
Electrolyser (connected to both the electricity and gas grid)	
Battery capacity	
Demand-side response capacity and price band	
Net Transfer Capacity (NTC) for 2025 and 2030	

Table 2: Energy specific data collection per sector for building the bottom-up scenario (National Trends)

2.1.2 Electricity Demand and Renewable Profiling

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

- **Demand profiling:** for most of the countries the Trapunta Tool (See section 2.2.3 and Appendix VI, section A(ii)) is used to produce hourly demand profile for a range of climatic years based on a climatic database (Appendix VII);
- **Wind and solar profiling:** hourly load factors are derived from a climatic database (Appendix VII) differentiating existing and new technologies for wind.

2.1.3 Electricity Interconnection Capacity

National policies and strategies do not provide a straight view of cross-border electricity interconnection development. As a result, TSOs have to build reasonable assumptions regarding future capacity developments:

- Time horizon 2025 and 2030: level consistent with European Resource Adequacy Assessment (ERAA) 2021 process in a nodal topology based on bidding zones
- For the time horizon 2040 the best estimate of the 2035 grid was used.

2.1.4 Electricity and Hydrogen System Modelling

The bidding zones considered for each country modelled can be seen in Figure 3.

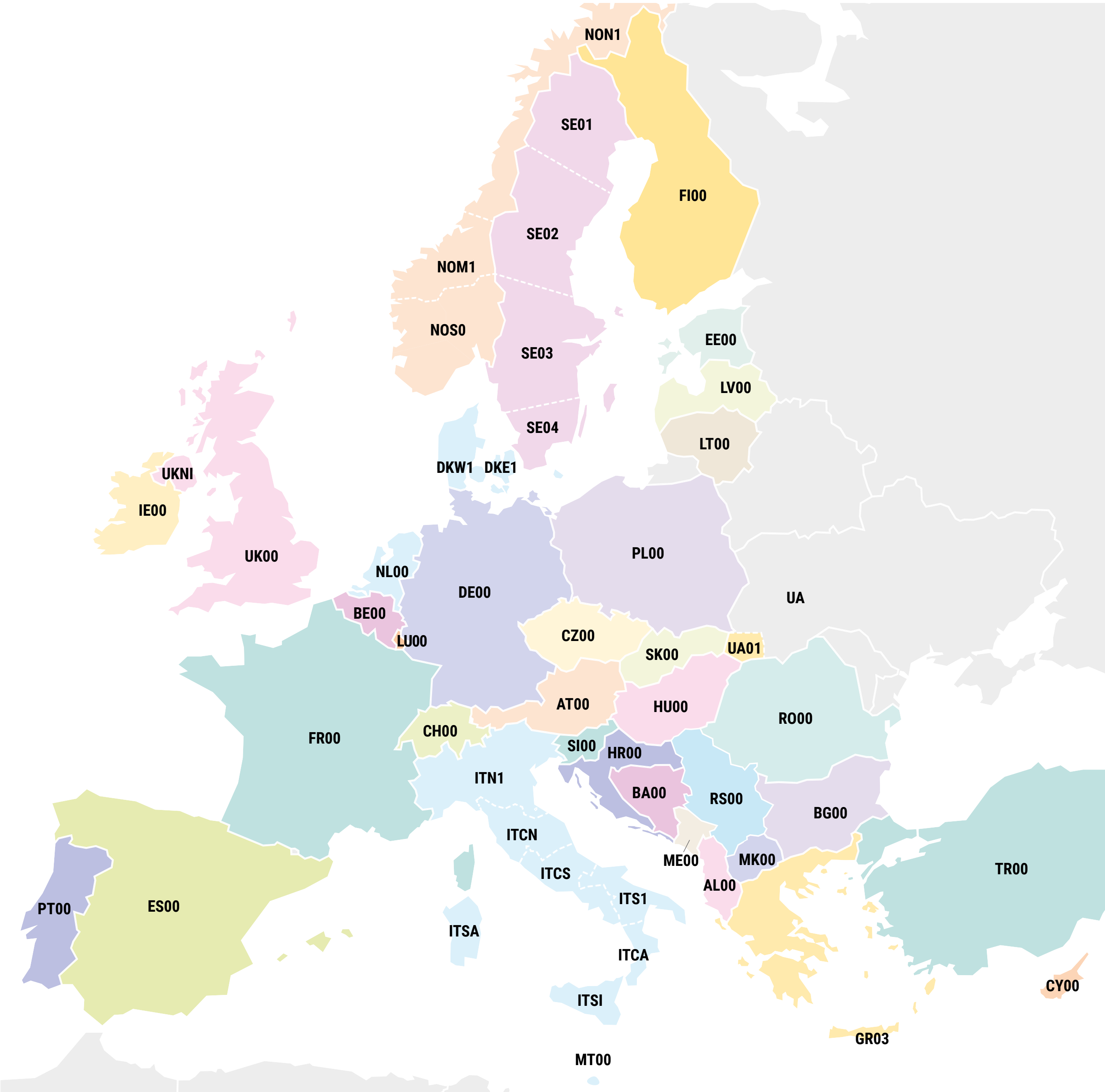

Figure 3: The bidding zones considered for each country modelled

For 2040, an expansion model is run to ensure the adequacy of the electricity system. As a difference with previous edition, this investment loop is carried out jointly with the electricity TYNDP process (Joint Identification of System Needs) and results in the selection of the most viable investment candidates among interconnections, storage and peak generation.

As an additional innovation compared to previous edition, Power-to-Gas (P2G) is now modelled as part of the electricity system using Configuration 3 (see Appendix III).

It enables to capture the impact of hydrogen production through electrolysis on the electricity system. Electrolysis occurs when the electricity marginal price is below a threshold corresponding to the cost of decarbonised hydrogen production (steam methane reforming of natural gas plus CCS and CO_2 cost taking into account a 90 % capture rate).

In addition, some TSOs have declared some P2G capacity operating out of the market based on dedicated RES.

2.1.5 Output of the National Trends Scenario Building Process

Table 3 provides an overview of the data flow according to the National Trends modelling process

Input data	Processing	Output data
Final electricity demand	No change: the output equals the input	Hourly demand profile based on PECD
P2G capacity	No change: the output equals the input	P2G capacity
	Dispatch modelling results	Electrolyser hourly load
RES capacity	No change: the output equals the input	Hourly generation profile based on PECD
	Dispatch modelling results	Spilled energy
Thermal (incl. nuclear) capacity and must-runs	No change: the output equals the input	Thermal capacity
	Dispatch modelling results	Aggregated unit commitment
Flexibility (Pump hydro, battery and DSR) capacity	No change: the output equals the input	Flexibility capacity
	Dispatch modelling results	Storage in and out flows DSR activation
Interconnection capacity	No change: the output equals the input	Interconnection capacity
	Dispatch modelling results	Flows
Final gas demand	No change: the output equals the input	Daily final gas demand per sector for yearly average, peak day, 2-week cold spell and dunkelflaute cases.

Table 3: Data flows in National Trends modelling process

2.2 COP21 Scenario Modelling Principles

For TYNDP 2022, Distributed Energy and Global Ambition are labelled as COP 21 scenarios as being compliant with Paris Agreement. These scenarios cover the overall European energy mix (all sectors including non-energy use and all energy carriers) in order to enable the assessment of carbon emissions at a given time horizon and carbon budget on the period.

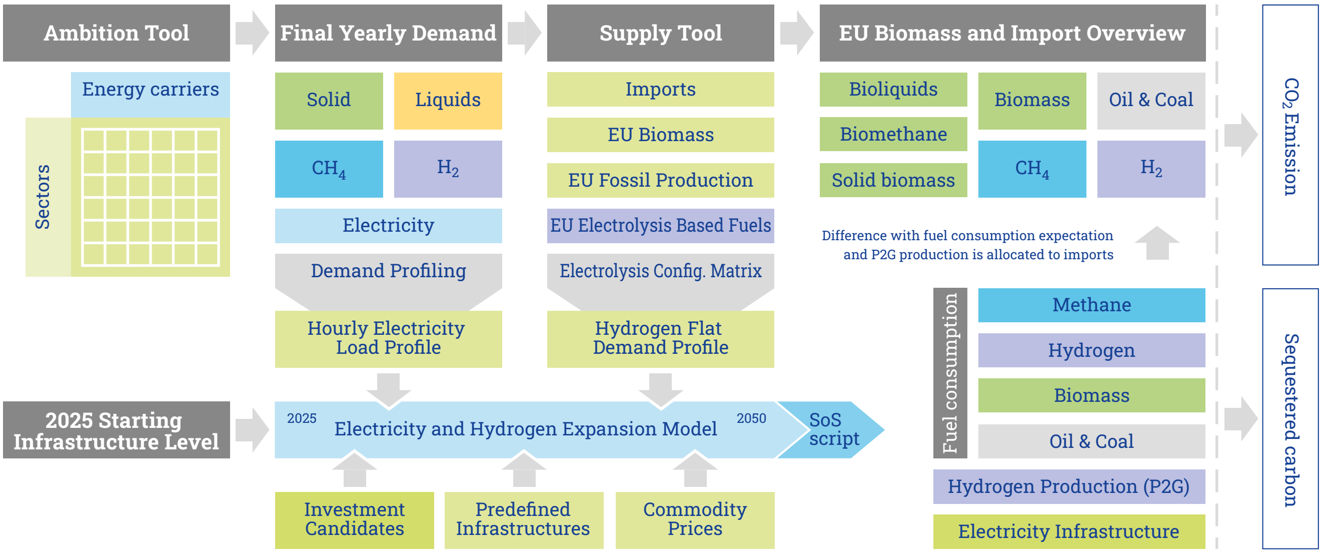

Figure 4: Building blocks for Distributed Energy and Global Ambition scenarios

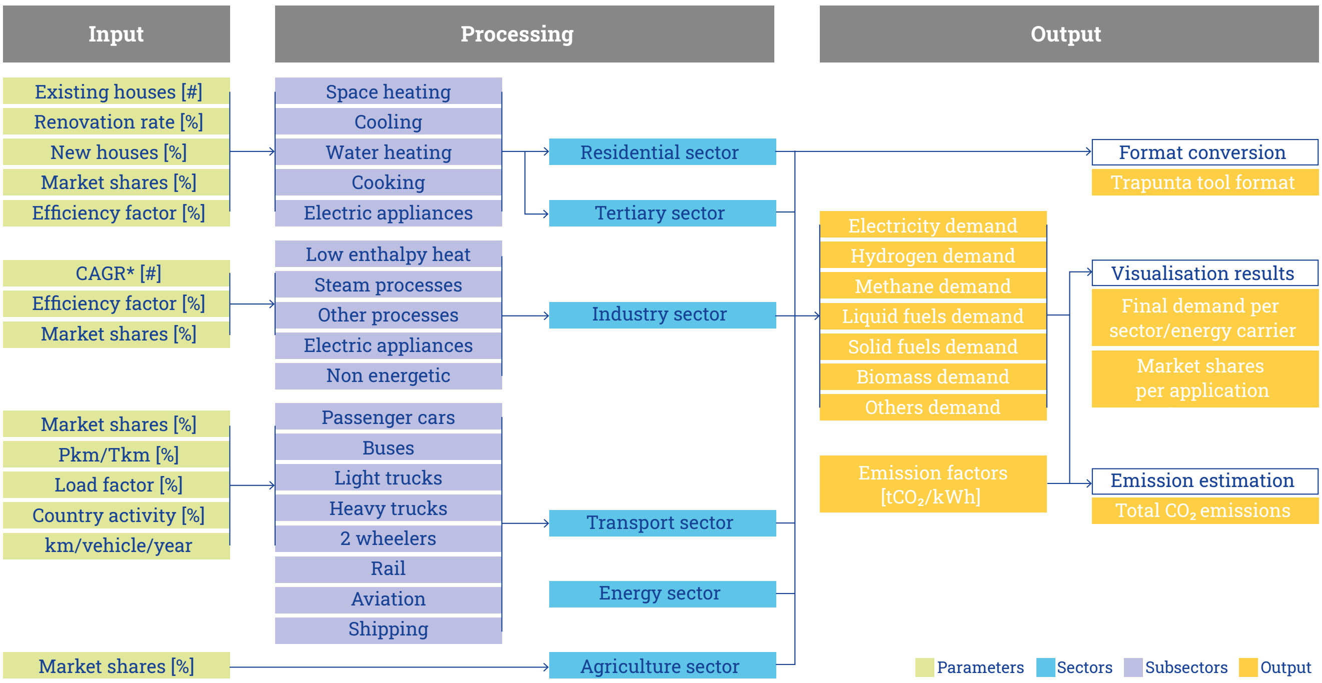

Figure 5: Schematic overview Ambition Tool

2.2.1 The Ambition Tool: the why and how

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.

In the course of the TYNDP 2022, the electricity and gas TSOs further developed the Ambition Tool that has already been used in the TYNDP 2020 cycle. The Ambition Tool in its current version is structured into an input data, a data processing and an output data part like shown in Figure 5.

The input data consists of reference data on the energy use per sector and application, fixed parameters defining technical properties (e.g., efficiencies) per technology and scenario parameters which can be adjusted by the user. These scenario parameters for example describe how certain market shares per technology will develop in the future. Whereas per default the parameter values were taken over from the JRC POTENCIA central scenario study as well as the "EU road vehicle energy consumption and CO_2 emissions by 2050 – Expert-based scenarios (Energy Policy, March 2020) for EVs efficiency values[1], the parameters for both the Distributed Energy (DE) and the Global Ambition (GA) scenario have been calibrated by the respective electricity and gas TSOs during the data collection process, to account for country specifics and consider the national expertise.

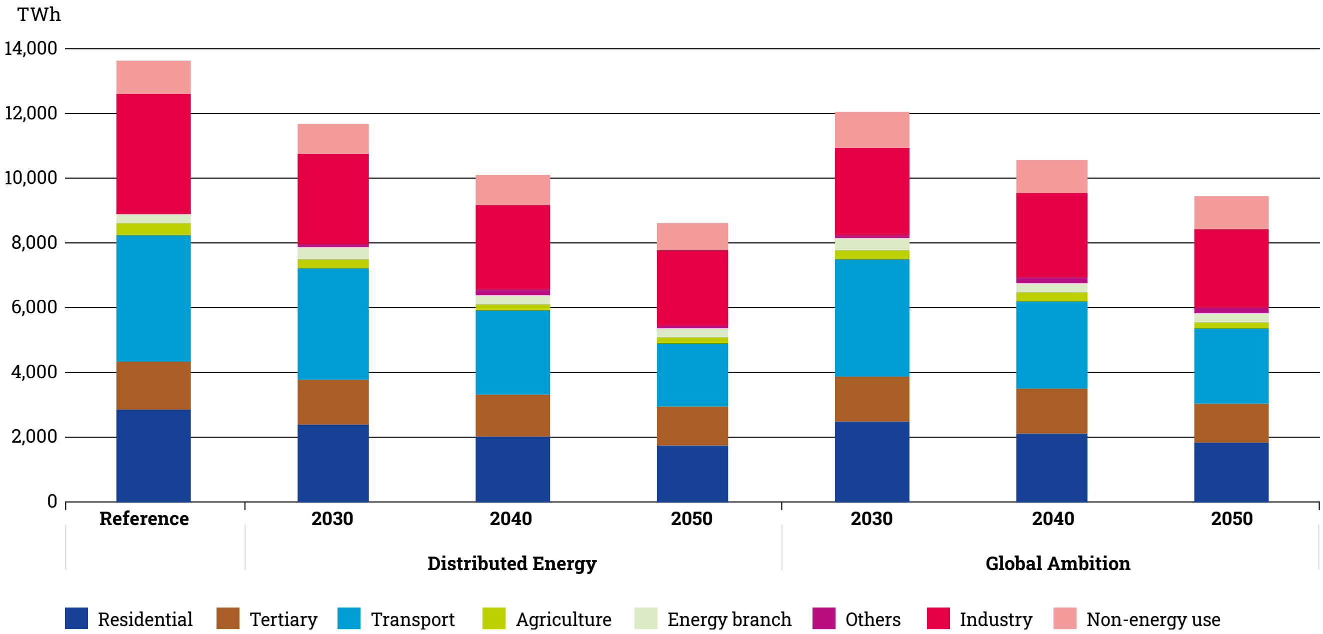

Figure 6: Exemplary results from the Ambition Tool: total sectorial energy demand

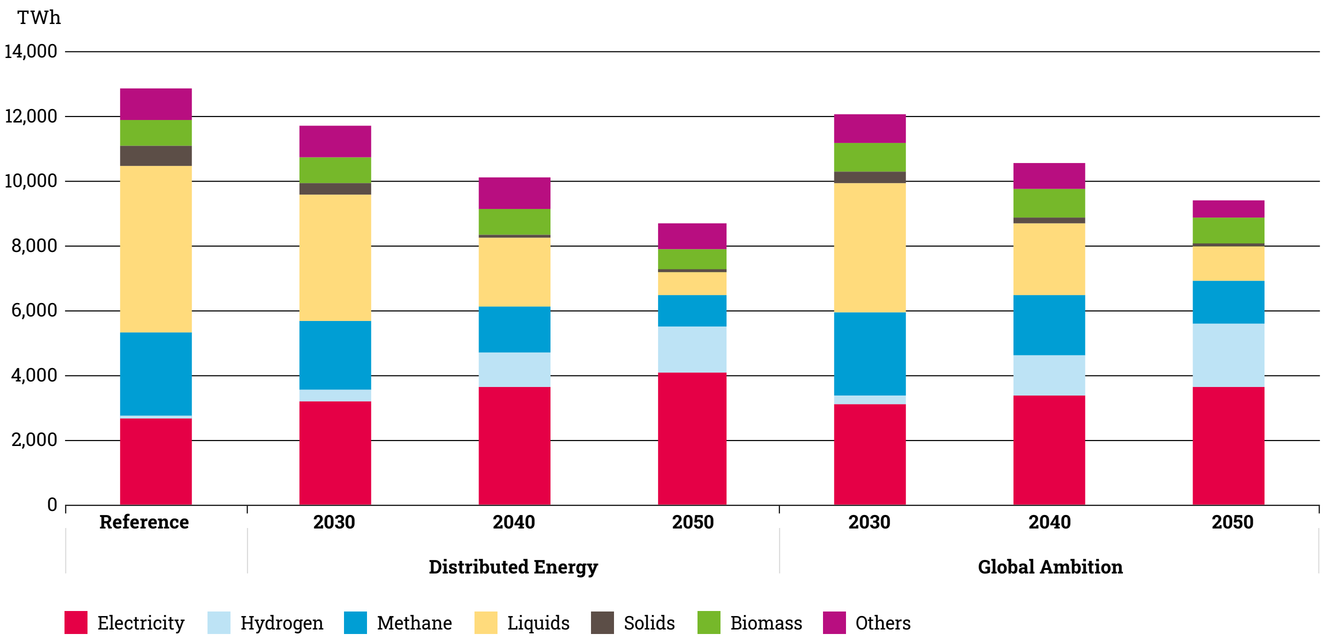

Figure 7: Exemplary results from the Ambition Tool: total demand per energy

1 The POTEnCIA Central scenario: an EU energy outlook to 2050: https://publications.jrc.ec.europa.eu/repository/handle/JRC123198. An exception was made for the EV efficiencies, which are based on "EU road vehicle energy consumption and CO_2 emissions by 2050 – Expert-based scenarios, Energy Policy, volume 138, 2020" : https://doi.org/10.1016/j.enpol.2019.111224.

In the data processing part, the input assumptions are per end-user sector and in several calculation steps translated to energy consumption volumes. Common starting point for each country is a description of historic[2] use of energy ("energy flows") which is in the following steps adjusted according to the user selected parameters. As an example, the assumption of higher market shares of electric vehicles will result in an increasing electrical and decreasing oil demand in the transport sector[3], taking into account the higher efficiency of electric motors compared to traditional combustion engines.

In the output part of the tool the calculation results are per (sub)sector and energy carrier gathered in a uniform structure and visualized in the form of different infographics to support validation and benchmarking against other European scenarios. Figure 6 and Figure 7 show in an exemplary way the development of the total sectoral energy demand and the demand per energy carrier respectively. In addition, data from the processing and output part of the Ambition Tool is converted to specific formats which are needed to feed the subsequent methodological steps (e. g., TRAPUNTA tool to generate load time series, see Appendix VI, section A(ii)).

2.2.2 Electricity profile building process: Trapunta tool

In this paragraph the steps are presented to use TRAPUNTA and to define the hourly electricity demand profiles for each market area, each scenario and each target year. The use of TRAPUNTA involves three main phases that are accomplished by the three main functions of the tool, as illustrated in Figure 8.

Step 1	Step 2	Step 3	Step 4	Step 5
Install TRAPUNTA	Download country folder structure & country trained TRAPUNTA models from WG D&M	Download and install: PECD data EV profiles Holiday profile	Use the latest Ambition Tool files Rename into convention PEMMDB-[xx]_{storylinename}	Run TRAPUNTA to create the output: Hourly demand profiles

Figure 8: Electricity demand profile building steps

Phase 1: The creation of the forecast model

This is the first step of the methodology for the electric load prediction. It consists of creating a regression model able to explain the correlations between the electrical load and the climatic variables present in the Pan European Climate Database (PECD, see Appendix VII for more information) For example population weighted temperature, city temperature, irradiance, wind speed, humidity, etc. The model is based on a training set of information, i.e., the electrical load and climatic variables time series. Since the regression is created based on this data, it should be representative of the market situation the user wants to simulate.

Phase 2: The creation of a normalised year

This function allows the user to create a normalised year for the different climatic variables. It could be used as input during the prediction of the electrical load. The normalised year is the mean value of the time series for a given climatic variable.

Phase 3: The computation of the scenario year

The computation of the electrical load with the application of the forecast model to a future (or the normalised) year and the load adjustment for market evolution.

This function is the final aim of TRAPUNTA, and the step used by WGSB to build the demand projections for each scenario and climate year. Starting from the information on the climatic variables (as normalised year or generic data) and the forecast model developed at the first step, the tool will provide the user with a prediction of the electrical load for future years characterised by the climatic variables given as input.

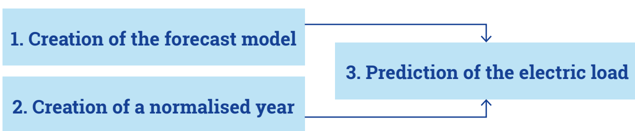

Figure 9: The 3-step TRAPUNTA process

2 For residential and tertiary sectors the historic values are based on 2018. For the other sectors (industry, agriculture, energy branch, mobility) 2015 values are the most recent with sufficient level of detail.

3 Assuming that the kilometres driven remain comparable to today's level

The latest version of the software (TRAPUNTA XL) is able to run a single simulation (with detailed information useful to investigate the effectiveness of the created model) or a "loop" of simulations simultaneously including all the climate years for all of the market zones, all scenarios and all target years.

2.2.3 Building of the energy demand overview

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 Ambition Tool is at the core of this quantification ensuring the translation of storylines into quantified demand scenarios taking into account 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 purpose.

For this purpose, profiling tools are used for all sectors except district heating for space and water heating in the residential and tertiary sectors (see Appendix I for more detailed information). Trapunta is the tool used for all countries with the exception of Poland and France where TSOs use their own tool to create the hourly profiles, in consistency with national developments.

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.

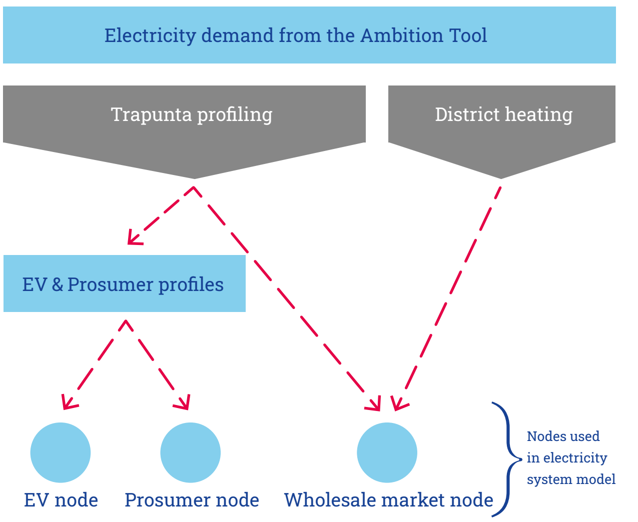

Figure 10: From the Ambition Tool to the hourly electricity load in every node of the electricity system model

The profile of electric heat-pumps on district heating network are defined separately (Appendix I for more details) before being added to the electricity wholesale market node of the electricity and hydrogen model.

2.2.4 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.

2.2.5. Building of the supply overview

From the aforementioned energy demand overview, the annual volume of each energy carrier (except electricity as power generation result from expansion modelling) is split between its different sources of supply and imports.

As methane demand and hydrogen production are dependent from the electricity and hydrogen modelling, it is necessary to make some preliminary assumptions on:

- the amount of gas to be consumed for power generation on the basis of TYNDP 2020 scenarios;
- the share of hydrogen to be supplied by European electrolysis.

These two parameters will be adjusted on the basis of the electricity and hydrogen modelling results.

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. As hydrogen is mostly used in the industrial and heavy mobility sectors, a flat hourly profile is assumed for modelling purpose.

2.2.6 Electricity and hydrogen expansion model

Using the electricity and hydrogen demand profiles defined in the previous step, 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.

In order 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 a particular transmission need or the identification of a project 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[4]" 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.

2.2.7 SoS script

Compared to the draft scenarios, a security of supply step has been added at the end of the modelling process in order to ensure an adequacy level close to the current level for all three TYNDP 2022 weather years. The script results in additional gas peaking units and batteries which are then taken into account in the dispatch modelling.

The additional peaking unit and battery capacity is defined at country level as described below:

1. For each climatic year the hourly unserved energy is calculated for the wholesale market, prosumer and EV node

2. For each climatic year and each country, up to 4 hours of highest unserved energy are ignored. The unserved energy in hour 5, is used to define the capacity of the new peaking unit that is then dimensioned to ensure a maximum of 4 hours of load loss. The highest capacity from the 3 possible climate years is chosen, and implemented in the model.

3. Battery capacity is defined as the difference between the highest unserved energy of the above period and the peaking unit capacity just defined

4. After having run the dispatch model, peaking unit capacity is decreased at their maximum hourly production.

5. For each country, if required peaker capacity X_N at the time horizon N (e.g. 2050) is lower than X_{N-1} at the horizon N-1 (e.g. 2040), X_N is set at X_{N-1} level.

2.2.8 Adaptation of the gas supply overview

Based on the expansion model and associated dispatch results, it is needed to adjust the preliminary assumptions related to gas demand for power generation and volume of hydrogen to be produced by electrolysis. Several modelling iterations were run to arrive at the final scenario results.

2.2.9 GHG emission accounting

CO_2 emissions are calculated based on the annual consumption of each primary fuel (being produced in Europe or imported) taking into account their specific emission factor. Non-CO_2 emissions are derived from EC Impact Assessment scenarios.

As each scenario is defined along a pathway from 2022 to 2050, it is possible to calculate the GHG emission for every year and thus evaluate their carbon budget.

2.2.10 Approval of Scenarios

When the scenarios are drafted, they are checked for possible technical errors, and to ensure that the scenarios live up to their purpose from the scenario storyline report. The scenarios are then approved, first by the WGSB, then by the Scenario Steering Group and finally by ENTSOG and ENTSO-E respectively. The purpose of the approval process is to align and correct both technical errors, and to ensure that the scenarios are consistent with other work done within ENTSOG and ENTSO-E before publication for consultation.

4 For more information about the Identification of System Needs study please see: https://tyndp.entsoe.eu/system-needs/

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 in order to capture its dynamics. It is particularly important when the energy transition results into a stronger influence of climatic parameters on the operation of the electricity system due to the development of electricity 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 system has two functional requirements:

- Defining the dispatch of electricity based on a pre-defined level of infrastructure (generation, flexibility and grid) and taking into account commodity prices -> Dispatch model;

- Identifying the infrastructures to be built on top of pre-defined infrastructure taking into account the evolution of electricity demand and commodity prices -> Expansion model.

3.1 Basic principles of Dispatch Model

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

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

Figure 11: Objective function for the dispatch model optimisation (variable costs of the electricity system)

In such an approach the level of resilience of the system is ensured through a monetised Value of Lost Load (VOLL) parameter rather than a technical Loss of Load Expectation (LOLE).

National Trends is based on a wide range of dispatch modelling tools, for example Plexos, Antares, PowerSym, Promed, BID3 and APG. 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 demand, different electricity system (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 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 inclusion of thermal fleet decommissioning is an improvement compared to previous edition when the thermal fleet capacity was defined ex-ante and kept constant across both the time horizon for both scenarios.

The tool then runs an optimisation of the overall system to identify investment candidates using a Benders'-decomposition[5] method with the energy dispatch as a sub-problem. The aim is to minimise the following objective function below along the time horizon. Dispatch results at the end of the time horizon are repeated for candidates which economic lifetime exceeds the modelled time horizon.

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

Figure 12: Objective function for the expansion model optimisation

5 Large-scale power system planning using enhanced Benders decomposition,IEEE Conference Publication, IEEE Xplore, https://ieeexplore.ieee.org/document/7038297

The reduction of CO_2 emissions is ensured through the combination of RES development (minimum trajectory and decreasing cost) and 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 being run on several climatic years, the investment candidates are selected in order to minimise the objective function for the weighted sum of these climatic years. Weights are used to ensure the representativeness of the combination of climatic years, as detailed in Section 4.1.

Draft TYNDP 2022 Distributed Energy and Global Ambition scenarios have been modelled using the expansion functionality of the Plexos (LT Plan) tool[6]. National Trends (time horizon 2040) will use the expansion functionality of Antares (Xpansion). Previous edition has shown a very close alignment between Plexos and Antares[7] modelling tools with a R^2 of 0.99[8].

3.3 Single Time Horizon vs. Multi-temporal Approaches

Taking into account the strong need of evolution of the energy system for the decades ahead, a multi-temporal approach has been used for this edition. It means that when selecting investment candidates at a given moment in time (e.g., 2030), the tool has a certain degree of visibility on the evolution still required (e.g., increasing carbon price and electricity demand up to 2037). It helps the model to decide at the best moment when to invest (or disinvest) compared to previous edition where the model only had visibility on the year of commissioning.

3.3.1 2020 Edition Methodology: Single Time Horizon

In the last edition, investment candidates were decided every five years having visibility only on the assessed year. Such an approach has three drawbacks:

- Investment decisions on year n were taken as if the rest of the time horizon will stay the same (e.g., flat electricity demand and carbon price);
- Lengthy iterative process: the starting grid for the selection of investment candidates on year n had to be manually updated using the selected candidates resulting from the assessment of year n-5;
- Expansion model was run only every five years due to the iterative process providing less information on the (dis)investment curve.

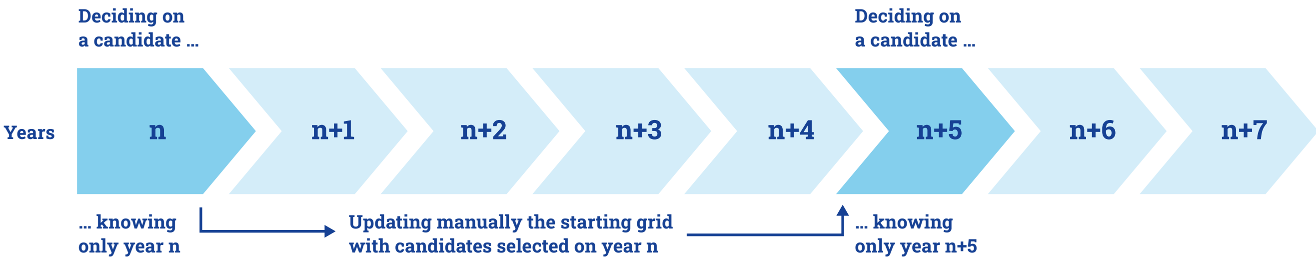

Figure 13: Single time horizon approach

6 PLEXOS Market Simulation Software, Energy Exemplar, https://energyexemplar.com/solutions/plexos/

7 https://antares-simulator.org/

8 TYNDP 2020 Scenario Building Guidelines chapter 6.2.1 see also https://2020.entsos-tyndp-scenarios.eu/wp-content/uploads/2020/06/TYNDP_2020_Scenario_Building_Guidelines_Final_Report.pdf

3.3.2 2022 edition methodology for Distributed Energy and Global Ambition: multi-temporal

To improve the expansion model compared to the last edition, 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, induce a computation load too large for present commercial modelling tool. For this reason, it is necessary to cluster the overall mathematical problem into sub-horizons. Taking into account the calculation capacity and the project timeline, the 25 years have been split into 8 sub-time horizons with a 2-year overlap:

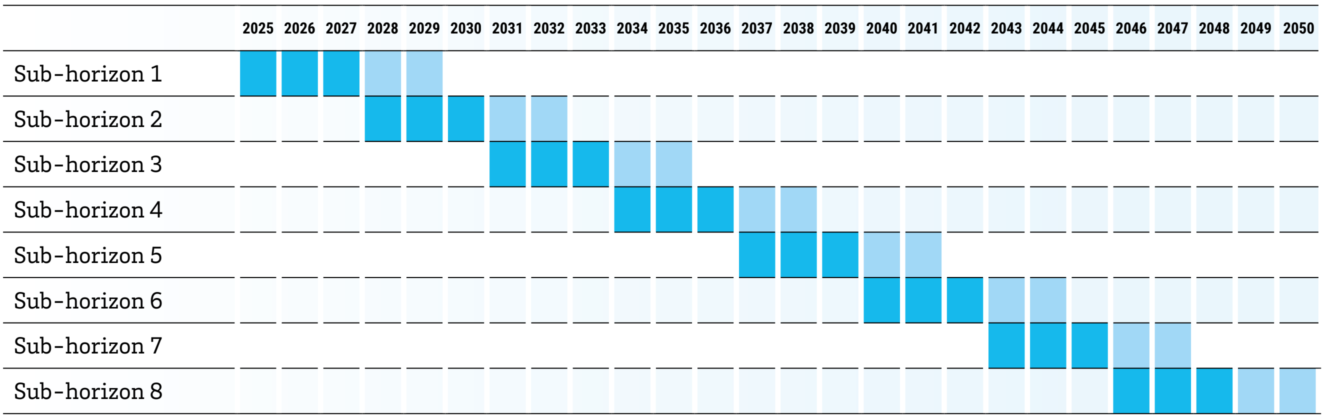

Figure 14: Sub-horizons clustering

The overlap enables 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:

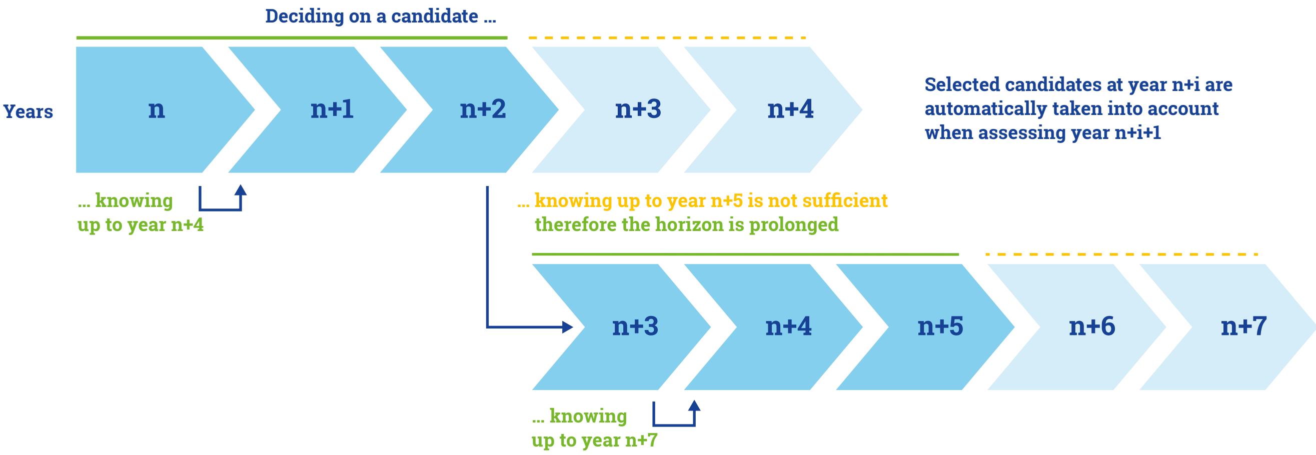

Figure 15: Multitemporal approach with sub horizons clustering

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.

4 Overview of modelling parameters of the COP21 scenarios

For Distributed Energy and Global Ambition, the expansion modelling aim at buildbuilding the power generation and P2G capacity mix in terms of level and location.

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

Building block		Distributed Energy & Global Ambition
Time horizon		2030, 2040 and 2050
Climatic years		Expansion Model – 2009; Dispatch – 1995, 2008, 2009; For the weights of climatic years, please see Section 4.1
Adequacy		VOLL: 10 k €/MWh for the electricity and hydrogen. SoS script ensuring each country ENS ≤ 4 hr
Commodity prices		Scenario specific. Please see Appendix VIII
Sector coupling modelling • Power-to-gas • EV/Prosumer • District heating		 • Four P2G configurations • Yes • Embedded in electricity load profile
Starting grid		TYNDP 2020 Reference Grid for 2025 Time Horizon has been updated by the TSOs to reach the best estimates in terms of infrastructure development for the given time horizon
Predefined capacity at time horizon		• Hydro • Nuclear • Solar thermal • Marine • H_2 storages • Electrolyser Capacity (config 1 & 2) • Batteries
Investment candidates:	NTC	Based on investment candidates of the NT 2040 IoSN of TYNDP 2022
	Generation	Onshore wind (wholesale market and dedicated for P2G) Offshore wind (wholesale market and dedicated for P2G) PV (wholesale market, prosumer and dedicated for P2G) CCGT (methane, hydrogen) Hydrogen salt cavern storage (hydrogen config 4)
	P2G	Yes, separately for each P2G configuration
	H2 grid	Retrofit methane pipeline Newly built pipeline
Decommissioning candidate:	Generation	Thermal units
Must-runs		Removed after 2030*

* Minimum supply profile has been kept for other Non RES in order to translate CHP operation.

Table 4: Modelling parameters

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

4.1 Climatic Years

The number of climatic years taken into account by the expansion model strongly influence the computation time. It is therefore necessary to select a limited combination of years while ensuring the representativeness of the climatic variability of the last 30 years. A statistical analysis performed on the last 35 years have helped to identify the most representative combinations of years.

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

- 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 climatic conditions;

- Compute delta indicators to assess how years compare to the 30-year average on a regional level;

- Selection of most representative combination of three years for the study

The weights are calculated based on the Pan European Climate Database (PECD, see Appendix VII for more information) according to their representativeness in terms of the solar infeed, wind infeed, hydro inflows and load parameters.

For Distributed Energy and Global Ambition, the computation time is very high due to the time horizon (25 years), sector coupling (combined H_2 and electricity modelling) and number of investment candidates. As priority has been given to an early release of the Draft Scenario Report, expansion modelling is run only on the most representative year (2009).

For National Trends, the reduced computation load enables the use of a wider climatic year panel. The selected years and associated weights (between brackets) are as follow: 1995 (23 %), 2008 (37 %) and 2009 (40 %).

It has to be noted that 2009 ranks at the second most stressful climatic year in terms of 2-week Dunkelflaute situation (see also Appendix V) at European aggregated level after 2012.

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 in order to avoid undue "non-served energy" of a given carrier. For this reason, the VOLL of hydrogen has been established at a parity level with electricity taking into account the efficiency of electrolysers.

4.3 Commodity prices and emission factors

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 emission factors are derived from JRC[9] and summarised below.

Fuel	Emission
Oil	0.267
Solids	0.354
Primary	0
Biogasoline	0
Other	0
Biomethane	0
Natural gas	0.202
Biomethane	0
Decarbonised hydrogen imports and European SMR/ATR with CCS*	0.0262
Hydrogen from electrolysis	Accounted as part of the power generation mix emission
Renewable hydrogen imports	0

* 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.

Table 5: Emission factor of fuels

9 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, http://publications.jrc.ec.europa.eu/repository/bitstream/JRC107518/jrc_technical_reports_-_com_default_emission_factors-2017.pdf

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.

Some 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 6 and Table 7 provide an overview of such prices.

€/GJ	2025	2030	2040	2050
Nuclear	0.47			
Biomethane	23.89	20.74	16.94	13.97
Shale oil	1.56	1.86	2.71	3.93
Lignite:				
– Group 1 (BG, MK and CZ)	1.40			
– Group 2 (SK, DE, RS, PL, ME, UK, IE and BA)	1.80			
– Group 3 (SI, RO and HU)	2.37			
– Group 4 (GR and TR)	3.10			

Table 6: Fuel prices common to all scenarios

Other commodities have a price depending either on the global energy context (natural gas, oil, coal) or European regulation (CO_2). As scenarios reflect different European and global storylines, it is necessary to define prices reflecting their respective storyline. More details on the methodology used to define commodity prices can be found under Appendix VIII.

	Unit	Scenarios	2025	2030	2040	2050
CO_2	€/tonne	NT	40	70	90	N.a.
		DE & GA	40	78	123	168
Hard coal	€/GJ	NT	2.30	2.48	2.41	N.a.
		DE & GA	2.30	1.97	1.92	1.87
Light oil		NT	12.87	13.78	15.41	N.a.
		DE & GA	12.87	10.09	9.61	9.12
Natural gas		NT	5.57	6.23	6.90	N.a.
		DE & GA	5.57	4.02	4.07	4.07
Biomethane		NT	23.89	20.74	16.94	N.a.
		DE & GA	23.89	20.74	16.94	13.97
Synthetic methane		NT	26.97	28.09	23.35	N.a.
		DE & GA	26.97	28.96	23.35	18.09
Renewable H2 imports		NT	Na	20.25	16.08	N.a.
		DE & GA	Na	20.63	16.08	12.52
Decarbonised H2 imports		NT	19.05	20.25	16.08	N.a.
		DE & GA	19.05	17.11	17.55	17.91

Table 7: Fuel and CO_2 prices per scenario and horizon

4.4 Sector coupling modelling

The operation and the evolution of the electricity system will increasingly depend on 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:

- **Electrolysers:** up to 4 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. A detailed description of electrolyser modelling can be found in Appendix III.

- **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 Appendix II.

- **District heating:** the combination of different heat supply and flexibility sources on a network enables an optimized 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. A detailed description of district heating modelling can be found in Appendix I.

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 Power-to-gas is modelled along two configurations which capacity is defined as part of the TSO data collection:

- Using Configuration 3 where the SMR/ATR is used as a generic back up at a price equivalent to decarbonised hydrogen. See Appendix III, section D(iii) for more information.

- Using dedicated RES and modelled out of the electricity market.

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 2025. It uses the 2025 time horizon of the TYNDP 2020 as a reference with some NTC updated taking into account the latest development in interconnection projects as seen early spring 2021.

4.6 Predefined capacity level

Distributed Energy and Global Ambition generation fleets will mostly differ in terms of wind, solar and nuclear capacity. The first two RES sources will result from the expansion model while nuclear is defined ex-ante based on range in the Final Storyline Report[10] of each scenario in order 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 data collection as stated in Table 8.

10 https://2022.entsos-tyndp-scenarios.eu/#download

Technology	2030	2040	2050
Wind and Solar	Defined by the expansion model based on 2025 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 2030	National Trends 2040	
Thermal	National Trends 2030	National Trends 2040	Nation Trends 2040, while considering expected decommissions after 2040
Battery – Prosumer	Up to 25 % of rooftop solar capacity		
Battery – Utility scale	Up to 25 % of market battery capacity		
Battery – V2G	Distributed Energy: up to 26 % of passenger vehicles Global Ambition: up to 11 % of passenger vehicles		

Table 8: Starting generation and battery capacity for Distributed Energy and Global Ambition scenarios

National Trends generation fleet is defined according to the TSO data collection for 2040 in order to picture national strategies and policies. As the expansion model is only run to ensure the scenario adequacy and in order not to overestimate flexible generation, CCGT and OCGT predefined capacity for 2040 is set at National Trends 2030 level. Capacity development of such technologies beyond 2030 are then subject to the expansion model.

The capacity of hydrogen storages (steel tanks and salt caverns) has been defined ex-ante.

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), flexibility sources (e.g. gas-fired thermal units), conversion facilities (electrolysers), power and hydrogen interconnections. Interconnection candidates enable a meaningful location of other candidates and do not intend to identify any investment gap.

RES candidates

They can be installed in different nodes of the system depending on its needs (electricity mix decarbonation, minimisation of the prosumer connection to the grid, hydrogen production, etc …). The expansion model will then select the best technology based on their cost and the specific need of each configuration. Table 9 describes the possible locations for wind and solar.

Technology	Transmission	Prosumer	EV node	P2G config. 1 & 4
Wind (onshore & offshore)	X			X
Solar	X (PV farm)	X (Rooftop PV)		X

Table 9: Location of RES investment candidates for distributed energy and global ambition

Each investment candidate is defined by a set of parameters taken into account by the expansion model to select them. Candidates are defined for each zone (and interconnection 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
- Maximum building rate by year
- CAPEX
- Fixed OPEX
- Variable OPEX
- Economic lifetime
- Weighted average cost of capital (WACC)
- Build-out rate as the maximum capacity that can be built in one year

In order to capture uncertainty on RES development and the challenge to maximise their development, the maximum trajectory has been broken down into 3 steps of increasing CAPEX. Such cost increase intends to capture both environmental and technology factors such as floating offshore wind which are not explicitly differentiated from fixed offshore turbine. In order to both reflect country specifics and some basic homogeneity in terms of RES ambition between countries, the capacity level of each steps combine TSOs data (Max and Push levels) and third party studies (3° Party Study[11]).

Potential	Capacity potential	CAPEX/OPEX premium
Level 1	Minimum (Max ; Level 2)	0 %
Level 2	Average (Max; 3rd Party Study)	+25 % for onshore wind and +100 % for PV and offshore wind
Level 3	Maximum [Level 2 ; Minimum (Push ; Max x AF)]	+50 % for onshore wind, +200 % for PV and +300 % for offshore wind

AF is an Ambition Factor used to match Final Storyline report upper ranges and capturing the potential easier expansion of Solar PV compared to wind and especially Rooftop PV which could be embedded in new buildings. As a result, AF equals 1.33 for onshore and offshore wind, 2 for PV Farm and 3 for Rooftop PV.For technologies strongly dependent on scenario storylines, CAPEX and OPEX are differentiated between scenarios in order to reflect the higher innovation and cost reduction associated with technology predominance.

The parameters of the investment candidates for the Level 1 of capacity potential can be found under Appendix IV.

Cross-border candidates

Investment candidates for electricity cross-border interconnection are based on the project collected within the framework of the Identification of System Need (IoSN) of National Trends 2040 to be published in spring 2022. In order to cover the 2050 time horizon, some additional projects have been added at the borders where projects exist. Those projects have an increased cost to picture the growing need of internal reinforcement.

It has to be noted that no IC investment candidateshave been considered on the links between internal bidding zones of a given country (e.g. Italy). As a result, both the location of new RES capacity and the dispatch can be suboptimal.

Candidates for hydrogen cross-border capacity are defines under Appendix III.C.iv.

Electrolyser candidates

The design of the electrolyser of configurations 1, 4 and 5 is part of the expansion model. For configuration 2 and 3, the electrolyser capacity is predefined by the hydrogen demand and H2 tank design (configuration 2).

The cost parameters of electrolyser candidates are defined under Appendix III.C.i.

4.8 Disinvestment options

For Distributed Energy and Global Ambition scenarios, the strong development of RES technologies and the sharp increase in CO_2 cost will strongly impact the economic viability of thermal units. Such situation is anticipated through the predefined decreased of thermal generation capacity. In addition, the expansion model has the ability to decide to decommission other thermal units when the electricity price is not sufficient to balance fixed costs.

4.9 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 the decarbonization on 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.

11 For Offshore wind, Wind Europe – Our Energy, our future completed with Mediterranean offshore strategy from Guidehouse for EC and World bank. For Onshore wind and Solar PV, LIMES-EU, P. Nahmmacher (p 21) together with Mediterranean offshore strategy from Guidehouse for EC

Appendix

Appendix I: District heating supply

District heating combines on a single network several heat sources. They are usually utility-scale equivalents of technologies that can be installed at household level (e.g., gas/biomass boilers, heat pumps, etc.). Their combination with some form of thermal storage, being the inertia of the network or dedicated assets, provides both flexibility in the design and operation of heat sources. In addition, such network can use residual heat from some industrial processes participating to the energy efficiency and circularity driver of the scenarios, especially for Distributed Energy.

In order to capture such district heating specifics, ENTSO-E and ENTSOG have initiated a cooperation with some district heating stakeholders in order to provide some first insights on how electricity, gas and heat networks can be smartly combined. For this edition, the aim is to define the electricity load of district heating heat pumps as an input to electricity modelling. An algorithm has been defined to define their capacity and electricity profile taking into account other heat sources and climatic impact on space-heating demand and the Coefficient of Performance (COP) of heat pumps. Defining heat to be supplied

District heating market share in space and water-heating is derived from the Ambition Tool (see Section 2.2.1) for each scenario, country, and time horizon. The TRAPUNTA profile for temperature dependent demand is used for space-heating while a flat profile is used for water-heating. See also Appendix VI, section A(ii) for more information

Heat losses at network level are assumed to account for 5 % of the heat demand.

TYNDP Scenarios have a country/bidding-zone granularity requiring an aggregated approach of district heating. Thermal storage is captured through a 12-hour moving averaging of heat demand. It may be optimistic for very large cities having reduced storage ability but conservative for smaller networks equipped with seasonal thermal storage.

A Building heat supply

The Ambition Tool (see Section 2.2.1) provides the annual share of each fuel in heat generation for district heating. It covers thermal generation (gas, oil, coal and biomass) as well as heat pumps. The aforementioned 5 % heat losses are compensated with the use of recovered heat from the industrial sector.

As district heating networks are designed for baseload, for the heat production the share of CHP is set as the minimum between:

- 80 % of the fuel consumption as defined in the Ambition Tool (see Section 2.2.1)

- The annual heat generation corresponding to electricity must-run of thermal units

For each fuel, the rest of heat generation is ensured by boilers.

Finally heat pump capacity is set at a level ensuring that their heat output on an average climatic year reflect their share as resulting from the Ambition Tool while giving them dispatch priority over boilers.

B Extracting heat pump load profile

The heat pump dispatch is then translated into an electricity load using the temperature-depend COP curve for each hour of the climatic year.

Figure 16 illustrates the difference of electricity load profile between individual and district heating heat pumps. It shows how the latter have a lower capacity design for a given yearly electricity consumption, because peak demand is provided by back-up boilers.

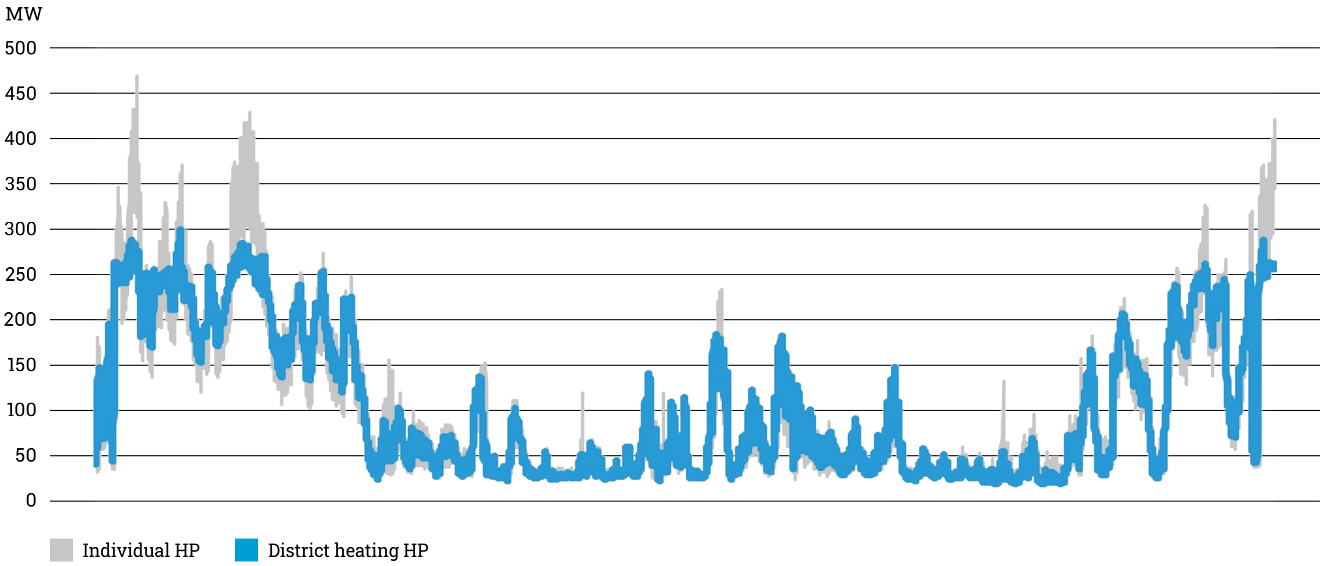

Figure 16: Comparison of all electric individual and district heating heat pump load profile (indicative data)

Appendix II: Prosumer and EV Modelling

As illustrated in Figure 17, the overall approach is to split each EU27 bidding zone of the model into three nodes (except for very small countries 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 in order to minimise their energy bill (including distribution costs)

- Electric Vehicle Node (EV Node): charging strategy will be impacted by mobility need and consumer's will to participate in the energy market.

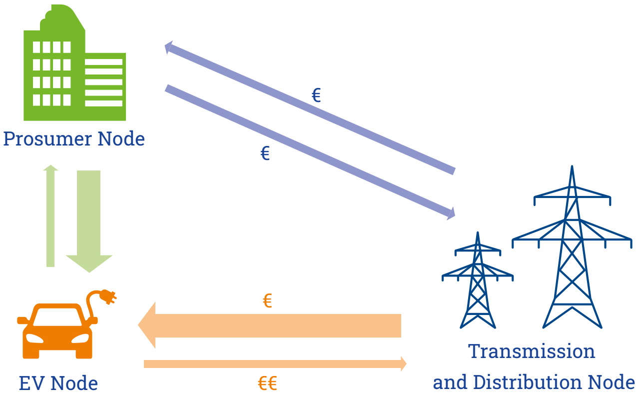

Figure 17: Nodes split: transmission and ristribution, EV and Prosumer nodes

A Prosumer Node

As can be seen in the illustration, there is a connection between the Electricity market and the Prosumer Node. A capacity/energy delivery cost will be attached to this connection. This cost is set to 54 €/MWh in TYNDP 2022 scenarios[12], based on European average derived from EC materials[13]. It is used to reflect the additional tariffs involved in supplying energy from the electricity market to the residential and tertiary buildings (excluding taxes). This cost will be used in the expansion process to determine how much rooftop solar and batteries will be installed in the Prosumer Node, reflecting that residential consumers invest in and operate their local assets in order to minimise their own energy bill. 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.

B EV Node

In addition, the EV Node is connected to both the Prosumer Node and Electricity market Nodes. Within the Scenario Building modelling exercise, the EVs are modelled as a battery storage. The EV demand profile represents the driving profile of passenger vehicles, i.e., the electricity demand of the EV motor when it provides energy to the driveshaft. Electricity will be supplied to the batteries in the EV Node at the market price. Energy supply from the EV to the Prosumer Node is at no cost (cost is already covered from the charging). To reflect the cost of vehicle-to-grid technology (V2G), an activation price is set at 30 €/MWh.[14] There is an extra tariff if V2G is supplied to the market resulting from the retail tariff. The storage capacity and instantaneous power in the EV Node is determined by the amount of EVs available in each country. Availability profiles must also be added between the nodes connecting to the EV node to consider what infrastructure the EVs are connected to at each hour and the types of charging technology available. In residential homes, the EVs are connected to the onboard chargers, which we assume has a capacity of 7.7 kW, this means users can charge EVs from the mains, supplying around 3.3 kW or use a wall charger supplying up to 11 kW, but still limited by the 7.7 kW onboard charger. We average these charging sources to give a capacity of 5 kW. The fast chargers which will typically come from street chargers, which can connect directly to the DC battery in the EV, therefore for the capacity connected to the market node is up to 40 kW, based on various EV technologies.

The concept of the availability profile is, an EV cannot simultaneously be connected to a residential property and a street charger. The availability of charging will add up to a sum of 100 % for each hour split between the prosumer connection[15] and the E-market connection. The share of EV participating to V2g services depends on the storyline. With higher prosumer involvement the share of V2g reaches 26 % in Distributed Energy and 11 % in Global Ambition. Such ratios are derived from National Grid FES 2021 scenarios. The scenario 'Leading The Way' is used as a proxy for Distributed Energy and the scenario 'System Transformation' is used as a proxy for Global Ambition. A minimum state of charge of 50 % is assigned to all EV's. This ensures that if the EVs are used for V2G, the system does not exhaust the batteries below a certain level.

C 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 (100 €/MWh in 2050)
- Utility-scale batteries (3 h 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 stream of water, but where water can be circulated between 2 reservoirs of different heights).

12 It is uncertain whether in the long run a energy price is more appropriate than an capacity price. It is possible that countries will move towards a more cost-based capacity-tariff, which will alter the signal to the prosumer from limiting energy pull from the grid. The chosen approach is a first try in trying to reflect this prosumer dynamics and its effect towards the transmission grid.

13 https://eur-lex.europa.eu/legal-content/EN/TXT/?qid=1602774170631&uri=CELEX:52020DC0951

14 https://iopscience.iop.org/article/10.1088/1748-9326/ab5e6b

15 The modelling considers that EVs are not connected all the time, for example while driving.

Appendix III: P2G modelling methodology

A Introduction

The purpose of this chapter is to introduce the modelling methodology of P2G used in the TYNDP 2022 scenarios. Firstly, 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 this is brought together in the individual P2G configurations used in the TYNDP 2022 scenarios. This chapter explains the operation of the P2G plants and the modelling methodologies. For information on how the system is build, see section 3.2 on Basic Principles of Expansion Model. For cost assumptions, see Appendix IV. The final capacities in each of the scenarios van 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 gasses of liquid fuels. The first step of the process, where hydrogen is produced is typically the most energy intensive, and here the operation on the electrolysers 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 2022 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. At this moment in time, hydrogen injection in the gas grid is in a pilot stage whereas synthetic methane can be fully injected. The permissible levels of hydrogen [injection into the gas grid] are typically set by national legislation and are currently up to 10 % (Germany). This source of renewable gas can be used to decarbonise 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 2022 scenarios has evolved dramatically compared to TYNDP 2020 Scenario Report where P2G was based only on curtailed electricity and the quantification of dedicated RES capacity to supply electrolysis-based hydrogen was considered outside the electricity market. There has been a large push, from both internal and external actors, to further develop the methodology with the purpose of taking the operation of P2G plants into account in the electricity market, and thereby explicitly modelling the different operational dynamics that are expected and the impact that they will have on the electricity market.

It should be noted, that there are large uncertainties in how future P2G plants will operate, and therefore how they should be modelled, as no major plants are in operation today. This uncertainty is reflected in the model, where a wider range of electrolyser configurations is modelled. They represent different levels of integration in the electricity and gas markets. In order to ensure meaningful interactions between electricity, hydrogen and methane systems, part of hydrogen infrastructure is modelled as well as some stand-alone P2G plants which do not interact with the hydrogen grid. The purpose of this approach is to reflect the correct dynamics towards the electricity market as well as investigating the benefits of a European hydrogen infrastructure from the standpoint of optimizing the European energy system with a holistic approach.

P2G modelling is at a juvenile stage on an international level, and very few European studies have dived into different modelling methodologies of P2G. The modelling methodology used in the TYNDP 2022 is one of the first attempts to tackle this challenge on a European level and has been based on interactions with European actors on hydrogen, as well as experts from various member states.

B Hydrogen Demand

The hydrogen demand that needs to be fulfilled in the modelling, consists both of direct and indirect hydrogen demand. The direct hydrogen demand accounts for the vast majority of the whole hydrogen demand.

The direct hydrogen demand is the demand for hydrogen as the energy carrier. This is most often used in industry, such as steel production, where current fuels like coal or 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.

The indirect hydrogen demand is the demand for other energy vectors, such as synthetic methane or synthetic liquid that has hydrogen as one of the main energy inputs – it is this input hydrogen, that is here defined as the indirect hydrogen demand. 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 or decentral, if there is an existing methane infrastructure like in biogas-upgrading facilities.

The total hydrogen demand modelled in the TYNDP 2022 scenarios is the sum of the direct and the indirect hydrogen demand and hydrogen demand for power generation. For more information on demand quantifications, see Section 2.2.1. It is assumed that the demand profile for hydrogen is a flat demand, as it is mostly used in large industries, both directly and indirectly.

C 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.

i Electrolysers

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

In the TYNDP 2022 process it is expected that all the technologies above will develop and that the European fleet of electrolysers will be a technological mix with alkaline electrolysers being dominant in the start, and in time PEM will see an increasing market share. Assumptions are shown in Table 10.

Technology	2020	2025	2030	2040	2050
Market share alkaline	90 %	90 %	77 %	51 %	25 %
Market share PEM	10 %	10 %	23 %	49 %	75 %

Table 10: Market share of european flee of electrolysers

In order 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 11.

		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 11: European electrolyser fleet efficiency and investment costs

The electrolysers are 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 electrolysers 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 electrolysers should be warm for stand-by.

The costs for the electrolysers, used in the investment loop, can be found in Appendix IV.

ii 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 CO2, the hydrogen produced by SMR and ATR is referred to as decarbonised hydrogen.

The SMR and ATR capacity currently installed in Europe can produce about 265 TWh/y[16]. Current SMR and ATR are an 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. 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 decarbonised hydrogen. As SMR and ATR plants are large scale facilities and a central point-source for CO_2 emissions, the European Hydrogen Strategy envisages that both technologies be retrofitted with CCS. It can be assumed that the current SMR and ATR facilities without CCS will be replaced by SMR+CSS and ATR+CCS facilities by 2030. Combining ATR with CCS shows a higher CO_2 capture rate (potential up to 95 %)[17] compared with SMR retrofitted with CCS (potential up to 90 %)[18]. Therefore, an overall average CO_2 capture potential rate of 90 % is used.

It is assumed that no new SMR and ATR plants will be built, so it is not an investment candidate in the investment loop. Depending on the scenario, the current SMR and ATR fleet will slowly be decommissioned (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 price for CCS and the CO_2 price for the residual CO_2 emissions. Based on the cost assumptions for commodities presented in Appendix VIII, and CAPEX and OPEX assumptions, the levelised cost of decarbonised Hydrogen (LCOH) was calculated, as presented in Table 12.

	2025	2030	2040	2050
Levelised cost of hydrogen [Euro/kg H_2]	2.29	2.05	2.11	2.15

Table 12: Levelised cost of decarbonised hydrogen

The decrease of the LCOH between 2025 and 2030 is mainly due to the drop of the estimated gas price used in the scenarios. Post 2030, the rapidly increasing CO_2 price dominating the overall price trend, driving the LCOH upwards again. The SMR and ATR plants are estimated to be fully flexible when hot, but due to the 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 is implemented in the model.

iii Extra EU-Imports

The assessment of the Extra EU-Imports taken into account for the P2G modelling are explained in Appendix IX, section A.

iv Hydrogen pipelines

Hydrogen infrastructure can be made, either by converting and repurposing existing methane grid or by building new and dedicated hydrogen infrastructure. As methane demand declines over time the utilization of existing methane infrastructure is expected to decline as well, which gives a potential for converting it to hydrogen. An indicative analysis of the possible speed and range of repurposing of the existing cross-border methane grid capacities was performed and consulted with gas TSOs as members of ENTSOG to confirm the potential conversion for modelling purpose. This indicative assessment shows the proportions of methane interconnectors that can be repurposed, as shown in Table 13.

	2030	2040	2050
Potential for repurposing of methane cross-border capacities	Up to 25 %	Up to 50 %	Up to 75 %

Table 13: Potentials for repurposing methane cross-border capacities

16 The 265 TWh are result of the assumption of 7,600 running hours for the SMR/ATR facilities multiplied with the capacity derived from of the estimated H_2 production provided by the Fuel Cells and Hydrogen Observatory, March 2020. The FCHO data is publicly available: https://www.fchobservatory.eu/observatory/technology-and-market/hydrogen-supply-capacity.

17 IFPEN and SINTEF. 20202. Hydrogen for Europe Final report of the pre-study. Available at: https://www.sintef.no/globalassets/sintef-energi/pdf/hydrogen-for-europe-pre-study-report-version-4_med-omslag-2020-03-17.pdf/

18 IEAGHG. 2017. Technical report 2017/02: Techno-economic evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS. Available at: https://ieaghg.org/exco_docs/2017-02.pdf

In parallel, the potential for building new hydrogen infrastructure has been assessed in cases where repurposing does not deliver the needed capacity. The boundary conditions and the potentials are based on experience from the methane grid, and it is determined to give the model the option to invest in up to 7,5 GW_{H2} per year per border.

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[19]. The costs used in the investment modelling are:

Type	Band	Capacity	Cost €/MW/km (until 2040)	Cost €/MW/km (from 2040)
Repurpose	1	Depending on the existing methane capacity	92	54
New Pipeline	2	Up to 13 GW	265	227

Table 14: Investment candidates for hydrogen infrastructure

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 in order to optimize the location of electricity production and electrolysers. 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.

v Hydrogen Storages

One of the main sources of flexibility in the hydrogen system, are the hydrogen storages. In the TYNDP 2022 scenarios, two different storage technologies are defined with different tasks assigned:

- Salt cavern storage: large scale storage option that is connected to the hydrogen grid in order 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 of time (up to 48 h), e.g., to avoid producing hydrogen during some hours with high electricity prices. No offer of security of supply.

vi Salt cavern

Salt caverns seems like one of the most promising storage technologies for large scale hydrogen storage and is 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. It is assumed that all salt cavern storage capacities can in time be converted, since there is still plenty aquifer storage capacity available for methane storage in the long term. Table 15 shows the salt cavern storage that can be converted to hydrogen storage as well as the resulting storage capacities that is available for modelling (same for DE and GA).

	2030	2040	2050
Conversion of current salt cavern storages (in %)	33	67	100
Hydrogen storage working gas volume (TWh_{NCV})	33.75	68.53	102.29

Table 15: Salt cavern storage conversion potentials for hydrogen in the investment loop

19 https://gasforclimate2050.eu/sdm_downloads/extending-the-european-hydrogen-backbone/

The costs for converting existing salt caverns from methane to hydrogen is expected to be in the range of 50 % of investment costs of a new built storage, as it is mostly the above-ground equipment that needs to be replaced or repurposed, resulting in a price of 167 €/MWh H_2 stored[20].

In the long term, other storage technologies, like aquifer storages, might prove feasible. As technologies develop and is proven, the TYNDP scenarios will in the future be updated to include these.

From a modelling standpoint, the flexibility from hydrogen storage is to be modelled as medium-long (days-months) term storage unit for the gas system, similar to the way that pumped hydro plants provide medium-long term flexibility for the electricity system.

vii 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. The 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 48 hours of hydrogen demand and be filled in 8 hours. This number was chosen based on experience from modelling and optimizing similar standalone systems from various TSOs, and is not an optimized 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, similar to the way that grid scale batteries short-medium term flexibility for the electricity system.

D The P2G configurations modelled in TYNDP 2022 scenarios

The future operation and configuration of P2G units, are still uncertain, which are the main drivers for developing and modelling P2G using a plurality of configurations in the TYNDP2022 scenarios. The main purpose of using different configurations is to reflect their distinct operational dynamics towards the electricity market. P2G is envisioned to be one of the main sources of demand side flexibility, and how that flexibility is activated depends on how the P2G is configured.

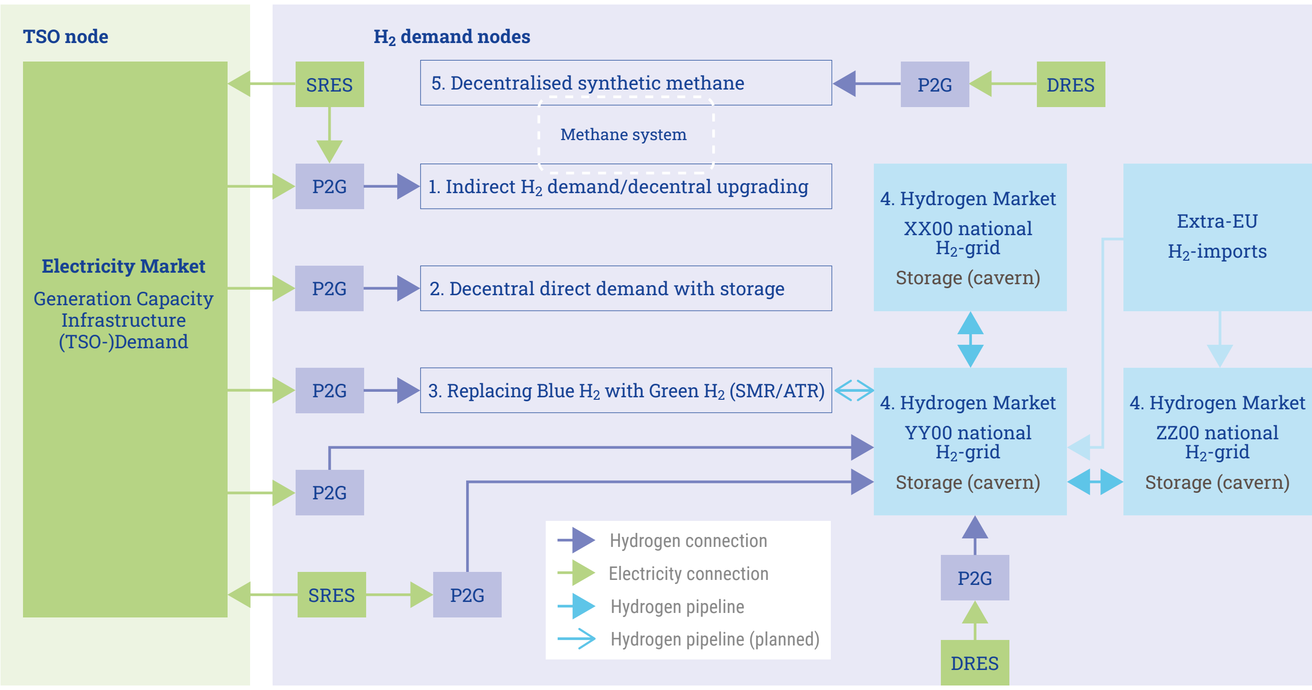

Figure 18: Modelling configurations for P2G and H_2-Grid in the TYNDP2022 scenarios

Figure 18 shows an overview of all the different modelling configurations for P2G and H_2 grid, which is used in the TYNDP 2022 scenarios. In general, it is seen that the H_2 demand is split into four different configurations, which each can be served with hydrogen, in their individual way depending on what plant type the configuration is reflect-

20 "Hydrogen generation in Europe: Overview of costs and key benefits (2020)" This study undertaken by Guidehouse and Tractebel estimates the investment cost for new salt cavern storages of 334 EUR / MWh H_2 stored. This value was then divided by two.

ing. The green box to the left is the "normal" electricity market node where a market clearing of electricity is done as usual. The four different configurations are in the model set up in each of their individual nodes and are assigned a specific hydrogen demand. This hydrogen can then be provided by different means, depending on the node, and flexibility can be provided in different ways to the different hydrogen nodes. In the following, each individual node will be elaborated.

i Configuration 1: Indirect H_2 demand for Decentralised upgrading facilities

The purpose of this configuration is to reflect plants that are Decentralised throughout Europe and that have a hydrogen demand that can be characterised as indirect hydrogen demand. This could typically be biogas plants producing a mix of methane and CO_2 through anaerobic digestion of biomass and/or farm waste. These plants will be in relative proximity to the locations where the biomass is available, as it can require a lot of resources to transport biomass for very long distances. To maximize value, the plants upgrade the raw biogas, which is typically containing in the range of 60 $\%_{vol}$ methane and 40 $\%_{vol}$ CO_2 instead of just flaring the CO_2 to the atmosphere.

Through synthesis of the CO_2 from the biogas and renewable H_2, the upgrading facility can either produce synthetic methane or synthetic fuels in processes like the Fisher-Tropsch.

The hydrogen can be produced with electricity from two different sources, either from electricity from shared renewable sources, noted SRES in the figure, or from electricity from the electricity market. Therefore, from an electricity market perspective there will be a pull for electricity that is inverse to the renewable production as the hydrogen demand must be met with either DRES or from the electricity market

In this configuration, the expansion model has the ability to invest in dedicated RES.

ii Configuration 2: Decentralised direct demand with storage

The purpose of this configuration is to reflect plants with a direct hydrogen consumption that has installed a system of Decentralised Pressurised hydrogen tanks in order to deliver flexibility for the demand. This configuration is meant to represent e.g. 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 build to decrease their carbon emission. Therefore, they install Pressurised hydrogen tanks to act as a buffer, so that they have room for optimizing 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 optimize 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 in order 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 decentralized pressurized hydrogen storage is defined ex ante to cover 48 hours of hydrogen demand.

iii Configuration 3: Complementing electrolysis with SMR/ATR

The purpose of this configuration is to reflect plants that currently have a hydrogen demand, which is served from sources like Steam Methane Reforming (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. To ensure security of supply, the plant, will keep their SMR/ATR plant in operation, and when electricity prices are too high to economically justify operation, the SMR/ATR will be used instead. Due to the fact that the hydrogen consumers in this category are already connected to the methane grid, and that 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 a simple cut-in/cut-out dynamics based on the price of hydrogen from the SMR/ATR plant. When renewable hydrogen is the cheapest alternative, it is prioritized, and when electricity prices rise, decarbonised hydrogen from the SMR/ATR is preferred. 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 has the ability to 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.

iv Configuration 4: 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 because hydrogen infrastructure is cost competitive to electricity infrastructure, it is concluded that much of Europe's hydrogen demand will be connected to the grid. This is in line with the perspectives seen in the European Hydrogen Backbone[21] study, and builds on the same principles.

In this configuration hydrogen can be produced from multiple sources. First, it can come from the interlinkage to configuration 3. Second it can come from extra EU imports via pipeline, see also Appendix IX, section A. Lastly, it can come from renewable hydrogen from various sources. The first source, 4.a, is an electrolyser that is grid connected. The second source, 4.b, are a dedicated feed-in-zone, where new build DRES is co-located with an electrolyser and partly connected to both the electricity and the hydrogen grid. This feed-in-zone approach is a key driver for co-location of RES and electrolyser as it has the potential to save costs on electricity infrastructure. The possibility to be partly connected to the electricity market, makes it possible for the plant to export valuable electricity to the market in low RES hours, and in high RES hours where electricity is plentiful, it can be converted directly to hydrogen , these RES sources are denoted as 'SRES' in figure 18. The last option for providing renewable hydrogen, 4.c, is by dedicated RES that is not connected to the electricity market, and could be in the form of new technologies like H_2-PV panels or H_2-wind turbines.

The flexibility in the hydrogen market comes from various sources as well. One of the largest sources for flexibility are the central salt cavern storages which are available for the hydrogen market, see section on salt cavern storage. The 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, similar to 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 has an excess or need for hydrogen.

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

v Configuration 5: Dedicated Renewables for Synthetic Methane Production

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 COP21 scenarios, the fuel which will be created is synthetic methane.

The synthetic methane demand is established on a EU27 level, which is distributed around Europe. The distribution is done through distribution keys, a method which uses multiple parameters to distribute demand between the 27 countries. The distribution keys used were Biomass potential (some synthetic fuel require biomass e.g., fischer trosphs process), Liquids Demand, Gas Demand, Hydrogen Demand. Each of those distribution keys are given a weighting which determines their influence.

Once the country level demand has been established, the renewables available after the market expansion and electrolysers are used as expansion candidates. The scenario-based technology costs are also considered.

Energy from the off-grid renewables flows uni-directionally to the electrolysers, where energy is converted to hydrogen. The hydrogen flows to a methanation plant where it is combined with CO2 to create synthetic methane. Once the methane has been created, the flexibilities of the gas system are made disposable. These flexibilities include gas storage and pipelines.

E 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 has to 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 the majority of demand over time will be moved to configuration 4 where it can be served from a market in order to exploit the benefits of an integrated and flexible hydrogen market. The total hydrogen demand is distributed in form of both direct and indirect hydrogen demand for the Distributed Energy and Global Ambition scenarios, as shown in Table 16 and Table 17.

21 https://gasforclimate2050.eu/wp-content/uploads/2021/06/European-Hydrogen-Backbone_April-2021_V3.pdf

Distributed Energy	2025	2030	2040	2050
Configuration 1:	50 % of indirect	50 % of indirect	50 % of indirect	50 % of indirect
Configuration 2:	25 % of direct	25 % of direct	20 % of direct	20 % of direct
Configuration 3:	50 % of direct	40 % of direct	10 % of direct	2 % of direct
Configuration 4:	25 % of direct	35 % of direct	70 % of direct	78 % of direct
	50 % of direct	50 % of direct	50 % of direct	50 % of direct

Table 16: Distribution of hydrogen demand across electrolysis configuration for Distributed Energy

Global Ambition	2025	2030	2040	2050
Configuration 1:	33 % of indirect	33 % of indirect	33 % of indirect	33 % of indirect
Configuration 2:	25 % of direct	20 % of direct	15 % of direct	5 % of direct
Configuration 3:	50 % of direct	40 % of direct	10 % of direct	5 % of direct
Configuration 4:	25 % of direct	40 % of direct	75 % of direct	90 % of direct
	67 % of direct	67 % of direct	67 % of direct	67 % of direct

Table 17: Distribution of Hydrogen demand across electrolysis configurations for Global Ambition

F First steps in the direction of interlinked modelling

Contrary to the TYNDP 2020, where potentials for P2G were investigated outside the electricity market, the TYNDP 2022 seeks to include the P2G in the electricity market models. Due to the nature of the market model software used by ENTSO-E and its members, the operation of the hydrogen network is modelled and operated under the same assumptions and market clearing rules as the electricity market. This means that the hydrogen market is cleared on an hourly basis, and that the model seeks to optimize societal welfare by producing, distributing, storing, and consuming hydrogen in conjunction with the electricity system. The drastic development of the P2G methodology in the TYNDP 2022 scenario is a step in the direction of interlinked modelling, where the energy system can be optimized across energy vectors, and where a holistic approach is taken to transmission planning.

The methodology will need future improvement, tuning and development to more carriers in future TYNDP scenario processes. The WGSB is open for input on this regard as it is acknowledged to benefit from the specialized knowledge of stakeholders.

Appendix IV: Investment Cost assumptions

This appendix provides further details on the different investment candidates available to the expansion model.

A Hydrogen interconnection and salt cavern

The conversion rate for retrofitted pipelines is explained in the Appendix III, section C(iv). Due to the limited experience with hydrogen grid development, the methane grid development is used as a proxy. The build-out rate is set at 7,5 GW/year per border.

A levelised cost of storage of 9 €/MWh[22] is used to capture the impact of salt cavern on hydrogen on the energy system and especially the level of electrolysis capacity.

B Electricity interconnection

The upper expansion limit offered on each interconnection to the expansion model intends to reflect the existence of actual projects on the considered horizon, based on the list taken from TYNDP 2020, and/or, where no projects were proposed, generic interconnection increments (100 MW, 500 MW or 2,000 MW) adapted to the size of the country and the pre-existing network.

For the COP 21 scenarios, the challenge is to manage the level of increase at a reasonable value avoiding too large increases in too short time for such infrastructures. TYNDP investment options are limited to the period between 2025 and 2040. After this period, and up to 2050, an estimate is used for yearly expansion rate based on the expansion

22 European Hydrogen Backbone, Analysing future demand, supply, and transport of hydrogen (June 2021) §4.4.2

options between 2025 and 2040. As capacity is increased across borders, the cost of additional interconnection capacity typically increases. A linear projection is therefore used to establish the cost of new grid between 2040 and 2050. The model is then capable of challenging various options, invest in RES in an area with high prices even with a rather low load factor, or co-invest in RES and grid, by selecting for example a high load factor area to develop RES together with an interconnector to export it into the high-priced area, if this is profitable.

C 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[23], with ASSET report "Technology pathways in decarbonisation scenarios"[24] used as a supporting reference. Annex II of this document presents the CAPEX and OPEX assumptions. All costs are in real terms.

Global Ambition and Distributed Energy scenarios differ regarding RES costs in order to reflect their different technology focus. Global Ambition considers the lower bound of costs for offshore wind in coherence with the focus on large generation units. Distributed Energy considers the lower bound for onshore wind and solar PV in coherence with Decentralised technologies. CCGT, OCGT, electrolysers, coal and lignite have the same CAPEX and OPEX for both scenarios.

National Trends			2025	2030	2035	2040	2045	2050	Lifetime (years)
Wind onshore*	CAPEX	€/kW	1,111	1,040	997	954	932	909	30
	OPEX	€/kW/a	13.7	12.6	11.9	11.3	11.0	10.7	
Wind offshore	CAPEX	€/kW	2,063	1,930	1,860	1,791	1,739	1,689	30
	OPEX	€/kW/a	38.7	36.1	34.5	32.8	31.8	30.7	
Solar PV (utility-scale)	CAPEX	€/kW	455	380	355	330	315	300	40
	OPEX	€/kW/a	8.1	7.3	7.0	6.6	6.5	6.3	
Solar PV (rooftop)	CAPEX	€/kW	1,000	870	800	730	660	590	40
	OPEX	€/kW/a	12.1	10.8	10.4	10.0	9.5	9.1	
CCGT	CAPEX	€/kW	855	830	815	800	800	800	25
	OPEX	€/kW/a	28.6	27.8	27.4	26.9	26.4	26.0	
OCGT	CAPEX	€/kW	445	435	430	424	418	412	25
	OPEX	€/kW/a	7.9	7.7	7.7	7.6	7.5	7.4	
Electrolyzer	CAPEX	€/kW	693	340	305	270	235	200	25
		€/kW/a	26.3	15.0	13.8	12.5	11.3	10.0	
Distributed Energy			**2025**	**2030**	**2035**	**2040**	**2045**	**2050**	**Lifetime (years)**
Wind onshore	CAPEX	€/kW	1,000	915	866	817	788	758	30
	OPEX	€/kW/a	11.2	10.5	9.8	9.1	8.9	8.6	
Wind offshore	CAPEX	€/kW	2,188	2,076	2,015	1,954	1,903	1,851	30
	OPEX	€/kW/a	41.1	38.8	37.3	35.9	34.9	33.9	
Solar PV (utility-scale)	CAPEX	€/kW	412	333	307	281	266	250	40
	OPEX	€/kW/a	6.8	6.0	5.7	5.4	5.2	5.0	
Solar PV (rooftop)	CAPEX	€/kW	904	762	692	622	556	492	40
	OPEX	€/kW/a	10.2	8.9	8.5	8.1	7.7	7.2	

* For wind onshore technologies, CAPEX and OPEX are adjusted to reflect expected load factor evolution in 2025-2050, given that utilized PECD time series are constant for the entire time horizon, but some incremental improvement in terms of load factors are expected. The costs presented reflect a standard technology in terms of hub height and specific power. As described in the section on PECD, the modelled onshore wind technology mix varies country-by-country, and CAPEX figures are variated depending on the technology mix.

Table 18a: OPEX and CAPEX costs for market capacties (for Level 1[25] Capacity Potential)

23 https://ens.dk/en/our-services/projections-and-models/technology-data

24 https://ec.europa.eu/energy/sites/ener/files/documents/2018_06_27_technology_pathways_-_finalreportmain2.pdf

25 Capacity potential available at the reference cost as defined under the Investment candidate chapter

Global Ambition			2025	2030	2035	2040	2045	2050	Lifetime (years)
Wind onshore	CAPEX	€/kW	1,271	1,220	1,193	1,166	1,147	1,127	30
	OPEX	€/kW/a	16.2	14.7	14.1	13.4	13.2	12.9	
Wind offshore	CAPEX	€/kW	1,799	1,620	1,532	1,444	1,395	1,348	30
	OPEX	€/kW/a	34.0	30.5	28.5	26.6	25.6	24.7	
Solar PV (utility-scale)	CAPEX	€/kW	532	444	415	385	368	350	40
	OPEX	€/kW/a	8.8	8.3	8.1	7.9	7.8	7.6	
Solar PV (rooftop)	CAPEX	€/kW	1,169	1,017	934	852	770	688	40
	OPEX	€/kW/a	13.2	12.3	12.1	11.9	11.4	11.0	
Decommissioning (DE & GA)			**2025**	**2030**	**2035**	**2040**	**2045**	**2050**	**Lifetime (years)**
Coal	OPEX	€/kW	25.6	25.6	25.6	25.6	25.6	25.6	
Lignite	OPEX	€/kW/a	32.5	32.5	32.5	32.5	32.5	32.5	

Table 18b: OPEX and CAPEX costs for market capacties (for Level 1[26] Capacity Potential)

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[27]. The reduction on CAPEX is as follow:

- Onshore wind: 50 €/kW
- Offshore wind: 370 €/kW in 2025 and 360 €/kW beyond
- Solar PV: 10 €/kW

The following table provides the resulting costs

Distributed Energy			2025	2030	2035	2040	2045	2050	Lifetime (years)
Wind onshore	CAPEX	€/kW	950	865	816	767	738	708	30
	OPEX	€/kW/a	11.2	10.5	9.8	9.1	8.9	8.6	
Wind offshore	CAPEX	€/kW	1,818	1,716	1,655	1,594	1,541	1,491	30
	OPEX	€/kW/a	41.1	38.8	37.3	35.9	34.9	33.9	
Solar PV (utility-scale)	CAPEX	€/kW	402	323	297	271	256	240	40
	OPEX	€/kW/a	6.8	6.0	5.7	5.4	5.2	5.0	
Global Ambition			**2025**	**2030**	**2035**	**2040**	**2045**	**2050**	**Lifetime (years)**
Wind onshore	CAPEX	€/kW	1,221	1,170	1,143	1,116	1,097	1,077	30
	OPEX	€/kW/a	16.2	14.7	14.1	13.4	13.2	12.9	
Wind offshore	CAPEX	€/kW	1,429	1,260	1,172	1,084	1,035	988	30
	OPEX	€/kW/a	34.0	30.5	28.5	26.6	25.6	24.7	
Solar PV (utility-scale)	CAPEX	€/kW	522	434	405	375	358	340	40
	OPEX	€/kW/a	8.8	8.3	8.1	7.9	7.8	7.6	

Table 19: opex and capex costs for dedicated RES (for Level 1[28] Capacity Potential)

26 Capacity potential available at the reference cost as defined under the Investment candidate chapter
27 https://ens.dk/sites/ens.dk/files/Statistik/technology_data_catalogue_for_el_and_dh_-_0009.pdf
28 Capacity potential available at the reference cost as defined under the Investment candidate chapter

Appendix V: 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 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 climatic years (from 1987 to 2016). This calculation is done at European aggregated level to reflect the European dimension of the electricity system balancing.

Table 20 provides the level of combined climatic stress for each time horizon (1 is the highest stress) based on the climatic years 1987 to 2016. It captures temperature, wind and solar radiation level on the most stressful 2-week period of the year. Among the 3 most representative climatic 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). Taking into account such factor, 1995 appears as the most stressful climatic 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[29] 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.

	Time Horizon		
Climatic year	**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
2007	15	15	14
2008	24	23	23
2009	2	2	2
2010	4	5	6
2011	21	21	21
2012	1	1	1
2013	11	14	15
2014	29	30	29
2015	30	29	30
2016	8	8	8

Table 20: Ranking of climatic years on the most stressful Dunkelflaute case for each time horizon

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

Appendix VI: Demand

The demand profile building process is necessary to allow annual final use energy volumes to be converted to hourly and daily volumes required for the power and gas sector modelling tools. The high-level process steps are shown in Figure 19.

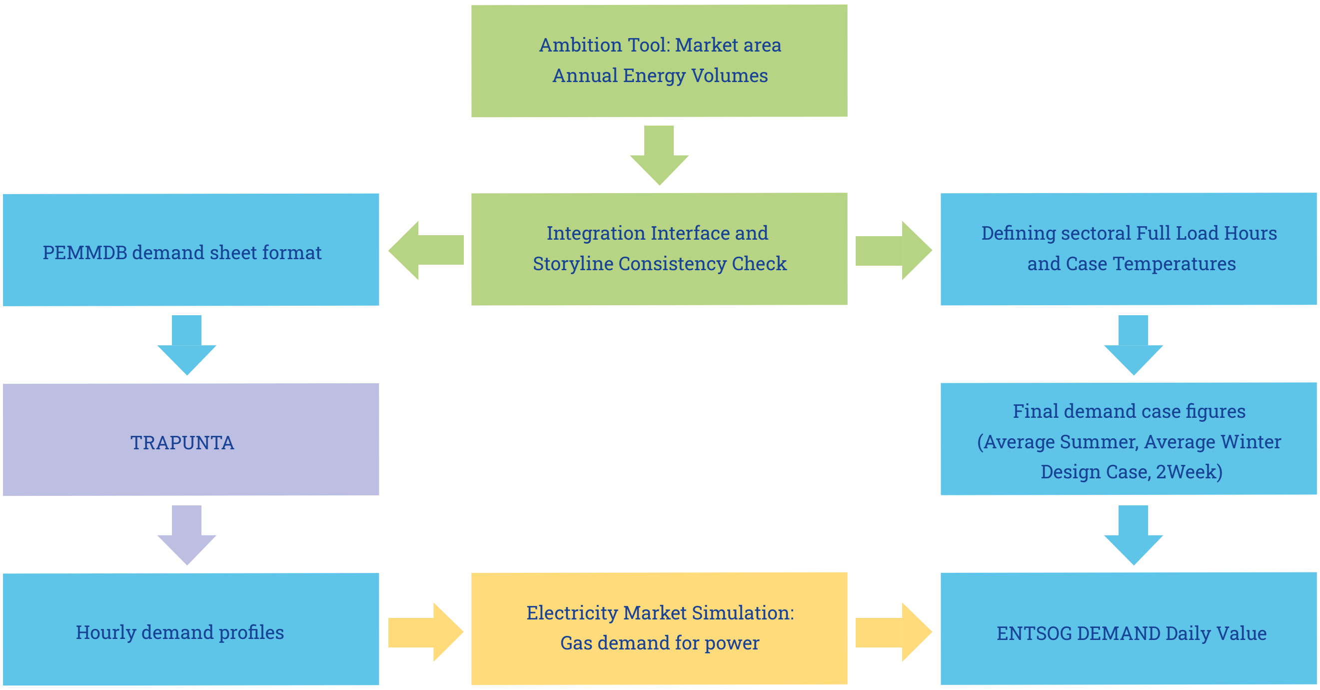

Figure 19: Demand profile building process

A Electricity Demand

Electricity demand is a fundamental input to the power sector investment modelling step in the scenario building process. Electricity demand is projected in two ways depending on whether a scenario is build using a "bottom-up" or "top-down" methodology;

- Bottom-up models use hourly profiles that are built by the ENTSO-E Working Group Data & Models based on TSO validation, or directly submitted by the TSO. The data files are based on normalised profiles spanning 30 climates years, 1987–2016

- Top-down models require a process to convert the annual electricity demand figures into hourly profiles as explained in the following sections.

i Top-down electricity demand construction

The following section describes the steps necessary to convert the outputs from the Ambition Tool into a data format that can be used as input for the investment tool used by the scenario building models.

In the electricity demand file building process, interactions between various teams are required in order to enable an efficient delivery of the final hourly demand profiles. Figure 20 provides a comprehensive description of roles and responsibilities to enable the demand file building process:

- The Working Group Data & Models provides key input data to the process in the form of trained normalised demand models along with the necessary PECD.

- The Ambition Tool team provides Excel-based individual market zone Ambition Tool files required to construct the demand input sheet. This is then to be read by the TRAPUNTA tool.

- The Demand Team is in charge to develop the simulations with TRAPUNTA in order to create the profiles for each market nodes, each time horizons and each scenario.

- The Innovation Team is the final user of the demand profiles and is responsible for demand profile adjustment and splitting this profile between wholesale market, prosumer and EV nodes.

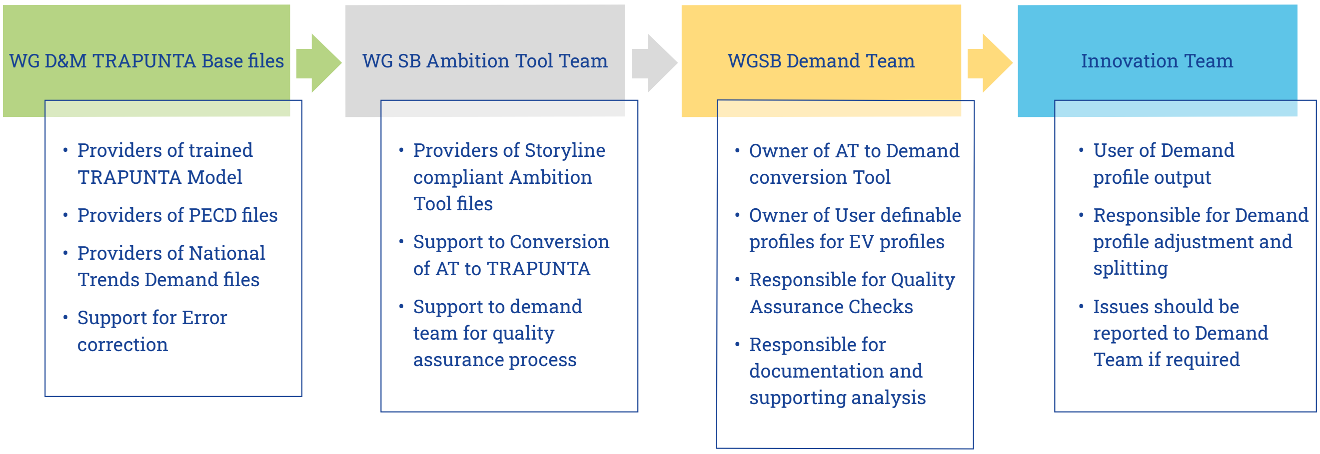

Figure 20: Electricty demand profile building process and team interactions

ii Ambition Tool to TRAPUNTA Conversion tool

In order to transform annual level electricity demand projected with the Ambition Tool into TRAPUNTA software used to create hourly-level electricity demand profiles, a specific conversion process was applied. Space heating and cooling-related demand was transferred per technology, i.e. splitting air-source heat pumps, ground-source heat pumps, direct electric heating and electrified district heating.

Generic assumptions were taken for categories that were required by TRAPUNTA but not considered by the Ambition Tool (namely heat pump split between sanitary water and other heat sources). This enabled the hourly load profiles of these technologies to be influenced by the ambient temperature assumption for the climate years used in the TRAPUNTA tool. Non-heating related demand was quantified as a sum of industrial demand evolution (including electrified heating for industrial processes) as well as lighting, power, cooking and catering demand from residential and tertiary sectors. This demand was assumed by the non-temperature dependent demand profiles in TRAPUNTA.

Transport demand was broken down to several transport segments, namely private vehicles, passenger rail, bus transport, rail freight transport and other freight transport, which were assigned type-specific transport demand profiles.

In case generic assumptions made in Ambition Tool, Conversion Tool and/or TRAPUNTA resulted in TRAPUNTA projection differing in annual level from the original Ambition Tool projection, the hourly profiles were afterwards adjusted evenly to match the annual values from the Ambition Tool.

iii Different EV patterns

In TRAPUNTA the additional load for electric vehicles is considered based on the following inputs:

- Additional EVs: the number of additional electric vehicles with respect to the training period
- Consumption: the average consumption of a specified electric vehicle, expressed in kWh/100 km
- Effective usage: the average use of a specified vehicle type, divided into weekdays and weekends (each one with a chosen charge profile), expressed in km per day
- Daily distribution of the aforementioned effective usage divided into weekdays and weekends.

TRAPUNTA allows creation of additional load, which includes four types of electric vehicles. During analytical work, the following types have been developed:

- Type A: Electric private cars
- Type B: Buses
- Type C: Passenger trains
- Type D: Heavy goods vehicles

Additionally, rail heavy goods and aviation have been calculated and added to the rest of the load profile with an even repartition of daily value within the day.

The number of EVs is one of the Ambition Tool results for every market node.

Electric private cars

Since TRAPUNTA differentiates load profiles with working days and weekends or seasonal changes using electricity consumption and effective usage values as input data, the daily load pattern should be as universal as possible. The current load pattern was created taking daily activity of potential users into account. A complete methodology of how EV are considered in the market modelling tools can be seen in III Appendix: Prosumer and EV Modelling, EV Node.

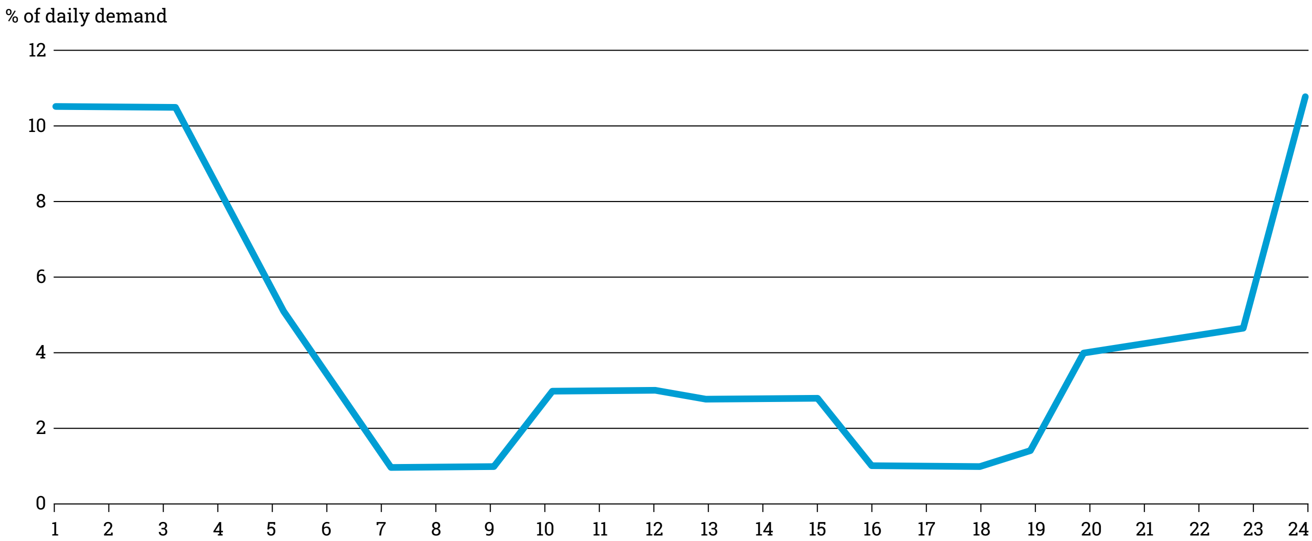

Figure 21: Electric private cars load pattern

Buses

The daily load profile was created based on the assumption that most of buses uses slow night charging. Fast chargers at bus depots are also available for around 30–35 % of the fleet. This profile reflects mainly public transport in cities.

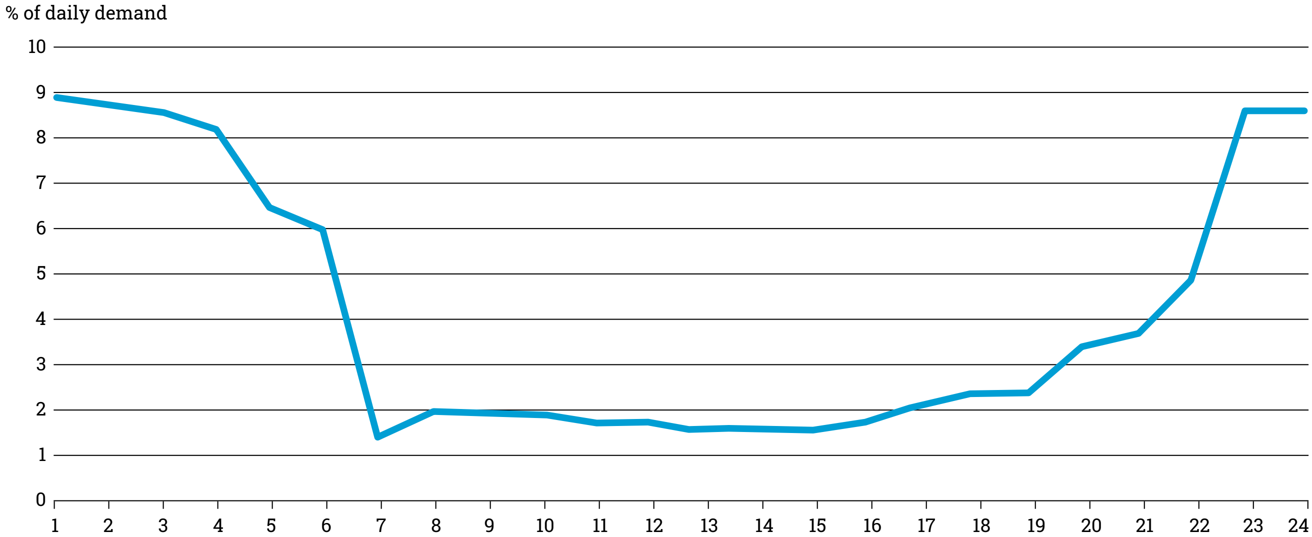

Figure 22: Electric buses load pattern

Electric passenger trains

The daily load profile is based on live data about the number of passenger trains operating 24 hours a day. According to live data, in simplified form, the railway line loading looks as follows.

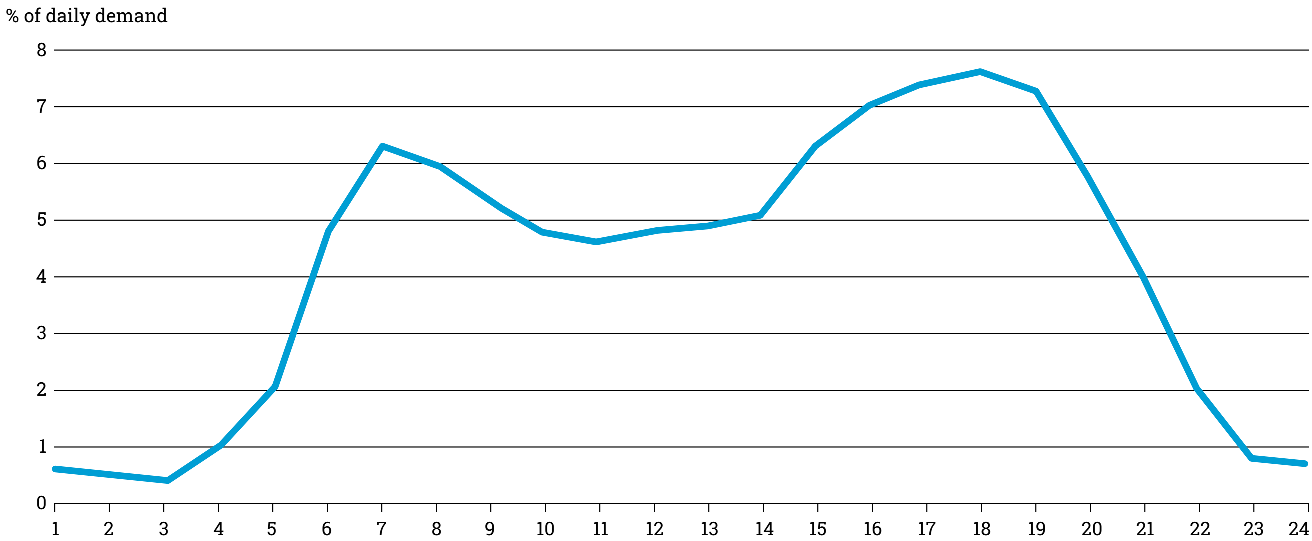

Figure 23: Electric passenger trains load pattern

Electric heavy goods vehicles

The daily load profile is focused on the fleet of a small trucks and was based on the assumption that trucks will be charged mostly at night. Nevertheless, the same assumption for Transport International Route vehicles can be applied.

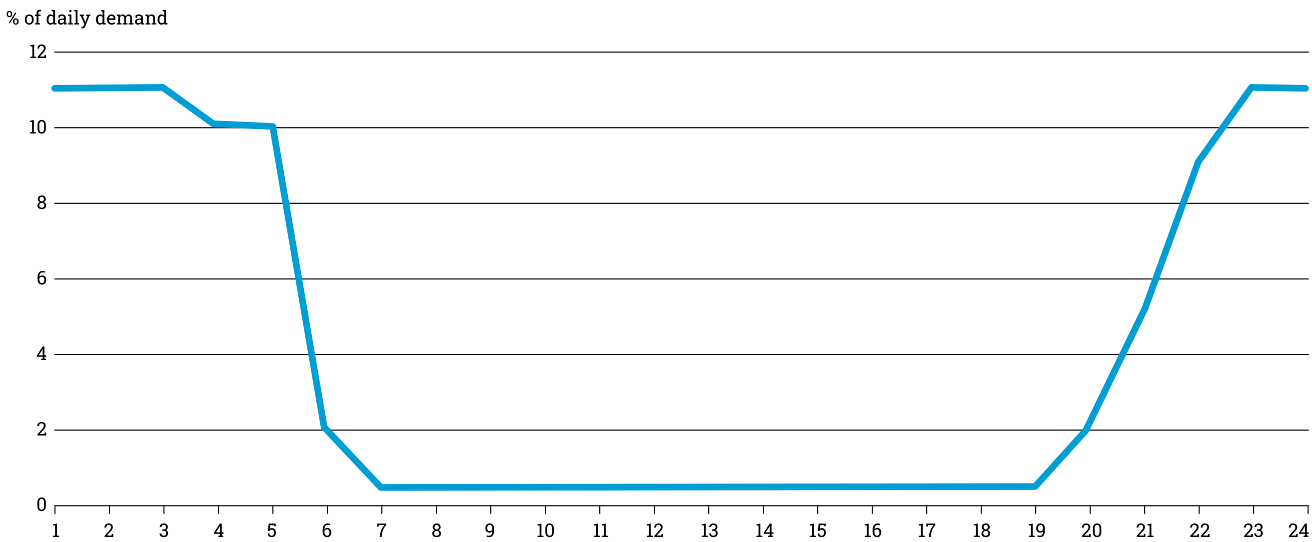

Figure 24: Electric heavy goods vehicles load pattern

iv 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.

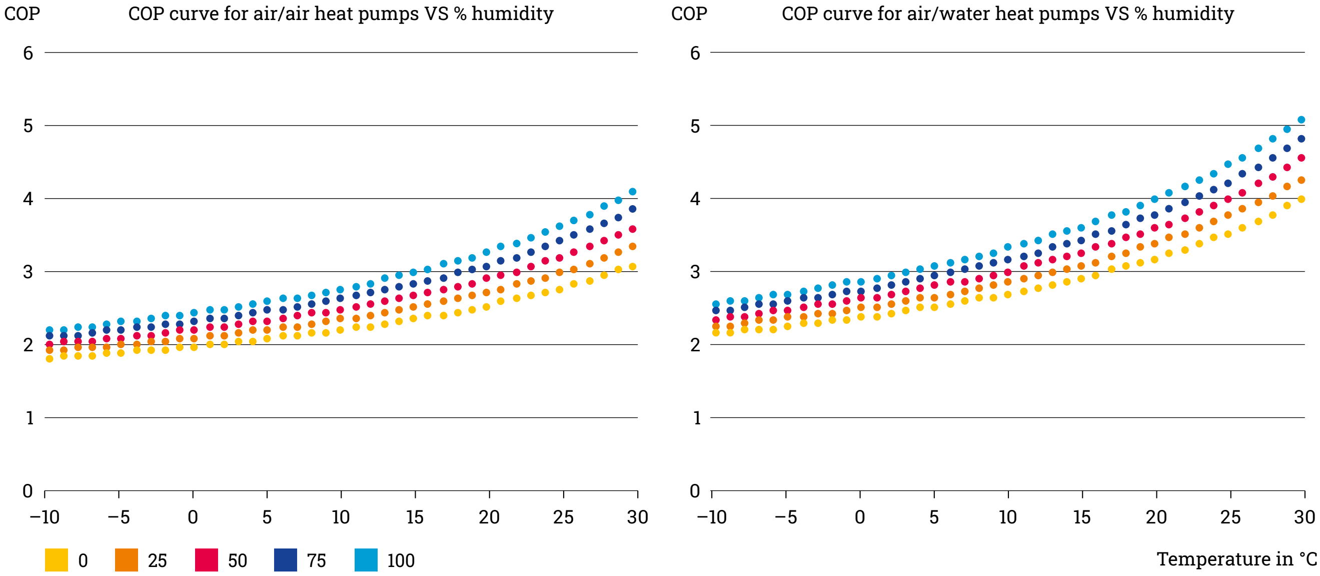

Figure 25: Example of COP curve for air/air and air/water heat pumps

v Assumptions for Hybrid Heat Pump modelling

Hybrid heat pumps combine an electric air/water heat pump with a gas boiler. The ENTSOs' made the assumption 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 or hydrogen). The major part of sanitary water heating is gas consumption. 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 by back-up boilers.

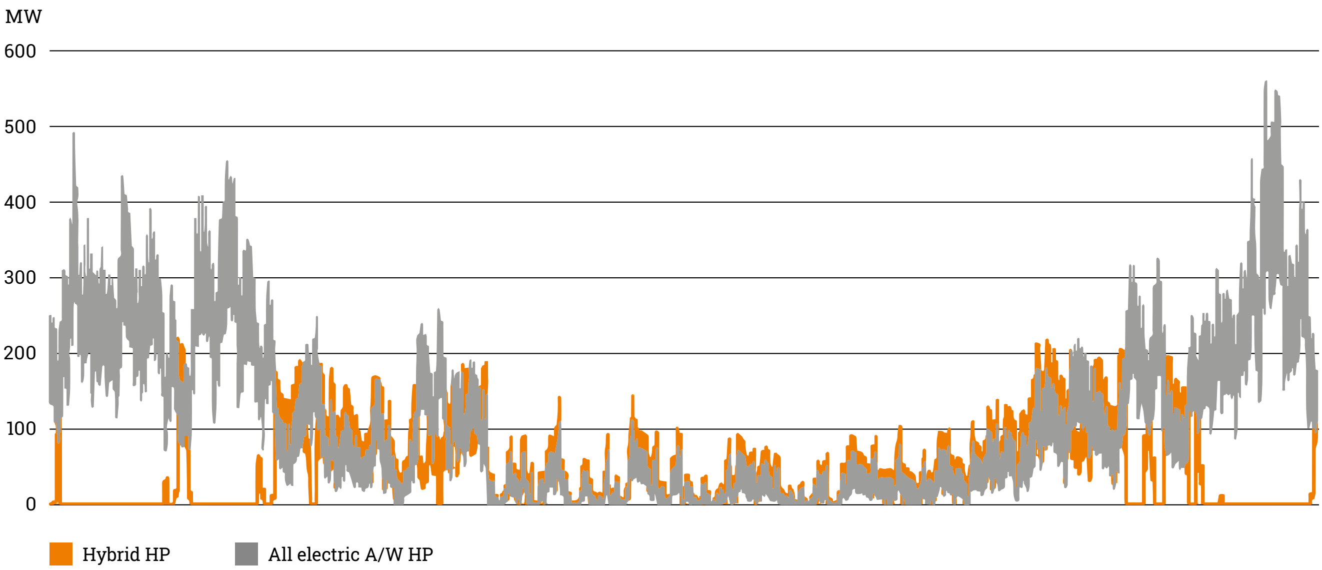

Figure 26: Example of all electric and hybrid heat pumps load across the year

B Gas 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 2022. 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 the electricity generation into gas demand.

For this TYNDP process there is a different approach for short-term demand (2022, 2025) and long-term demand (2030, 2040) that will be explained in the following section.

The innovation of this TYNDP is the separation of methane and hydrogen demand in all scenarios.

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, seasonal variation and high case demand data is contemplated. Table 21 presents an overview the different cases.

i Seasonal and high case demand situations

Situation	Demand
Average Summer (AS)	Final Injection Period Demand
	Power Injection Period Demand
Average Winter (AW)	Final Withdrawal Period Demand
	Power Withdrawal Period Demand
Design Case (DC)	Final Peak Demand
	Power Peak Demand
2 Week Cold Spell (2W)	Final 2W Demand
	Power 2W Demand
Dunkelflaute (DF)	Final 2W Demand
	Power Demand Dunkelflaute

Table 21: Seasonal and high case variations

ii Seasonal variation

Average demand and the Seasonal Demand Factor (SDF)
Seasonal variation is divided into two periods: storage injection period and withdrawal period. These periods correspond to the average summer and average winter demand respectively.

The storage injection period covers seven months (April – October), while the storage withdrawal period covers five months (January, February, March, November, December).

The Seasonal Demand Factor (SDF) is a parameter to calculate average winter and average summer demand as part of the total annual demand for the TYNDP Simulations.

Storage injection period average demand =
"SDF" × Yearly average demand

SDF represents a yearly factor to derive the final demand for the 7-month storage injection period from the yearly demand. These values were given by TSOs in the data collection questionnaire and used both for all scenarios.

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 in the Data Collection Questionnaire. Gas demand for power generation is calculated from the results of ENTSO-E modelling process, as it is explained in chapter 3.

- COP 21 scenarios: Final demand values are calculated following the Gas Peak Demand Methodology, explained in Appendix VI, section B(iv). 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 days 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 in the Data Collection Questionnaire. Gas demand for power generation is calculated from the results of ENTSO-E modelling process, as it is explained in chapter 3.

- COP 21 scenarios: Final demand values are calculated based on the Gas Peak Demand Methodology, explained in Appendix VI, section B(iv). 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 of time 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.

iii Data estimation methods for final gas demand

Short term demand

Short-term demand is the data for the years 2022 and 2025. For these years only one scenario is considered, Best Estimate, based on the best-knowledge of ENTSOG's members.

The Best Estimate scenario is a bottom-up scenario. 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 questionnaire is provided, which covers all bottom-up scenarios as well as any gas demand as a result of newly gasified areas enabled by future projects where applicable, which is classified as gasification demand.

Where no data was provided by a country, data from Best Estimate from TYNDP 2020 was used for TYNDP 2022 (Romania and Serbia), with the same share to split the hydrogen/methane demand as EU average.

Year	Scenario name	Type	Demand derived from
2022	Best Estimate (BE)	Bottom-up	TSO Data Collection
2025	Best Estimate (BE)	Bottom-up	TSO Data Collection

Table 22: ENTSOG short-term Scenario Types

Long term demand

Long-term demand is the data for the years beyond 2030. For these years three scenarios are considered: National Trends, Global Ambition and Distributed Energy. Whereas National Trends relies on bottom-up collected data, for Distributed Energy and Global Ambition, ENTSOE and ENTSOG computed the final demand figures with top-down methodologies.

Year	Scenario name	Type	Demand derived from
2030–2040	National Trends (NT)	Bottom-up	TSO Data Collection
2030–2050	Global Ambition (GA)	Top-down	Ambition Tool
2030–2050	Distributed Energy (DE)	Top-down	Ambition Tool

Table 23: ENTSOG long-term scenario Types

Bottom-up data

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 questionnaire is provided, which covers all bottom-up scenarios as well as any gas demand as a result of newly gasified areas enabled by future projects where applicable, which is classified as gasification demand.

Values are provided for all years up to 2040 for the yearly and average volume, seasonal variation, as well as high demand cases for the peak day (Design Case), the 2-week high demand case and the "Dunkelflaute" case.

Top-down data

Annual demand data is calculated using the Ambition Tool. The Ambition Tool calculates country-level demand (methane, hydrogen and electricity) based on historical data and using different end-user technology shares for each country. Each country specific input was obtained using an EU-27 default approach and then reviewed by TSOs, both electric and gas.

The EU-27 default approach is a sectorial approach based on the storylines for Global Ambition and Distributed Energy, considering fuel and technology switch, energy efficiencies and decarbonization.

iv Gas peak final demand methodology for COP 21 scenarios

In order to calculate the gas high case demand for COP 21 scenarios the same methodology as for TYNDP 2020 is used, with the difference of the split of methane and hydrogen.

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. Figure 27 illustrates the temperature-demand-relation in the gas sector and how it is applied to calculate the different daily case figures for the gas demand.

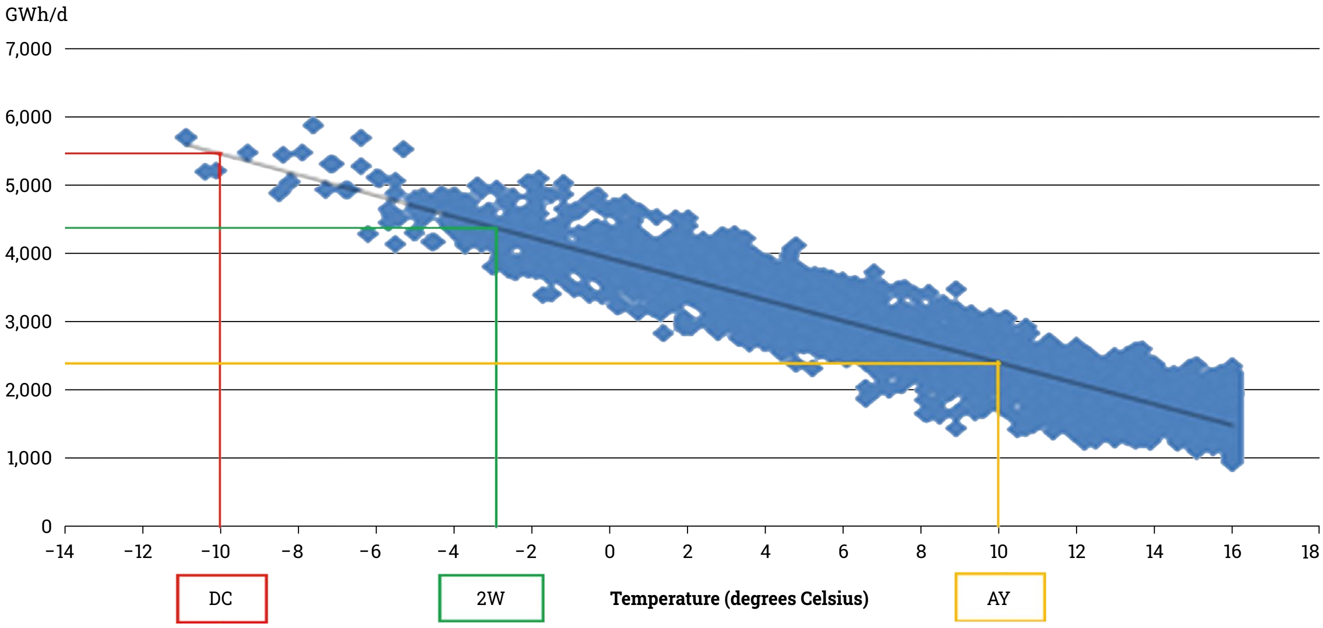

Figure 27: Temperature versus demand interpolation

Alternative Approach: Using bottom-up data as reference

For the calculation of the final high case demand in the residential and tertiary sectors for COP 21 scenarios the same relation between final high case demand and final average demand from bottom-up scenarios 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 need to be considered. Hybrid heat pumps are used for space heating and sanitary water. The ENTSOs' made the assumption 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). The 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[30].

v Gas demand for power generation

The gas demand for power is the primary energy used for electricity generation in the electricity market. It is determined by the electricity models and used in the gas TYNDP to ensure there is enough supply to meet all gas demand.

30 For the switch from electricity to gas there is a linear smoothing functions that apply between 3 °C and 7 °C

Appendix VII: Climatic 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 in particular, 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 in particular 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 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 of 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, also solar power 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.

Appendix VIII: 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. In order to understand and capture the possible futures (in line with the scenario storyline), a two-step approach was followed as illustrated in Figure 28.

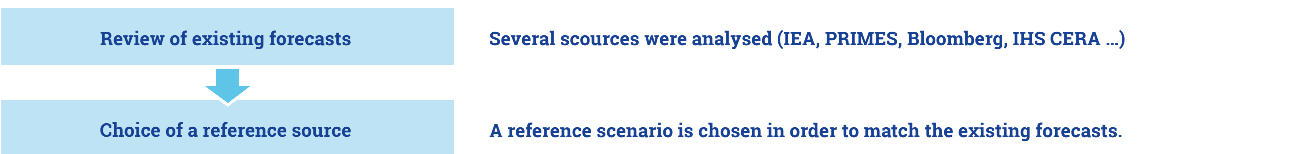

Figure 28: Commodity price review process

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 € 2020).

- 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).

A 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 variations over time. Given those particularities, the nuclear and lignite prices are assumed to stay stable over the time horizons and across the scenarios. Those will be based on the TYNDP 2018 and 2020 prices for nuclear and on an external, dedicated study for Lignite costs and prices[31]. 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: 0.47 €/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

B Prices driven by policies and world/regional markets

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

The market forecasts considered and compared for coal, oil and natural gas are:

- IEA World Energy Outlook for coal, crude oil and natural gas,
- For hard coal only: Coal (API2) CIF ARA (ARGUS-McCloskey) future prices 2022–2025, Newcastle benchmark thermal coal price forecasts 2021–2025
- For natural gas only: Rystad Energy Research and Analysis (reporting on real prices forecast for Henry Hub prices, Title Transfer Facility -TTF- prices, NE Asia Spot LNG prices)

After review of these studies, IEA World Energy Outlook 2020 has been chosen as the reference source for the gas, coal and oil prices.

Since significant differences between market forecast and WEO STEPS prices for 2025 are not observed, WEO STEPS (Stated Policies Scenario) prices for hard coal, natural gas and crude oil prices have been considered fit for 2025 Best Estimate and for NT Scenario while WEO SD (Sustainable Development Scenario) for DE and GA Scenarios. The choice of the reference scenarios from the WEO has been driven by the following considerations:

- Stated Policy Scenario is designed to give feedback to decision makers about the course that they are on today, based on stated policy ambitions. This scenario assumes that the pandemic is brought under control over the course of 2021. It incorporates stated policy ambitions, including the energy components of announced stimulus or recovery packages (as of mid-2020) and the Nationally Determined Contributions under the Paris Agreement. This scenario can be considered in line with National Trend scenario.
- In the Sustainable Development Scenario, a surge in clean energy policies and investment puts the energy system on track to achieve sustainable energy objectives in full, including the Paris Agreement, energy access and air quality goals. The assumptions on public health and the economy are the same as in the STEPS. This scenario has been considered a good match with Distributed Energy and Global Ambition Scenarios.
- 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.

Originally, WEO prices were published in USD 2019/tonne for hard coal and USD2019/Mbtu for natural gas[32]. As TYNDP prices should be converted to EUR/GJ for hard coal and natural gas, the parameters below were used:

- USD/EUR average ratio 2020 – 0.877
- 1 t – 25.12 GJ (ARA 6,000 kcal)
- 1 GJ – 0.947817 Mbtu

Light and heavy oil prices have been derived by applying respectively a 28 % and 8 % price increase to 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.

The hard coal, natural gas and oil prices for the different scenarios and horizon are shown in Table 7 (chapter 4.3).

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31 Booz & Co, "Understanding Lignite Generation Costs in Europe, https://www.dei.gr/documents2/investors/meleth%20booz/understanding%20lignite%20generation%20costs%20in%20europe.pdf

32 Based on gross calorific value

Given that its use is restricted only to Estonian power system, the forecast of the price for shale oil has been directly provided by the related TSO. It evolves over time but it is not scenario dependent. The prices used for all the scenarios are presented in Table 6.

C Driven by European policies: CO_2 and Hydrogen

i CO_2 price

The carbon price for the electricity market is driven by the cap on emissions that policy makers set on the European Trading System (ETS) in order to reach the carbon emissions ambitions. CO_2 prices the following existing forecast have been reviewed[33]:

- WEO 2020
- EU Impact Assessment 2030, PRIMES model, SEP 2020
- Refinitiv
- Bloomberg NEF
- Energy Aspects
- ICIS

There are several uncertainties that can lift the prices up or down such as:

- National policies (e.g. carbon floor)
- European stability reserve intervention
- Coal phase outs in electricity generation
- Additional RES in the system lowering the generation of fossil units
- Long-term effects as UK leaves the ETS

Coherently with the approach chosen for demand/supply driven fuel prices, WEO 2020 forecasts have been selected as primary source. However, the WEO 2020 Stated Policy Scenario prices, supposed to be used for the 2025 horizon and National Trend Scenario, have been considered too low in light of the recent price increases. Hence 2025 and 2030 NT price forecasts have been derived from the average rounded values presented by Refinitiv during the Expert workshop on the Market Stability Reserve[34] (Figure 29).

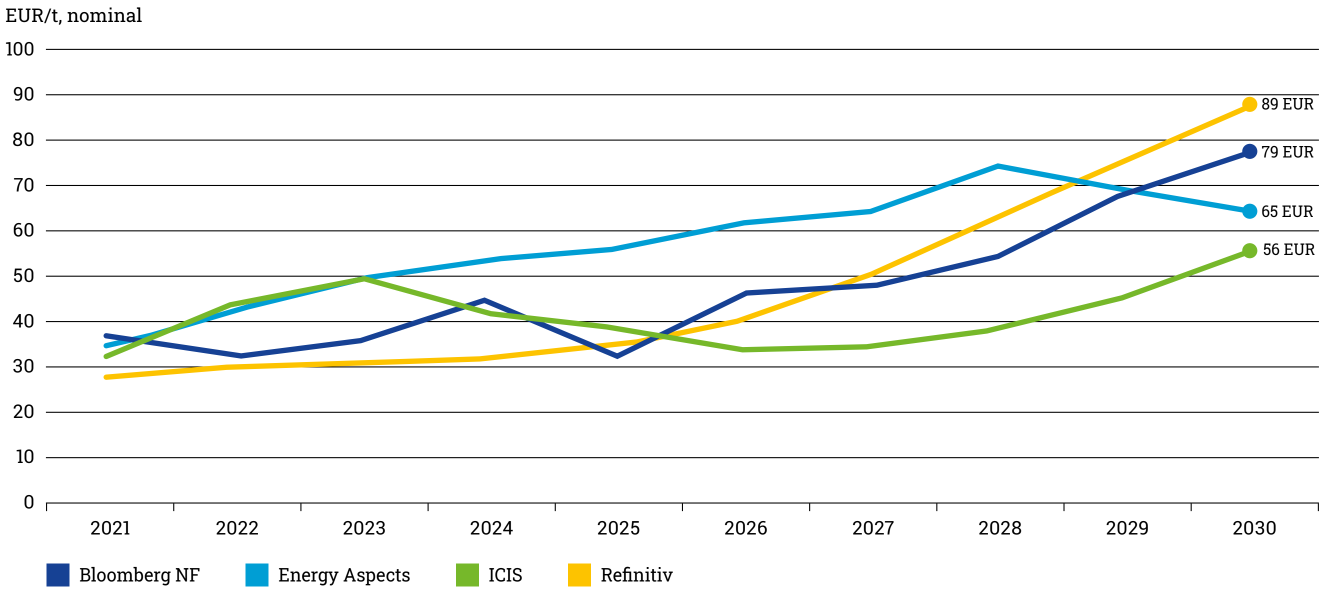

Figure 29: Refinitiv CO_2 price forecasts (dec 2020)

Since this source does not provide long-term expectations for CO_2 prices, it was necessary to create 2040 price internally. For this purpose, it was assumed that the percentage difference between WEO STEPS and NT 2040 price will be the same as the difference between WEO STEPS 2040 and the market based price in 2030: a price increase of 94%.

For De and GA the CO_2 price forecasts have been instead based on WEO 2020 Sustainable Development Scenario prices following the same approach applied for Coal, Natural Gas and Oil prices. Whenever not provided for a given horizon, prices have been linearly extrapolated from the forecasts available.

The final prices are presented in Table 7 (chapter 4.3).

33 CO_2 price is only considered an input for NT, for DE and GA it is an output of the model.

34 Hæge Fjellheim Head of Carbon Research, Refinitiv, What role for the MSR in EUA formation? https://ec.europa.eu/clima/events/expert-workshop-market-stability-reserve_en (Dec. 2020).

ii Hydrogen price

Hydrogen prices are expected to reflect both the required capital invested to produce hydrogen and the European policies toward a climate neutrality. TYNDP 2022 Scenarios consider only decarbonised and renewable hydrogen. For National Trends just one price for hydrogen is used for a given year Distribution Energy and Global Ambition Scenarios consider distinct prices for decarbonised and imported renewable hydrogen.

Those prices are derived by using the techno-economic assumptions (e. g., Interest rate, Efficiency or the CAPEX (\$/kW H_2) from EWI[35], complemented by applying the CO_2 price forecast expected to be used for TYNDP 2022 Scenarios. Regarding the renewable hydrogen, a mark-up was added to reflect the necessity to "structure" the fluctuating hydrogen production to the baseline demand. It is assumed that H_2 storages will be used for that task. These prices are shown in Table 7 (chapter 4.3).

It's important to highlight that the renewable hydrogen prices presented in this paragraph are valid only for hydrogen imports. of the price of hydrogen from European electrolysis production are an output of the electricity modelling.

iii Synthetic methane and Biomethane

The biomethane prices are derived from the "Navigant Biomethane Tool" that is used to calculate the domestic biomethane production per county. This tool is a further development of the methodology used by Navigant in the study by Gas for Climate and was already was used for TYNDP 2020[36]. Compared the methodology used in TYNDP 2020, the use of sequential cropping was reduces, based on stakeholder feedback. Furthermore, the share of injection in the grid was slightly reduced. More information on the biomethane assumptions can be found in Appendix IX, section C.

The study estimates prices for 2025 and 2050. For the years 2030 and 2040, a linear interpolation was applied.

Synthetic methane prices have been assessed by applying a mark-up of €12/MWh of investment costs and €8/MWh of O&M to the estimated hydrogen prices to consider the additional costs for the process. (based on GasforClimate Study from 2019[37] and 2020[38]).

Appendix IX: 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 types: There are two different gas types, which are methane and hydrogen. For all scenarios, National Trends, Distributed Energy and Global Ambition, the quantification of the type-specific demand is described in appendix VI.B

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:

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

For hydrogen, potential sources are:

- Natural gas with SMR (steam methane reforming) or ATR (Autothermal Reforming)
- Natural gas with SMR+CCS/ATR+CCS
- Electrolysis
- 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.

35 Estimating Long-Term Global Supply Costs for Low-Carbon Hydrogen, Institute of Energy Economics at the University of Cologne (EWI), November 2020, https://www.ewi.uni-koeln.de/de/publikationen/estimating-long-term-global-supply-costs-for-low-carbon-hydrogen/

36 https://2020.entsos-tyndp-scenarios.eu/wp-content/uploads/2020/07/TYNDP_2020_Scenario_Building-Guidelines_05_Annex_4_Biomethane_Assumptions_final_report.xlsx.zip

37 https://gasforclimate2050.eu/?smd_process_download=1&download_id=282

38 https://gasforclimate2050.eu/?smd_process_download=1&download_id=339

A Hydrogen Import Potentials

It is assumed that the imported hydrogen is only used for direct hydrogen demand and not to provide for the indirect hydrogen demand. This assumption is based on the fact that it is cost-efficient to use the existing import infrastructure for oil and methane to directly import hydrogen-based energy carriers, such as synthetic fuels (e.g. ammonia) and synthetic methane instead of importing hydrogen first and converting it in a second step within the EU to one of the above-mentioned synthetic energy carriers. The Extra EU supply potential for TYNDP22 was consulted with stakeholders on 27 May 2021[39], and feedback was generally positive.

The import potentials of hydrogen are assessed in a different way compared to the assessment of the import potential of methane in order 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 midterm 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. In the long run, hydrogen imports via shipping might be based on other reasoning then pure cost perspective, such as diversifying import sources, but in the short to medium-term, it is assumed that shipping will not develop. This might change post 2040. Therefore, all the imports of hydrogen in the TYNDP22 scenarios are assumed to be via pipelines from adjacent regions.

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, and the Turkish Hub. 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.

These H_2 supply sources have been revised to include Ukraine in the updated scenario report. The country was added as a potential H_2 supply source based on the good climatic and geographic conditions for H_2 production and the existing connection to the trans-European gas infrastructure.[40]

The figures 30–35 on the following page show the hydrogen import potentials used in the TYNDP22 scenarios in TWh per year (based on net calorific value).

It is assumed that for European actors to import hydrogen, the hydrogen must be cost competitive to domestically produced hydrogen. This would also make sense from the exporting regions, that they seek new markets, as the export of methane declines over time. Therefore, the cost of imported hydrogen is set marginally lower than European produced decarbonised hydrogen. This has the effect that import of hydrogen, will act as a baseload import at almost full capacity with few hours of below-capacity operation. The cost of imported hydrogen, including transmission costs are provided in Table 24.

Global Ambition	2025	2030	2040	2050
Levelised cost of hydrogen (€/kg H_2)	2.25	2.05	1.93	1.50

Table 24: Prices for hydogen imports

The import demand in terms of energy volumes is then the difference of the total gas demand and all domestically produced gases.

39 https://www.entsog.eu/entsog-and-entso-es-workshop-extra-eu-supply-potentials-tyndp-2022

40 United Nations Economic Commission for Europe (UNECE): Draft Roadmap for production and use of hydrogen in Ukraine, https://unece.org/sites/default/files/2021-03/Hydrogen%20Roadmap%20Draft%20Report_ENG%20March%202021.pdf

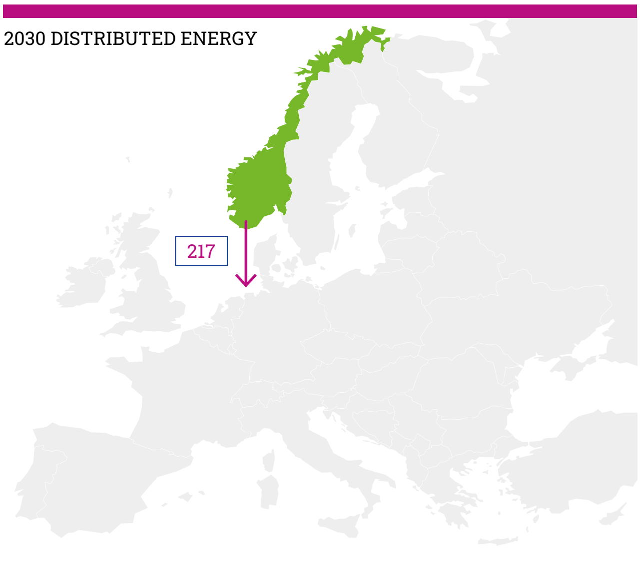

Figure 30: Extra-EU supply potential for Hydrogen in Distributed Energy in 2030 [TWh]

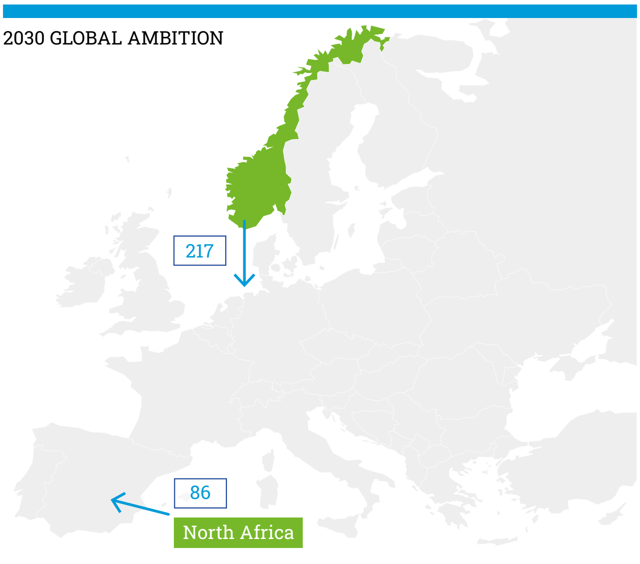

Figure 31: Extra-EU supply potential for Hydrogen in global ambition in 2030 [TWh]

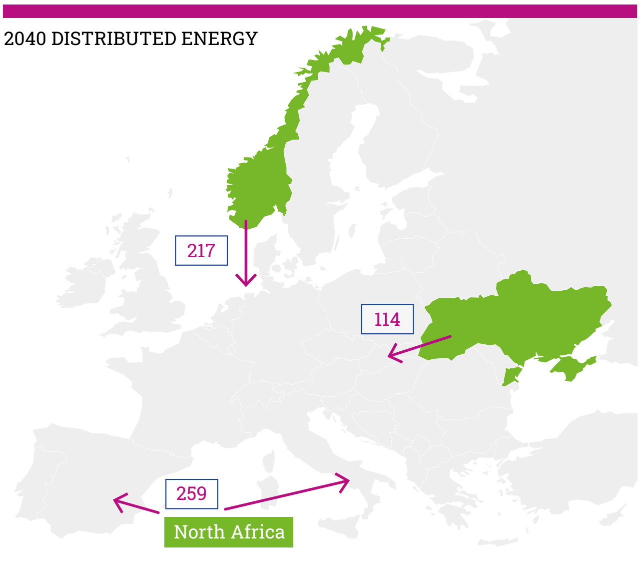

Figure 32: Extra-EU supply potential for Hydrogen in Distributed Energy in 2040 [TWh]

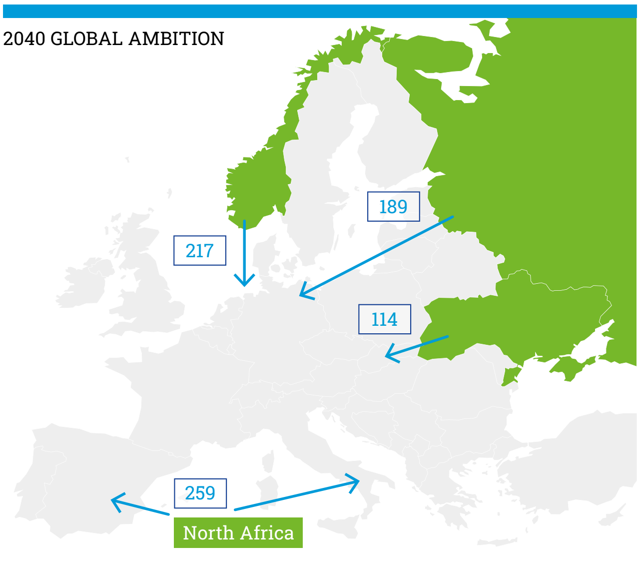

Figure 33: Extra-EU supply potential for Hydrogen in global ambition in 2040 [TWh]

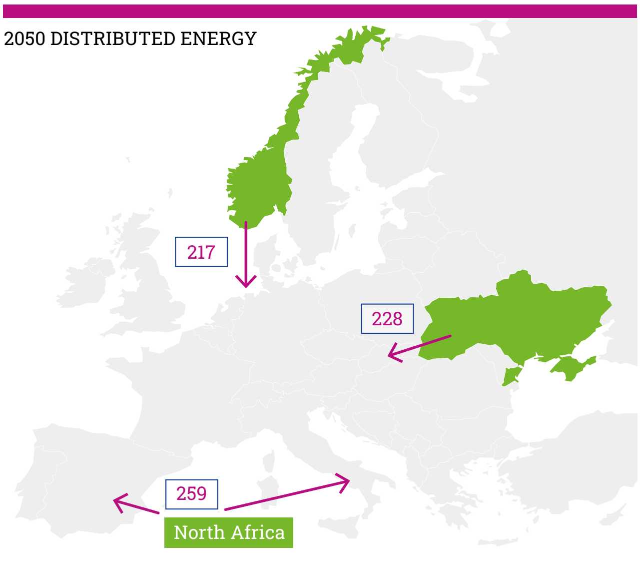

Figure 34: Extra-EU supply potential for Hydrogen in Distributed Energy in 2050 [TWh]

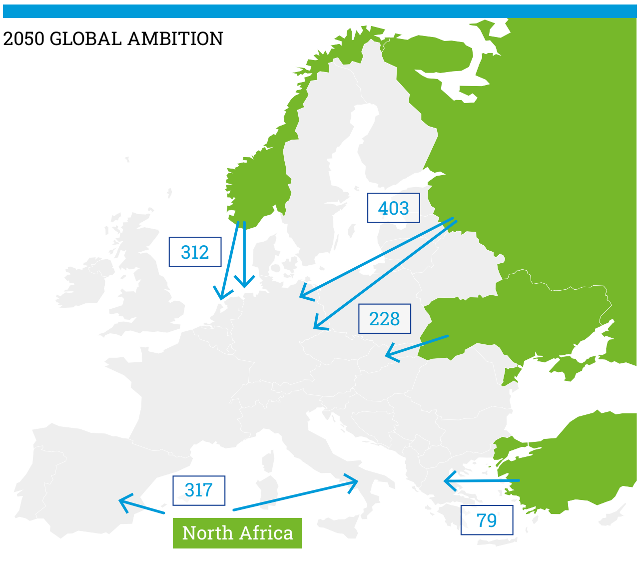

Figure 35: Extra-EU supply potential for Hydrogen in global ambition in 2050 [TWh]

B Methane Import Supply Potentials

The extra-EU supply sources – that is sources of EU energy imports – today include Russia, Norway, Algeria, Libya, Azerbaijan and the LNG market. Azerbaijan has started supplying the EU by pipeline at the end of 2020. The LNG market is split into basins to reflect difference in supply potentials: Middle East, North Africa, Russia, North America and Others.

i Methodology

The extra-EU supply potentials are assessed as a range between the minimum and the maximum potential for each source. These supply specific ranges are boundary conditions in the gas balance simulations, thereby always respected in the resulting supply mix. They are introduced to avoid unrealistic supply mix situations. The simulation will find the optimal supply mix within the given supply range for the given market assumptions. Supply mix results are thereby determined by a combination of the supply potentials, network constraints and market assumptions. This assessment is not part of the joint scenarios scope, but will be made in the ENTSOG TYNDP.

Definition of extra-EU gas supply potential

The gas supply potentials are given as a range between minimum and maximum supply potentials.

The minimum supply potential of a supply source is defined as the current long-term contracts, and their expected extension with reference to the national projection of production and domestic demand, possible production and infrastructure constraints, as well as the historical EU supply share.

The maximum supply potential of a specific source is defined as the export potential to EU with reference to the national projection of production and domestic demand, possible production and infrastructure constrains as well as the historical EU supply share.

Literature review

The assessment of the extra-EU supply potentials is done by a literature review of published studies on the future energy mix of EU. For TYNDP 2022 extra-EU supply potentials, the IEA's World Energy Outlook 2018[41] is chosen as a key reference.

Historical gas supply

The historical data is taken from ENTSOG's data warehouse, which contains EU supply data provided by ENTSOG members.

Infrastructure projects

For new and future extra-EU supply sources, the potentials are assumed to be correlated with the submitted infrastructure projects for the TYNDP 2020, which can be found on ENTSOG's webpage[42]. The potential of export production from a given source is very much dependent on the willingness of investment in new exploration fields and connecting infrastructure projects.

ii Stakeholder Engagement

ENTSOG has engaged stakeholders during the development of the extra-EU supply potentials. This has been done by both bilateral meetings[43] with key stakeholders and hosting a public workshop[44] for stakeholders to give their view on extra-EU supply potentials and feedback on ENTSOG's draft of the TYNDP 2022 Supply Potentials. In the following section the individual supply potentials are analysed and the results for the TYNDP 2022 are presented.

iii Historical supply

Indigenous production has decreased since 2010 inducing an increasing dependency on extra-EU supply. With the planned end of regular gas production from the Groningen field (Netherlands)[45] after 2022, this overall trend will most likely accelerate in the near future. Russia is currently listed as the main extra-EU supplier with an increasing market share reaching 32 % in 2019. The second largest supplier is Norway with a market share of around 22–26 %. The North African supply from Algeria and Libyan has been between 5 and 9 % the last decade. LNG supply is the source with the most fluctuating market share due to price changes in the global LNG market. In 2011 LNG had a significant share of the market of 16 % which subsequently decreased to 8 % in 2013. In 2019 the share of LNG in the EU market has increased significantly to reach 21 %. In the historical supply mix for the EU is illustrated with data from ENTSOG's database (in gross calorific value).

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41 https://www.iea.org/weo2018/

42 https://www.entsog.eu/tyndp#

43 GAZPROM, IOGP, SOCAR

44 ENTSOG and ENTSO-E's workshop on the extra EU supply potentials for TYNDP 2022

45 https://nos.nl/artikel/2301110-gaswinning-groningen-stopt-al-in-2022.html

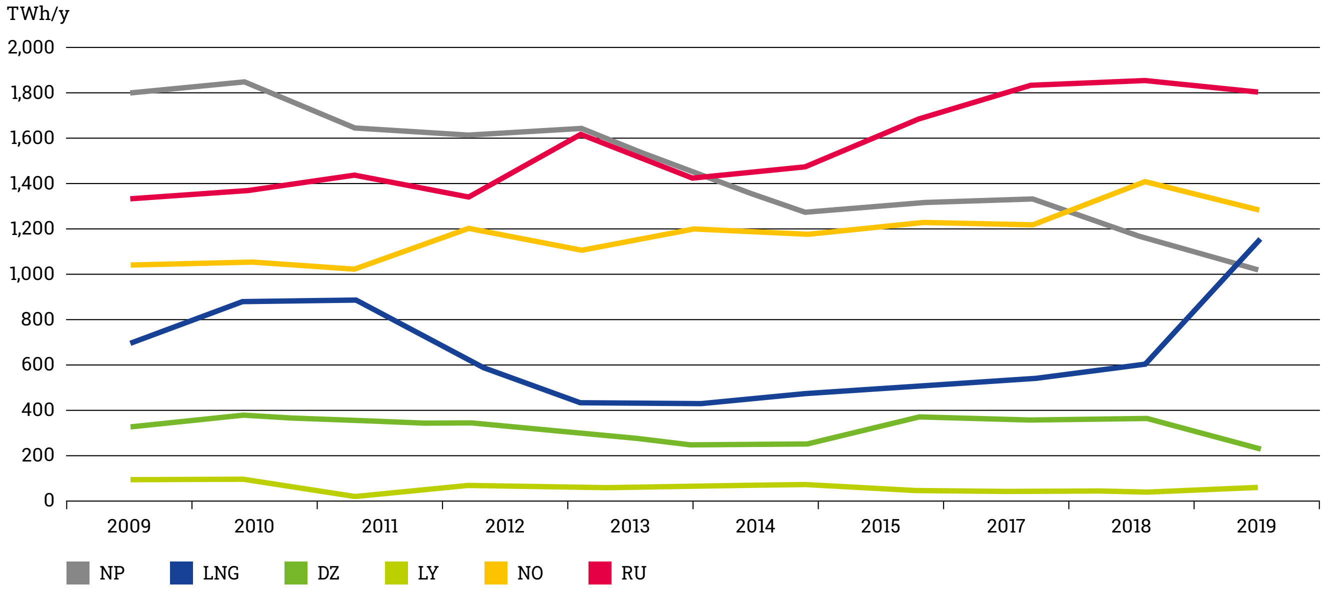

Figure 36: EU gas supply mix in the period 2009–2019 (ENTSOG)

iv Russian Supply Potential

The Russian Federation is currently the main gas supplier to the EU gas market and supplied 170 bcm (1,800 TWh) in 2019 via pipeline. This represented 32 % of the EU market share and resulted in a load factor of utilised capacity of about 0.60. Russia has its own domestic demand that can influence its export potential. The gas production in Russia in 2019 was 750 bcm and the internal demand was 492 bcm in 2019[46]. The maximum potential projection for EU is around 210 bcma, which accounts for 40 % of EU demand (2019). The minimum potential is aligned with WEO 2018.The future of Russian export potential for EU imports will basically depend on the European demand level, on the competition from other big consumers in Asia to import Russian gas and the amount of investment in the upstream sector (e. g. LNG). The projected Russian supply potentials for the EU are illustrated in Figure 37.

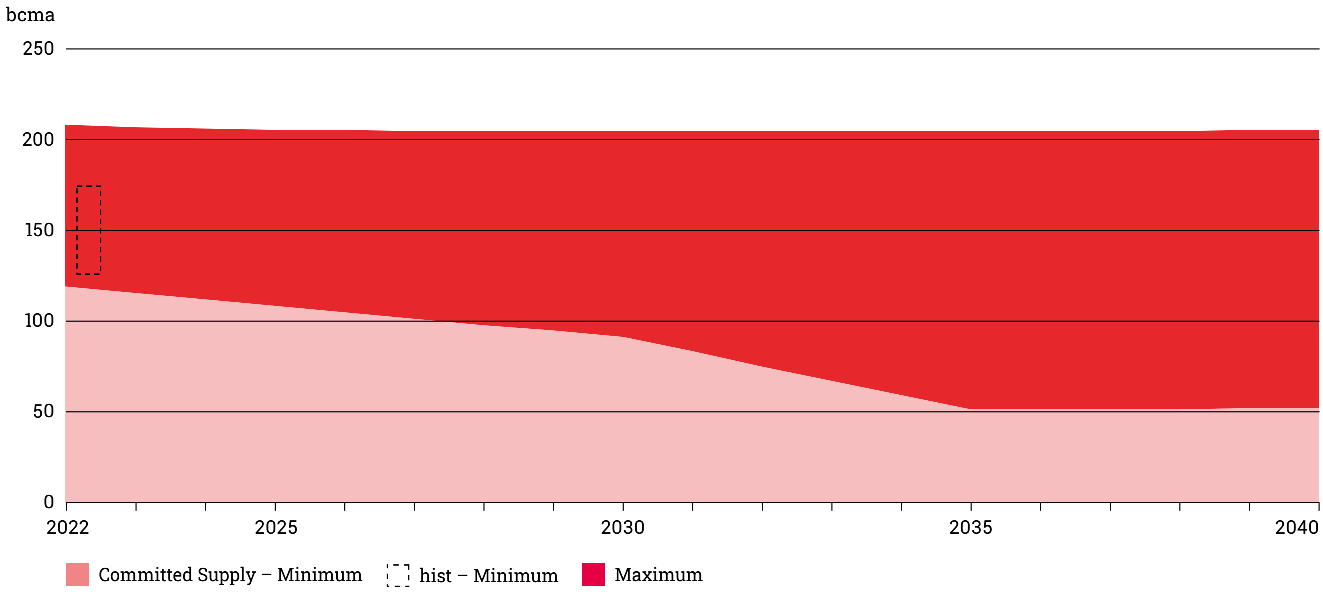

Figure 37: Russia pipeline supply potential for EU

46 IEA World Energy Outlook 2020

v Norwegian Supply Potential

Norway is currently the second largest gas supplier to the EU and supplied 116 bcm (1,288 TWh) via pipeline in 2019. This accounted for a load factor of utilised capacity of approximately 0.82 and an EU market share of 23 %.

Norway has no significant domestic demand and almost solely supplies the EU market (excluding LNG production). The northern gas fields are not connected to the EU market via pipelines, and LNG is produced for the global gas market. If an infrastructure investment to connect these gas fields with the southern infrastructure going to EU is made, the Norwegian supply potential for the EU would increase notably but also affect the production and transport cost.

The Norwegian maximum supply potential (excluding LNG) is forecasted by both the Norwegian Petroleum Directorate[47] (including discoveries and undiscovered resources) and IEA (WEO NPS additional supply) to decrease towards approximately 80 bcma in 2040. For the TYNDP 2022 projection of maximum supply potential, ENTSOG has used both the Norwegian Petroleum Directorate and the World Energy Outlook New Policy Scenarios as guidance.

For the Norwegian minimum supply potential, ENTSOG has used the IEA's assessment of committed supply (WEO NPS). The projected Norwegian supply potentials are illustrated in Figure 38.

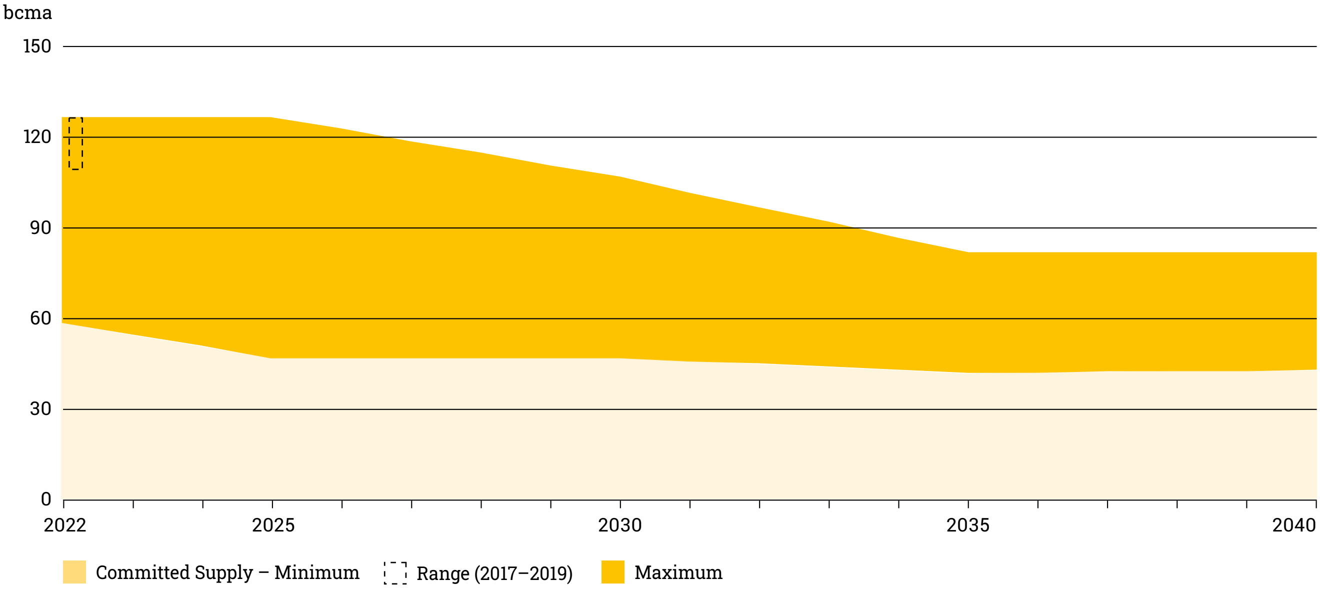

Figure 38: Norwegian pipeline supply potential for EU

vi North African Supply Potential

The North African supply from Algeria and Libya had an EU market share ranging from around 5 % to 9 % from 2010 to 2019. In average, that is 35 bcma with a load factor of utilised capacity of approximatively 0.45.

The domestic demand is increasing according to WEO 2018 and the Oxford Institute for Energy Studies[48] in 2019.

For the short-term the North African maximum supply potential is expected by ENTSOG not to exceed highest historical recorded supply and for the long-term the projection is aligned with the expectation from the WEO 2018. For the minimum potential, the projection is aligned with WEO 2018. The projected North African Supply potentials for EU are illustrated in Figure 39.

47 https://www.norskpetroleum.no/en/production-and-exports/exports-of-oil-and-gas/

48 Algerian Gas in Transition: domestic transformation and changing gas export potential (OIES, 2019), https://www.oxfordenergy.org/wpcms/wp-content/uploads/2019/10/Algerian-Gas-in-Transition-NG-151.pdf

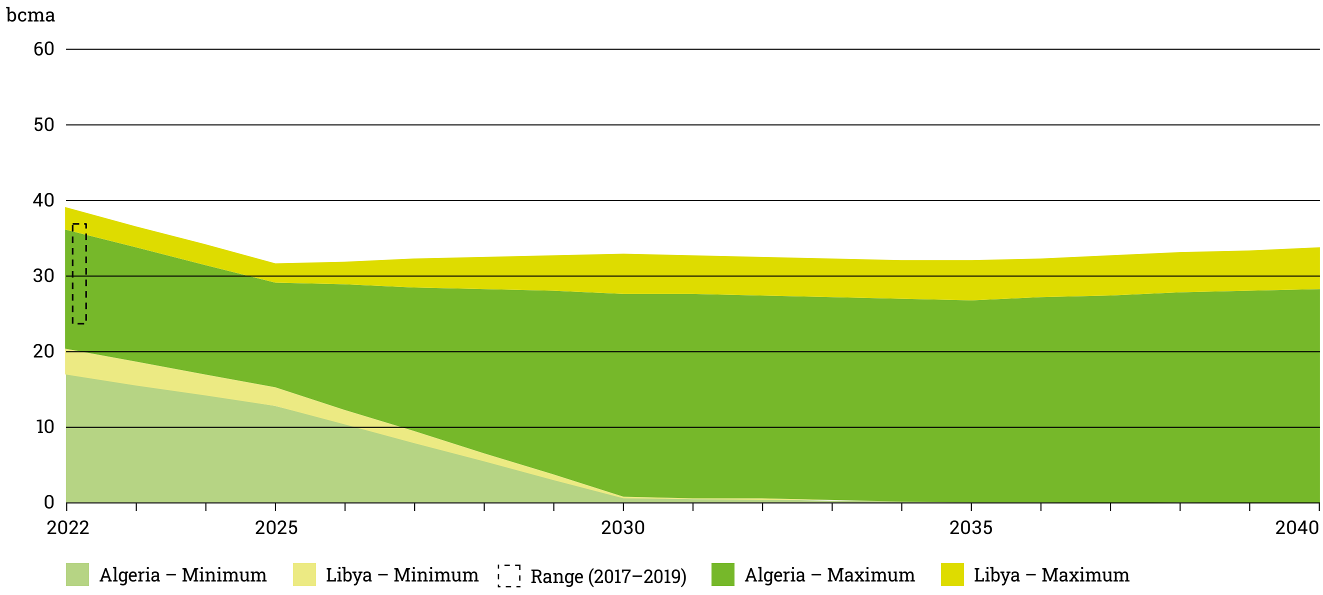

Figure 39: North Africa pipeline supply potential for EU

vii Caspian and Turkish Supply Potential

The Caspian supply potential consist of gas production from Azerbaijan and Turkmenistan, where the Turkish supply potential is gas redirected to EU from a diversity of supply sources. This can in principle be all the gas sources supplying the Turkish gas market (included LNG). The Caspian region is a new supply source to EU and is very much dependent on the current infrastructure projects.

The potential exports of gas from Azerbaijan to EU are closely linked to the development of the Shah Deniz field but other fields can potentially be relevant for export in the future. The Shah Deniz field has produced 17 bcm in 2019 and 18 bcm in 2020. Of the Shah Deniz production, 6 bcma are contracted to Turkey and 10 bcma to the EU market via the route known as the Southern Gas Corridor.

The Southern Gas Corridor consist of the Trans Anatolian Pipeline (TANAP) and Trans Adriatic Pipeline (TAP) projects, in combination with the extension of the South Caucasus Pipeline (SCPX). The Trans Adriatic Pipeline (TAP) started delivering Azerbaijani gas to Italy on December 30th 2020.

The potential for Azerbaijan export gas is correlated with infrastructure projects and with the possible expansion of the Southern Gas Corridor (e.g. SCPFX, 2025), the export potential from Azerbaijan are projected to include additional 5 bcma from either the current exporting fields or the remaining Azerbaijani fields.

The potential exports of gas from Turkmenistan to EU in the TYNDP 2022 are linked to the Trans-Caspian pipeline (TCP) project with a capacity of 30 bcma crossing the Caspian Sea to Azerbaijan with objective to transport Turkmenistan gas to the EU. This project will further need an expansion of the Southern Gas Corridor to reach Europe.

Turkey imports gas from a variety of supply sources i.e. Russia, Iran, Azerbaijan and the global LNG market (with gas from Russia as the main supplier). As EU, Turkey is looking to diversify its supply portfolio, and with that objective, BOTAS are looking to expand its infrastructure[49]. Furthermore, BOTAS has a vision of creating a Southern Gas Hub for the South East European gas market, which potentially then can supply EU with gas in the future.

The Turkish maximum supply potential is assumed to be around 7 bcma in 2030, which can be redirected gas from Azerbaijan, Russia or LNG. The projection of the Caspian and Turkish supply potentials for the EU are illustrated in figures 40 and 41 on the following page.

49 Gas Supply Changes in Turkey (OIES, 2018),
https://www.oxfordenergy.org/wpcms/wp-content/uploads/2018/01/Gas-Supply-Changes-in-Turkey-Insight-24.pdf.
Turkeys gas demand decline reasons and consequences (OIES, 2017),
https://www.oxfordenergy.org/wpcms/wp-content/uploads/2017/04/Turkeys-gas-demand-decline-reasons-and-consequences-OIES-Energy-Insight.pdf

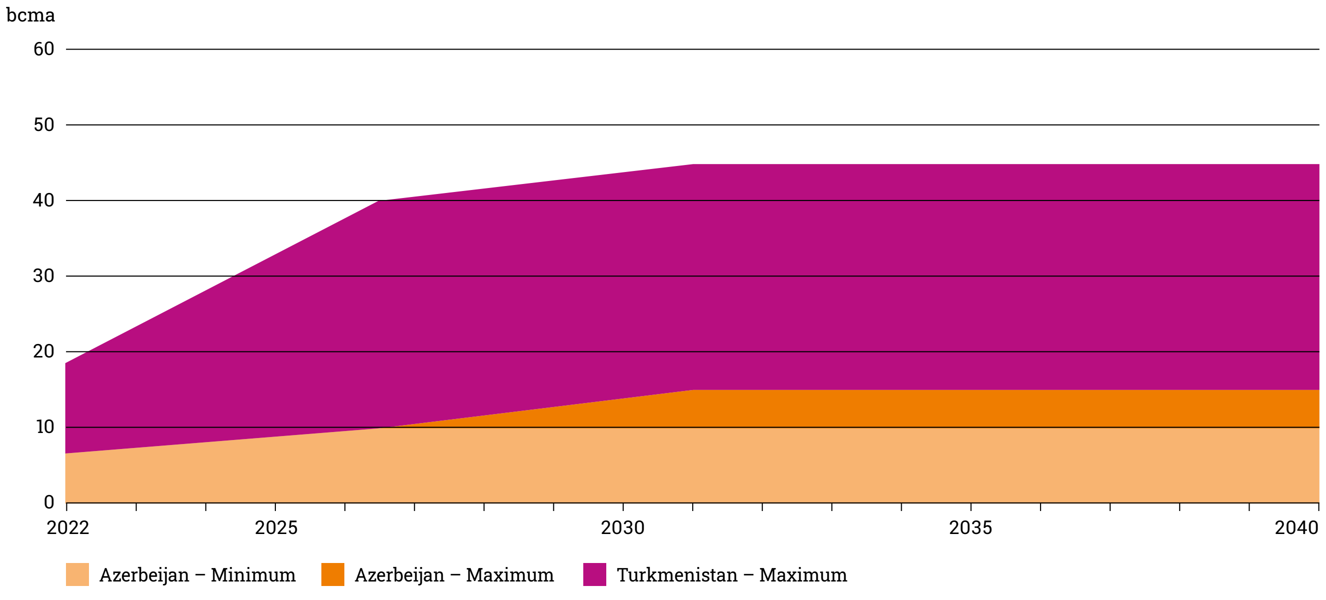

Figure 40 Caspian supply potential for EU

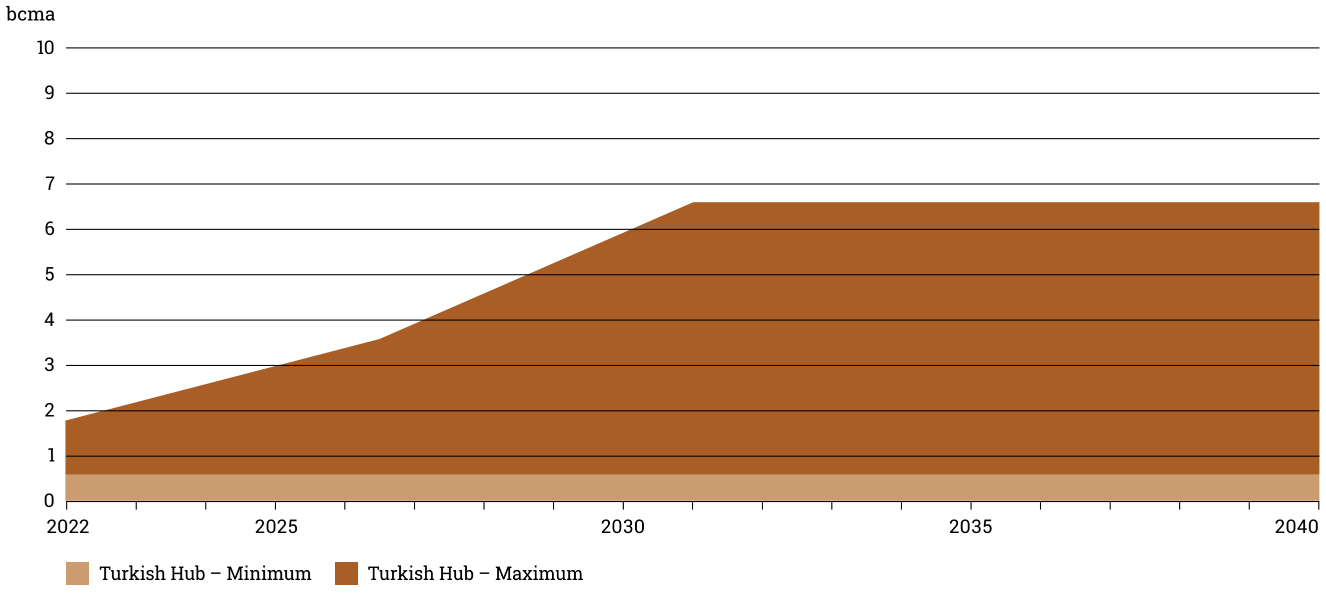

Figure 41: Turkish supply potential for EU

viii LNG Supply Potential

The market share of LNG supply has increased significantly from around 10 % from 2015 to 2018 to around 21 % in 2019. In 2019 the corresponding load factor of utilised capacity is 0,74.

LNG is expected to play an increasingly important role in Europe. This is partly expected because of the decreasing indigenous EU production and the increase in liquefication capacity in the world.

For the TYNDP 2022, the projection of the supply to EU is based on IEA's WEO. This is a specific projection of the supply potential for EU (WEO 2018).

The projection of the maximum potential is approximately constant after 2025 and accounts for 32 % of EU demand (2019). The projection for the LNG supply potential for EU is illustrated in Figure 42. The long-term LNG contracts related to the minimum potentials are projected to slowly start expiring from 2030 onwards to 2040.

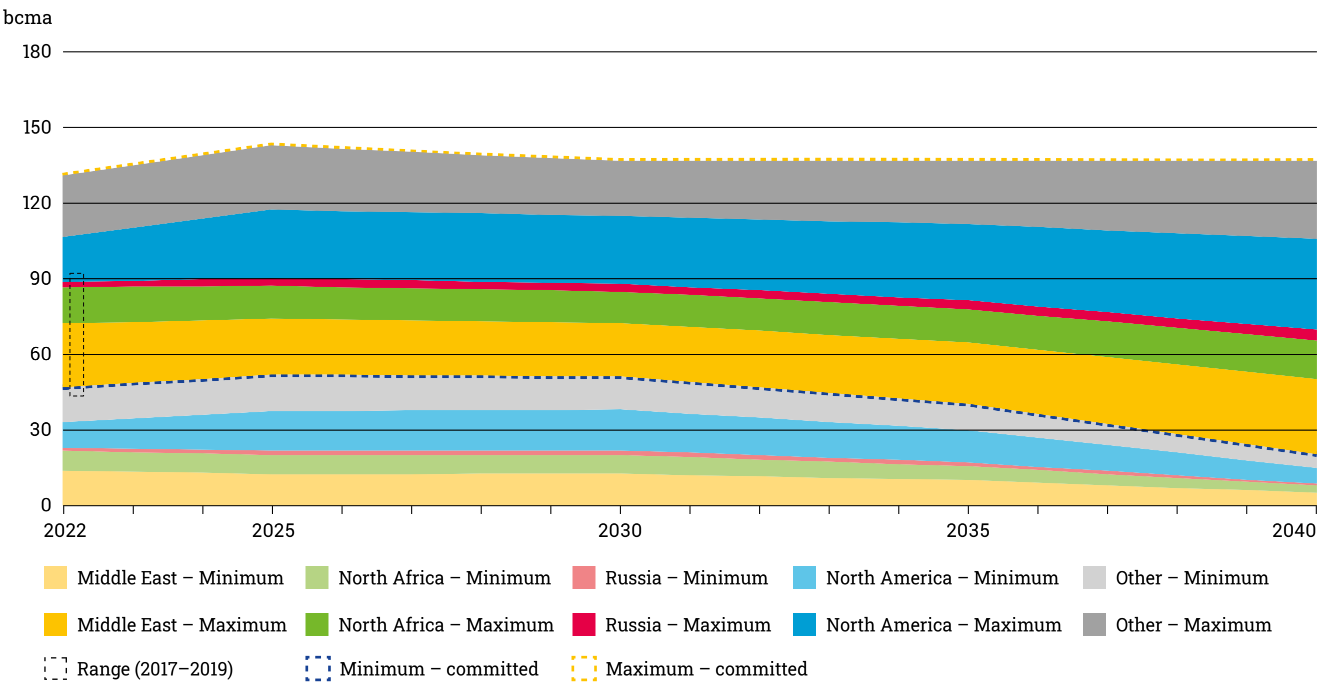

Figure 42: LNG supply potential for EU

C Biomethane – 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 75 %[50] compared to Distributed Energy.

i 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 list
- the feedstock categories and feedstock types
- natural gas low heating value
- biomethane low 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 (%)

ii 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

50 For France the values for Distributed Energy and Global Ambition are identical.

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.

iii 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.

Land for sequential cropping in 2017 (1,000 ha) =
UAA per MS (1,000 ha) × 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 25 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.

Sequential crop yield in 2050 ((tonne DM)/ha) =
Average summer silage crop yield in 2050 ((tonne DM)/ha) × Sequential crop yield (% of average summer silage crop yield) Member State region

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 25: 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.

Average summer silage crop yield in 2050 ((tonne DM)/ha) =
Average summer silage crop yield in 2017 ((tonne DM)/ha) × (1 + Yield increase to 2050 (%))

Finally, the actual sequential crop harvested in 2050 is calculated taking into account 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.

Harvested sequential crop in 2050 (ktonnes DM) =
Land for sequential cropping in 2017 (1,000 ha) × Sequential crop yield in 2050 ((tonne DM)/ha)

Table 27 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	Default 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***

* 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.)

Table 27: Input assumptions used for feedstock potential in 2050 from sequential cropping

iv 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.

Sustainable potential allocated to biomethane use in 2030 (ktonne DM) =
Sustainable potential per agricultural residue type in 2030 (ktonne DM) × 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-energy 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.

Sustainable potential allocated to biomethane use in 2050 (ktonne DM) =
Sustainable potential allocated to biomethane use in 2030 (ktonne DM) × (1+Yield increase to 2050 (%))

Table 28 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 share of agricultural residues to biomethane use – Cereal straw	%	30 %*
Allocation share of agricultural residues to biomethane use – Grain maize stover	%	50 %**
Allocation share of agricultural residues to biomethane use – Rapeseed & sunflower stubbles, rice, straw and sugarbeet leaves	%	50 %**
Allocation share of agricultural residues to biomethane use – Prunings (including apples, peers, cherries, vineyards, olive pits and citrus)	%	100 %***
Yield increase to 2050	%	0 %****

* Spottle et al., 2013, "Low ILUC potential of wastes and residues for biofuels: Straw, forestry residues, UCO, corn cobs", http://www.mvak.eu/test5674213467/Ecofys_2013_low_ILUC.pdf

** Navigant expert opinion

*** Elbersen et al., 2016, "Outlook of spatial biomass value chains in EU-28", http://iinas.org/tl_files/iinas/downloads/bio/biomasspolicies/Elbersen_et_al_2016_Outlook_of_spatial_biomass_value_chains_in_EU28_(D2.3_Biomass_Policies).pdf

**** Navigant expert opinion considering the EU Agricultural Outlook for 2030, https://ec.europa.eu/info/sites/info/files/food-farming-fisheries/farming/documents/medium-term-outlook-2018-report_en.pdf

Table 28: Input assumptions used for feedstock potential in 2050 from agricultural residues

v 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.

Sustainable potential of food waste in 2030 (ktonne as received) = Total technical potential of animal & mixed food waste plus vegetable waste in 2030 (ktonne as received) × (1 + 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.

Sustainable potential of food waste in 2030 (ktonne DM) =
Sustainable potential of food waste in 2030 (ktonne as received) × (1 – 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 20 gives an overview of the input assumptions related to the calculation steps followed to estimate the feedstock potential from food waste in 2050.

Sustainable potential of food waste in 2050 (ktonne DM) =
Sustainable potential of food waste in 2030 (ktonne DM) × (1 + Yield increase to 2050 (%))

Parameter	Units	Default value
Additional share from technical to sustainable potential	%	10 %*
Moisture content	%	40 %**
Yield increase to 2050	%	0 %*

* Navigant expert opinion)

** Elbersen et al., 2016, "Outlook of spatial biomass value chains in EU-28", http://iinas.org/tl_files/iinas/downloads/bio/biomasspolicies/Elbersen_et_al_2016_Outlook_of_spatial_biomass_value_chains_in_EU28_(D2.3_Biomass_Policies).pdf

Table 29: Input assumptions used for feedstock potential in 2050 from

vi 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.

Sustainable potential of manure produced in stables in 2010 (ktonne DM) =
Technical potential of manure produced in stables in 2010 (ktonne DM) × 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.

Sustainable potential of manure produced in stables in 2050 (ktonne DM) = Sustainable potential of manure produced in stables in sustainable scenario in 2010 (ktonne DM) × (1 + Yield increase to 2050 (%))

Member State	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 31: Sustainable potential shares to calculate the sustainable potential for different manure types and per member state

vii 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 32 shows, the potential is estimated to remain the same as in 2030.

Total potential of common sludges produced in households and in other sectors in 2050 (ktonne DM) = Total potential of common sludges produced in households and in other sectors in 2030 (ktonne DM) × (1 + Yield increase to 2050 (%))

Parameter	Units	Default value
Yield increase to 2050	%	0 %*

* Elbersen et al., 2016, "Outlook of spatial biomass value chains in EU-28", http://iinas.org/tl_files/iinas/downloads/bio/biomasspolicies/Elbersen_et_al_2016_Outlook_of_spatial_biomass_value_chains_in_EU28_(D2.3_Biomass_Policies).pdf (53)

Table 32: Input assumptions used for feedstock potential in 2050 from sewage sludge

viii 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.

Organic municipal waste generated in 2017 (ktonne as received) =
Municipal waste generated in 2017 (ktonne as received) × Share of organic fraction in MSW (%)

Organic municipal waste generated in 2017 (ktonne DM) =
Organic municipal waste generated in 2017 (ktonne as received) × (1 – Moisture content (%))

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

Organic municipal waste generated allocated to biomethane use in 2017 (ktonne DM) =
Organic municipal waste generated in 2017 (ktonne DM) × 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.

Organic municipal waste generated allocated to biomethane use in 2050 (ktonne DM) =
Organic municipal waste generated allocated to biomethane use in 2017 (ktonne DM) × (1 + Yield increase to 2050 (%))

Table 33 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
Share of organic fraction in MSW	%	60 %*
Moisture content	%	40 %*
Allocation share of organic volume to biomethane use	%	30 %*
Yield increase to 2050	%	–30 %*

* Navigant expert opinion

Table 33: Input assumptions used for feedstock potential in 2050 from Municipal Solid Waste (MSW)

ix 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 stabilize, so same figures as in 2016 apply for 2050.

Wood waste generated in 2016 (ktonne DM) =
Wood waste generated in 2016 (ktonne as received) × (1 – Moisture content (%))

Wood waste generated allocated to biomethane use in 2016 (ktonne DM) =
Wood waste generated in 2016 (ktonne DM) × Allocation share of waste wood to biomethane use (%)

Wood waste generated allocated to biomethane use in 2050 (ktonne DM) =
Wood waste generated allocated to biomethane use in 2016 (ktonne DM) × (1 + Yield increase to 2050 (%))

Table 34 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 share of waste wood to biomethane use	%	50 %*
Yield increase to 2050	%	0 %*

* Ecofys, 2018, "Mobilising woody residues to produce biomethane",
https://gasforclimate2050.eu/wp-content/uploads/2020/03/GfC-Memo-Rethinking-the-EU-biomethane-potential-from-woody-biomass-residues.pdf

Table 34: Input assumptions used for feedstock potential in 2050 from waste wood

x 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 share 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.

Landscape care wood in 2030 (ktonne DM) =
Landscape care wood in 2030 (ktonne as received) × (1 – Moisture content (%))

Roadside verge grass in 2030 (ktonne DM) =
Roadside verge grass in 2030 (ktonne as received) × (1 – Moisture content (%))

Landscape care wood allocated to biomethane use in 2030 (ktonne DM) = Landscape care wood in 2030 (ktonne DM) × Allocation share of landscape care wood and roadside verge grass to biomethane use (%)

Roadside verge grass allocated to biomethane use in 2030 (ktonne DM) = Roadside verge grass in 2030 (ktonne DM) ×
Allocation share of landscape care wood and roadside verge grass to biomethane use (%)

Landscape care wood allocated to biomethane use in 2050 (ktonne DM) =
Landscape care wood allocated to biomethane use in 2030 (ktonne DM) × (1 + Yield increase to 2050 (%))

Roadside verge grass allocated to biomethane use in 2050 (ktonne DM) =
Roadside verge grass allocated to biomethane use in 2030 (ktonne DM) × (1 + Yield increase to 2050 (%))

Table 35 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 share of landscape care wood and roadside verge grass to biomethane use	%	90 %**
Yield increase to 2050	%	0 %** ***

* Navigant expert opinion

** Ecofys, 2018, "Mobilising woody residues to produce biomethane", https://gasforclimate2050.eu/wp-content/uploads/2020/03/GfC-Memo-Rethinking-the-EU-biomethane-potential-from-woody-biomass-residues.pdf

*** Elbersen et al., 2016, "Outlook of spatial biomass value chains in EU-28", http://iinas.org/tl_files/iinas/downloads/bio/biomasspolicies/Elbersen_et_al_2016_Outlook_of_spatial_biomass_value_chains_in_EU28_(D2.3_Biomass_Policies).pdf

Table 35: Input assumptions used for feedstock potential in 2050 from landscape care wood and roadside verge grass

xi 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 m3. In order 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/m3) – 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 actually primary thinnings
- Allocation share of primary thinnings to biomethane use – finally, this accounts for the share of primary thinnings that will be allocated to biomethane production

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

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

Roundwood removal – seasoned wood in 2016 (ktonne DM) =
Roundwood removal – seasoned wood in 2016 (ktonne as received) × (1 – Moisture content (%))

Roundwood removal – seasoned wood in 2050 (ktonne DM) =
Roundwood removal – seasoned wood in 2016 (ktonne DM) × (1 + Harvest increase to 2050 (%) + Yield increase to 2050 (%))

Primary thinnings in seasoned wood in 2050 (ktonne DM) =
Roundwood removal – seasoned wood in 2050 (ktonne DM) × Share of primary thinnings from roundwood removal (%)

Primary thinnings in seasoned wood allocated to biomethane use in 2050 (ktonne DM) =
Primary thinnings in seasoned wood in 2050 (ktonne DM) × Allocation share of primary thinnings to biomethane use (%)

Table 36 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	%	5 %**
Allocation share of primary	%	100 %**

* Engineering toolbox: https://www.engineeringtoolbox.com/wood-density-d_40.html

** Navigant expert opinion

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

xii 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 (1,000 m3) for the year 2015 per Member State.

In order 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 climatic zone. Member States are categorised by climatic zone. Within the EU-27, Member States are predominantly located in the temperate climatic 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/m^3) – 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.

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

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

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

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

Sustainably removed roundwood in 2050 – coniferous & non-coniferous species (ktonne DM) =
Sustainably removed roundwood in 2015 – coniferous & non-coniferous species (ktonne DM) × (1 + Yield increase to 2050 (%))

Table 37 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 %***

* Spottle et al., 2013, "Low ILUC potential of wastes and residues for biofuels: Straw, forestry residues, UCO, corn cobs", https://zoek.officielebekendmakingen.nl/blg-248798.pdf

** Engineering toolbox: https://www.engineeringtoolbox.com/wood-density-d_40.html

*** Navigant expert opinion

Table 37: Input assumptions used for feedstock potential in 2050 from branches and tops

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