ACCOMPANYING DOCUMENT TO SCENARIO

Adequacy and flexibility study 2026-2036

Details on the scenario and data submitted to public consultation

05/11/2024

Contents

1. Introduction

1.1. Context

Elia organizes a public consultation on the input data and assumptions, as well as on methodology that will be used for the study regarding the adequacy and flexibility needs of the Belgian power system for the 2026-2036 time horizon.

The consultation aims at receiving any comment from market participants on this data and the methodology or any other comment on the provided supporting documents.

The consultation period is set from 05/11/2024 until 05/12/2024, 6PM, is publicly announced on the Elia website and is discussed at an Adequacy Working Group on November 5, 2024.

This public consultation is a voluntary initiative by Elia in order to elaborate a robust study and to collect the valuable input from market parties, both on input data and the methodology. Note that the complete methodology (made of several appendix documents and which builds further on the methodology of the previous study) is also available within this public consultation. It should be noted that only a part of the methodology could be adapted based on stakeholders' feedback (some methodological changes require several months/years of work and/or are not always possible in the context of this legally required study).

The recent years have been profoundly marked by events such as the COVID-19 pandemic and its lockdowns, the Ukraine war and the energy crisis. Important policies/announcements have been made in 2021 and 2022 by European Commission (i.e. Fit-For-55 packages, RePowerEU) alongside new national ambitions for some countries. In 2023 and 2024, European Commission has released relevant updates (Fit-For-55 packages, draft updated NECP by MS) and political agreements (e.g. reform of the EU's electricity market design and Net-Zero Industry Act).

Based on today's known information, the **'current commitment' (CENTRAL) scenario** submitted to consultation for this Adequacy and Flexibility study follows the **current commitments and ambitions**. Regarding this scenario, Elia would like to highlight two points:

- In order for the stakeholders to have enough time to react and for Elia to perform and publish the study by June 2023, the consultation is taking place during the month of November. However, **reality checks** with latest available 2024 data will be performed beginning of 2025, with the final scenario to be presented in February 2025.
- The recent years have also shown substantial uncertainty, making it challenging to create a CENTRAL scenario. Therefore, Elia welcomes any **proposal for quantified sensitivities and alternative scenarios to be assessed**.

The input data submitted to this public consultation as well as the proposed changes in the methodology itself have been discussed during four 'Comité de Collaboration' meetings that took place prior to the launch of this public consultation (meetings between Elia, FPS Economy, Federal Planning Bureau and CREG). The answers of the public consultation will also be discussed within the same 'Comité de Collaboration'.

In the framework of this new study, several documents are submitted for consultation:

- The present document which gives an overview on all input data and assumptions;
- An Excel file with detailed input data;
- Methodological & assumptions appendices:
    - Unit Commitment and Economic Dispatch;
    - Electricity consumption;
    - Thermal generation modelling;
    - Electric vehicle modelling;
    - Heat pump modelling;

  - Batteries modelling;
  - Adequacy metholodology;
  - Reliability standard;
  - Adequacy patch;
  - Climate years;
  - Cross-border exchange capacities;
  - Economic viability assessment.
- The study from Professor K. Boudt on « *Analysis of hurdle rates for Belgian electricity capacity adequacy and flexibility analysis over the period 2026-2036* ».

Regarding the **flexibility assessment**, focusing on the flexibility required to cover unexpected variations of demand and generation through intra-day and balancing markets, two specific documents are submitted to consultation:

- Methodology for the assessment on short-term flexibility;
- Assumptions for the assessment on short-term flexibility.

All documents are available in the same location on Elia's website.

1.2. Belgian regulatory framework

The legal ground of this study has not evolved since the 2019 study. Article §4bis of the electricity law still reads (in NL and FR):

"§ 4bis. Uiterlijk op 30 juni van iedere tweejaarlijkse periode voert de netbeheerder een analyse uit met betrekking tot de noden van het Belgische elektriciteitssysteem inzake de toereikendheid en de flexibiliteit van het land voor de komende tien jaar.

De basishypotheses en -scenario's alsook de methodologie die gebruikt worden voor deze analyse worden bepaald door de netbeheerder in samenwerking met de Algemene Directie Energie en het Federaal Planbureau en in overleg met de commissie."

§ 4bis. Au plus tard le 30 juin de chaque période biennale, le gestionnaire du réseau réalise une analyse relative aux besoins du système électrique belge en matière d'adéquation et de flexibilité du pays sur un horizon de dix ans. Les hypothèses et scénarios de base, ainsi que la méthodologie utilisés pour cette analyse sont déterminés par le gestionnaire du réseau en collaboration avec la Direction générale de l'Energie et le Bureau fédéral du Plan et en concertation avec la commission.

Prior to this public consultation, there have been four 'Comité de Collaboration' meetings (meetings between Elia, FPS Economy, Federal Planning Bureau and CREG). Throughout these meetings, the elements currently submitted for consultation have been presented and discussed.

Further collaboration and concertation with the aforementioned entities is foreseen throughout the further elaboration of this study.

Concerning the legal reliability standard, Elia has followed the most recent legal basis, being the royal decree of 31 August 2021 on the determination of the Reliability Standard and the approval of the values of the Value of Lost Load and the Cost of a New Entrant, where the reliability standard for Belgium is set at 3 hours.

1.3. European regulatory framework

The Regulation 2019/943 of June 5th 2019 foresees in its article 23 that a methodology should be elaborated for the European resource adequacy assessment to be followed and carried out by ENTSO-E. This methodology has been adopted by ACER on October 2nd 2020. The link with the national adequacy assessments is made through article 24 of Regulation 2019/943, which stipulates that such assessments shall be based on the European methodology.

Under the Electricity Regulation (Regulation 2019/943, article 23), ENTSO-E is thus required to consider, among others, the following aspects:

- An economic viability assessment (EVA) of resource capacities;
- Flow-based (FB) modelling of the power network (when applicable);
- Impact of climate change on adequacy;
- Analysis of additional scenarios, including the presence or absence of CMs;
- Consideration of energy sectoral integration;
- Time horizons of 10 years with annual resolution.

The first application of this adopted European methodology by ENTSO-E was in 2021 with the ERAA2021 report. Furthermore also under the Electricity Regulation (Regulation 2019/943, article 23), the ERAA methodology is to be implemented by ENTSO-E in a stepwise process, following an implementation roadmap starting from the 2021 edition [1].

In May 2024, ACER approved ERAA (ERAA 2023) for the first time. Currently ENTSO-E is aiming towards the publication of the ERAA2024 edition by the end of this year.

Similarly as for the previous Adequacy and Flexibility study published in 2023 (AdeqFlex'23 study), the proposed methodology for this Adequacy and Flexibility study to be published in 2025 (AdeqFlex'25 study) is expected to be fully compliant with the ERAA methodology.

2. Geographical scope and time horizon

2.1. Geographical scope

In this study, 28 European countries will be simulated. This is similar to the previous Adequacy & Flexibility study published in 2023 (i.e. including Lithuania, Latvia, Estonia, Romania, Bulgaria, Greece and Croatia). This means that all EU countries and enables to simulate the Central Europe CCR (Capacity Calculation Region) used for the flow-based domains.

Note that, although it is required to simulate whole Europe in order to perform a qualitative adequacy study, the adequacy results will be focused on Belgium, as it is the main reason of this study. Other analysis at EU-level could be done but it will not be the main focus of this study.

[1] https://www.entsoe.eu/outlooks/eraa/implementation-roadmap/

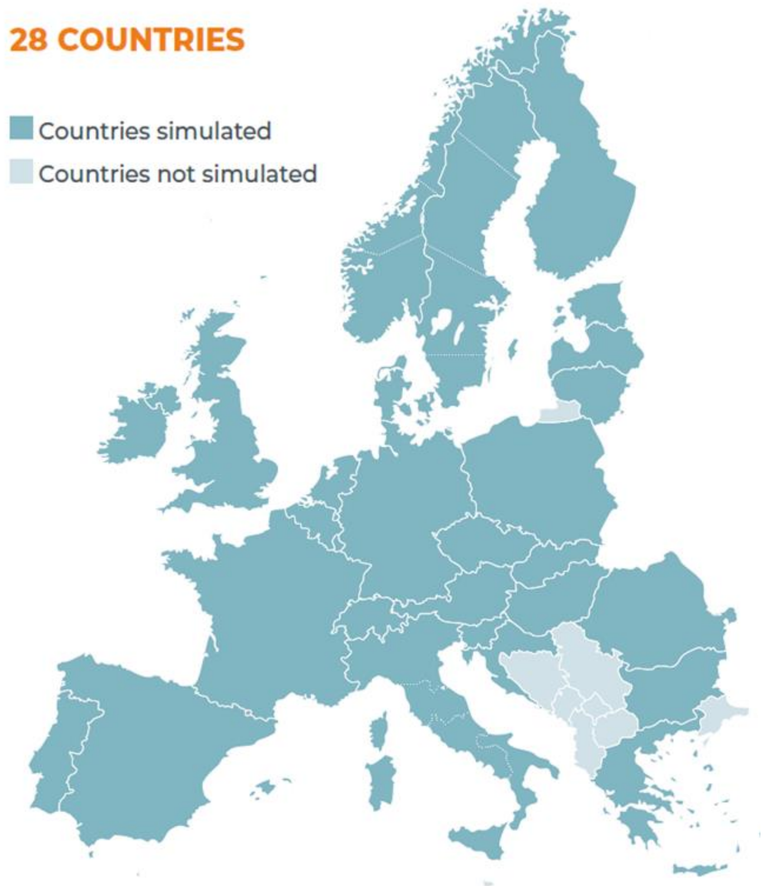

Figure 2-1 Geographical scope of the study

2.2. Time horizon

Regarding the time horizon, the study will cover the years from 2026 to 2036 corresponding to Y+1 to Y+10.

While most TSO and ENTSO-E only analyse a limited number of target years, Elia goes further and proposes to analyse the adequacy situation for each year of the 10-years horizon.

Next to the adequacy analysis, Elia will perform the flexibility study and the economic analysis. Sensitivities will also be performed on certain years.

Given the large amount of time horizons but also the type of analysis, it is important to note that not all the detailed analysis will be done for all time horizons/type of analysis. A choice will be made to have the most relevant target years.

Note that each year examined in the study will be run from 1 September to 31 August of the following year. Therefore, the year 2025 will include the entire winter period of 2025-26. This calendar does not prevent to compare the results with other studies which are also straddling the calendar years.

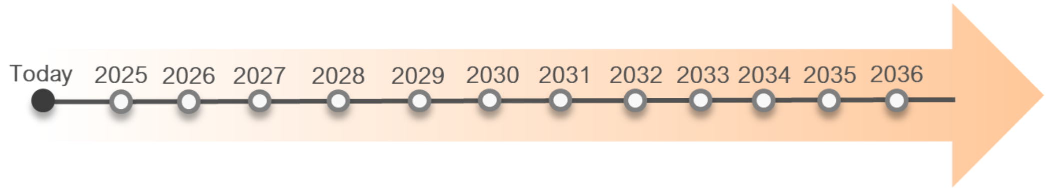

Figure 2-2 Time horizon of the study

3. Methodology

The whole methodology is submitted for consultation. It is based on the previous study but also complemented with additional information and proposal for improvements. Those are detailed in the different documents also submitted to public consultation. The main updates on the methodology were also presented during the WG Adequacy of 05/11/2024.

The methodological appendices:

- Unit Commitment and Economic Dispatch;
- Electricity consumption;
- Thermal generation modelling;
- Electric vehicle modelling;
- Heat pump modelling;
- Batteries modelling;
- Adequacy study;
- Reliability standard;
- Adequacy patch;
- Climate years;
- Cross-border exchange capacities;
- Economic viability assessment;
- Methodology for the assessment on short-term flexibility;

The study from Professor K. Boudt on « Analysis of hurdle rates for Belgian electricity capacity adequacy and flexibility analysis over the period 2026-2036 » is also submitted to consultation, together

4. Main references for the scenario

The scenario proposed for this AdeqFlex'25 study takes into account several references (see Figure 4-1 below). In general, the CENTRAL scenario is built following the current commitment and announced policies of Belgium and other countries.

In particular for Belgium, it should be noted that the scenario is aligned with the **updated draft Federal Energy and Climate Plan** published in November 2023[2] or with more recent governmental announcement (e.g. 'Nieuwe Vlaamse Regeerakkoord' Sep. 2024)[3].

Elia is calling the stakeholders to react to the consultation on the CENTRAL scenario. Given the unpredictable factors Europe has experienced recently, Elia is also asking stakeholders to react on suggestions for **sensitivities and alternative scenarios** which would deviate from the current commitments.

The scenario proposed for this study is aligned with the most recent figures and ambitions of Belgium and other countries

- aligned with the last published **updated draft Federal Energy and Climate Plan** for **Belgium or** with more **recent governmental announcements,** including feedback from DSO's and Regions**;**
- **data** for **other countries** are based on the **ERAA24** complemented with more recent information/ambitions and national studies;
- the approved **Federal Grid Development plan** for Belgian grid assumptions;
- the **Clean Energy Package** for the capacity calculation;
- the **TYNDP 2024** for countries outside Central Europe Region's **grid** assumptions;
- the **IEA** – World Energy Outlook 2024 for fuel and carbon prices complemented with **forward prices**;
- different **sources** for CAPEX and fixed costs of technologies;
- an **academic study** for defining the **economic viability metric**;
- **local flexibility profiles** considering regional tariffs evolution;

Figure 4-1 Main references used for the CENTRAL scenario

5. Thermal fleet

The 'CENTRAL' scenario for thermal fleet considers all existing capacities, unless a closure has been officially announced, as well as the capacities contracted in a CRM auction. It also includes the foreseen official nuclear phase-out calendar plus the lifetime extension of the two newest nuclear units. New CHP capacities under construction and information available on REMIT is considered too.

Thermal generation in Belgium is made of:

- **nuclear** power plants;
- combined cycle **gas** turbine (CCGT) units and open cycle gas turbine (OCGT) units, which are gas-fired power plants;
- **turbojets**, which can be compared to aircraft motors, using oil as fuel;
- **biomass** and **waste** units, using wood and waste as fuel;
- **combined heat and power** (CHP) units, also called co-generation units, that generate electricity and another by-product such as heat at the same time.

In the study, two types of thermal generation unit are considered, corresponding to the type of units which are modelled:

[2] **https://www.nationalenergyclimateplan.be/en**

[3] https://www.vlaanderen.be/nieuwsberichten/nieuwe-vlaamse-regering-en-vlaams-regeerakkoord-2024-2029

- large units which are usually directly connected to the Elia grid; these units are individually modelled in the simulations of the electricity market; Information is provided on a unit-by-unit basis on the net generation capacity, the efficiency, the variable operating and maintenance cost, the in-service year and assumed out-of-service year if the information is available as well as the status of the unit for the economic viability assessment.;
- smaller decentralised units which are usually connected to the distribution grid; these units are aggregated and a profile based on historical data is applied.

The list of individually modelled thermal units is given in the Excel file under the sheet '1.1. Ind. mod. thermal prod'.

The profiled thermal capacity is given in the Excel file under the sheet '1.2. Renewables and profiled'.

Figure 5-1 illustrates the proposed thermal capacity (both individually modelled and profiled generation) to be considered in the CENTRAL scenario.

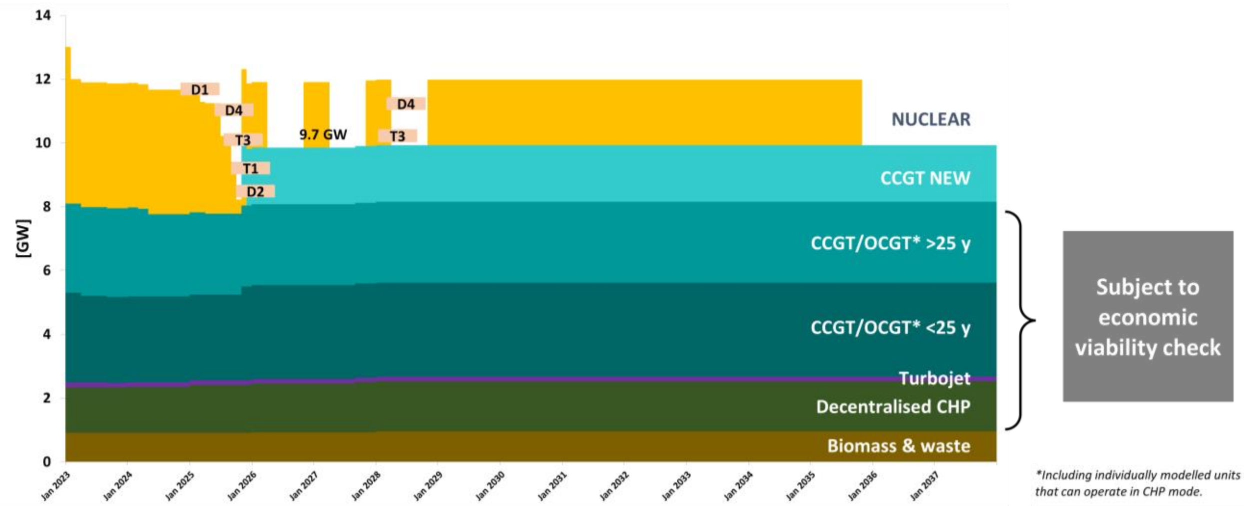

Figure 5-1 Proposed thermal capacity evolution in Belgium

5.1. Nuclear

For the CENTRAL scenario, the proposal is to use the following assumptions:

- Closure of the following nuclear units as planned in the current official nuclear phase-out calendar being:
  - Doel 3: 1 October 2022;
  - Tihange 2: 1 February 2023;
  - Doel 1: 15 February 2025;
  - Doel 4: 1 July 2025;
  - Tihange 3: 1 September 2025;
  - Tihange 1: 1 October 2025;
  - Doel 2: 1 December 2025.
- 10-year nuclear extension of Doel 4 & Tihange 3 with partial availability during summer 2026 to 2028 included due to long-term operation (LTO) works; those units are therefore available from the 1st of November 2025 until the 30th of October 2035 and are not considered in the CENTRAL scenario for winters 2035-36 and 2036-37.

Those assumptions are summarised in Figure 5-2.

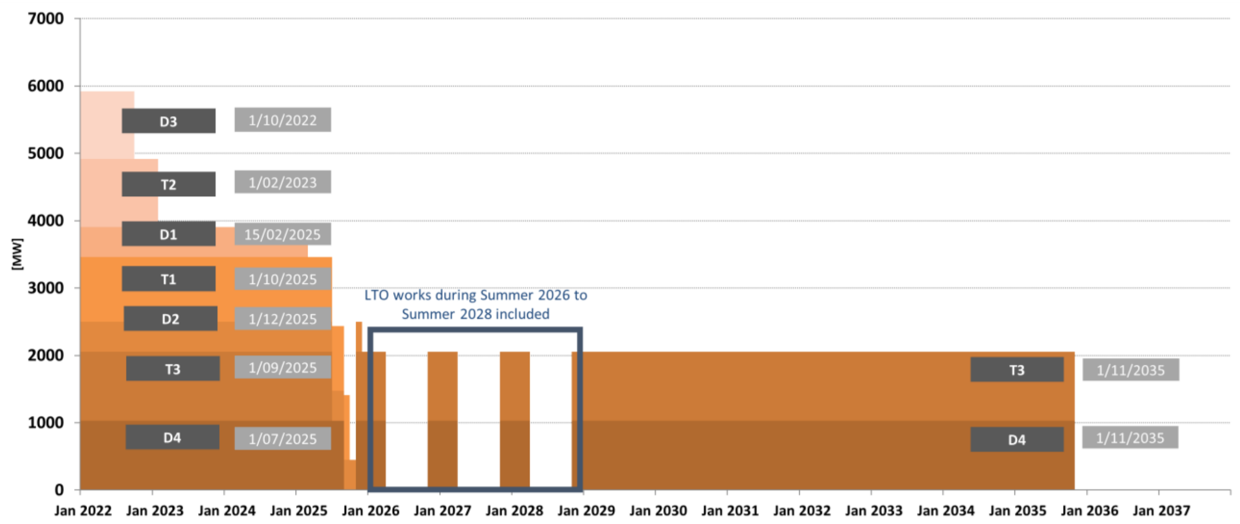

Figure 5-2 Planned evolution of the installed nuclear capacity in Belgium

5.2. Gas-fired units

The CENTRAL scenario considered the following assumptions:

- 2 new CCGT units (Seraing 885 MW and Flémalle 890 MW) contracted in the CRM Y-4 auction for Delivery Period 2025-26 with a 15 years contract, are assumed available as from 01/11/2025;
- Vilvoorde GT (255 MW) is considered as available as from the 1st of November 2025, following the information published on NordPool[4];
- Vilvoorde ST (105 MW) and Zwijndrecht Lanxess ST (15 MW) are considered as decommissioned in 2023 and Sappi Lanaken (43 MW), Fluxys Zeebrugge (40MW), and Seraing ST (170 MW) are considered as decommissioned in 2024 (Art. 4 bis)[5], therefore not considered for the time horizon of this study.
- Rodenhuize is considered as a backup unit to Zelzate Knippegroen for burning steel gas when Knippegroen is unavailable;
- A repowering of Zandvliet Power is considered as of November 2024, following the information published on NordPool[6].

The capacity assumed for the smaller gas-fired CHP units is based on existing and future projects. To do so, Elia uses the PISA database: an Elia database containing all units of the Belgian system (which are connected to the TSO and DSO grids), which is based on data that DSOs communicate to Elia on a regular basis. In addition to the known future

[4] https://umm.nordpoolgroup.com/#/messages/937ab00f-4cd1-4aca-9c2d-0ef05594fd28/2

[5] https://economie.fgov.be/fr/themes/energie/securite-dapprovisionnement/electricite/mecanismes-de-capacite/reserve-strategique/notifications-de-mise-larret

[6] https://umm.nordpoolgroup.com/#/messages?publicationDate=all&eventDate=custom&units=22WZANDVL000255D&status=active&eventDateStart=1970-01-01&eventDateStop=2124-10-31

projects, a rather optimistic assumption is taken by considering no potential additional decommissioning of the existing capacities, considering that those units can still participate in CRM auctions, at least until the mechanism is available.

5.3. Oil-fired units (turbojets)

The capacity of turbojet (oil) is considered constant (140 MW) for the whole time horizon of this study (considering the closure of turbojet Volta in 2023).

It is important to note that these units have high specific CO_2 emissions and will not be able to participate in upcoming CRM auctions.

The economic viability of existing turbojets is also assessed via the EVA. Due to the high specific emissions associated with oil-fired units, no new units are considered as EVA candidates.

5.4. Biomass & waste

The existing fleet of individually modelled biomass and waste units is considered constant throughout the time horizon of this study.

Regarding decentralised biomass and waste units (modelled as profiled thermal units in the simulations), the existing capacity is considered constant (no closure assumed) and about 40 MW of new projects in biomass by 2030 are assumed, based on information available in the PISA database.

6. Renewable energy sources (non-thermal)

6.1. Solar PV

Solar photovoltaic (PV) energy is becoming an increasingly significant part of Belgium's electricity landscape. Belgium has seen substantial growth in solar PV installations over recent years. The 2023 year was a record year with nearly 2,000 MWp installed. The total installed capacity in Belgium has now reached more than 10 GWp.

Even though the high increase observed in 2023 has been influenced by the recent energy crisis and by the rush in Wallonia to benefit of the advantages of net metering, the installed capacity is expected to continue growing in Belgium (reduced solar panel prices, legislation in Flanders for certain consumer to be equipped with solar pannels, etc.).

Note that the data in the Excel file and in this document are expressed in [MWp] or [GWp] – also called MWpeak / MWcrete (on the DC side of the solar pannel).

The proposed evolution of solar capacity in Belgium is based on the following assumptions:

- A best estimate for installed capacity end of 2024 (using online data from BRUGEL for Brussels, data from SPWallonia and online data from VEKA for Flanders[7]);
- Interpolation between 2024 best estimate and 2030, considering for 2030 the latest official targets
    - For Wallonia, a target of 5 GWp is assumed, considering the 5100 GWh stated in the updated draft NECP;
    - For Brussels, a target of 0.325 GWp is assumed, considering the 334 GWh stated in the updated draft NECP;
    - For Flanders, a target of 11.2 GWp is assumed, considering the recent 10 GW announced in the recent Flemish governmental agreement (target assumed to be in GWac and considering conversion factor MWp/MWac of 1.12).
- Extrapolation based on 2025-2030 growth rate for the period after 2030.

This leads to a proposed installation rate of 900 MWp per year in Belgium with a total capacity of 16.5 GW by 2030.

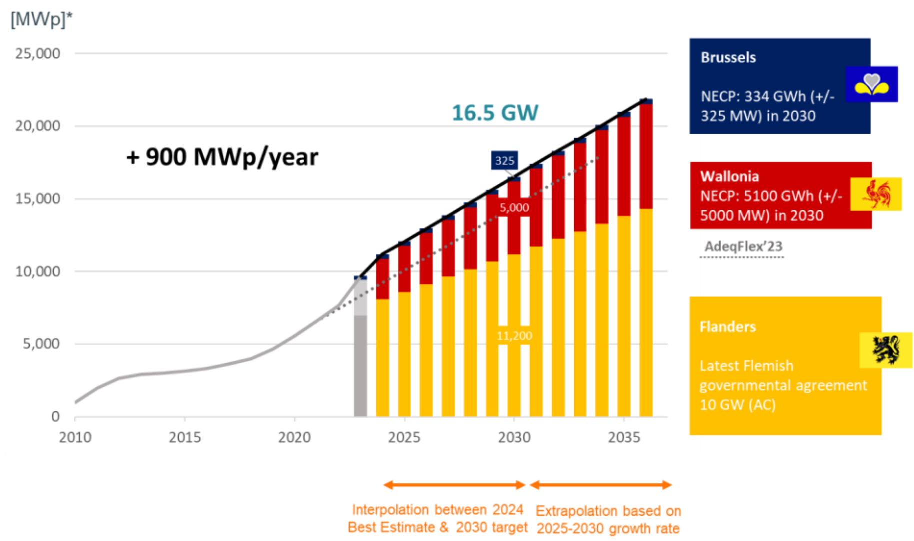

Figure 6-1 Proposed solar PV capacity evolution in Belgium

The solar PV capacity is given in the Excel file under the sheet '1.2. Renewables and profiled'

[7] Considering a conversion factor MWp/MWac of 1.12 for the online data from VEKA

6.2. Onshore wind

Regarding onshore wind, the recent Flemish governmental agreement (Sep. 2024) has increased the 2030 target from 2.6 GW to 2.8 GW. In Wallonia, the Walloon governmental agreement confirmed its commitment to achieve the European objectives while revising the wind onshore development framework.

The proposed evolution of onshore wind capacity in Belgium for the CENTRAL scenario is based on the following assumptions:

- A best estimate for installed capacity end of 2024 about 3.4 GW (using EDORA data for Wallonia and VEKA data for Flanders)
- Interpolation between 2024 best estimate and 2030, considering for 2030 the latest official targets
    - For Wallonia, a target of 3.2 GW is assumed, considering the 6200 GWh stated in the updated draft NECP;
    - For Flanders, a target of 2.8 GW is assumed, considering the announcement in the recent Flemish governmental agreement.
- Extrapolation based on 2025-2030 growth rate for the period after 2030 for Wallonia. For Flanders, a slower uptake after 2030 is considered (limited additional capacity under current permitting conditions, according to exchanges with the Region).

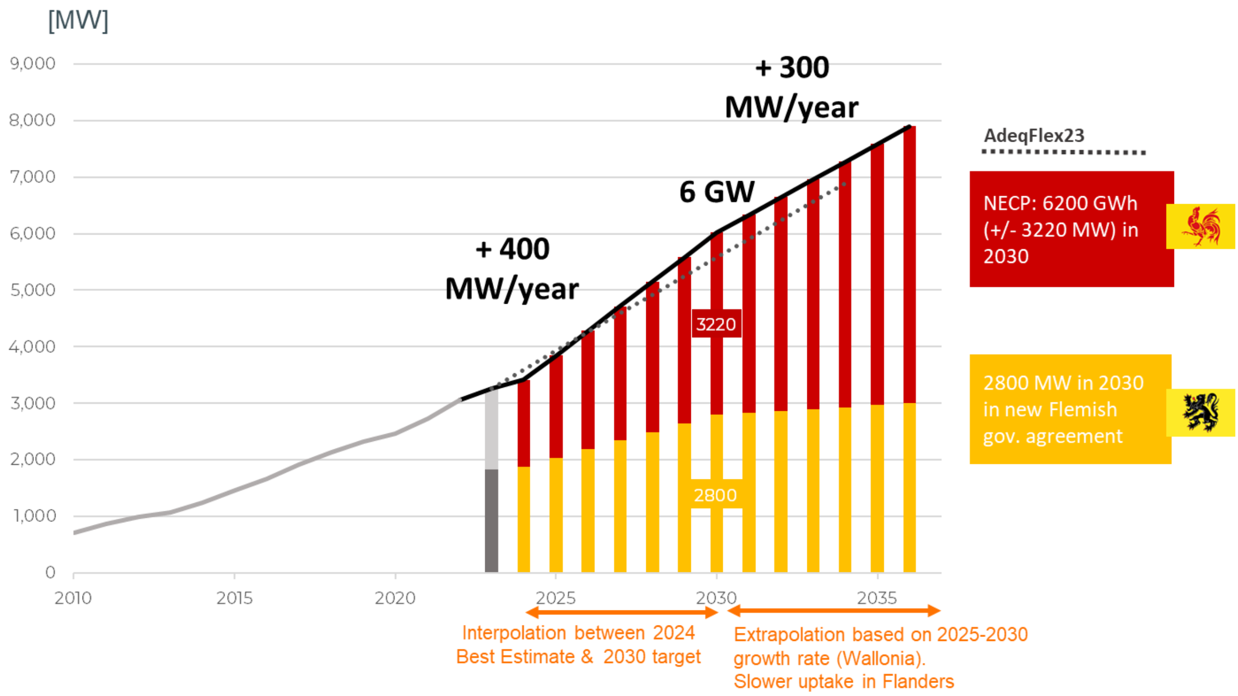

Figure 6-2 Proposed onshore wind capacity evolution in Belgium

The onshore capacity is given in the Excel file under the sheet '1.2. Renewables and profiled'

6.3. Offshore wind

When it comes to offshore wind, Belgium already accounts for 2,261 MW of installed capacity. Additional capacity related to the Princess Elisabeth Island (PEI) project is considered in the proposed trajectory, based on the foreseen realisation timing of the validated Federal Development Plan.

- The first phase of PEI, with an additional 700 MW, is to be realised by end of 2029 and is proposed to be assumed as available for adequacy as from winter 2030/31 in this study.
- The second phase of PEI, with an additional 2,800 MW, is to be realised by end of 2030 and is proposed to be assumed as available for adequacy as from winter 2031/32 in this study.

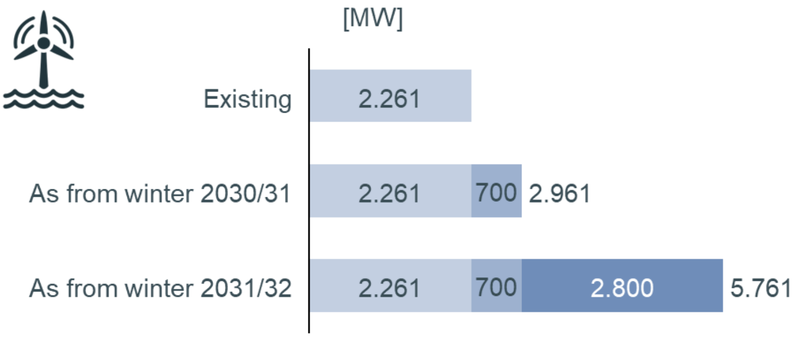

Figure 6-3 Proposed offshore wind capacity evolution in Belgium

The offshore capacity is given in the Excel file under the sheet '1.2. Renewables and profiled'

6.4. Run-of-river hydroelectricity

The existing run-of-river hydroelectricity capacity in Belgium consist of small hydro units installed along the river. Most of the capacity is located in Wallonia, along the Meuse. According to the Bilan Energétique de Wallonie 2020, the evolution of the installed capacity in Wallonia seemed to stagnate since the 1980's[8].

The proposed trajectory for run-of-river hydroelectricity is based on the following assumptions:

In the NECP, a target of 440 GWh of run-of-river hydroelectricity towards 2030 is specified. Based on

- Best estimate for installed capacity end of 2024 about 136 MW based data from estimation from PISA database and historical data;
- Interpolation between 2024 best estimate and 2030, considering a target of 170 MW for Belgium (based on the 440 GWh specified for Wallonia in NECP and historical capacity factors), a capacity which is then maintained constant.

[8] bilan-transformation-renouvelable-cogeneration-2020.pdf

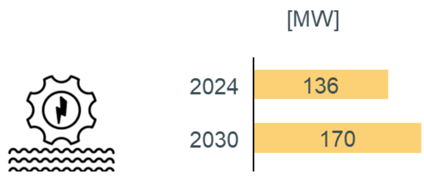

Figure 6-4 Proposed RoR hydroelectricity capacity evolution in Belgium

The run-of-river capacity is given in the Excel file under the sheet '1.2. Renewables and profiled'.

7. Electricity demand

The total electricity demand for Belgium is constructed with several building blocks as illustrated on Figure 7-1. The building blocks are the following:

1) **Existing usages** (residential & industry): evolution of the existing usages of electricity considering macro-economic forecasts, energy efficiency, price elasticity and demand recovery (see section 7.1);
2) **New transport electrification**: additional electric vehicles (EV) (see section 7.2);
3) **New building heat electrification**: it includes the trends in terms of electrification of heating (see section 7.3).
4) **New large-scale loads**: additional data centers and electrification of industry (section 7.4);
5) **Losses**: transport and distribution losses estimates based on total load;

This chapter will further describe the assumptions of the 4 first building blocks. Note that the flexibility associated to each of the building block is described in the next chapter.

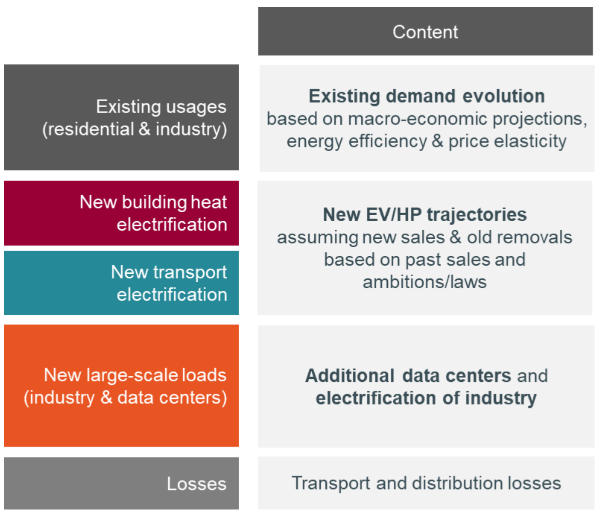

Figure 7-1 Building blocks of the electricity demand scenario

The total electricity demand is shown in Figure 7-2. More information regarding the consumption per building block is given in the dedicated sections.

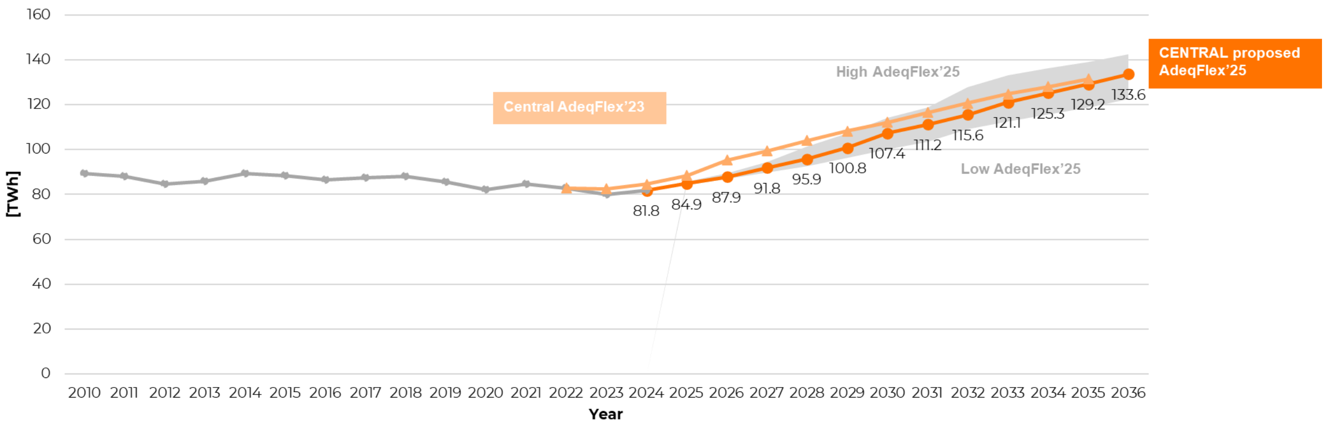

Figure 7-2 Proposed electricity demand evolution for Belgium

Precise numbers are presented in the Excel. In the figures in this document, some numbers are rounded (by thousands) for presentation purposes.

Electricity demand is presented in the Excel file under the sheet '2.1. Tot. elec. Demand'.

7.1. Existing usages

The existing use of electricity demand in Belgium has been defined and quantified with tools and methodologies developed by Climact, a Belgian consultancy company. They perform their analysis after the Federal Planning Bureau[9]'s publication of their yearly detailed macroeconomic projections at the end of June, within the framework of the scenario choice for the Capacity Remuneration Mechanism (CRM) calibration reports. The latest available projections are considered (June 2024) for this study.

The model used by Climact is based on the 'BECalc tool', which was developed by Climact for the FPS Environment, and was improved to take into account factors such as short-term economic projections to quantify total electricity demand projections in the short- and medium-term[10]. The tool factors in continuous improvements in terms of energy efficiency throughout the time horizons in all demand sectors and in different sub-categories.

In order to review the demand projections considering the recent energy crisis and high prices (which had an impact on energy demand across Europe), the Price-Linked Electricity Demand Evolutions (PRICED) study was launched before the summer 2024. The goal of the study is to distinguish the demand reduction per segment ('temporary' vs 'permanent') by:

[9] Bureau fédéral du Plan - Publication - Perspectives économiques 2024-2029 – Version de juin 2024

[10] https://www.elia.be/-/media/project/elia/elia-site/public-consultations/2020/20200603_total-electricity-demand-forecasting_en.pdf

- Capturing electricity demand evolution of the last 5 years, for each sector and each end-use;
- Computing elasticity of electricity demand (i.e. a measure of how much electricity increase/decrease changes if electricity prices decrease/increase);
- Analysing appliances sales data for energy efficiency.

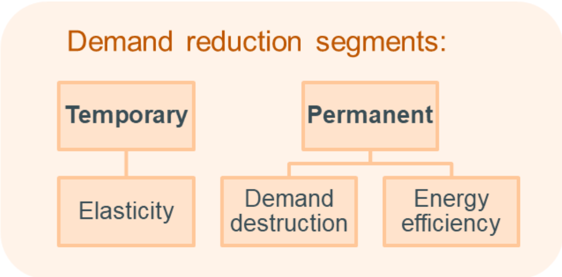

Figure 7-3 PRICED study – demand reduction segments

The study is performed in two steps (see Figure 7-4):

- The first part of the study was carried out by E-CUBE and delivered in July 2024 (results were used for the CRM load projections). Thanks to energy efficiency quantification and definition of permanent destruction, E-CUBE has delivered a first estimate for demand recovery. This was presented to stakeholders in WG Adequacy on the 27/08/2024 [11]. This first estimate for the demand recovery in the residential and tertiary sector is considered in the proposed electricity demand for this study. Due to uncertainty, a range is considered assuming either a partial recovery or a total recovery. The numbers are available in the excel published with this document. The results published and presented by E-CUBE are also subject to public consultation- and are part of a separated pdf document.

- The second part of the study will deliver final results from CLIMACT and the LIDAM institute. The latter has developed an econometric model that quantifies elasticity of the electricity demand. The model is fed various data impacting electricity demand and helps assess the impact each variable has on electricity demand. This model-based approach illustrated in Figure 7-5. To have the most relevant conclusion, the model needs to be fed with latest available data: data (monthly granularity) from 2014 until 2023. The data of electricity consumption at DSO level for 2023 were not yet available at the time of writing and are expected in the coming weeks. The final demand recovery will be delivered in the report after public consultation in early 2025. However, temporary results based on data from 2014 until 2022 has shown results in the range of E-CCUBE's estimate (integrated in the current load assumption).

Figure 7-4 PRICED study – two steps

[11] https://www.elia.be/en/users-group/wg-adequacy/20240827-meeting

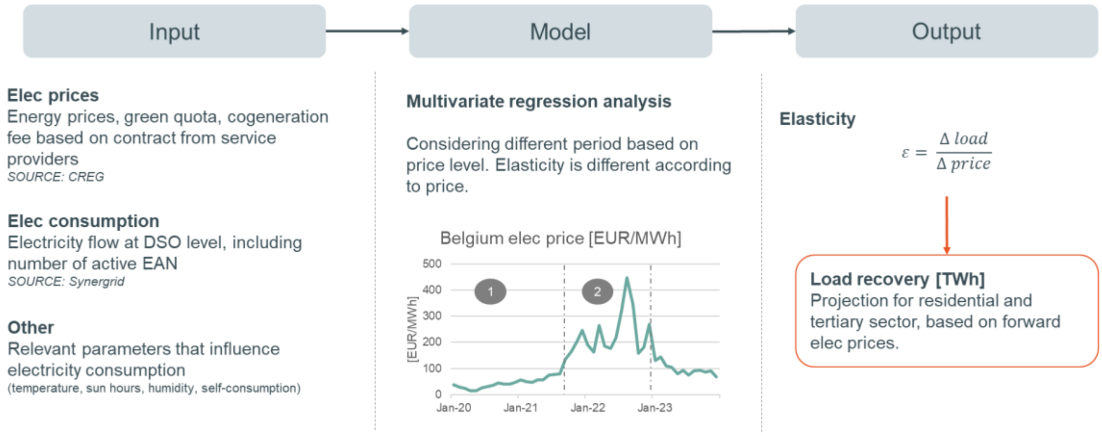

Figure 7-5 PRICED study - CLIMACT model approach for the final load recovery

7.2. Electrification of transport

Road transport is expected to electrify in the near term. Within this study we distinguish 4 different segments each with their own electrification trajectory:

- Passenger cars, where a distinction is made between private & company (including self-employed) owned vehicles;
- Vans;
- Trucks ;
- Buses, where a distinction is made between public & privately owned buses.

The proposed trajectories are derived from observed trends, discussions with relevant stakeholders and (where possible) from regional, federal, and European legislation. Detailed assumptions are included in the Excel accompanying the public consultation (sheet '2.2. Road transport demand').

The trajectories are computed by taking into account assumptions on the amount of vehicles that enter and leave the Belgian market as illustrated in Figure 7-6.

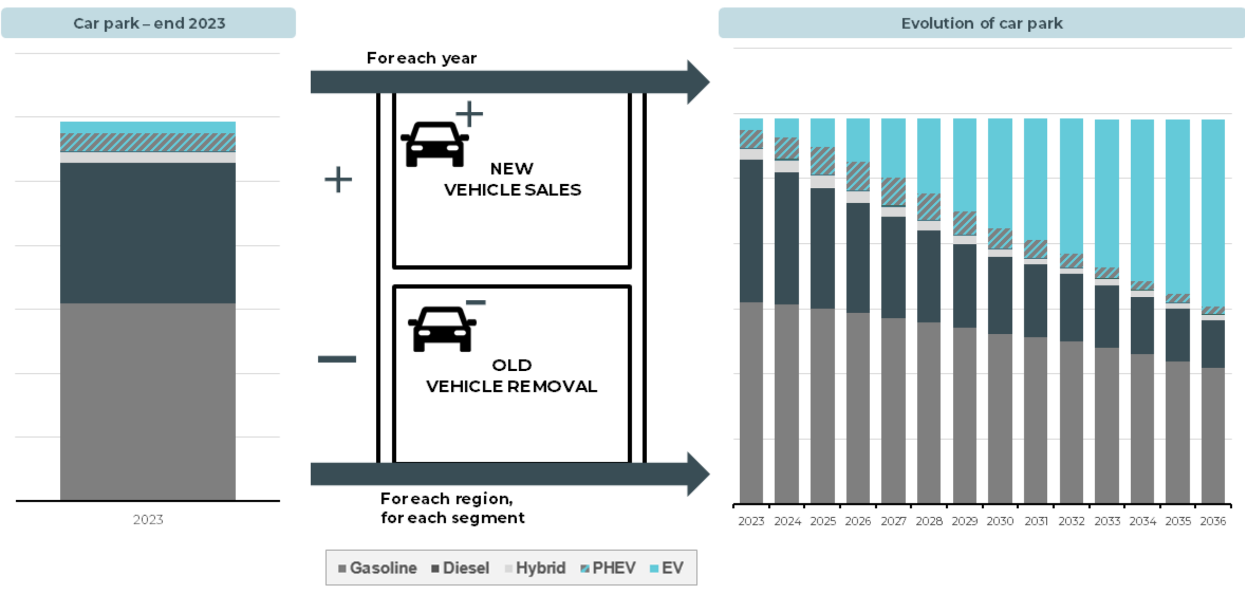

Figure 7-6 Methodology to compute vehicle stock – illustrative example for passenger cars

Passenger cars

End 2023 there were around 5.9M passenger cars on the road in Belgium, of which 180k were Battery Electric Vehicles (BEV) and 280k Plug-in Hybrid Electric Vehicles (PHEV), representing a share of around 8% of the total car stock.

In recent years, company cars have become ever more important in the total car stock, being composed of around 1.4M vehicles. It must be noted that 80% of the BEV & PHEVs are currently company owned vehicles, while this segment only represents 24% of the total market. Therefore, a clear distinction between private/company owned cars is made within this study, as these segments differ greatly in terms of expected future uptake of EVs and their usage.

For the evolution of passenger car EVs, the following assumptions are made:

- Yearly car sales follow the average of the last 5 years 2019-2023, leading to around 440k cars sold per year, including 260k/y company cars and 180k/y private cars.
- It is assumed that all passenger car sales will be fully electric by 2035, due to the EU-wide ban on the sale of petrol & diesel cars[12].
- For company cars, it is assumed that due to the fiscal measures implemented on the federal level, all sales will be fully electric by 2029 [13]
- In Brussels it is assumed that no more diesel cars are sold from 2030, gasoline from 2035 due to the Low-emission-Zone[14].

The resulting number of BEV & PHEV vehicles are provided in Figure 7-7. The rapid electrification of vehicles observed between 2024 and 2030 is mainly driven by the company car segment. As the purchasing cost remains the key driver in the private car segment, it is assumed that the electrification will take place at a somewhat slower rate, accelerating mainly from 2030 onwards.

[12] EU ban on the sale of new petrol and diesel cars from 2035 explained | Topics | European Parliament

[13] Minister Van Peteghem maakt van bedrijfswagens en laadpalen de hefbomen naar een groener wagenpark | Vincent Van Peteghem

[14] Praktisch pagina | Low Emission Zone

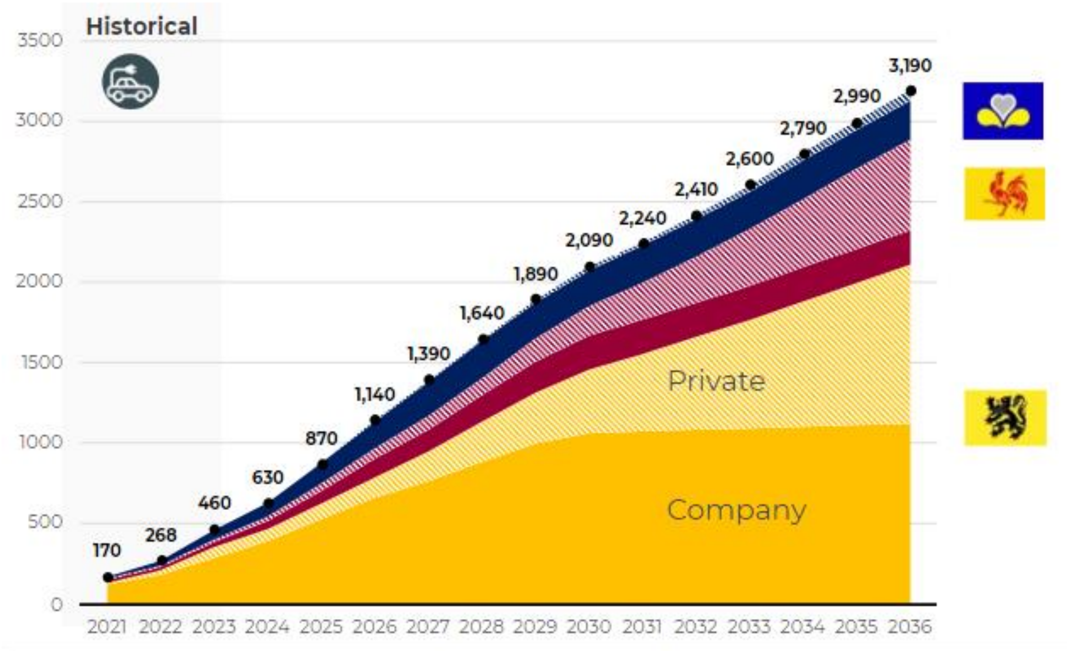

Figure 7-7 Proposed BEV+PHEV fleet per region – passenger cars

Vans

End 2023 there were around 895k vans in Belgium, of which less than 1% are electrified. In the run-up to 2035, it is assumed that vans follow the last 5 years trend (2019-2023) with around 70k sales per year. The main policy considered is the EU-wide ban on the sale of petrol & diesel engines which will also apply to vans. Therefore, it is assumed that all van sales will be fully electric by 2035. As such, LDV sales will likely follow a similar trajectory to the trajectory of passenger cars, but with a more delayed mass uptake, as shown in Figure 7-8.

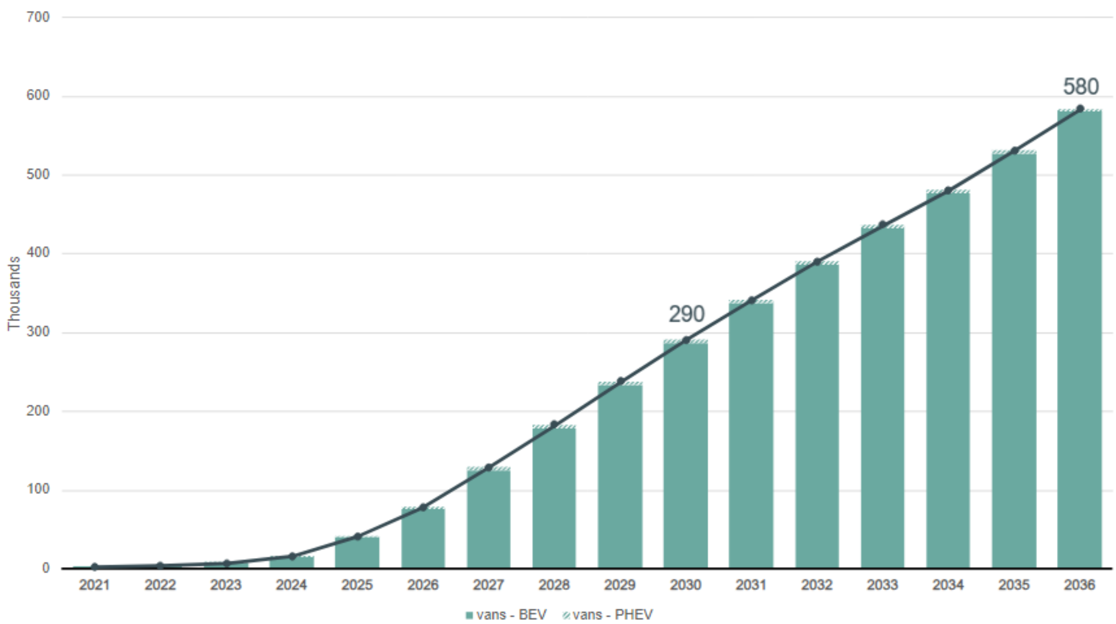

Figure 7-8 Proposed evolution of vans

Trucks

At the end of 2023, there were around 150,000 trucks in Belgium, practically none of which were electric. However, European truck manufacturers are currently starting the production of their first BEV units. This is mainly done in response to the recently stricter EU regulation[15]. According to the sector, such targets can only be reached by truck manufacturers switching from traditional drivetrains (i.e. diesel) to low-carbon ones (such as battery electric).

Therefore, it is assumed that 40% of new truck sales in Belgium will be battery electric in 2030, increasing to 75% by 2035. There are reasons to assume a stronger uptake since some major truck manufacturers have put different objectives to reach 100% Zero Emissions Vehicles (ZEV) trucks by 2040.

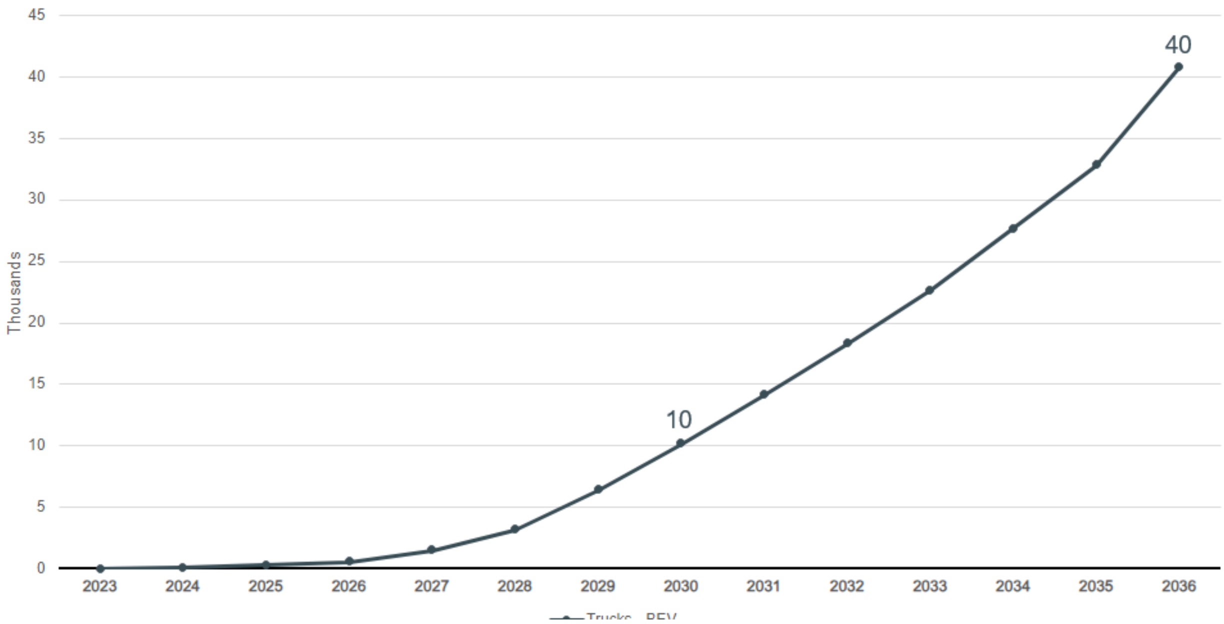

Figure 7-9 Proposed evolution of BEV trucks

Buses

At the end of 2023, there were around 16,500 buses & coaches (6200 public buses, 10300 private buses) on the road, around 3.5% of which were either BEV or PHEV.

The electrification of this segment is mainly driven by ambitions communicated by the regional public bus companies, as follows:

- in Flanders, 'De Lijn' wants to own a 100% electric bus fleet by 2035[16].
- in Brussels, the ambition is to have a 100% electric fleet by 2035[17].

[15] https://ec.europa.eu/commission/presscorner/detail/en/ip_24_287

[16] https://www.delijn.be/nl/content/over-de-lijn/toekomst-waarden/elektrificatie/

[17] https://www.rtbf.be/article/un-nouveau-pas-a-la-stib-vers-une-decarbonisation-complete-des-bus-d-ici-2035-au-tec-cela-prendra-un-peu-plus-de-temps-11426099

- In Wallonia, the objective for TEC is also to reach 100% BEV buses but with no final target year. However, as per EU regulation, all urban buses need to be zero-emission. Therefore, it is assumed all public buses to be BEV by 2035.

Note that the European regulation[18] also means that all urban buses must be zero-emission by 2035.

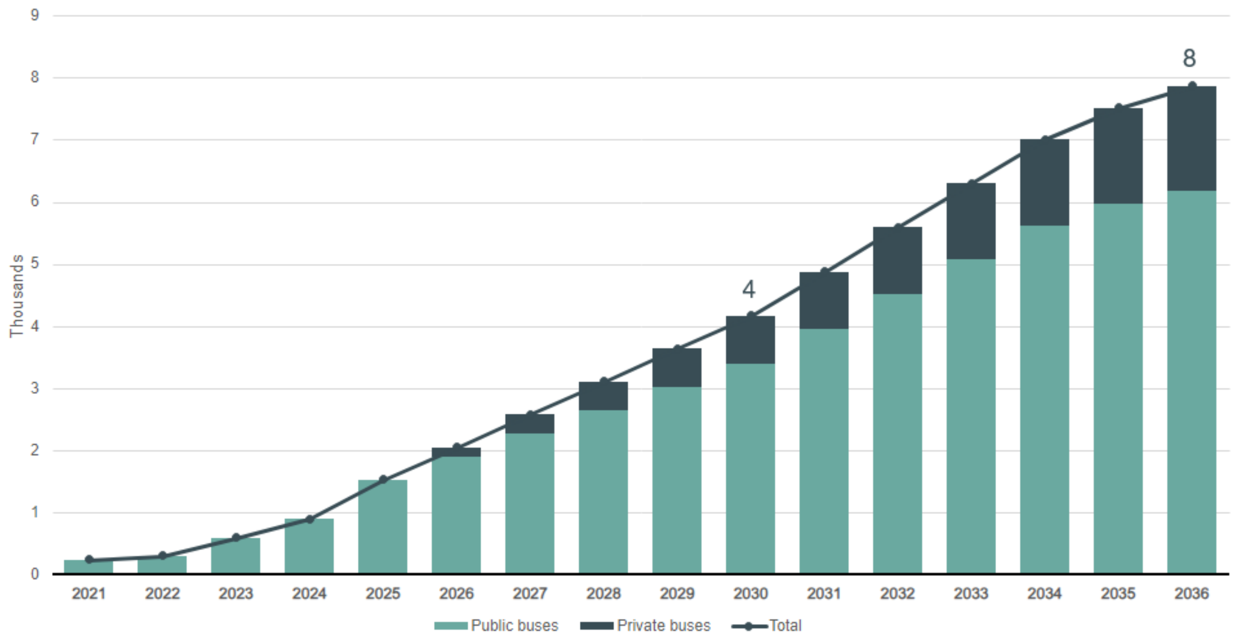

Figure 7-10 Proposed evolution of buses

Electricity demand

Bringing together the above mentioned trajectories leads to electricity demand as presented in Figure 7-11. Detailed assumptions including the amount of kilometres per year and the average efficiency per vehicle type are included in the Excel accompanying the public consultation (sheet '2.2. Road transport demand').

[18] https://ec.europa.eu/commission/presscorner/detail/en/ip_24_287

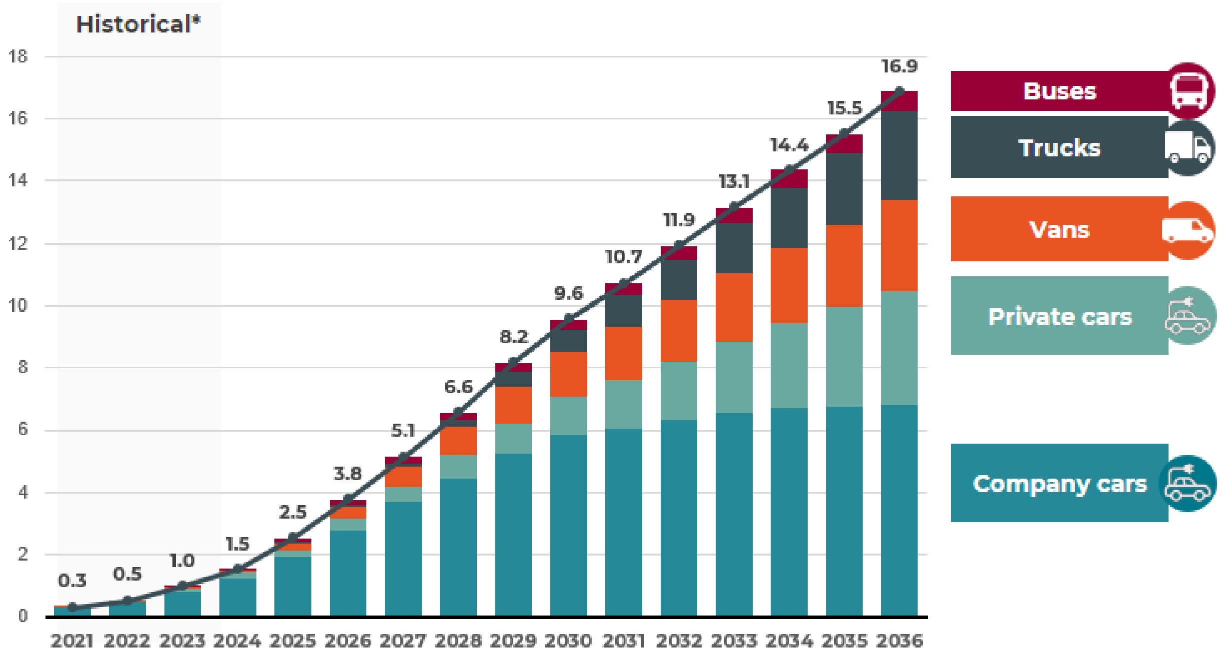

Figure 7-11 Proposed electricity demand for road transport in the current CENTRAL scenario

> The data regarding electrification of transport is given in the Excel file under the sheet '2.2. Road transport demand'.

7.3. Electrification of heat

In this paragraph an overview is given concerning the assumed amount of heat pumps for the residential and tertiary sector. Additional assumptions on heating demand per building type are included in the Excel accompanying the public consultation (sheet '2.3. Building heat demand').

In the two sectors a distinction will be made between 'hydronic' and 'aerothermal' heat pumps. The reason for this lies in the uncertainty around the heating supply and usage of both types.

The trajectories are computed by taking into account assumptions on the amount of heating devices that enter and leave the Belgian market, which depends on the number of new buildings, renovations, demolitions and heating devices being replaced at end of life, as illustrated in Figure 7-12 .

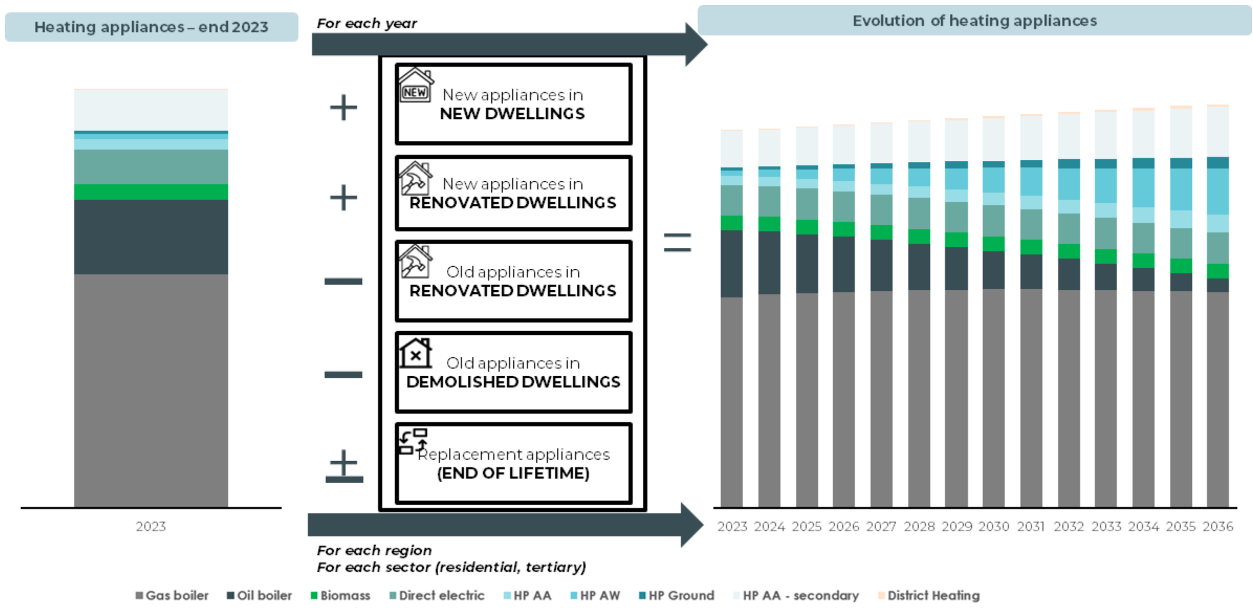

Figure 7-12 Methodology to compute heating stock – illustrative example for the residential sector

Residential

Driven by the high gas prices following the Ukraine war, sales of hydronic heat pumps have increased by respectively +75% and +65% in 2022 and 2023 to around 50k units.

The most widely installed units are currently Air-Air (AA; reversible) heat pumps with more than 900k units installed end 2023. After discussions with the sector, it is assumed that most of these units are primarily used for cooling purposes, where due to their reversible character heating is used as a secondary purpose. It is assumed that for the existing air-air heat pumps, 80% of these will be categorised as a secondary heating system (categorised as 'HP Air-Air secondary'). These secondary units are assumed to only provide 20% of the buildings annual heating demand and progressively provide less heat in (very) cold temperatures, as such contributing less to peak demand.

Assumptions on the evolution of the number of HPs in the run-up to 2035 depend on the number of new buildings, renovated buildings and old heating systems being replaced, since each of these are considered to be opportunities for HPs to be used. The following assumptions are therefore made in this study:

- 40k new dwellings added each year (which is 15k below the 5-year historical average)[19];
- The building renovation rate is assumed to increase from around 0.7% today[20] to 1.5% in 2036;
- Regarding existing heating devices, 5% of the stock is assumed to be replaced on an annual basis, which represents an asset lifetime of around 20 years.

Changes in the number of HPs across Belgium depend on the relative share of heat pumps installed in these new environments. Taking into consideration the aforementioned points, the following assumptions are made:

- Today, full-electric heat pumps are mostly installed in new buildings. For Flanders it is assumed that by 2025 all new buildings will be equipped i) either with a fully electric heat pump (96%) or ii) district heating (4%)

[19] https://statbel.fgov.be/nl/themas/bouwen-wonen/bouwvergunningen

[20] https://statbel.fgov.be/nl/themas/bouwen-wonen/bouwvergunningen

due to the phase-out of new gas connections in this region[21]. For Wallonia and Brussels no strict obligations are yet in place and it is assumed that 100% heat pump & district heating would be reached in 2035 for new buildings.

- For renovations and end-of-life boiler replacements, not a single region has put in place a strict ban on the use of fossil gas. Therefore, the replacement rate of old heating systems with HPs is assumed to increase at a modest rate to reach 23% and 35% by 2030 and 2035 respectively in buildings which have been renovated; and 20% and 27% in 2030 and 2035 respectively as end-of-life boiler replacements.

The resulting final stock of HPs is presented in Figure 7-13 and Figure 7-14.

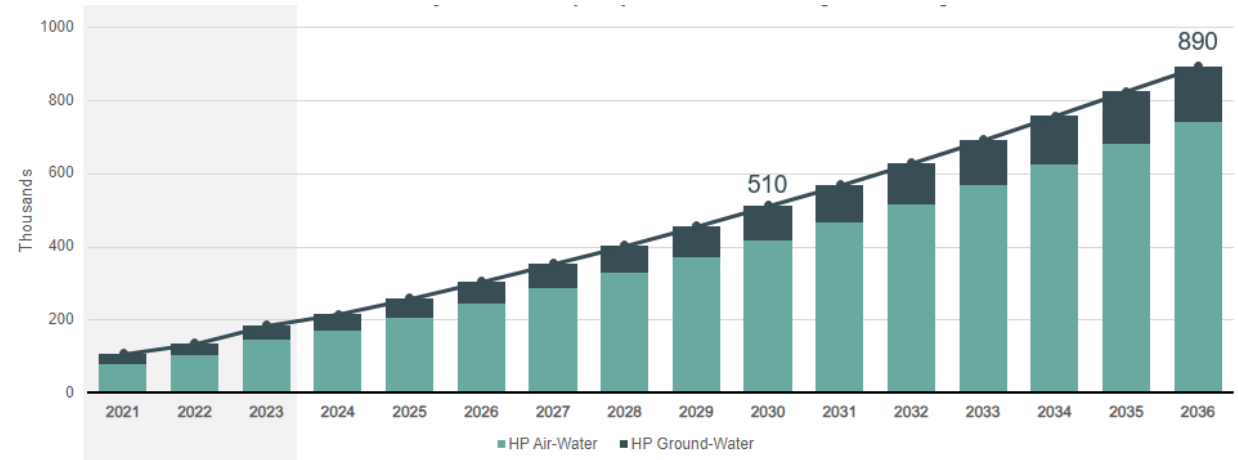

Figure 7-13 Proposed evolution of hydronic heat pumps in the residential sector

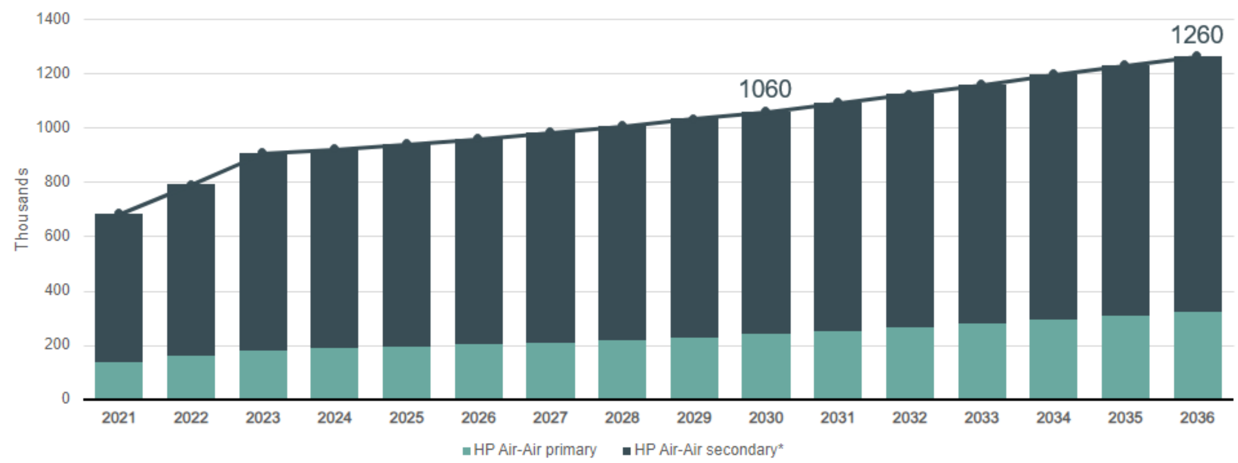

Figure 7-14 Proposed evolution of Aerothermal heat pumps in the residential sector

[21]Aansluiting voor elektriciteit of aardgas | Vlaanderen.be

Tertiary

The stock of installed HPs for primary heating purposes in the tertiary sector remained rather limited until 2023. Similar to the residential sector, their number consisted primarily of Air-Air (reversible) units, with 80% of these categorised as secondary heating units. The evolution in the number of heat pumps towards 2035 depends on:

- The number of new buildings until 2035 is assumed to remain constant until 2035, with 5.2k units being added each year, corresponding to the previous 5 year average;
- The renovation rate is assumed to increase from around 0.7% to 1.5% in 2036, similar as in the residential sector.

Compared to the residential sector, a slightly faster uptake of electrification is assumed, with fossil fuels being completely phased-out in new builds by 2030 in all regions (and by 2025 for Flanders as for residential). Additionally, in renovations it is assumed that by 2030 all heating systems are replaced by a heat pump, whereas for end-of-lifetime heating systems (without renovation) the share of heat pumps is assumed at 25% (2030) and 30% (2035).

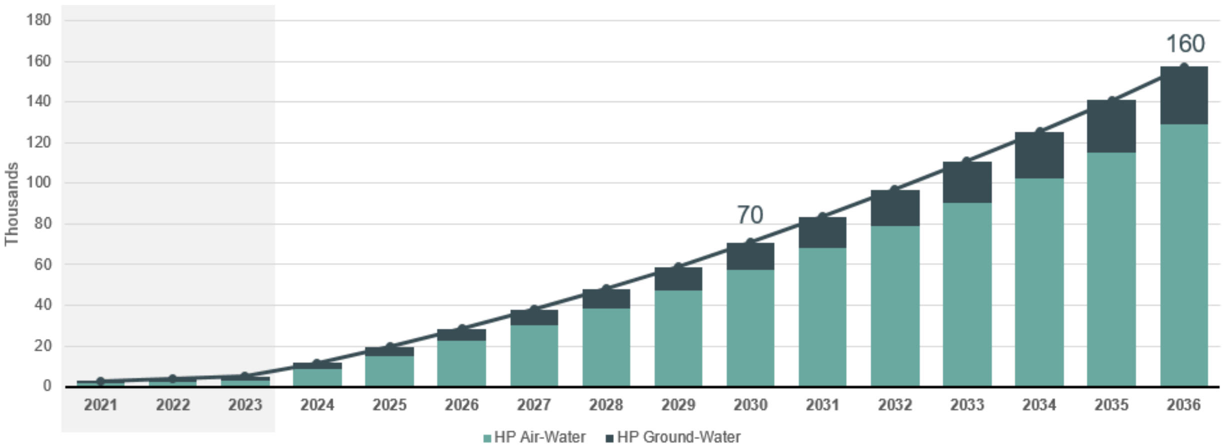

Figure 7-15 Proposed evolution of hydronic heat pumps in the tertiary sector

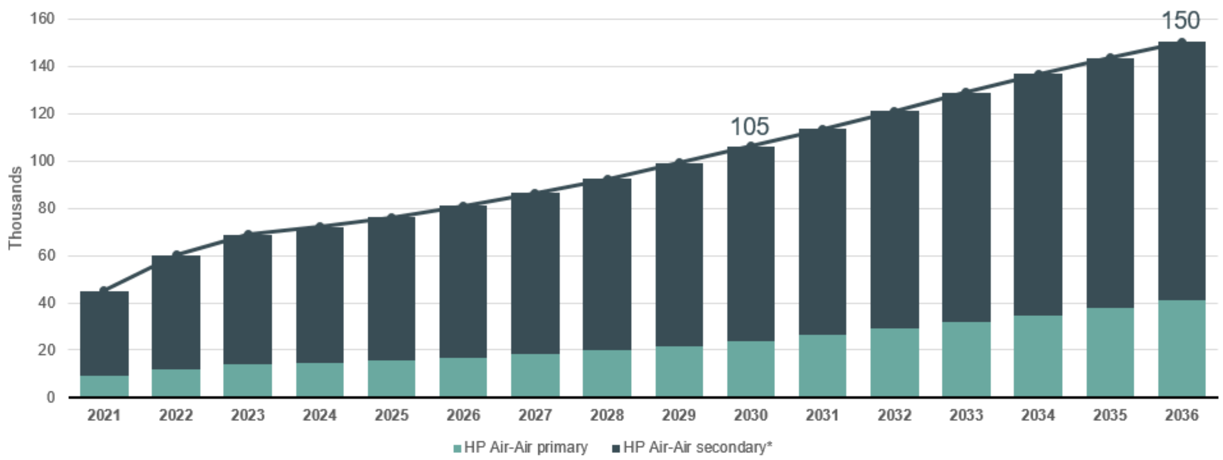

Figure 7-16 Evolution of aerothermal heat pumps in the tertiary sector

Totals per region

Figure 7-17, show the hydronic heat pump deployment per region, where most heat pumps are assumed to be installed in Flanders, which is explained simply by the larger amount of buildings in that region but also with the more stringent regulations in place, especially for new builds.

It must also be noted that the revised Energy Performance of Buildings Directive (EPBD)[22] from the EU needs to be translated into regulation by the regional authorities in Belgium. Amongst other elements, this directive aims to increase the amount of renovations and finally achieve a decarbonised building stock by 2050. Therefore, regional regulations accelerating the deployment the installations of heat pumps can be expected in the near term.

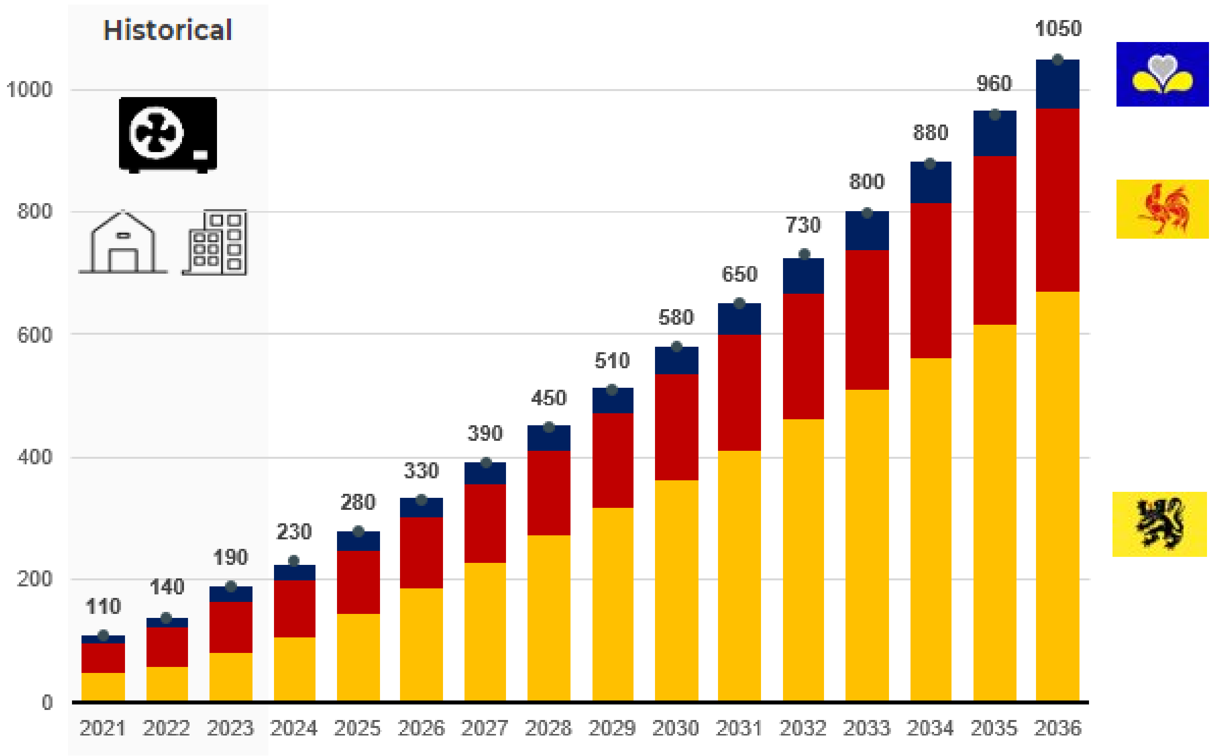

Figure 7-17 Regional evolution of hydronic heat pumps in the residential & tertiary sector

7.4. New large-scale loads

The proposed projections for Elia customers are informed by our load management exercise, conducted yearly with our industrial customers. In 2024's edition, customers defined for the first time decarbonisation scenarios associated to probabilities of realisation. These scenarios were then aligned into Low, Central & High scenarios to account for the diverse ways in which customers defined scenarios (i.e., a single scenario vs a more nuanced set of scenarios

[22] Energy Performance of Buildings Directive (europa.eu)

considering varying levels of electrification, inclusion of technical and economical key decision factors). This section aims to clarify the process for the reader, who can find more information on this, in the slides of the Working Group adequacy of 27 August 2024[23].

Load management exercise as primary data source

The load management exercise was trialled for the first time in 2023 and was repeated in Q2 2024. Customers were asked to submit a forecast up to 2033 (included) of their expected gross consumption (both annual GWh and peak MW). Since this year, they were asked to go a step further by a) defining alternative scenarios together with their estimated probability, b) disaggregating their consumption into processes, and c) answering per process questions on current or future flexibility.

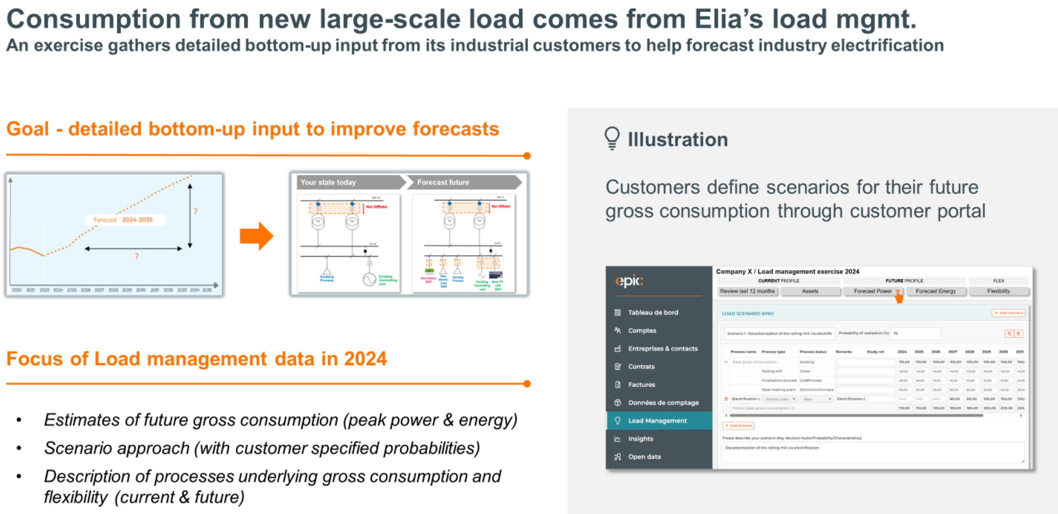

Figure 7-18 Elia load management exercise introduction

Scenario realignment as sense-check and for consistency

The scenarios submitted by customers were subsequently realigned into coherent Elia scenarios. This was needed because each customer chose a different focus in defining their scenarios: technical feasibility of electrification, commercial potential, etc. This was done manually for the 15 biggest customers (good for ~80% of the increase in consumption) by their key account managers, whilst the ~20% tail of smaller customers was treated mechanistically. Refer to the figure below for a summary and some more detail on what this means per Elia scenario for data centres & heavy industry.

[23] https://www.elia.be/en/users-group/wg-adequacy/20240827-meeting

Submitted scenarios of biggest customers aligned to 3 scenarios

Aligned Elia scenarios

	High	Central	Low
For **15 biggest players** accounting for 80% of increase in power, scenarios are realigned			
Data centers	Datacenter consumption grows exponentially as uptake of AI demands more and more computing power	Growth materializes in next 3 years and then continues at the same rate as in '24-'27 after that	Growth materializes in next 3 years as players try to enter AI market first, but remains flat after
Heavy industry	Most optimistic customer scenarios materialize, thanks to positive technological results on electrification and strong governmental support	Companies electrify partially or with a 2-year delay compared to their most optimistic scenario, helped by moderate governmental support	Companies continue as-is or with a 4-year delay compared to their most optimistic scenario, due to technological infeasibility and/or low governmental support
Scenarios of **remaining tail of 112 grid users**, good for 20% of increase, are aligned mechanistically			
	Highest submitted forecast	Weighted combination of scenarios by reported probability	Lowest submitted forecast

Figure 7-19 Elia load management exercise aligned to 3 scenarios

Split into process types to facilitate flexibility modelling

Finally, the gross consumption increase in TWh was split into process types. This is mostly based on the breakdown provided directly by industrial customers.

These processes include:

- **Electric ovens**: Industrial ovens are used for a variety of applications (e.g.: curing raw materials, removing moisture from products or elements, sterilizing, etc…). The two main principles of the industrial oven are the heat sources and airflow patterns.
- **Electric boilers**: covering additional electricity demand due to fuel switching, generally from gas to electricity, and involving processes which require heat temperatures to be above 200°C (typically steam). These systems can be installed in combination with (existing) fossil fuel-based systems. This allows a hybrid running mode, which allows electricity to be used when prices are low and vice versa.
- **Heat pumps**: covering additional electricity demand due to fuel switching, generally from gas to electricity, and involving processes which require limited heat temperatures (e.g. 200°C). Their uptake is mostly expected in the food and drink, chemical, and paper industry. These systems can be installed in combination with (existing) fossil fuel-based systems. This allows a hybrid running mode, which allows electricity to be used when prices are low and vice versa.
- **Electric arc furnace**: this is a technology used for primary steelmaking by first reducing iron ore with gas (potentially hydrogen), after which it is finally treated using EAF. These machines typically consume a lot of electricity. However, since EAFs operate on a batch basis, it is estimated that due to the build-out of some excess capacity, there is potential for load shifting within a given timeframe which would still allow production targets to be met.
- **Carbon Capture Storage (CCS)**: different options exist to capture the CO_2 generated by industrial processes; however, all of these require additional amounts of electricity. This technology is expected to take off in refineries and the chemical, cement and steel sectors. Electricity consumption from this process remains limited until 2030, but comes with significant energy needs towards 2035. Theoretically, it could be possible to deliver some flexibility through CCS, either by storing the solvent and only heating it when the market prices are low or by making a valve where you can choose to run the waste gas through the CCS system based on market prices. However, due to the high CAPEX costs and additional complexity of these options, the potential for these processes to be made flexible is estimated to be low. When flexibility is assumed, it is assumed that (part of the) load will be shed when the price of electricity rises.
- **Data centres**: the number of data centres is expected to gradually increase in the near term. These typically have baseload electricity requirements and are associated with high costs in case they fail and/or black out. Hence, even though some of these units have back-up generators, their flexibility potential is considered to be low. When flexibility is considered, it is assumed that (part of the) load will be shed when electricity

price is above a certain threshold and back-up generators are activated. Based on input from customers, the increase is expected to be of roughly 0.4 TWh per year.

- **Miscellaneous and inflexible processes**: this category includes the increase of electricity demand which cannot be categorised under the previous categories, or non-heat related processes which are assumed to have lower flexibility (various sectors: chemicals, steels, metals, automative, glass, transport, paper, logistics)

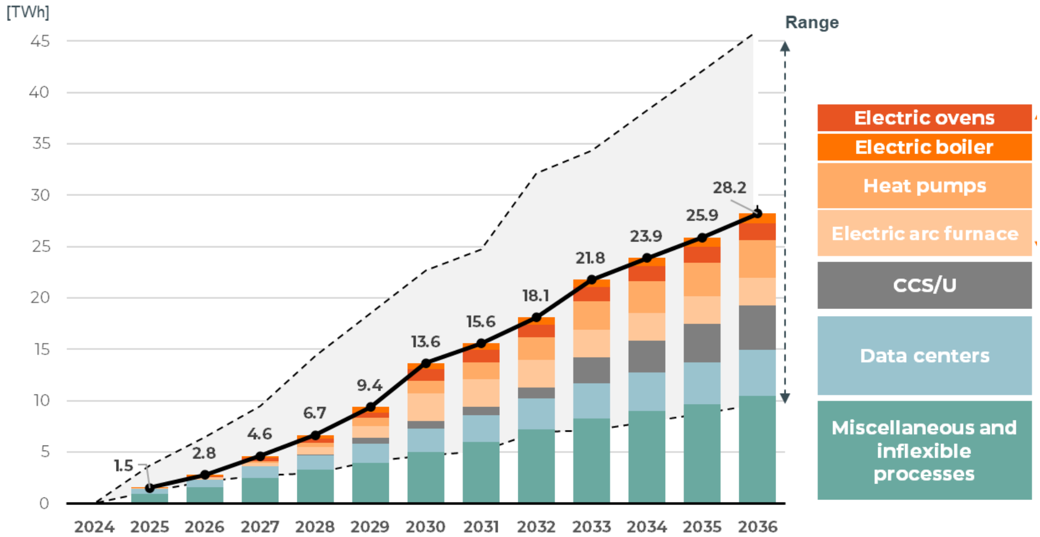

Figure 7-20 Proposed CENTRAL additional electricity demand (vs 2024) for new industry processes

As stated, load management data are available up to 2033 (included). In order to cover to whole time horizon of this study which goes up to 2036, the proposed CENTRAL electricity demand takes as assumption for 2033-2036 an extrapolation of the demand projections based on the 2030-2033 growth rate.

The reader should note that for DSO-connected industries, an update is planned early 2025 based on desktop studies carried out with several Belgian DSOs.

8. Flexibility

8.1. Storage

Pumped-storage

Existing pumped-storage in Belgium consists in 2 sites: Coo and Platte -Taille.

Regarding Coo, the ongoing extension to bring the overall pumped-storage installed capacity to 1161 MW and a storage reservoir capacity of 5600 MWh is taken into account for all time horizons, as summarised on Figure 8-1. Regarding Platte -Taille, a turbining capacity of 144 MW and a reservoir volume of 700MWh is considered.

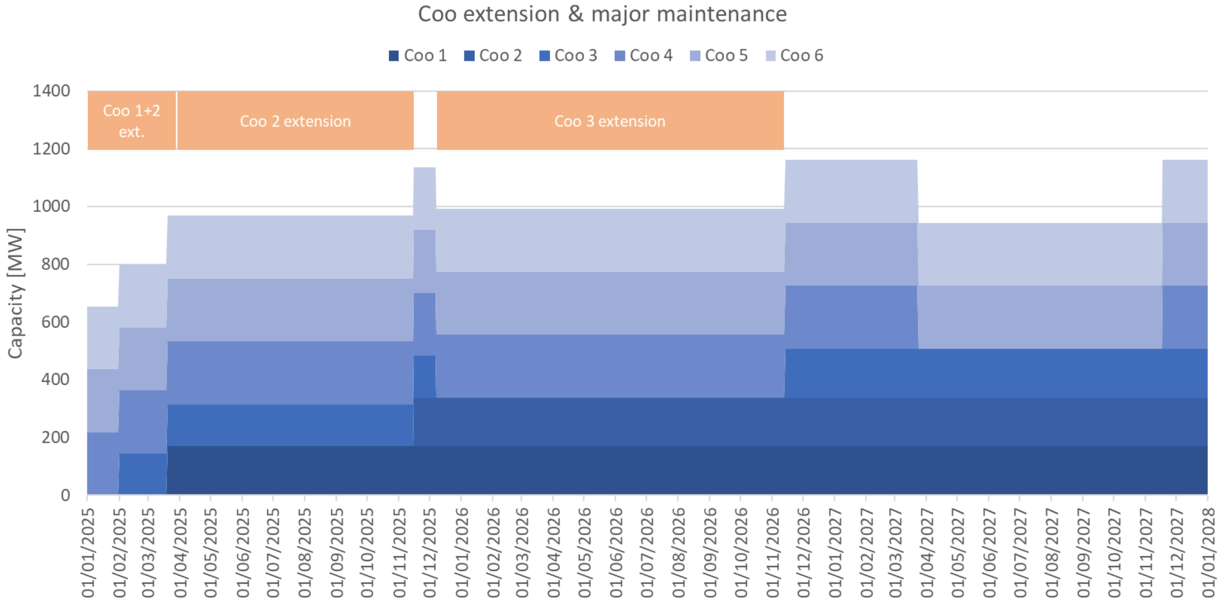

Figure 8-1 Coo extension and major maintenance planning based on REMIT data

Considering that 500 MWh is dedicated to black-start services, the total reservoir volume of pumped-storage available for economical dispatch, after extension, is equal to 5800 MWh.

Note that a recent study realised by ICEDD, ULiège and ULB (published in July 2024) on the potential for future hydro-storage shows a potential for up to 822 MW (3.836 MWh) for additional storage capacity, divided over 17 potential new hydro storage sites[24]. In absence of concrete projects and giving the lead time to develop such capacities, only Coo and Platte-Taille are accounted for in this study.

[24] Cartographie du potentiel de stockage d'énergie par pompage-turbinage | H_2O

Unit	Capacity [MW]	Reservoir [MWh]
Coo	1161	5600
Platte-Taille	144	700
Storage reservoir derating (black-start services)		-500
TOTAL	**1305**	**5800**

Figure 8-2 Proposed pumped storage capacity in Belgium for all time horizons

The pumped-storage data is presented in the Excel file under the sheet '3.1. Storage'.

Large-scale battery storage

Large-scale batteries are batteries which are usually directly connected to a DSO or TSO grid. These operate in a similar way to pumped-storage, in the sense that they can produce electricity and store it at opportune moments. They are therefore modelled in a similar way as pumped-storage (storage/production moments are optimised by the economic dispatch model), assuming they are in-the-market. Large-scale batteries are subject to the following constraints: maximum power, maximum energy storage, state of charge, charging/discharging efficiency.

Two categories of capacity are considered

- In service capacity based on
  - total expected existing capacity at the end of 2024 and;
  - capacity already contracted in a CRM auction volume, including the 2024 auction results.
- Additional potential capacity based on
  - all the projects in the 'realisation phase';
  - percentages of the projects in 'connection study' and 'feasibility study' phase;
  - extra additional potential, considering an extrapolation of the installation rate.

The additional potential capacity could come based on projects known today at Elia. These projects will be considered in the scenario if it is proven that they are economically viable without support mechanism. This will be determined via the Economic Viability Assessment.

The percentages of the projects assumed (33% of the 'connection study' projects and 15% of the 'feasibility study' projects) are based on expert view from all projects known by Elia. It takes into account several parameters in order to reflect realistic evolutions.

The energy content of large-scale batteries is based on the information available for each project individually.

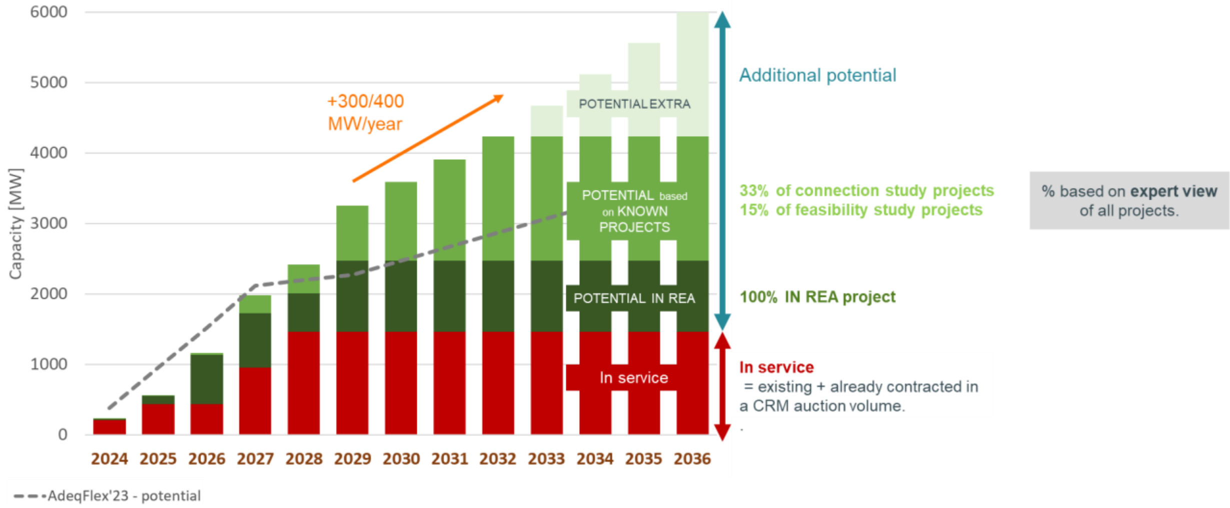

Figure 8-3 Proposed evolution of the large-scale battery capacity in Belgium

The large-scale batteries data is presented in the Excel file under the sheet '3.1. Storage'.

Small-scale battery storage

Small-scale batteries are batteries which are usually connected to people's homes, and are also called 'residential' or 'home batteries'. They are assumed to be managed behind the meter. The capacity of small-scale batteries is based on historic data from Fluvius and VEKA for Flanders. From 2019 to the 1st of April 2023, subsidies/bonuses for home batteries have been put in place in Flanders. Around 19,000 subsidies were asked in 2021 in Flanders for home batteries. This volume increased to more than 33,000 in 2022 and 39,000 in 2023.

For later years, the residential batteries for Flanders are aligned with regional assumptions, considering 200,000 units installed in 2030. For Wallonia and Brussels, as the installation of small-scale batteries is mostly driven by the installation of solar panels, an additional capacity equivalent to 0.3% of the total installed existing photovoltaic capacity is considered to be installed.

The projection assumes a battery of 4.5 kW in average with a duration of 2 hours in average (9 kWh).

Small-scale batteries are mainly considered as 'out-of-market in the short-term but is assumed to evolve in the future towards a higher share of 'in-the-market' batteries. Regarding the battery profiles, the modelling approached (in the market vs out-of-market) is described in the dedicated Appendix F.

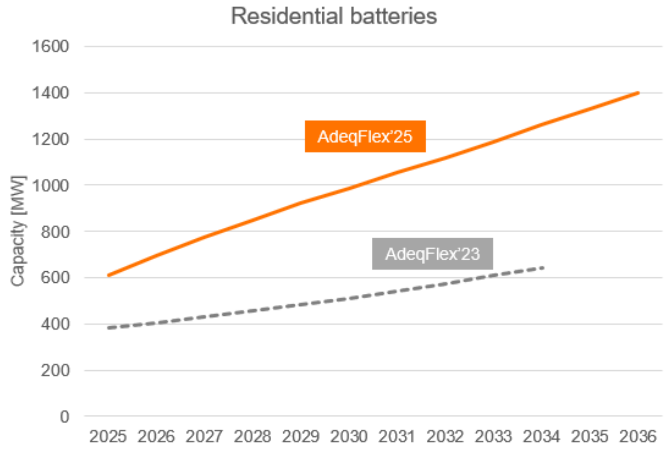

Figure 8-4 Proposed evolution of small-scale batteries in Belgium

The small-scale batteries data is presented in the Excel file under the sheet '3.1. Storage'.

8.2. Industry flexibility

DSR from existing processes (not related to new electrification)

Demand-Side Response (DSR) from existing processes in the industry is presented on Figure 8-5.

The installed capacity for DSR is divided in two categories:

- Existing capacity;
- Additional potential if economically viable.

Regarding existing capacity, the installed capacity is based on the study performed by N-SIDE consultants. The volume for 2023 is based on the assessment performed on winter 2023-24.

On top of this existing capacity, an additional potential volume can be integrated in the model. This volume will be considered in the scenario if it is proven that they are economically viable without support mechanism. This will be determined via the economic viability assessment (EVA). This additional potential volume is increasing on the time horizon foreseen and is split between different cost ranges, from 25€/kW to 100€/kW by step of 25€/kW.

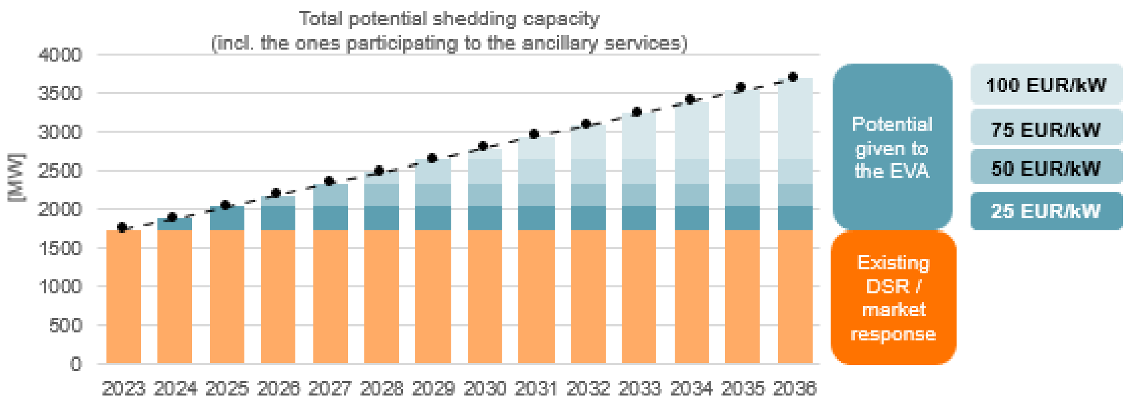

Figure 8-5 Proposed DSR capacity from existing processes (existing DSR and potential additional DSR from existing processes)

Flexibility expected from new large-scale loads

As described in Section 7.4**Error! Reference source not found.**, the consumption expected from new large-scale loads has been built on the load management exercise (see Section 7.4). In this exercise, Elia surveyed TSO-connected customers to estimate future electricity consumption and also to gather information on the expected flexibility from the different processes.

Based on past literature review (carried out in the scope of the last AdeqFlex'23 study) and the new information from the load management exercise, the flexibility assumptions have been reviewed. The percentage of flexibility per process type is shown in the table below. This percentage is applied on the installed power capacity and allows to reduce demand in times of high electricity prices.

Process	Percentage of flexibility
Electric ovens	80%
Electric boiler	75%
Heat pumps	40%
Electric arc furnace (EAF-DRI)	75%
Carbon Capture and Storage	0%
Data centers	20%
Miscellaneous and other processes	5%

Table 8-1 Proposed flexibility % associated with each industrial process

DSR from industry is presented in the Excel file under the sheet '3.2. DSR industry'.

8.3. End-user flexibility

End-user flexibility defines flexibility for Heat pumps (HP) in the residential and tertiary sector, part of the electrified transport (passenger cars and light-duty vehicles), and residential batteries.

These assets can be operated in different ways, and these ways will likely change in the future. To capture this, each asset can fall in one of three categories:

- No flexibility: the load/generation has a fixed profile, following expected usage behavior (eg: charging as soon as plugged-in).
- Local flexibility: the load/generation is dispatched based on a local signal (eg: regional tariff, or PV self-consumption).
- Market flexibility: the load/generation is dispatched based on a market signal (eg: day-ahead price signal). In this case, this means that these assets will be dispatched by the economic dispatch model.

This section aims to detail the modelling improvements included in this edition of the study, and the proposed CENTRAL scenario for unlocked flexibility.

Improvements of end-user flexibility modelling

Regarding end-user flexibility, many improvements have been included in this study, compared to last edition of AdeqFlex'23. Notably:

- Based on 2023 metered data, the inclusion of work & public charging profile in complement to home charging to represent natural charging of EVs.
- Local flexibility profiles have been developed for all assets considering regional tariffs (capacity tariff in Flanders[25], and coming Time of Use tariff in Wallonia as of 2026[26]), and PV self-consumption. Hence, these profiles change for each day of each climate year. Illustrative examples are published in the excel for public consultation.
- Based on 2023 metered data, EV availability (i.e. connection of cars to a charger) is updated. The availability considers connection of EVs to a charger at home and at work. No flexibility is expected from public charging.

Associated data to these improvements are available in the excel published with this document, in tab 3.3 DSR end-user.

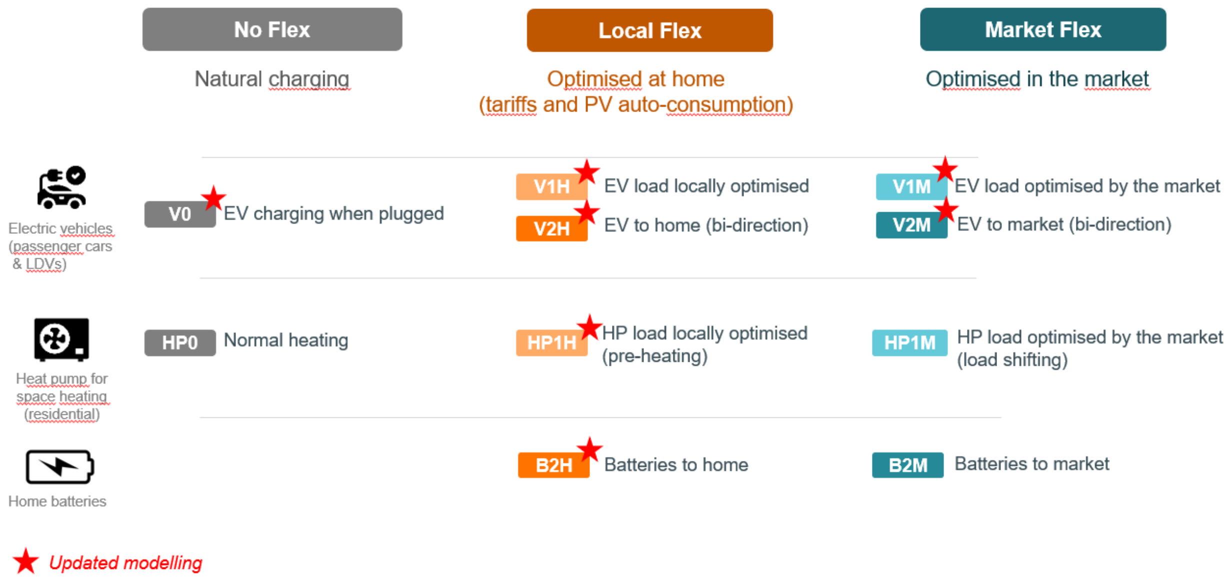

Figure 8-6: overview of improvements in end-user flexibility modelling realised for AdeqFlex'25

Proposed CENTRAL scenario for unlocked flexibility

With growing fleet of assets like electric vehicles, heat pumps and residential batteries. These assets could be operated in different ways. As stated earlier in this section, it is proposed to consider three ways in which asset can be operated: (i) in an unflexible way (or 'naturally'), (ii) based on a local signal (local flexibility), or (iii) based on a market signal (market flexibility).

To cipher the last two categories, the following framework is proposed:

- Define the amount of asset to consider:
  - For electric vehicles, it is proposed to consider that passenger cars and light-duty vehicles. Busses and high-duty vehicles are expected to minimise charging time and hence have low to no flexibility

[25] Capacity tariff in Flanders The capacity tariff | Flanders.be

[26] Time of Use tariff in Wallonia Méthodologie tarifaire 2025-2029 | CWAPE

to offer during the day. Also, PHEV should be considered as a fraction of an equivalent BEV vehicle, as they do not consume the same amount of electricity.
    - For heat pumps, as secondary air-air HP are assumed to deliver only 20% of the heating needs of a house, they are counted as 20% of an equivalent HP.
- Quantify projections of key drivers to unlock local and market flexibility:
    - It is proposed to consider simple key drivers that will drive unlocking flexibility.
    - For market flexibility, projections of dynamic contracts developments are used.
    - For local flexibility, projections of smart meters (aligned with DSOs development plans) are considered per region.

The reader should note that this topic is subject to assumptions based on talks with experts of the field, and that any quantified feedback is welcome. A CENTRAL scenario is proposed in the Excel linked to the public consultation based on this methodology. Main evolutions are depicted in Figure 8-7.

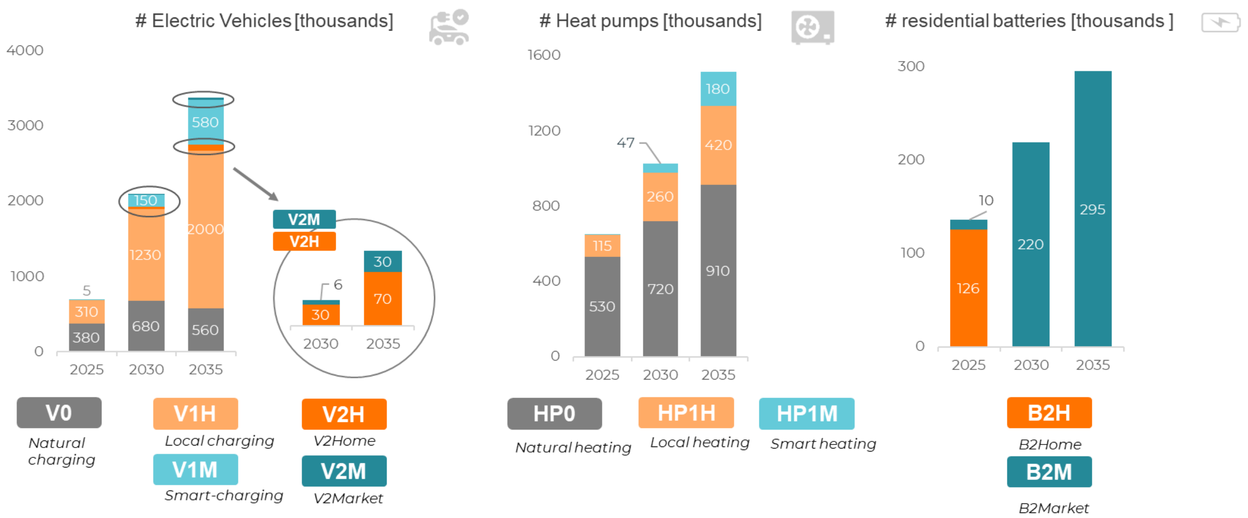

Figure 8-7: Proposed evolution of the unlocked flexibility (share) for the CENTRAL scenario

End-user DSR is presented in the Excel file under the sheet '3.3. DSR end-user'.

8.4. Electrolysers

This section presents the assumptions considered for electrolysers dedicated to green H_2 production.

Based on the following elements:

- The 'Vision and strategy Hydrogen' (Oct. 22) aimed for 150 MW in 2025.
- By end-October 2024, there is 1 publicly planned project for electrolysers: Hyoffwind, 25 MW.

The proposed assumption in the CENTRAL scenario is to keep 25 MW constant as total hydrogen electrolyser capacity for the studied horizon, as long as no other concrete project is known.

Note that hydrogen electrolysers are assumed fully flexible, and dispatched when prices are low. Their final consumption is an output of dispatch simulation.

Data for electrolysers are presented in the Excel file under the sheet '3.4 Electrolysers'.

8.5. Assumptions on short-term flexibility

Elia's **flexibility study** focuses on the flexibility required to cover unexpected variations of demand and generation through intra-day and balancing markets. While the modifications of data and assumptions to determine the flexibility needs are limited to regular updates (cf. updateof prediction error time series and forced outage assumptions following latest data), the assumptions on some technologies to provide flexibility means in intra-day or the balancing time frame are updated in a more fundamental way.

- **For industrial flexibility from new large-scale loads,** no short-term flexibility means were previously accounted. While the previous Adeqflex study already accounted their flexibility capabilities through several categories (as in Section 8.2) in the economic dispatch simulations, insufficient information was available at that time to consider them for participation in intra-day or balancing markets. Based on the load surveys conducted in 2024, and interviews with sector experts, it is proposed to consider three large-scale industrial demand technologies for providing short-term flexibility:

    - electric boilers and electric ovens are considered flexible for the part considered flexible for adequacy simulations (cf. table Table 8-1). This capacity is assumed to be able toprovide ramping, fast and slow flexibility. These two categories can provide both up- and downward flexibility as they are assumed flexible through modulation of a gas back-up alternative.

    - electric arc furnaces (EAF), the part considered flexible for adequacy simulations, can only provide slow up- and downward flexibility by shifting its consumption as it needs to be informed at least several hours in advance to adapt the production process.

    Note that other large industrial loads such as heat pumps, data centers and carbon-capture and storage are still not considered at this point as available information indicates too many uncertainties and complexities on their capabilities to provide short-term flexibility. Feedback and input from stakeholders on these assumptions are welcomed.

- **For end-user flexibility such as electric vehicles (EV), heat pumps (HP) and home batteries (HB),** flexibility was already accounted in the previous AdeqFlex study through the economic dispatch simulations (Section 0) as well as short-term flexibility:

    - While electric vehicles and heat pumps were already assumed to provide upward flexibility (temporarily reducing consumption) through smart charging or smart heating, they are assumed in this study to also provide downwards flexibility (temporarily increasing consumption when not charging or heating at full capacity, e.g. when providing consumption reductions in the day-ahead market).

    - Additionally, and similar to the previous study, home batteries and electric vehicles with bi-directional charging capabilities can change offtake and injection both in an upwards and downwards direction. All controllable EV, HP and HB assets are assumed to be sufficiently fast to be deliver ramping, fast and slow flexibility.

    - Note that the share of assets able to provide short-term flexibility is only a minor part (estimated at 10% today) of the "market flexibility " defined in Section 0 as the amount of consumers exposed to intra-day or balancing market prices or signals today is observed to be low. Towards 2036, this percentage share is assumed to increase to 40%.

Assumptions for short-term flexibility are presented in the Excel file under the sheet '4.4. Flex. Charact' and further described in the document 'Assumptions for the assessment of short-term flexibility'. The methodology used is described in the document 'Methodology for the assessment of short-term flexibility'.

9. Economic and technical variables

9.1. Fuel and CO_2 prices

In this section, the assumptions regarding fuel prices (Natural gas, Coal, Oil) & CO_2 are presented. Prices are published in EUR2024 per MWh, except for the CO_2 where the price displayed is in EUR2024 per ton of CO_2.

The methodology to define Fuel & CO_2 prices differs based on the time horizon studied.

On the short-term, forward prices are available on the market for the different fuels. Hence, the market price from the forward contracts are used for natural gas, coal, oil and CO_2 from the EU ETS market until 2028 at least.

The long-term prices are defined by the World Energy Outlook (WEO) 2024 published by the IEA on 18/10/2024. In the WEO, data are available for 3 scenarios (Stated Policies, Announced Pledges & Net Zero). Out of the three scenarios, it is proposed to use the Announced Pledges for the CENTRAL scenario. For fossil fuel commodities, data are available for the years 2030, 2040 and 2050. For CO_2, values are available for 2030, 2035 and 2040.

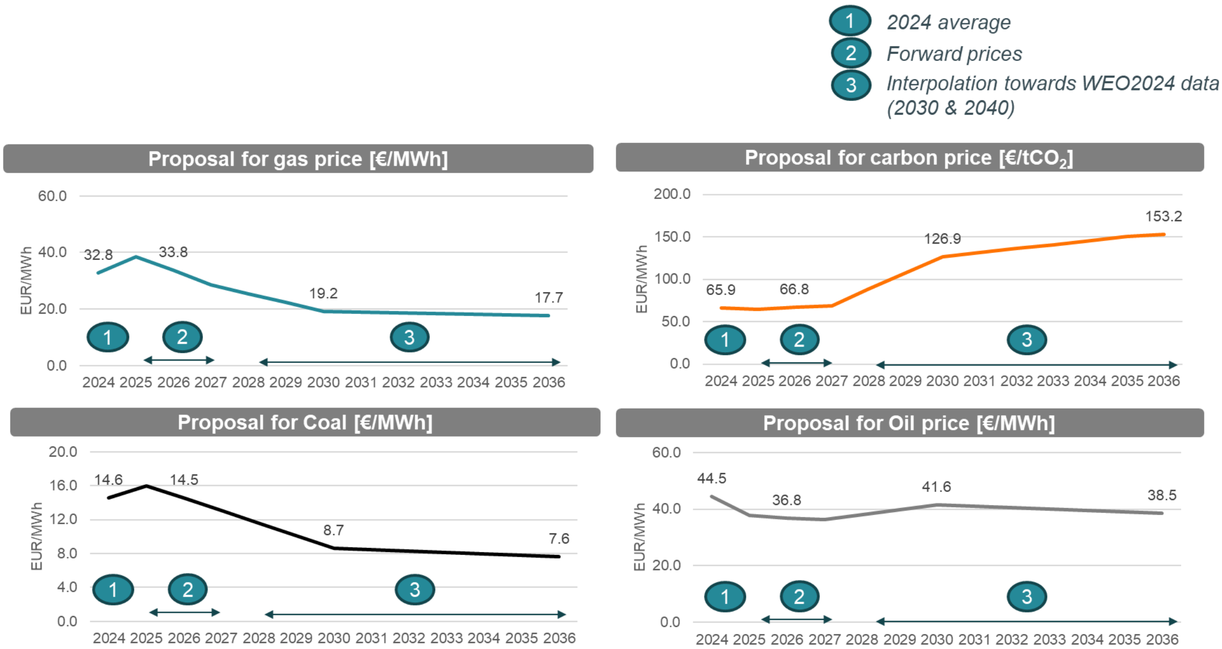

Figure 9-1 : Proposed evolution of prices of commodities

Prices for commodities are presented in the Excel file under the sheet '4.1 Fuel and CO_2 prices'.

9.2. Investment costs

All costs are expressed in euros 2024. In this way, the most recent trends in general and industrial inflation are taken into account. The costs have been compared to several recent studies before coming up with the proposed values presented in Table 1.

FOM (fixed operation & maintenance costs)

The FOM values are based on the ENTRAS study for the thermal fleet and storage technologies, presented in Working Group Adequacy[27]. For Renewable technologies, several sources are used, and they are all listed in the accompanying excel to this document.

CAPEX

The CAPEX values for all new thermal plants are extracted from the values chosen by the minister in the framework of CRM 2024 (August 2024). The exception is made for the hydrogen fuelled CCGT and OCGT, for which the mean of Blueprint's values of 2030 and 2040 are used for the time window 2031-2035.

Blueprint's values are used for the storage and renewable production assets.

Hurdle rates

The hurdle rates are based on the study by Professor K. Boudt, which is provided separately within this public consultation.

<table>
<tr><th colspan="2" rowspan="2">Technologies part of the structural block</th><th rowspan="2">Applies to</th><th colspan="2">CAPEX [€/kW]</th><th>FOM (including major overhauls) [€/kW/y]</th></tr>
<tr><th>2025-2030</th><th>2031-2036</th><th>2025-2036</th></tr>
<tr><td rowspan="6">Existing (assumed no extension costs)</td><td>CCGT</td><td rowspan="2">Existing units <25 years</td><td>-</td><td>-</td><td>36</td></tr>
<tr><td>OCGT</td><td>-</td><td>-</td><td>27</td></tr>
<tr><td>CHP</td><td>All existing capacity</td><td>-</td><td>-</td><td>34</td></tr>
<tr><td>Turbojets</td><td>All existing capacity</td><td>-</td><td>-</td><td>35</td></tr>
<tr><td>Demand Response</td><td>All existing capacity in 2024</td><td>-</td><td>-</td><td>12</td></tr>
<tr><td>Pumped Storage</td><td>All existing capacity</td><td>-</td><td>-</td><td>30</td></tr>
<tr><td rowspan="2">Existing (assuming extension costs needed)</td><td>CCGT</td><td rowspan="2">Existing units >25 years</td><td colspan="2">120</td><td>31</td></tr>
<tr><td>OCGT</td><td colspan="2">100</td><td>29</td></tr>
<tr><td rowspan="19">New</td><td rowspan="4">CCGT</td><td>>800 MW</td><td colspan="2">840</td><td>31</td></tr>
<tr><td>400 < 800 MW</td><td colspan="2">1020</td><td>31</td></tr>
<tr><td>< 400 MW</td><td colspan="2">1260</td><td>31</td></tr>
<tr><td>H2 fueled >800W</td><td>-</td><td>1120</td><td>38</td></tr>
<tr><td rowspan="3">OCGT</td><td>>100 MW</td><td colspan="2">660</td><td>29</td></tr>
<tr><td><100 MW</td><td colspan="2">1200</td><td>29</td></tr>
<tr><td>H2 fueled >100W</td><td>-</td><td>900</td><td>33</td></tr>
<tr><td>CHP</td><td>New capacity < 100 MW</td><td colspan="2">1200</td><td>35</td></tr>
<tr><td rowspan="4">Demand response</td><td>New capacity 0 < 300 MW</td><td colspan="2" rowspan="4">All cost included in FOM</td><td>25</td></tr>
<tr><td>New capacity 300 < 600 MW</td><td>50</td></tr>
<tr><td>New capacity 600 < 900 MW</td><td>75</td></tr>
<tr><td>New capacity 900 < 1200 MW</td><td>100</td></tr>
<tr><td rowspan="3">Batteries/Storage</td><td>Large scale batteries (1h)</td><td>320</td><td>300</td><td>26</td></tr>
<tr><td>Large scale batteries (2h)</td><td>540</td><td>500</td><td>26</td></tr>
<tr><td>Large scale batteries (4h)</td><td>1010</td><td>910</td><td>26</td></tr>
<tr><td>Pumped Storage - new unit</td><td>New unit</td><td colspan="2">2230</td><td>19</td></tr>
<tr><td colspan="2">Renewables</td><td></td><td></td><td></td></tr>
<tr><td>Wind onshore</td><td>New</td><td>1290</td><td>1210</td><td>31</td></tr>
<tr><td>Wind offshore</td><td>New (after 2 GW)</td><td>2230</td><td>2100</td><td>60</td></tr>
<tr><td>RES</td><td>PV</td><td>New</td><td>650</td><td>610</td><td>13</td></tr>
<tr><td></td><td>Biomass</td><td>New</td><td>2940</td><td>2860</td><td>96</td></tr>
</table>

Table 9-1 Proposed investment cost assumptions

The investment costs assumptions are presented in the Excel file under the sheet '4.2. Investment costs'.

[27] WG Adequacy - 20231013 meeting

9.3. Outages

The outage parameters for CCGT, OCGT, CHP, TJ, HVDC links, and Pumped Storage units were calculated using the same methodology detailed in Appendix IV of AdeqFlex'23. This methodology, along with the tools used, was developed for AdeqFlex'23 by N-side. The tool employs historical data to calculate outage rates, outage durations, and the average number of outages.

For Belgian units, the historical data is sourced from Elia, while data for other countries is obtained from the ENSTO-E transparency platform. This approach ensures a more representative dataset, given the limited number of units in Belgium. For AdeqFlex'25, the dataset (from 2015) has now been updated to include data from 2022 and 2023 for more accurate outage parameters. The updated parameters are presented in Table 9-2.

For nuclear power plants, an average forced outage rate of 10% was agreed upon with stakeholders during the public consultation for the CRM 2024 scenarios. The number of forced outages per year and the average duration were calculated using historical data from Belgian nuclear power plants, taking into account the agreed 10% forced outage rate.

Category	Number of FO per year	Average FO rate [%]	Average duration of FO rate [hours]
Nuclear	1.2	10%*	576 hours [around 24 days]
CCGT	9.4	6.7%	117 hours [around 5 days]
OCGT	3.3	8.1%	217 hours [around 9 days]
TJ	4.3	10.1%	126 hours [around 5 days]
CHP, waste, biomass	3	6.2%	120 hours [around 5 days]
Pumped Storage	7	7.2%	177 hours [around 7 day]
DC links	1.8	6.1%	212 hours [around 9 days]

** Nuclear FO rate of 10% as agreed with stakeholders during the public consultation of the CRM scenarios 2024*

Table 9-2 Proposed forced outage rate parameters

Assumption for outages is presented in the Excel file under the sheet '4.3 Outages'.

10. Cross-border exchange capacity

10.1. Flow-based domains parameters

As explained in the annex regarding cross-border exchanges, the exchanges of electricity between bidding zones inside Central Europe region are modelled using the flow-based methodology. This methodology is developed and explained in the annex and the input parameters are presented below, in Figure 10-1.

Regarding the bidding zone configuration, ACER Decision No 11-2022 on alternative bidding zone configurations refers to an assessment to be performed by the transmission system operators, the so-called Bidding Zone Review study. After the delivery of the Bidding Zone Review study, which is expected by end 2024, relevant Member States have 6 months to take a decision on their future bidding zone configuration. Such decision is thus not yet available. Hence the bidding zone configuration of the simulated perimeter is the current bidding zone configuration.

A perfect market model is proposed as reference, and represent the following set-up:

- No limitations on the implementation of the minimum 70% requirement, aside from the existence of action plans until the end of 2025. The resulting minimum margins available for cross-zonal trade (minMACZT) are summarised in Figure 10-1. Note that the minMACZT is the capacity assumed available for the sum of all market exchanges, thus covering both exchanges taking place on bidding zone borders inside the Central Europe region and exchanges on bidding zone borders external to the Central Europe region.

- Maximum efficiency for the allocation of capacities. The external borders directly connected to the Central Europe region are modelled through Advanced Hybrid Coupling (AHC), which is in line with the Central Europe (and Core) capacity calculation methodologies. Also borders to the United Kingdom and Switzerland are modelled through AHC as it makes sense from a technical and market perspective, although subject to political agreements. Allocation constraints are not considered, as they have been phased out in Belgium and the Netherlands and it remains to be seen if and for how long these will be allowed for in the Central Europe region (use cases of Poland and Italy North).

The HVDC interconnectors on bidding zone borders internal to the Central Europe region are also optimised in the allocation (technically the same set-up as AHC), which is in line with the Central Europe (and Core) capacity calculation methodologies.

Market Parameters	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	Comments
Flow-based perimeter	Central Europe CCR												
Bidding zones	As Is												*ACER Decision No 11-2022 on the alternative bidding zone configurations only refers to assessment by next BZR study, so no official new configuration is known at*
minMACZT	See table below												*Perfect model assumption https://acer.europa.eu/Official_documents/Acts_of_the_Agency/Publications%20Annexes/ACER%20Report%20on%20the%20result%20of%20monitoring%20the%20MA*
Treatment of external flows	Advanced Hybrid Coupling (AHC)												*Perfect model assumption*
External & Allocation constraints	No Allocation constraints												*Perfect model assumption* Perfect market model
Use of PST in capacity calculation	For Belgium: 1/2 For other: 1/3												*All get a setpoint based on the nodal flow estimation (FE). In capacity calculation only the currently known PST's are selected (BC). In capacity allocation none*
Use of HVDC in flow-based capacity allocation	ALEGrO HVDC Piémond-Savoie		ALEGrO HVDC Piémond-Savoie Celtic Interconnector										

Bidding zones	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	Justification
Austria	60	70	70	70	70	70	70	70	70	70	70	70	*Action plan 2021-2025*
Belgium	70	70	70	70	70	70	70	70	70	70	70	70	
Netherlands	63	70	70	70	70	70	70	70	70	70	70	70	*Action plan 2020-2025*
Germany	60	70	70	70	70	70	70	70	70	70	70	70	*Action plan 2020-2025*
France	70	70	70	70	70	70	70	70	70	70	70	70	
Slovenia	70	70	70	70	70	70	70	70	70	70	70	70	
Kroatia	70	70	70	70	70	70	70	70	70	70	70	70	*Plans to adopt a action plan mid-2022*
Romania	63	70	70	70	70	70	70	70	70	70	70	70	*Action plan 2021-2025*
Czechia	70	70	70	70	70	70	70	70	70	70	70	70	
Slovakia	70	70	70	70	70	70	70	70	70	70	70	70	
Poland	63	70	70	70	70	70	70	70	70	70	70	70	*Action plan 2020-2025*
Hungary	70	70	70	70	70	70	70	70	70	70	70	70	
Ireland	70	70	70	70	70	70	70	70	70	70	70	70	
Italy Nord	70	70	70	70	70	70	70	70	70	70	70	70	

A perfect market model is proposed as reference. Reality is different for multiple reasons:

1. Electricity Regulation includes provisions to derogate or deviate (=validation step in capacity calculation) from the minimum 70% requirement, justified by the need to ensure the operational security of the grid. Facts and figures are available in ACER's 70% monitoring report.
2. UK and CH are not part of the single implicit price coupling. These borders are explicitly coupled and implemented through Standard Hybrid Coupling in capacity calculation, implying forecast inefficacies.
3. Allocation constraints are applied in market coupling in line with the legal framework (PL, IT, …)

➔ Candidate for sensitivity: a lower minimum available capacity assumption as proxy to model these differences

Figure 10-1 Proposed flow-based domains parameters

Flow-based domain assumptions are presented in the Excel file under the sheet '5.1. Flow-based domains'.

10.2. Belgian cross-border and interconnector

Regarding the major internal reinforcements planned for the Belgian grid as well as the planned new interconnections, the timeline proposed follows the one of the validated Federal Development Plan[28] (FDP – see the document for more information on the projects), except for Triton (see below).

- The realisation of Ventilus[29], a high-voltage grid infrastructure in West-Vlaanderen, is foreseen by end of 2028 in the FDP and therefore assumed available for adequacy as from winter 2029/30;
- The realisation of Boucle du Hainaut[30], a high-voltage grid infrastructure in Hainaut, is foreseen by end of 2029 in the FDP and therefore assumed available for adequacy as from winter 2030/31;
- The realisation Nautilus, a second subsea interconnector between Belgium and the United Kingdom, is foreseen by end of 2030 in the FDP and therefore assumed available for adequacy as from winter 2031/32;
- The realisation of Triton[31], hybrid interconnector between Denmark and Belgium is now planned to happen during 2036 and therefore assumed available for adequacy as from winter 2036/37.

The cross-border links outside Central Europe region are based on TYNDP2024 data, updated with latest official announcements.

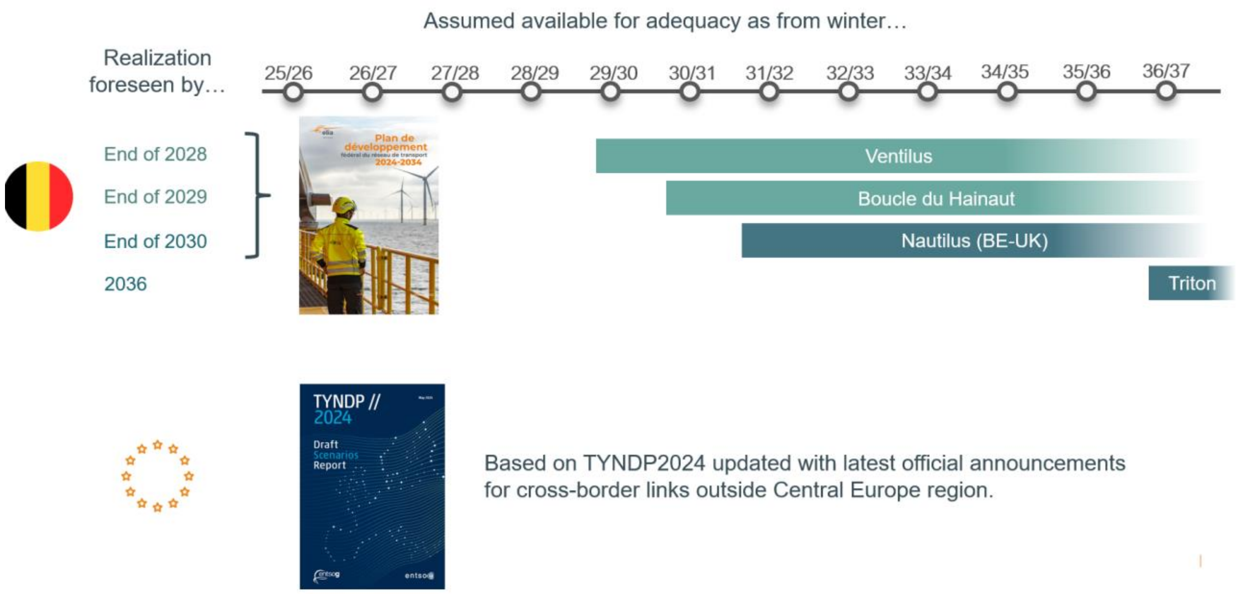

Figure 10-2 Proposed assumptions regarding internal backbone and cross-border links in Belgium

[28] Plan de développement fédéral 2024-2034

[29] Ventilus

[30] Boucle-du-Hainaut

[31] TritonLink

11. Scenario data for other countries

The assumptions for other EU countries are mainly based on the latest European Resource Adequacy Assessment, the ERAA 2024 by ENTSO-E, which relies on the 'ERAA 2024: Call-for-Evidence on Preliminary Input Data' package[32].

This dataset is then updated based on latest policies, announcements and published studies. These sources include national studies and governmental announcements. The following section describes the assumptions taken for neighboring countries and main European countries impacting the adequacy in Belgium.

EU assumptions are presented in the Excel file under the sheet '6.1. Data for other countries'.

11.1. France

The dataset for France mainly comes from the latest 'Bilan Prévisionnel', published by RTE in September 2023[33]. The central scenario is used for all technologies. Onshore wind and solar trajectories are aligned with the historical installation rate while offshore wind follows the objective set in the 'Pacte éolien en mer', published in March 2022[34].

Regarding coal generation, no extension of Cordemais is considered in the EU-BASE scenario, following the latest publication from EDF[35].

The assumptions for France are summarised on Figure 11-1.

[32] https://www.entsoe.eu/news/2024/03/08/eraa-2024-call-for-evidence-on-preliminary-input-data/

[33] https://www.rte-france.com/analyses-tendances-et-prospectives/les-bilans-previsionnels

[34] https://www.ecologie.gouv.fr/sites/default/files/documents/2022.03.14_pacte-eolien-mer.pdf

[35] https://www.edf.fr/groupe-edf/espaces-dedies/journalistes/tous-les-communiques-de-presse/avenir-du-site-de-cordemais-edf-envisage-darreter-le-projet-ecocombust-et-confirme-sa-volonte-de-maintenir-sur-le-site-une-activite-industrielle

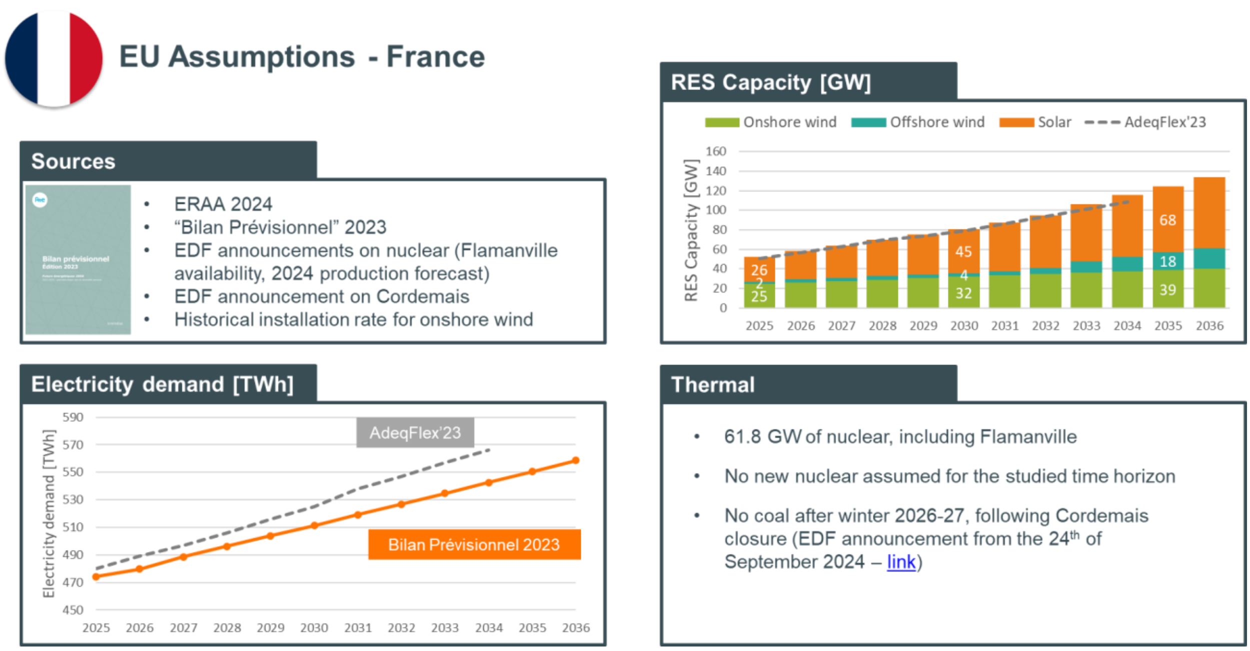

Figure 11-1 Proposed assumptions for France

The methodology associated to the modelisation of French nuclear has been improved. In the short-term, it is proposed to use information from REMIT, calibrated to the estimated yearly generation output from EDF and to integrate uncertainties on outages length, as performed by the French TSO. In the long-term, the methodology is aligned with the 'case de base' from 'Bilan Prévisionnel'.

RTE considers different levels for the modelisation of French nuclear, each calibrated to an average yearly generation:

- 3 scenarios:
  - 'Cas de base' (360 TWh);
  - 'Variante basse' (330 TWh);
  - 'Variante haute' (400 TWh);
- 1 stress test sensitivity (280 TWh).

For the EU-BASE scenario, it is proposed to consider the 'cas de base' as reference, as illustrated on

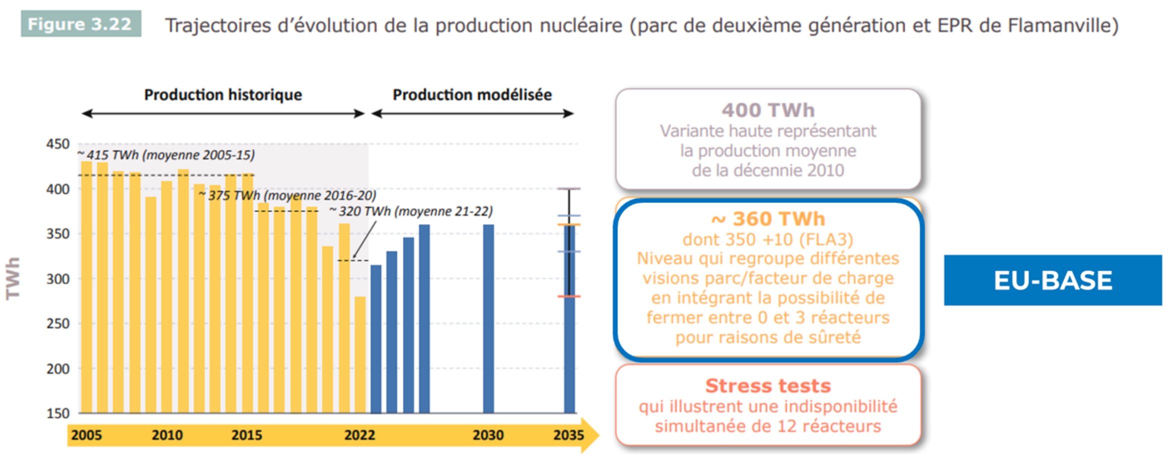

Figure 11-2 Proposed assumptions for nuclear in France (figure from Bilan Prévisionnel)

As winter availability is the most critical information for adequacy purpose, the study also provides the average availability, including the modelled spread, as illustrated on figure 3.21 from the 'Bilan Prévisionnel', in the generation and storage part, which also includes additional information on French nuclear availability.

11.2. Germany

Regarding assumptions for Germany, the main source is ERAA24, complemented with the NEP2025[36] (network development plan, Jun. 2024) scenario B for 2037 when needed.

Mid-2022, Germany has set renewables targets in its 'Easter package' (with several laws and ordinances in the field of energy legislation), making it the biggest energy policy reform in decades. The proposed trajectories for solar and onshore wind are based on the 2025 ERAA24 data and an interpolation towards 2030 targets (assuming that those targets are reached by the end of 2030), i.e. 115 GW for onshore wind and 215 GW for solar. This is also in line with the final updated NECP (Aug. 2024)[37]. After 2030, an extrapolation (based on 2025-2030 growth rate) is done towards 2037 following the scenario B from NEP2025.

Regarding offshore wind, the proposed trajectory is based on the development plans of offshore wind farms published in June 2024 by BSH (part of Federal Ministry for Digital and Transport). This trajectory is similar to ERAA24 data and in line tiwth the final updated NECP (Aug. 2024).

The electricity demand proposed trajectory is based on ERAA24. The coal trajectory is also based on ERAA24 and in line with a coal phase-out by 2038 (previously assumed by 2030).

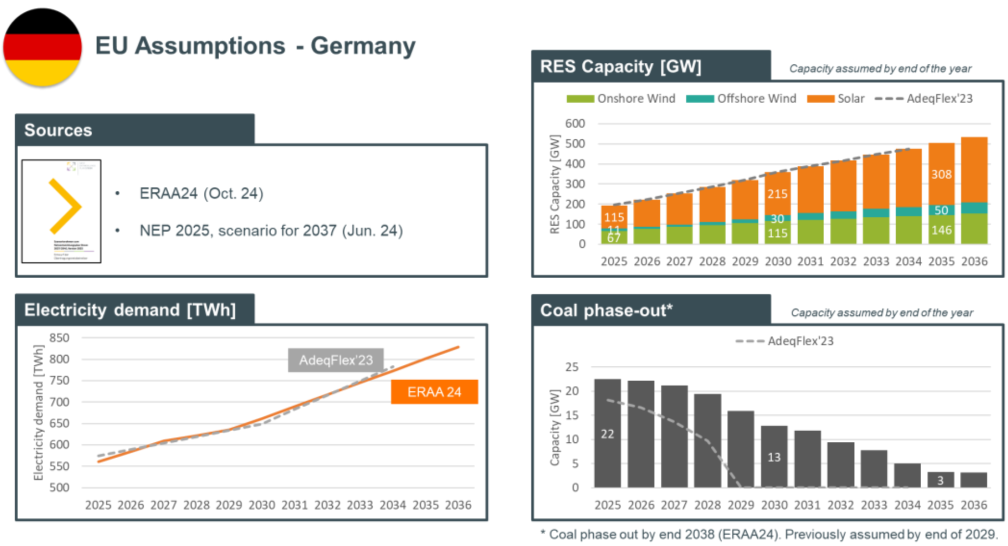

Figure 11-3 Proposed assumptions for Germany

[36] **Szenariorahmenentwurf_NEP2037_2025_1.pdf**

[37] **https://commission.europa.eu/publications/germany-final-updated-necp-2021-2030-submitted-2024_en**

11.3. Netherlands

Regarding assumptions for Netherlands, the sources are (i) the ERAA24 database, (ii) the 'Monitoring leveringszekerheid'[38] published by Tennet in 2024 for solar and onshore wind, and (iii) the 'Routekaart wind op zee'[39] for offshore wind.

The assumptions for Netherlands are summarised on Figure 11-4.

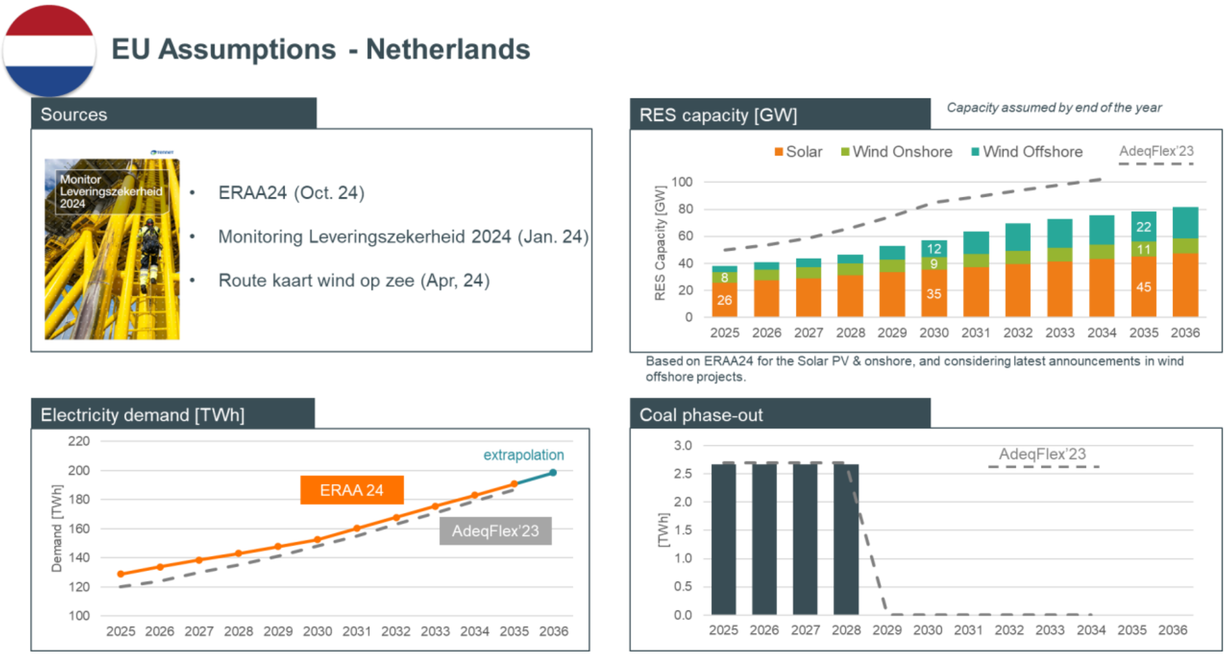

Figure 11-4 Proposed assumptions for the Netherlands

11.4. United-Kingdom

Regarding assumptions for the United-Kingdom, the main source considered is the 'Future Energy Scenarios'[40], published in July 2024. The 'Electric Engagement' scenario is the reference for electricity demand, solar, onshore wind, offshore wind and gas capacity. The assumptions are also aligned with the auction results[41].

The gas capacity follows this trajectory until 2029 and is kept constant after to ensure the security of supply criteria of the country.

[38] tennet-drupal.s3.eu-central-1.amazonaws.com/default/2024-05/20240514 Monitor Leveringszekerheid 2024_0.pdf

[39] https://open.overheid.nl/documenten/a5b91671-5b23-45b5-aa0b-72439730a4dc/file

[40] https://www.neso.energy/publications/future-energy-scenarios-fes

[41] https://www.emrdeliverybody.com/CM/Auction-Results.aspx

Regarding nuclear, a unit-by-unit analysis has been performed based on the most up-to-date information. The de-commissioning of Hartlepool 1 and Heysham 1 is foreseen in 2026 while Torness and Heysham 2 is foreseen in 2028[42]. Hinkley Point C is assumed to be commissioned in 2030[43], Sizewell C in 2033 and Bradwell B in 2036.

The assumptions for United-Kingdom are summarised on Figure 11-5 .

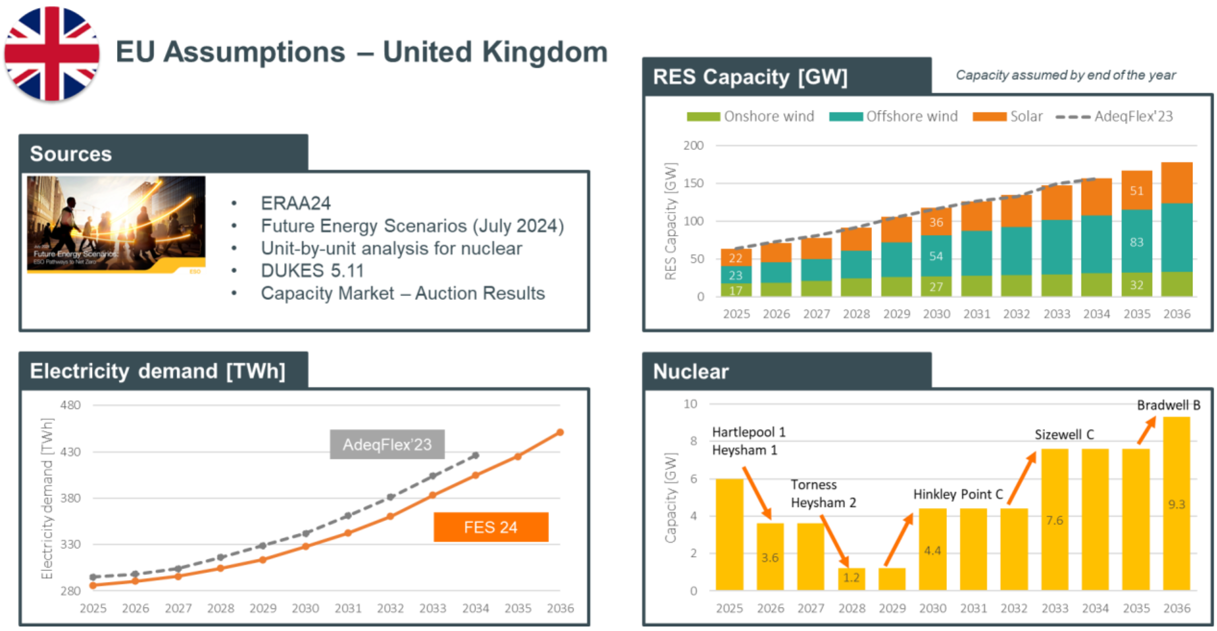

Figure 11-5 Proposed assumptions for the United Kingdom

10.5 Spain

Regarding assumptions for Spain, the sources are (i) the ERAA24 database, (ii) the National Energy and Climate plan (NECP) published in 2024.

The assumptions for Spain are summarised on Figure 11-6.

[42] https://www.edfenergy.com/media-centre/investment-boost-maintain-uk-nuclear-output-current-levels-until-least-2026

[43] https://www.edf.fr/groupe-edf/espaces-dedies/journalistes/tous-les-communiques-de-presse/point-dactualite-sur-le-projet-hinkley-point-c

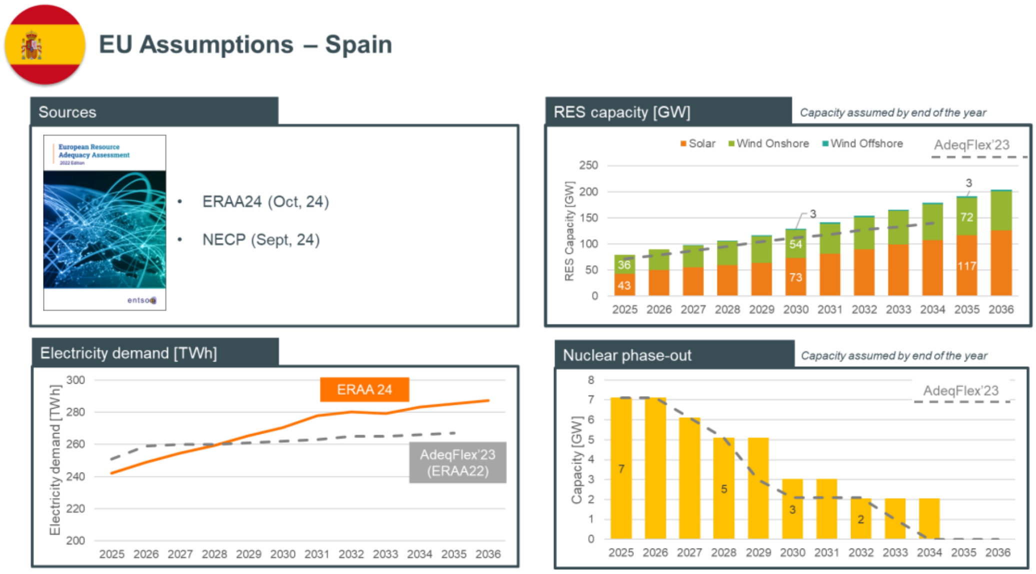

Figure 11-6 Proposed assumptions for Spain

11.5. Italy

Regarding assumptions for Italy, the sources are the ERAA24 database and the 'Documento di descrizione degli scenario 2024'[44] for onshore and offshore wind.

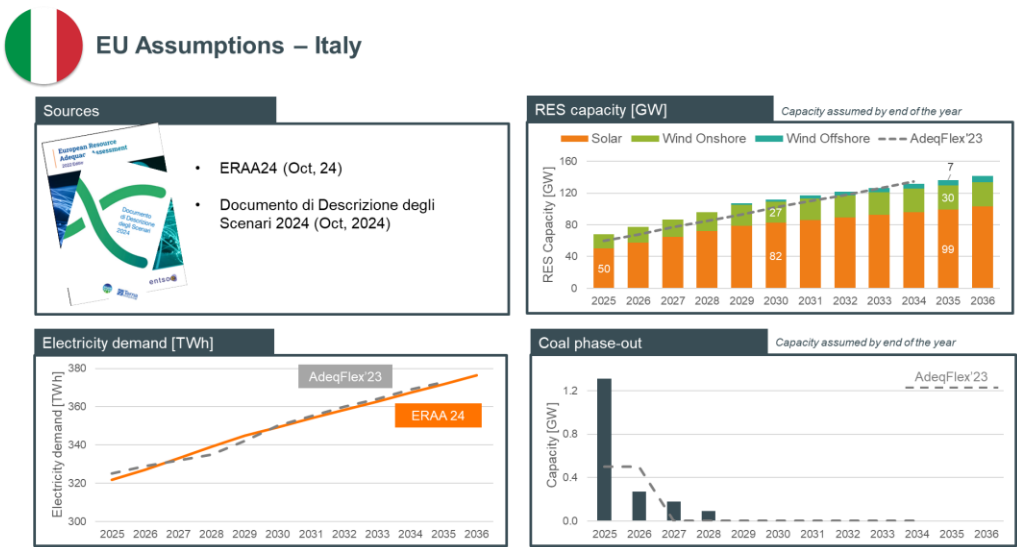

Figure 11-7 Proposed assumptions for Italy

[44] https://download.terna.it/terna/Documento_Descrizione_Scenari_2024_8dce2430d44d101.pdf

11.6. Poland

Regarding assumptions for Poland, the main source is ERAA24, which is mostly in line with latest draft updated NECP from March 2024 (final updated NECP not yet available).

A coal phase-out is assumed by end 2049. No new nuclear reactor is assumed for the time horizon of this study.

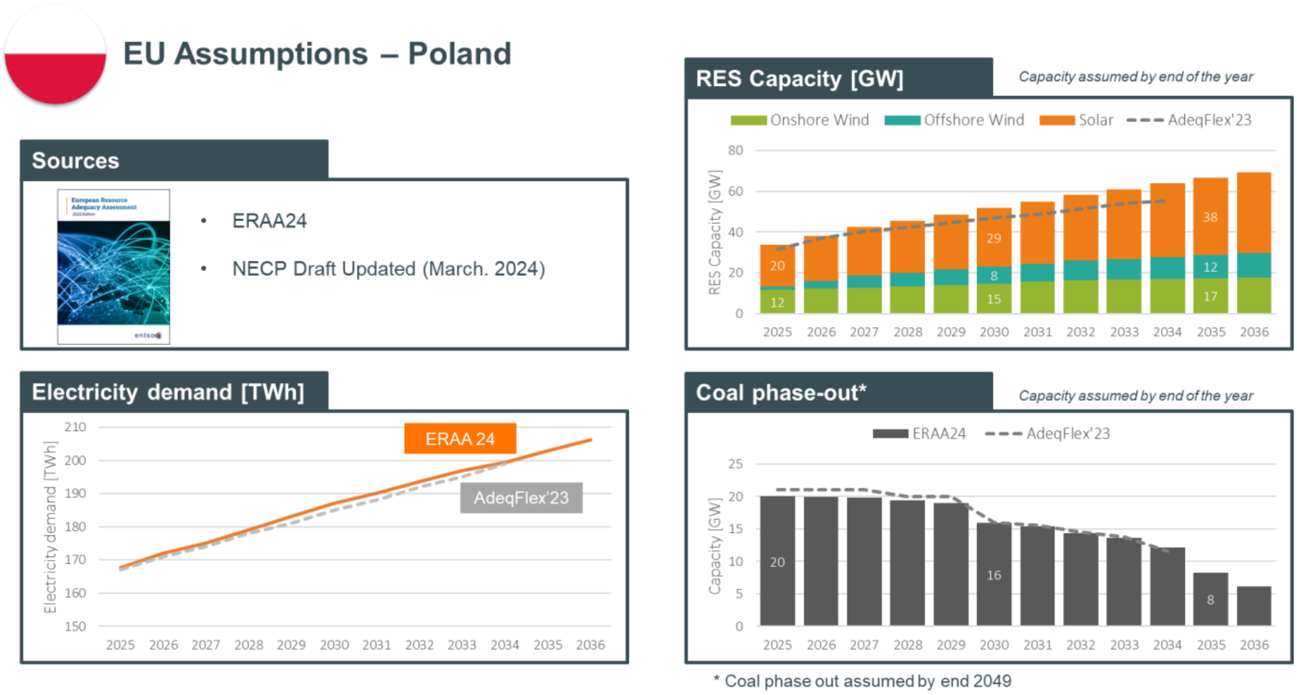

Figure 11-8 Proposed assumptions for Poland