Development of a transition pathway towards a close to net-zero electricity sector in Italy by 2035

A state-of-the-art model-based optimisation approach

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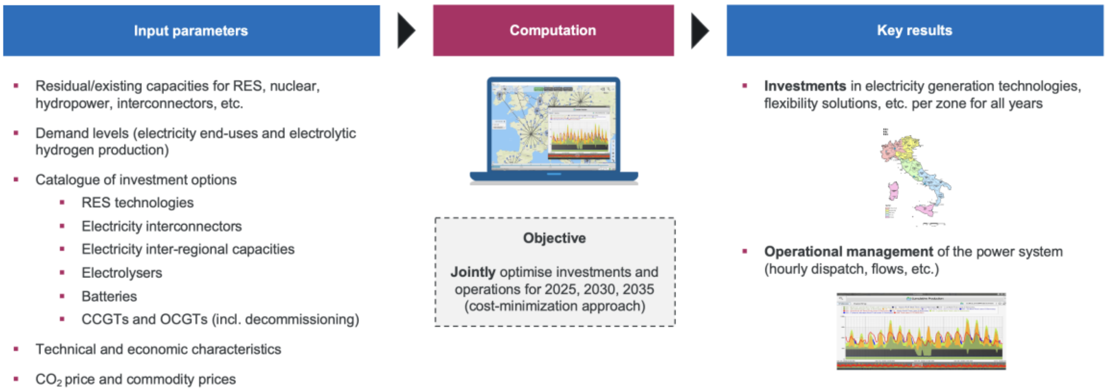
Executive summary

Meeting the commitments of reaching an overwhelmingly decarbonized power system in Italy by 2035 will require a substantial acceleration of the investments in low-carbon electricity generation technologies. Solar PV and wind power are expected to play a key role in decarbonizing the current power system and need to further scale up to meet the demand from other sectors such as mobility and hydrogen production. The investments in variable electricity generation capacities need to be accompanied by the deployment of a diversified portfolio of solutions to provide flexibility services on all timescales, from the daily to the seasonal level.

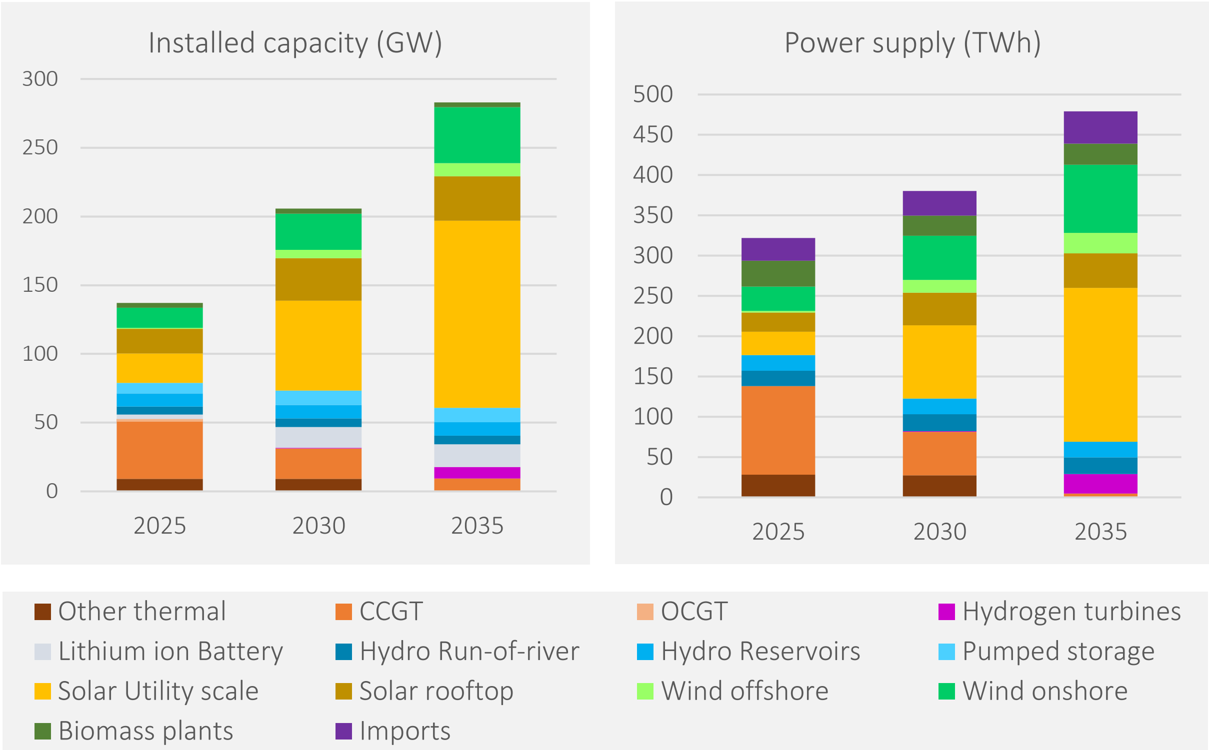
This study demonstrates that there exists a plausible transition pathway towards a close to net-zero electricity sector by 2035. The development of this transition pathway has been informed by a modelling exercise undertaken with the multi-energy modelling platform Artelys Crystal Super Grid and by inputs provided by numerous stakeholders. The pan-European model that has been leveraged adopts a bidding-zone level representation of Italy, with endogenous investment decisions in all Italian zones to ensure the system can meet the electricity demand-supply balance with an hourly time resolution.



The most significant features of the pathway are:

- **Significant investments in RES technologies are required**

  The evolution of the installed capacities shown hereunder shows that the power system will be dominated by variable production capacities, leading to dispatchable assets adopting a very different role compared to today's practices: they are required to provide flexibility services, and will run much less often than today.



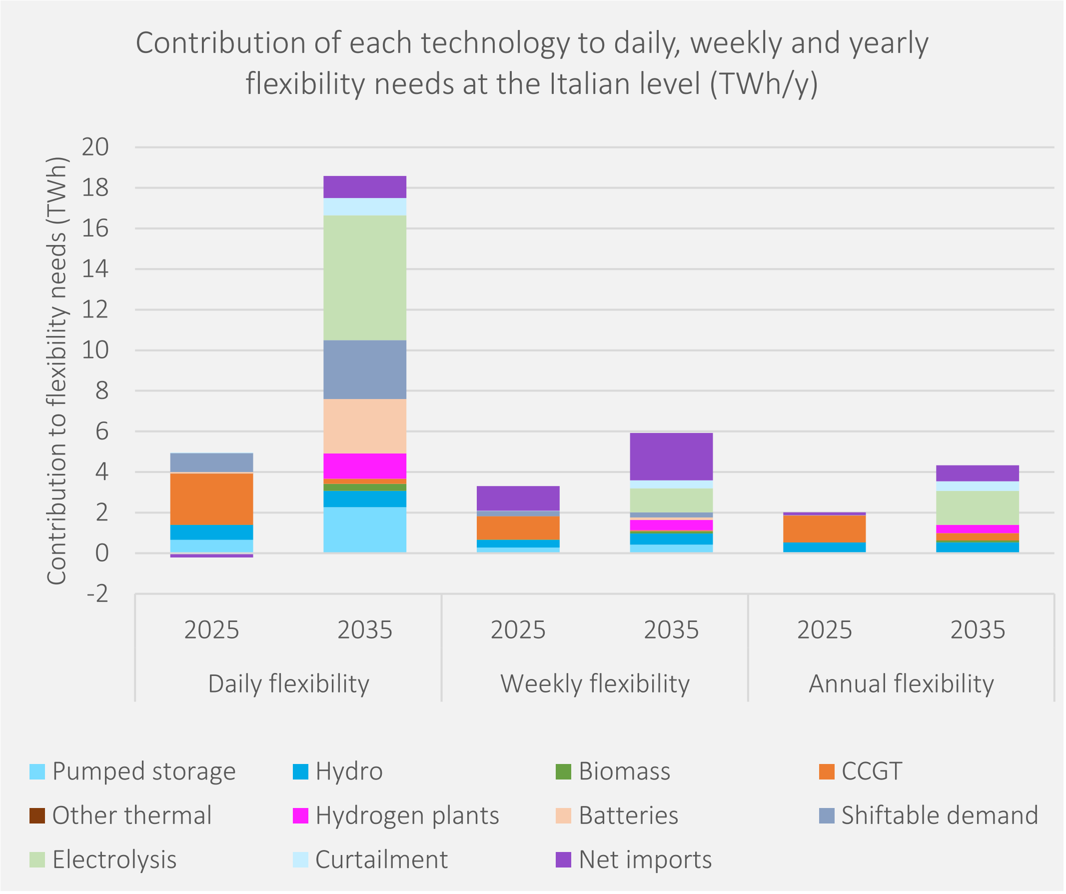
The pathway showcased in this study heavily relies on the deployment of solar PV installations and on wind power to decarbonize the current power system and enable the decarbonization of others, be it in a direct way via the electrification of mobility or in an indirect way via the production of electrolytic hydrogen. The deployment of solar PV has to be multiplied by a factor 6 by 2035, and wind by a factor 4. This significant increase of renewables allows a sharp decrease of CO_2 emissions: the projected carbon content of power demand is below 5 gCO_2/kWh in 2035.

- **A diversified portfolio of flexibility solutions is key to tackle the increasing demand for flexibility services on all timescales**

The evolution of solar PV and wind capacities shown above results in a sharp increase of the flexibility services required on all timescales. The portfolio of flexibility solutions should not only be able to integrate large swings in solar PV production across the day, but also to provide weekly and seasonal flexibility services that are induced by the development of wind power (wind regimes can have a duration of several days) and solar PV (high solar PV production in summer, low in winter).

Furthermore, some of the technologies that are currently providing flexibility services will be phased-out, leading to a complete overhaul of the way flexibility will be provided in 2035, as is shown on this graph, where one can notice the sharp increase in flexibility needs between

2025 and 2035, as well as the evolution of the way the different technologies provide these services.



- **The development of the hydrogen sector is both a challenge and an opportunity**

The decarbonising of part of the industry and of the transport sector will likely require hydrogen-based solutions to be put in place. Given the importance of these sectors, producing the required amount of hydrogen has a structural impact on the annual demand for electricity, as can be read on the first graph above. Therefore, the transition of the power sector is even more challenging, as it needs to decarbonize and scale-up at the same time.

However, the electricity demand emerging from hydrogen production is also an opportunity to facilitate the integration of variable renewable technologies as electrolysers can provide flexibility services on all timescales by adapting their operational management to the system's conditions, taking advantage of the flexibility that can be offered by the hydrogen infrastructure (via linepack, above-ground and, where relevant, underground hydrogen storage options). In some conditions, especially when restricting the reliance on imports from other countries, we find that hydrogen turbines can also play a role in helping the system meet the demand.

- **An increased level of power exchange capacity between Italy and the rest of Europe and between Italian regions would decrease system costs**

  In the transition pathway highlighted in this study, we find investments in additional interconnectors with Austria, Switzerland, France, Greece, Malta, Montenegro, and Slovenia allow to exchange flexibility services that can help balance the Italian power system. Furthermore, investments in exchange capacities between Italian regions are essential to enable an efficient cross-border trade, an extensive use of regional renewable deployment potentials and the exchange of energy and flexibility services between regions. Finally, an investigation of the impacts of different levels of net imports reveals that in the case one allows for more net imports than in our central pathway (60 TWh per year instead of 40), then one can reduce the reliance on inefficient power-to-hydrogen-to-power processes.

Planning and operational challenges to tackle

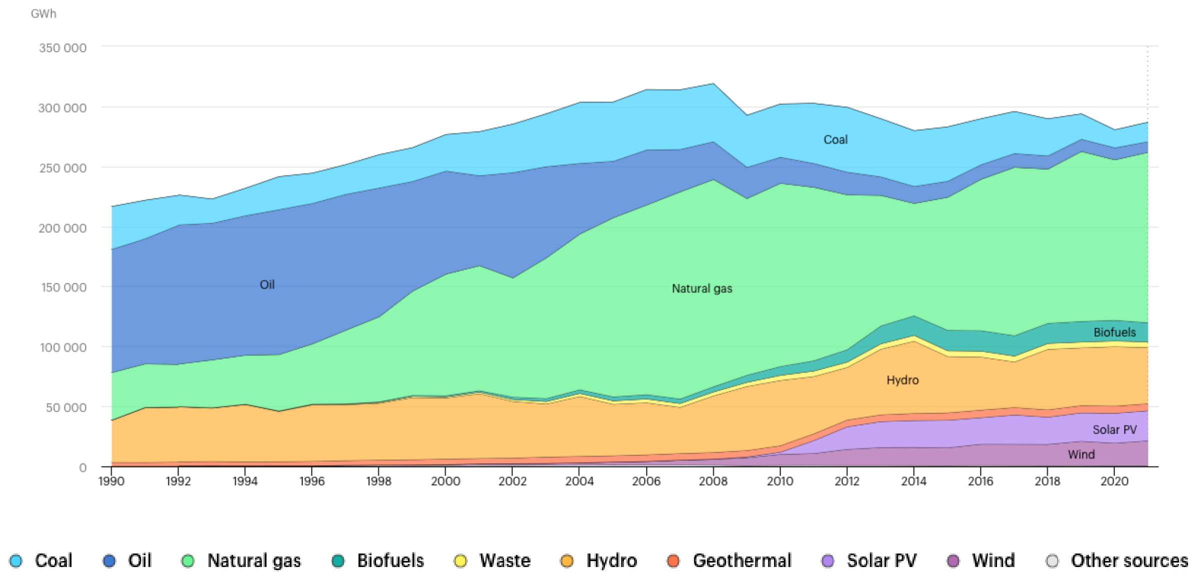
For a pathway such as the one described in this study to materialise, a number of key challenges must be tackled, both in terms of planning the evolution of the energy system and in terms of operating it. For a planning process to be efficient at avoiding unnecessary investments, it should be as holistic as possible, jointly considering the evolution of the electricity, gas and hydrogen sectors, as strong synergies and interdependencies exist between these sectors. Furthermore, given the magnitude of the investment challenge in RES technologies, the introduction of streamlined procedures should be encouraged. On the operational side, the results described in this study show that demand-side flexibility has a key role to play, notably in the residential sector (via EV charging for example) and industry level (via a system-friendly operation of electrolysers). Further work is needed on the way to design efficient incentives (e.g., support schemes, tariffs, etc.) that can encourage end-users to provide these essential flexibility services.

A complete set of policy recommendations can be found in the accompanying material prepared by ECCO.

1 Context and objective of the study

1.1 Challenges in the transition towards a clean energy system in Italy

The Italian power sector is still to this day heavily dependent on fossil resources, as more than 50% of electricity is generated by burning natural gas, oil or coal[1]. Whilst coal and oil capacities can be expected to be phased-out in the coming years, the fate of the reliance on natural gas heavily depends on the policy framework and in particular the way investments in renewables will be mobilized in the near future.



As a member of the G7, Italy has committed[2] "to rapidly scaling-up technologies and policies that further accelerate the transition away from unabated coal capacity and to an overwhelmingly decarbonised power system in the 2030s".

The recent energy crisis sheds a new light on these commitments, as phasing-out the use of natural gas would also enable Italy to increase its resilience to price shocks on global markets, and thereby reduce the need for government spending for energy affordability measures[3].

Italy has had considerable successes in implementing ambitious energy and climate policies. Notably, the development of solar capacities has reached unmatched levels in 2011. During that year, Italy was responsible for more than 40% of the total EU27 solar PV additions (9.5 GW out of 22.3 GW), outpacing Germany, China, and the US[4].

[1] https://www.iea.org/countries/italy
[2] https://www.gov.uk/government/publications/g7-climate-and-environment-ministers-meeting-may-2021-communique/g7-climate-and-environment-ministers-communique-london-21-may-2021
[3] https://www.iea.org/data-and-statistics/data-tools/government-energy-spending-tracker-policy-database
[4] Based on data retrieved from https://pxweb.irena.org/pxweb/en/IRENASTAT/

To enable the level of investments required for Italy to reach a close to net zero power sector by 2035, clear and impactful policies must be implemented. This report offers a technical and economic trajectory to deliver a near zero electricity market by 2035 in line with the g7 commitment and aligned with the 2030 target. It includes policy areas where energy and climate measures should be targeted.

A unique combination of model-based work and policy analysis

The work presented in this report and in the accompanying policy document is the result of a collaboration between Artelys and ECCO, supported by the European Climate Foundation.

- **Artelys** is a consultancy specialised in energy modelling, notably thanks to the Artelys Crystal Super Grid solution. Artelys have supported ECCO by undertaking the modelling the future of the European energy system with a focus on Italy to define a decarbonisation pathway while ensuring system reliability.
  For more information: www.artelys.com

- **ECCO** is the first independent Italian, non-profit climate change think tank. It was founded in 2021 with the mission to accelerate climate action in Italy and around the world. ECCO has been the overall coordinator of the project and has led the translation of the outcome of the modelling into actionable policy recommendations.
  For more information: www.eccoclimate.org

1.2 Objective of the study

The main objective of the study is to provide insights into an evolution of the Italian power sector, to meet a close to net-zero configuration by 2035, in accordance with the ambitions set out by the G7.

The study starts with a quantitative analysis of the evolution of the final demand for electricity and electrolytic hydrogen. Based on this analysis and on an estimation of the availability of demand-side management, it proceeds with a model-based optimisation of investments in renewables (residential solar PV, utility scale solar PV, onshore wind, offshore wind), electricity interconnectors between Italy and neighbouring countries, electricity capacities between the Italian bidding zones, electrolysers, and batteries.

Finally, the study provides recommendations based on an analysis of the results from the technical, economic and policy points of view.

2 Overview of the methodology

This section is devoted to presenting the methodology put in place to undertake the analysis of the Italian electricity system in a European perspective for the period 2025-2035 and to formulate policy recommendations.

We have structured our work in three subsequent work packages. The first work package was dedicated to adopting demand projection assumptions and identifying investment options. The second work package has resulted in the identification of the set of technologies in which one should invest to minimise the overall transition costs and meet the demand for electricity and hydrogen. Finally, the third work package was dedicated to analysing the results and providing recommendations.

Work package 1 – Demand projections and identification of investment options

The first work package has consisted in performing a literature review and to compare different demand projection exercises performed by the European Commission, the ENTSOs, Terna, EMBER, etc. Based on this review, Artelys and ECCO have proposed a pathway of demand evolution for 2025, 2030 and 2035, both for electricity end-uses and the production of electrolytic hydrogen.

The second objective of this work package was to identify the investment options, and the set of constraints that can limit their deployment (e.g. maximum plausible investment rates, minimum and/or maximum capacities, technical potentials, etc.). Artelys has proposed an approach that is similar to the one adopted to undertake the EMBER New Generation study[5], with the additional ability for the model to decommission gas-fired turbines.

The assumptions have been discussed and validated via a workshop involving the different stakeholders of the project. This workshop has been held in Milano on 13 October 2022, and has involved ECF, Greenpeace, Legambiente, WWF, FSR, Terna, RSE, Politecnico di Milano, ARERA and MBS. All workshops have been organised under the Chatham House Rule.

A description of the key assumptions and of the modelling framework can be found in Section 4.

Work package 2 – Optimisation of investments over the 2025-2035 period

The second work package has consisted in performing an optimisation of the deployment of technologies based on the investment options identified in the first work package over the 2025-2035 period. This assessment is based on the use of the Artelys Crystal Super Grid software solution, which jointly optimises investments and operational management of interconnected energy systems.

[5] https://ember-climate.org/insights/research/new-generation/

An overview of the modelling framework is provided in the following paragraphs:

- **Time resolution and time horizon**
  In order to capture all relevant phenomena related to the integration of large shares of intermittent renewable capacities, the model uses an hourly time resolution, over entire years (i.e. 8760 consecutive timesteps per represented year). This choice allows to capture the need for flexibility services on timescales ranging from the day (driven by daily solar patterns and day-night demand patterns), to the year (driven by solar and wind seasonal patterns and by the thermo-sensitivity of the demand) via the week (driven by wind regimes and the differences in demand pattern between weekdays and weekends). The model considers the 2025, 2030 and 2035 time horizons.

- **Geographical scope and granularity**
  Exercises aiming at optimising the investments in the electricity sector of a country must recognise the dynamic exchanges of electricity with neighbouring countries. Therefore, we have used a pan-European model, based on the assumptions published by EMBER as part of its New Generation study. The model covers EU27, Switzerland, Norway, and the United Kingdom.
  Furthermore, to recognise the constraints that may emerge due to the structure of the internal Italian network, we have subdivided Italy into its 7 bidding zones, which are shown below.

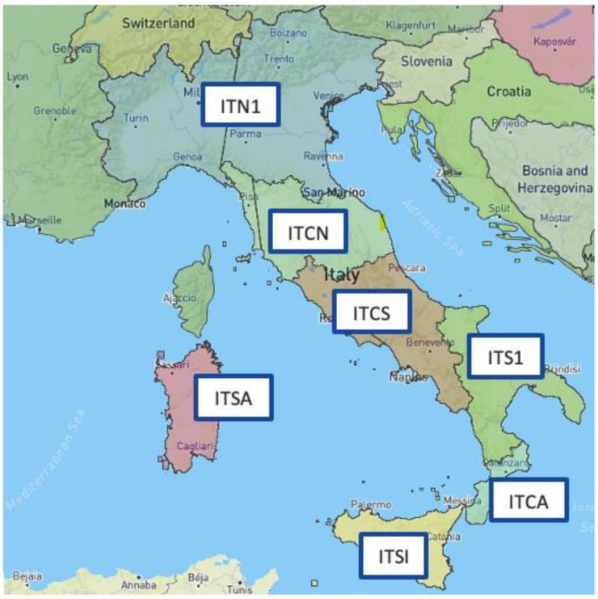


Figure 1 – Map of the Italian bidding zones used in this study

- **Workflow**

  A least-cost optimisation aiming at minimising investment and operational costs has been put in place. Capacities were considered as being fixed for the year 2025 (generation, storage and transmission technologies), and the model was able to invest in a set of investment options identified during the first work package.

  The following figure presents the workflow that has been implemented to identify the optimal transition pathway towards a close to net-zero electricity sector in Italy by 2035:

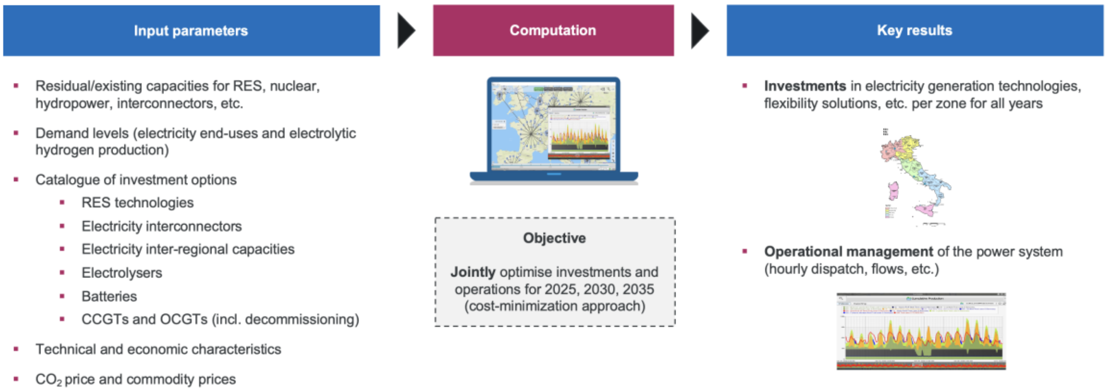


Figure 2 - Artelys Crystal Super Grid inputs and outputs

The preliminary results have been discussed during a workshop involving the different stakeholders of the project. This workshop has been held in Milano on 2 March 2023, and has involved ECF, Greenpeace, Legambiente, WWF, FSR, IEA, RSE, Politecnico di Milano, ARERA and EIEE. All workshops have been organised under the Chatham House Rule. Based on the discussions held during this workshop, Artelys and ECCO have amended assumptions, notably related to the hydrogen demand levels.

Work package 3 – Analysis and recommendations

The third and final step of the study was to examine the results and to support the elaboration of policy recommendations by ECCO based on the modelling outputs. The outcome of this work package is presented in detail in Section 3.

3 Key findings and associated policy recommendations

This section focuses on the presentation of the key findings that have emerged from the modelling work, with a focus on the set of technologies that should deploy in order for Italy to reach an overwhelmingly decarbonised power sector by the mid 2030s.

3.1 The deployment of renewable generation capacities has to increase significantly

The analysis shows that the installed solar PV capacity will have to be multiplied by more than 6 by 2035 and the wind capacity will need to more than quadruple within Italy to reach a close to net-zero power system by 2035 and enable the production of the required volumes of electrolytic hydrogen.

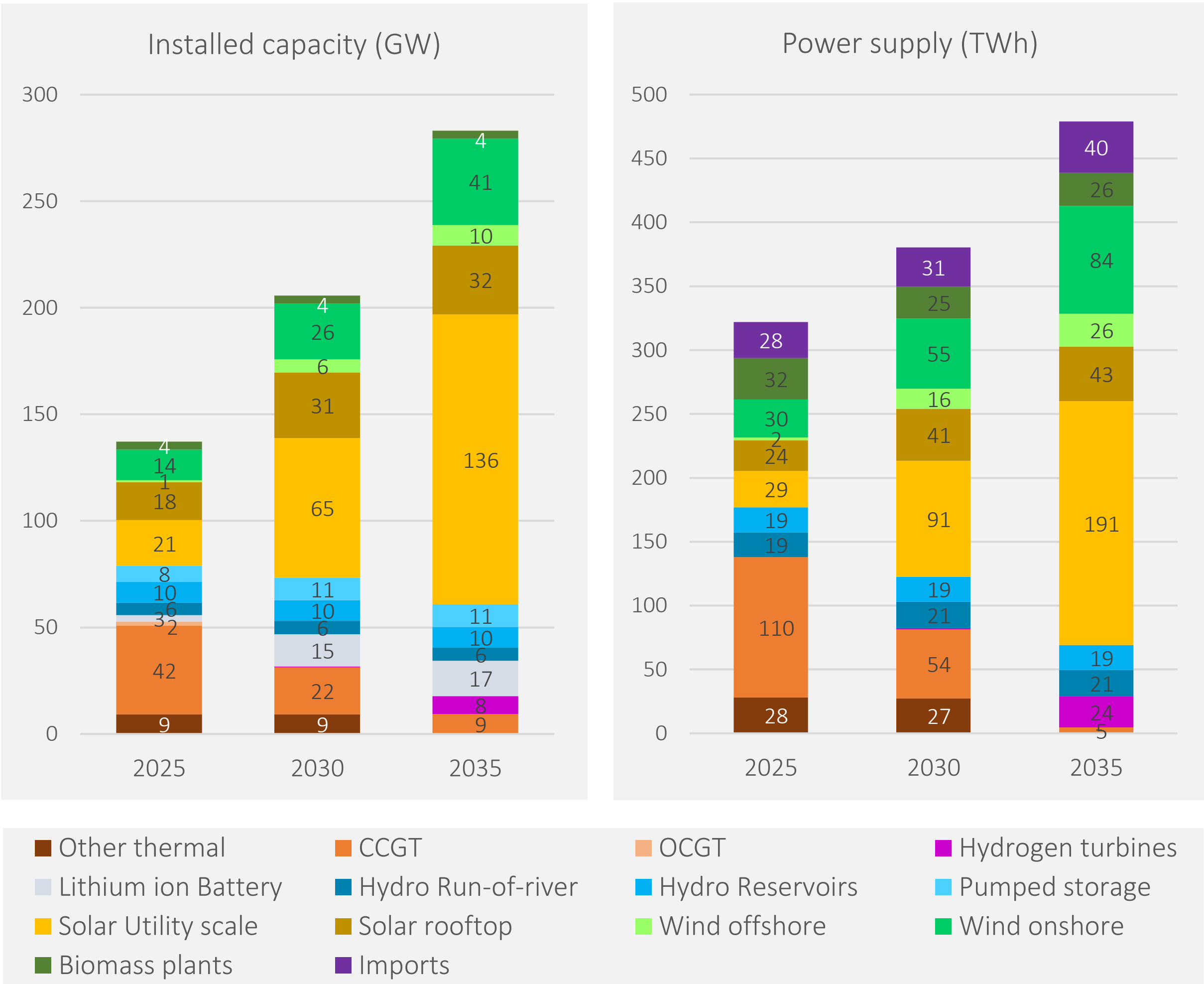


Figure 3 – Evolution of installed capacities and power production in Italy. Source: Artelys modelling

Currently, solar capacities and wind capacities respectively represent 24.2 GW and 11.7 GW in Italy (Terna, 2022). Our modelling exercise indicates that a substantial increase in these capacities is required to reach a close to carbon neutral power system by the mid 2030s. We find that by 2035, 168 GW of solar capacities (of which 32 GW is solar rooftop, and 136 is solar utility scale) and 51 GW of wind capacities (of which 10 GW is wind offshore, and 41 GW is wind onshore) are required to achieve an overwhelmingly decarbonised electricity sector. The projected evolution of installed capacity of each renewable production technology is shown in Table 1.

Renewable installed capacity (GW)	2025	2030	2035
Solar PV – Utility scale	21	65	136
Solar PV – Rooftop	18	31	32
Wind power – Offshore	1	6	10
Wind power – Onshore	14	26	41
Biomass power plants	4	4	4
Hydro reservoirs	10	10	10
Run-of-the-river hydro	6	6	6
Pumped-hydro storage	8	11	11

Table 1 – Evolution of renewable installed capacities in Italy (GW). Source: Artelys modelling

In total, solar and wind generation respectively account for 56% and 27% of total power generation within Italy in 2035.

This considerable deployment of renewable generation will allow for a decrease in fossil power production. These changes will enable a considerable decrease in carbon emissions from the power sector.

As shown in Figure 4, CO2 emissions from power demand will strongly decrease, from just below 50 MtCO2 in 2025 to below 2 MtCO2 in 2035. These emissions can be achieved with an increased level of direct power demand, and with a high-power demand for hydrogen production[6]. The decarbonation of power production is thus projected to support the decarbonation of the industrial, residential and transport sectors.

[6] Section 4.1 describes the hypotheses for the evolution of direct and indirect power demand.

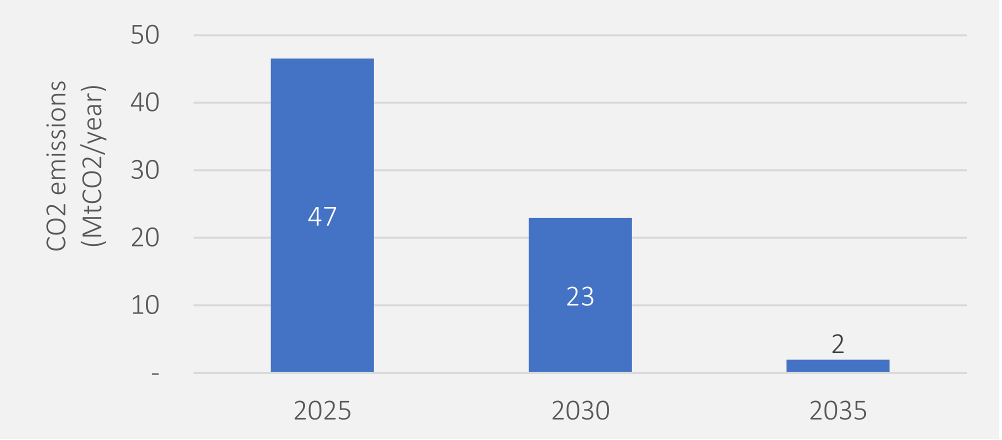


Figure 4 - Projected evolution of CO2 emissions from the power sector from 2025 to 2035 (MtCO2/year). Source: Artelys modelling.

The associated carbon content of the total power demand decreases from around 140 gCO2/kWh in 2025 to around 5 gCO2/kWh in 2035 as shown in Figure 5.

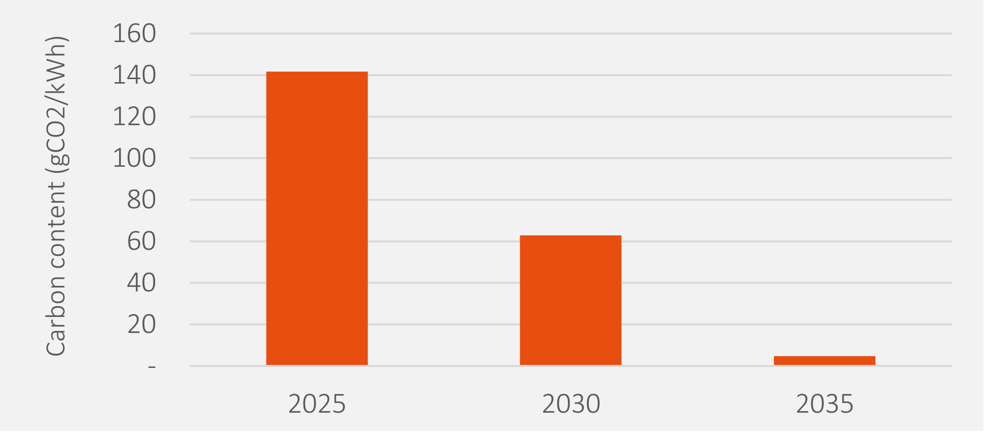


Figure 5 - Evolution of the carbon content of power demand (both direct and indirect power demand) in gCO2/kWh. Source: Artelys modelling.

Reaching these levels of renewable deployment requires the installation rate of solar and wind capacities to multiply by 7 by 2030, and by more than 8 by 2035.

Current installation rates amount to 1.7 GW/year for solar PV capacity, and 0.4 GW/year for wind capacity. These installation rates will have to increase significantly to ensure the decarbonisation of the Italian generation mix, while limiting its dependence on imports.

On average, over the 2025 – 2035 period, the installation rates will have to reach 11.5 GW/year for solar utility scale, 1.4 GW/year for solar rooftop, 2.6 GW/year for wind onshore, and 0.9 GW/year for wind offshore capacity. Figure 6 compares the projected evolution of installation rates with historical rates.

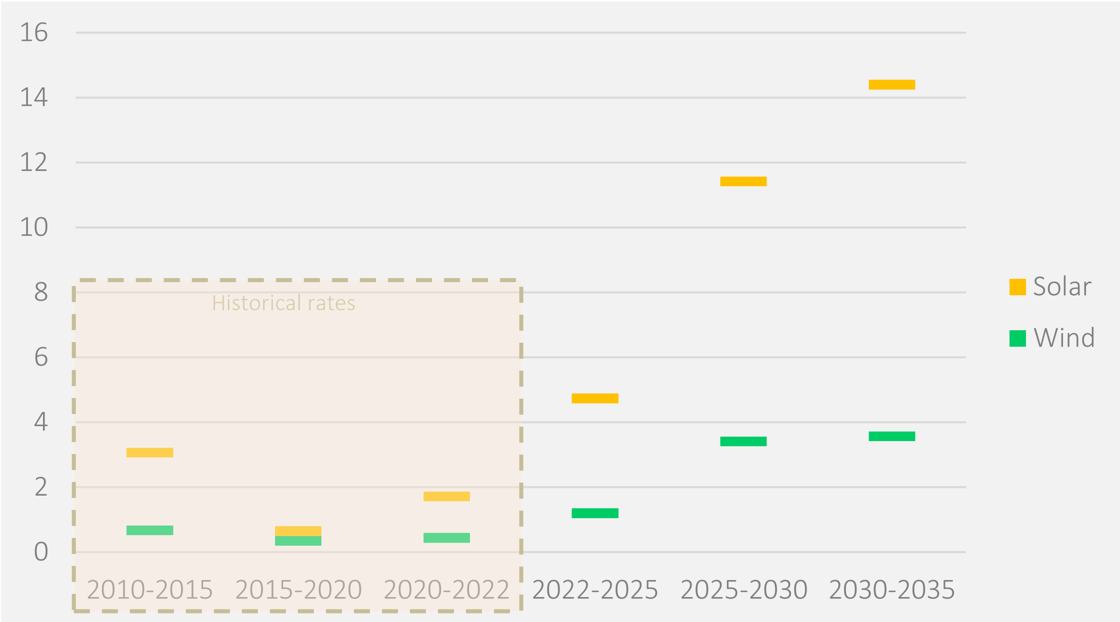


Figure 6 - Historical and projected deployment rates for wind and solar capacities (GW/year). Source: Artelys modelling for projected rates and IRENA for historical rates (IRENA, 2022)

Solar deployment had already reached high levels from 2010 to 2015: up to 9.5 GW of solar capacity were installed over a year within Italy (IRENA, 2022).

Solar and wind power investment costs are projected to account for around two thirds of total investment costs in electricity generation and flexibility assets

Figure 7 shows the projected evolution of yearly overnight investments for the 2025 to 2030 and 2030 to 2035 periods. Solar and wind each account for more than a third of total average investment costs. The rest of the investment mainly corresponds to the cost of new hydro and batteries between 2025 and 2030, and electrolysis and hydrogen turbines between 2030 and 2035. Transmission costs represent a small proportion of total overnight costs: around 2% between 2025 and 2030, and 6% between 2030 and 2035.

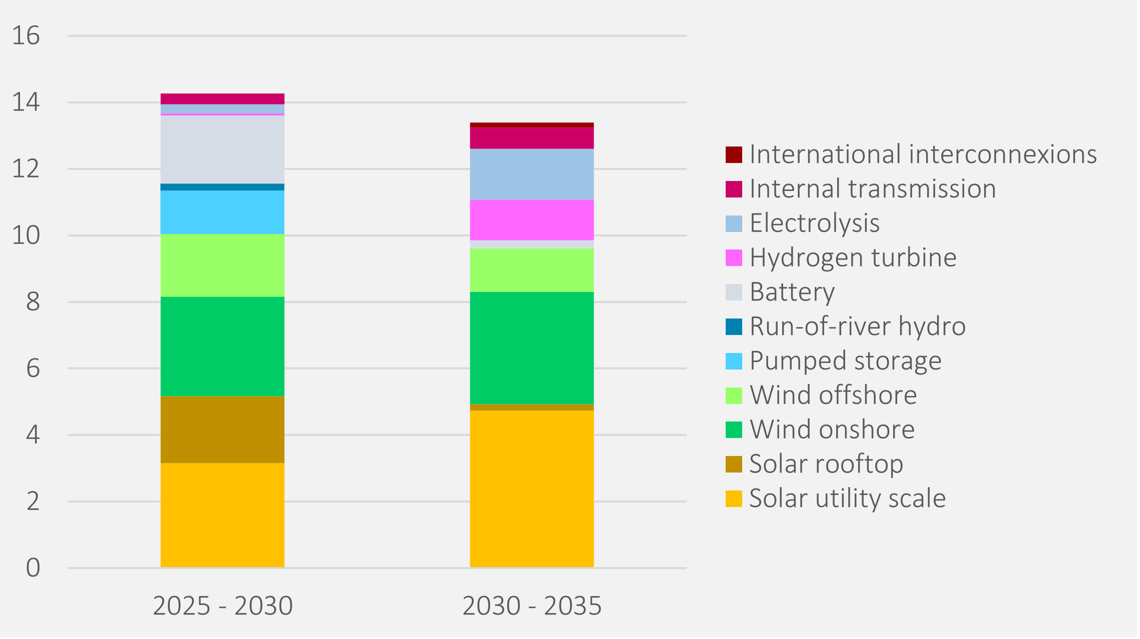


Figure 7 - Average yearly overnight cost of the portfolio for 2025 - 2030 and 2030 - 2035 (billion euros/year)[7]. Source: Artelys modelling.

The deployment of renewable technologies will not be homogenous across Italian regions: Southern regions will account for a large share of installed renewable capacities. In the Northern regions the deployment of renewables will likely be limited by the local potential.

Figure 8 shows the evolution of renewable capacities in each of the regions of Italy we have considered in this work (corresponding to the current bidding zone structure). Whilst installations of solar PV strongly develop in each of the regions, solar PV on rooftops mainly develops in the north, as a result of the high demand, the high regional solar rooftop potential and the limited potential for other renewable production technologies. Indeed, as solar rooftop installations are more expensive than solar utility scale ones, rooftop installations tend to deploy when the installation potential for utility scale solar PV is largely used. Solar capacities also significantly increase in the South, notably in Central South, the Southern region, Sicily, and Sardinia, as both the load factors and local installation potentials are high in these regions.

[7] The values shown are the average yearly investment costs without annualization and without integrating interest costs. Investment costs for international interconnection lines are divided equally between the two transit countries.

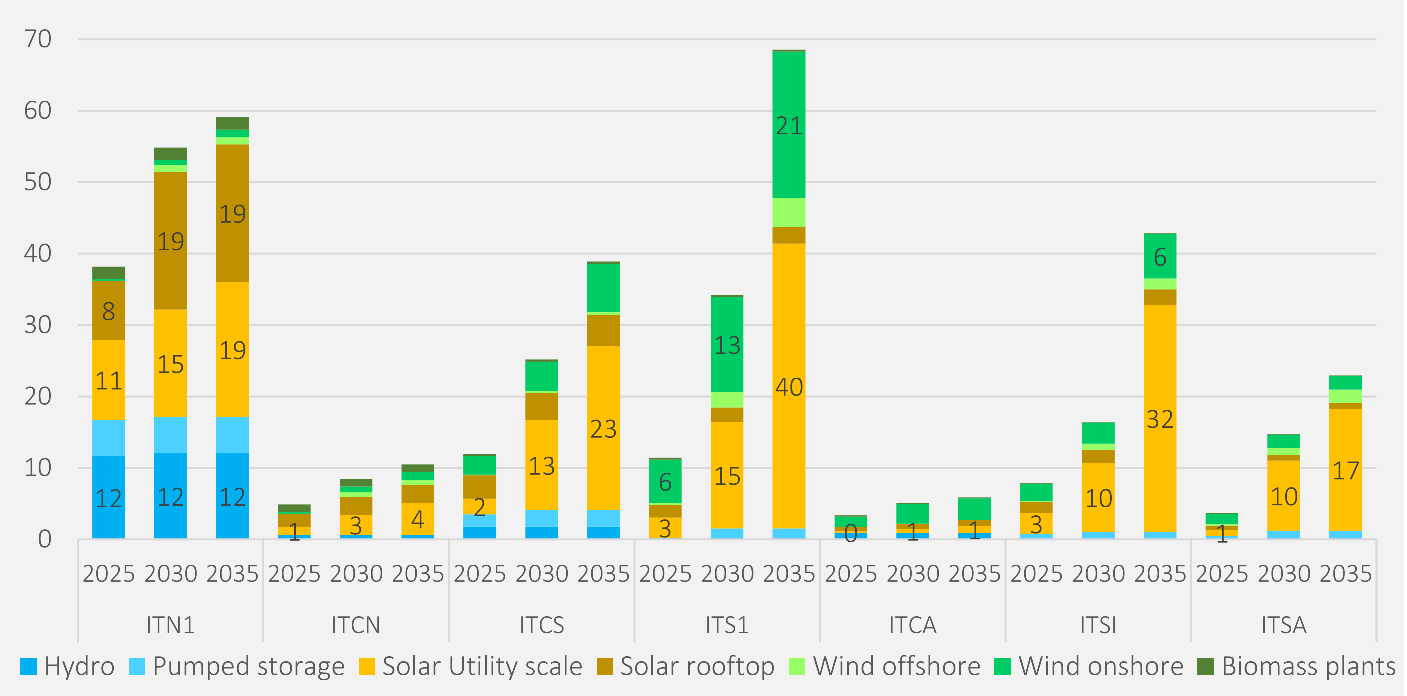


Figure 8 Projected evolution of installed renewable capacity by region (GW). Source: Artelys modelling.

Table 2 and Table 3 provide the regional installed capacity for solar utility scale, solar rooftop, wind onshore and wind offshore from 2025 to 2035.

Solar Utility Scale	2025	2030	2035
ITN1	11	15	19
ITCN	1	3	4
ITCS	2	13	23
ITS1	3	15	40
ITCA	0	1	1
ITSI	3	10	32
ITSA	1	10	17

Solar Rooftop	2025	2030	2035
ITN1	8	19	19
ITCN	2	2	2
ITCS	3	4	4
ITS1	2	2	2
ITCA	1	1	1
ITSI	2	2	2
ITSA	1	1	1

Table 2 – Projected evolution of solar installed capacities (GW). Source: Artelys modelling.

Wind Onshore	2025	2030	2035
ITN1	0	1	1
ITCN	0	1	1
ITCS	3	4	7
ITS1	6	13	21
ITCA	1	3	3
ITSI	2	3	6
ITSA	1	2	2

Wind Offshore	2025	2030	2035
ITN1	8	19	19
ITCN	2	2	2
ITCS	3	4	4
ITS1	2	2	2
ITCA	1	1	1
ITSI	2	2	2
ITSA	1	1	1

Table 3 - Projected evolution for wind power installed capacities (GW). Source: Artelys modelling.

The maximum investment limits we have assumed are reached in the Northern part of Italy. Unlocking additional investment options in this area could prove to be beneficial to the system.

Figure 9, Figure 10, Figure 11, and Figure 12 show both the installed capacity and the remaining potential available for solar and wind power production technologies. The remaining potential corresponds to investment options that are not found to be economically viable in our assessment. This is the result of the trade-off between installing capacities in regions with high demand (with limited need to reinforce inter-regional electricity networks) and installing capacities in regions with the best potentials (with the associated need to reinforce electricity networks).

As mentioned above, the installation potential for solar, wind onshore and wind offshore is reached in the North, where the demand is the highest, while additional investment options are still available in the Southern regions of Italy.

Therefore, incentivising the development of additional potentials in the Northern part of Italy, potentially combined with a strategy aiming at better allocating future electricity demand centres across the country, could help decreasing the overall costs of the transition towards a close to net-zero power sector.

The following figures present the installations of solar and wind power generation capacities by regions, with the remaining potential being shown as a dashed area.

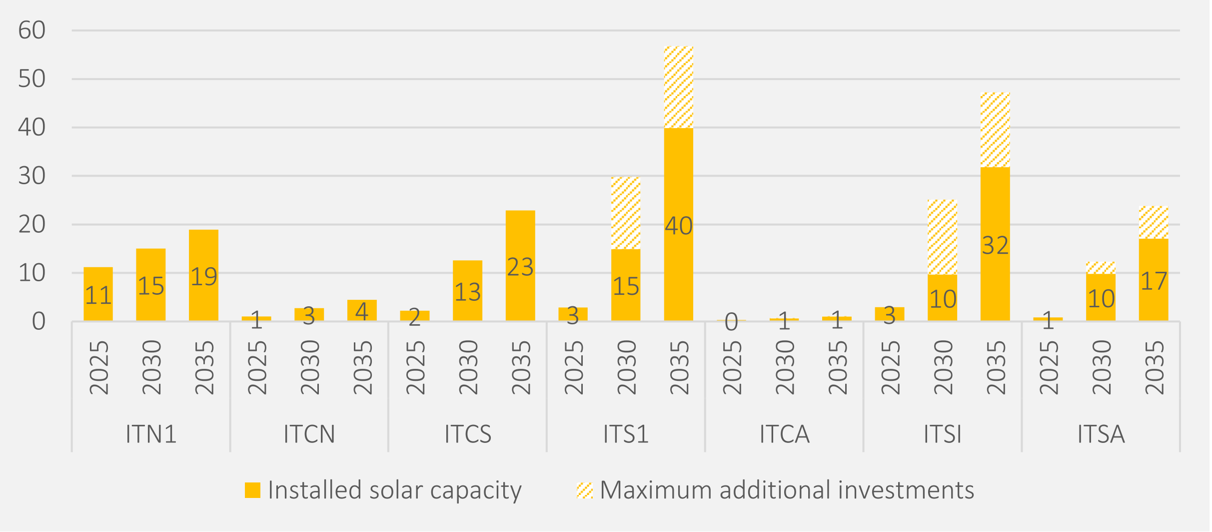


Figure 9 - Installed solar capacity and additional investments available (GW). Source: Artelys modelling

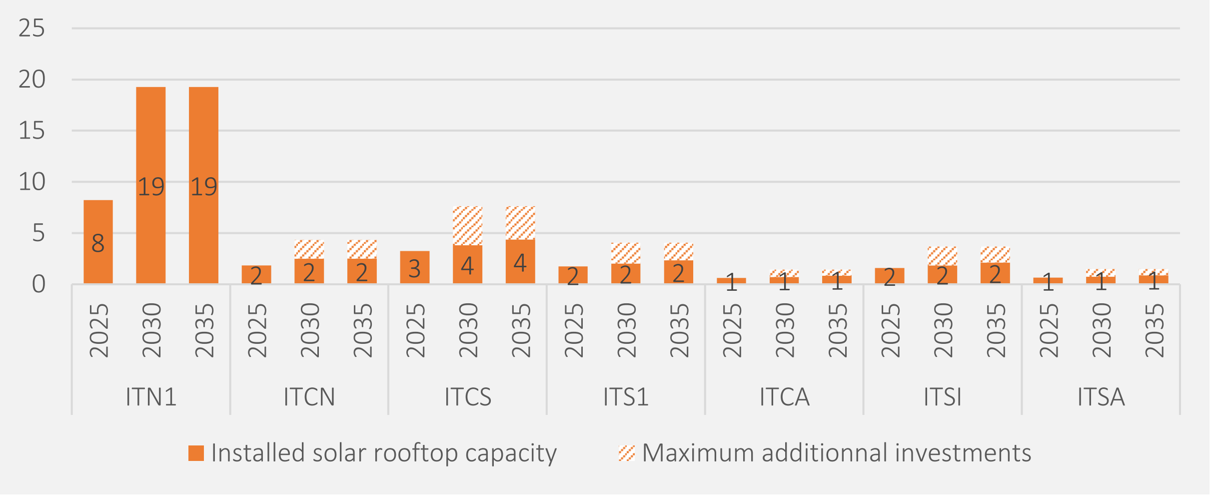


Figure 10 - Installed solar rooftop capacity and additional investments available (GW). Source: Artelys modelling.

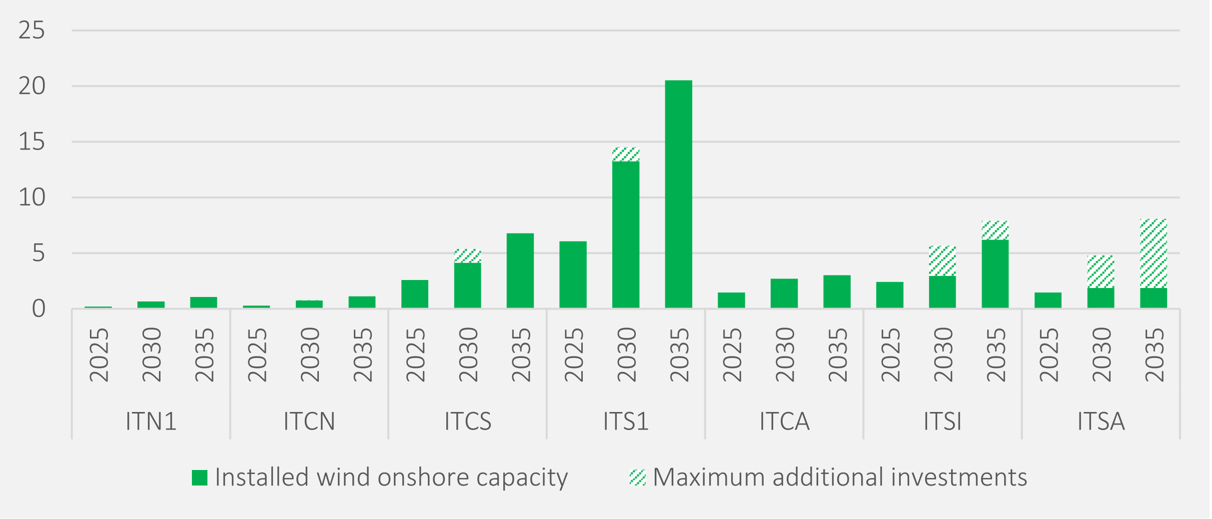


Figure 11 - Installed wind onshore capacity and additional investments available (GW). Source: Artelys modelling.

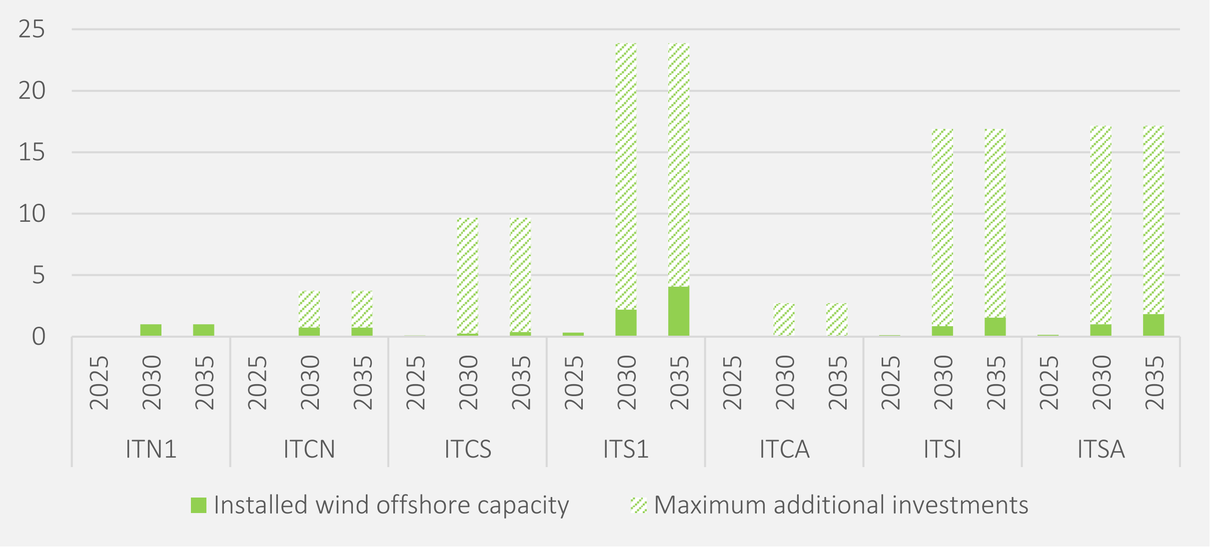


Figure 12 - Installed wind offshore capacity and additional investments available (GW). Source: Artelys modelling.

3.2 A diversified portfolio of flexibility solutions is required to address growing needs for flexibility

3.2.1 Metrics describing flexibility needs and services

This section is devoted to defining daily, weekly, and seasonal flexibility needs, and to presenting the way different technologies participate in meeting these needs. We then use these definitions to analyse the needs for flexibility services in the case of the pathway highlighted above in Section 3.1.

Flexibility is defined as the ability of the power system to cope with the variability of the residual load[8] at all times.

Hence, flexibility needs can be characterised by analysing the residual load curve. (Artelys, Trinomics, Enerdata, 2020). Hereunder, we introduce three metrics that enable the analysis of the dynamics of the residual load on several timescales, to take into account all the underlying phenomena that drive the need for flexibility:

- **Daily flexibility needs**, mainly driven by the need to integrate solar PV and by the day-night pattern of the demand;
- **Weekly flexibility needs**, mainly driven by wind regimes that tend to have a duration of several days, and by the weekday-weekend pattern of the demand;
- **Seasonal flexibility needs**, mainly driven by the seasonal variation of solar and wind power, and by the thermo-sensitivity of the electricity demand.

We described below these three metrics, which each aims at extracting a subset of the dynamics of the residual load.

Daily flexibility needs

On a daily basis, if the residual load were to be flat, no flexibility would be required from the dispatchable units. Indeed, in such a situation, the residual demand could be met by baseload units with a constant power output during the whole day. In other words, a flat residual load does not require any flexibility to be provided by dispatchable technologies.

We therefore define the daily flexibility needs of a given day by measuring by how much the residual load differs from a flat residual load. The daily flexibility needs computed in this report are obtained by applying the following procedure:

1. Compute the residual load over the whole year by subtracting variable RES generation and must-run generation from the demand.

[8] The residual load is defined as the demand time-series to which one subtracts the RES generation time-series. In other words, the residual load is that part of the demand that must be met with dispatchable assets and imports/exports.

2. Compute the daily average of the residual load (365 values per year).
3. For each day of the year, compute the difference between the residual load and its daily average (the light green area shown on the figure below). The result is expressed as a volume of energy per day (TWh per day)
4. Sum the result obtained over the 365 days. The result is expressed as a volume of energy per year (TWh per year).

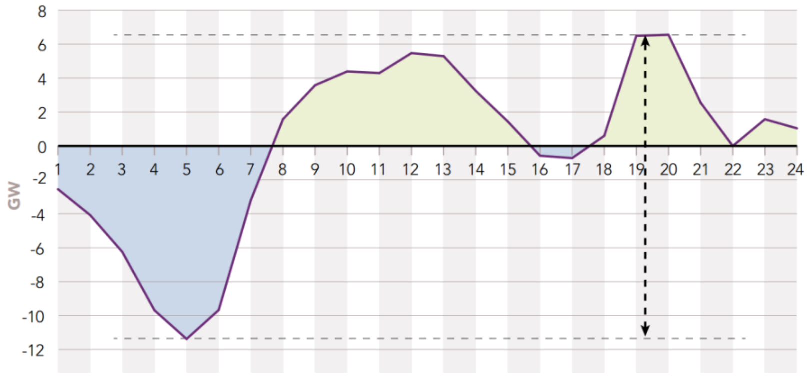


Figure 13 - Illustration of daily flexibility needs (the solid purple line measures the deviation of the residual load from its daily average for a given day). Source : RTE, Bilan prévisionnel de l'équilibre offre-demande, 2015

Weekly flexibility needs

The same reasoning is applied to evaluate the weekly flexibility needs. However, in order not to re-capture the daily phenomena that are already taken into account by the daily flexibility needs indicator, we define weekly flexibility needs as follows:

1. Compute the residual load over the whole year by subtracting variable RES generation and must-run generation from the demand with a daily resolution
2. Compute the weekly average of the residual load (52 values per year)
3. For each week of the year, compute the difference between the residual load (with a daily resolution) and its weekly average (the light green area shown on the figure below). The result is expressed as a volume of energy per week (TWh per week).
4. Sum the result obtained over 52 weeks. The result is expressed as a volume of energy per year (TWh per year).

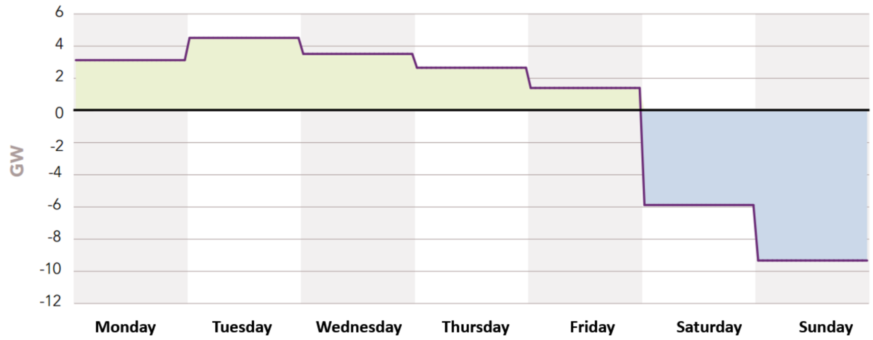


Figure 14 - Illustration of weekly flexibility needs (the solid purple line measures the deviation of the residual load from its daily average for a given week). Source: RTE, Bilan prévisionnel de l'équilibre offre-demande, 2015

Seasonal flexibility needs

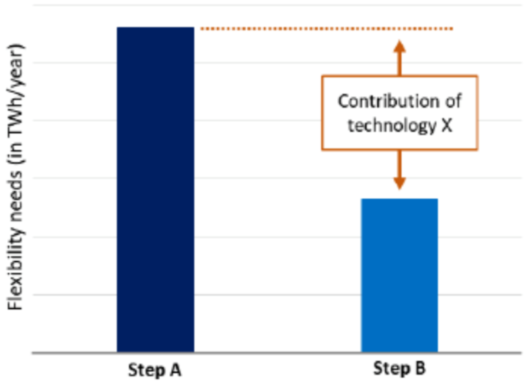
Finally, the seasonal flexibility needs are defined in a similar way:

1. Compute the residual load over the whole year by subtracting variable RES generation and must-run generation from the demand with a monthly time resolution
2. Compute the annual average of the residual load
3. Compute the difference between the residual load (with a monthly time resolution) and its annual average. The result is expressed as a volume of energy per year (TWh per year).

Contribution to flexibility

Once the flexibility needs are defined, the *contribution* to meeting the needs for flexibility by a given technology can be evaluated by re-computing the indicator by subtracting its production/consumption time-series from the residual load. More precisely, the provision of flexibility of a given technology is calculated by comparing the flexibility needs based on the residual load (as explained above) to residual flexibility needs. The latter are based on the residual load minus the specific technology generation/consumption profile.

The figure below illustrates the computation of the contribution to daily flexibility services of a given technology:



Step A – Compute the daily flexibility needs based on the residual load

Step B – Compute the residual daily flexibility needs based on the residual load – technology X generation/consumption profile

The difference between the two quantities is the contribution of technology X in the provision of flexibility. The same approach can be used to evaluate the contribution of technologies to meeting the different needs for flexibility (i.e. daily, weekly and seasonal flexibility needs).

Traditionally, controllable assets such as gas-fired power plants and interconnectors have been the primary contributors to the provision of flexibility services. In a RES-dominated and largely decarbonized power system, the contribution to flexibility services will extend to other technologies such as electric vehicles, stationary batteries, electrolysers, etc.

This fact can already be observed without calculating the contribution to the provision of flexibility services, by looking at the way generation and demand assets are operated.

In Figure 15, it can be noticed that controllable generating assets such as hydrogen and hydroelectric power plants produce when the solar and wind generation is low, thereby contributing to the provision of daily and weekly flexibility services.

Likewise, flexible consumption assets, shown on Figure 16, adapt to the demand and RES generation. For example, the electricity consumption by electrolysers concentrates during high solar generation periods. Therefore, electrolysers offer flexibility by only extracting power from the system during times when it is the cheapest. In this example, electrolysers provide daily flexibility services.

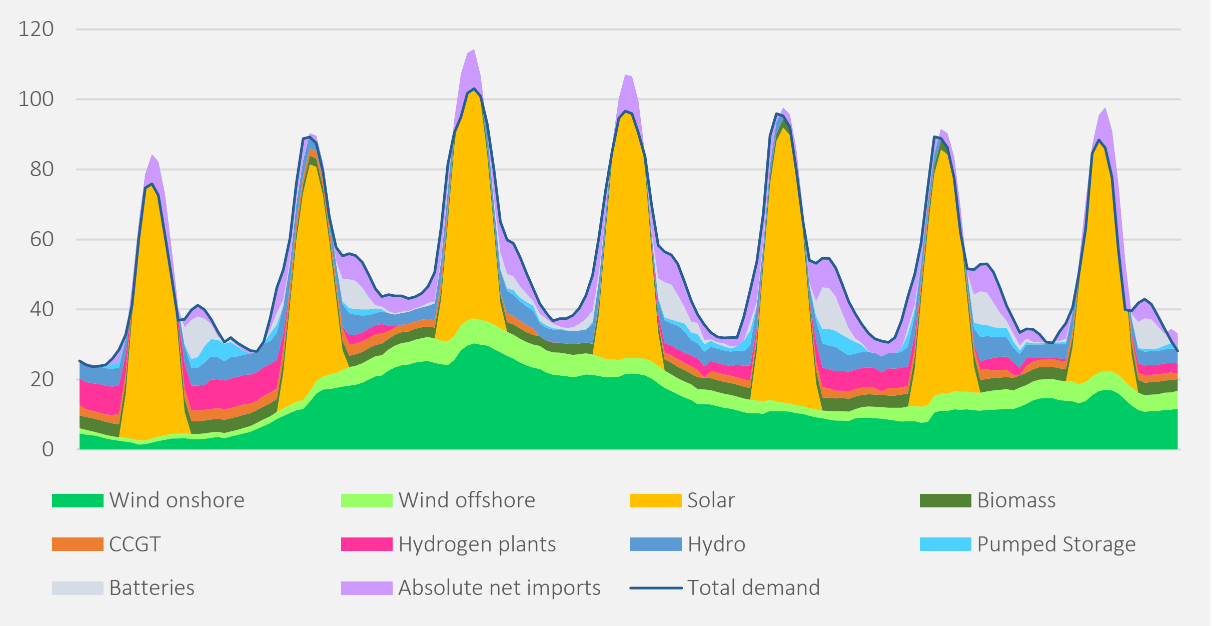


Figure 15 - Optimised power supply profiles during the first week of February of 2035 (GWh)[9]. Source: Artelys modelling.

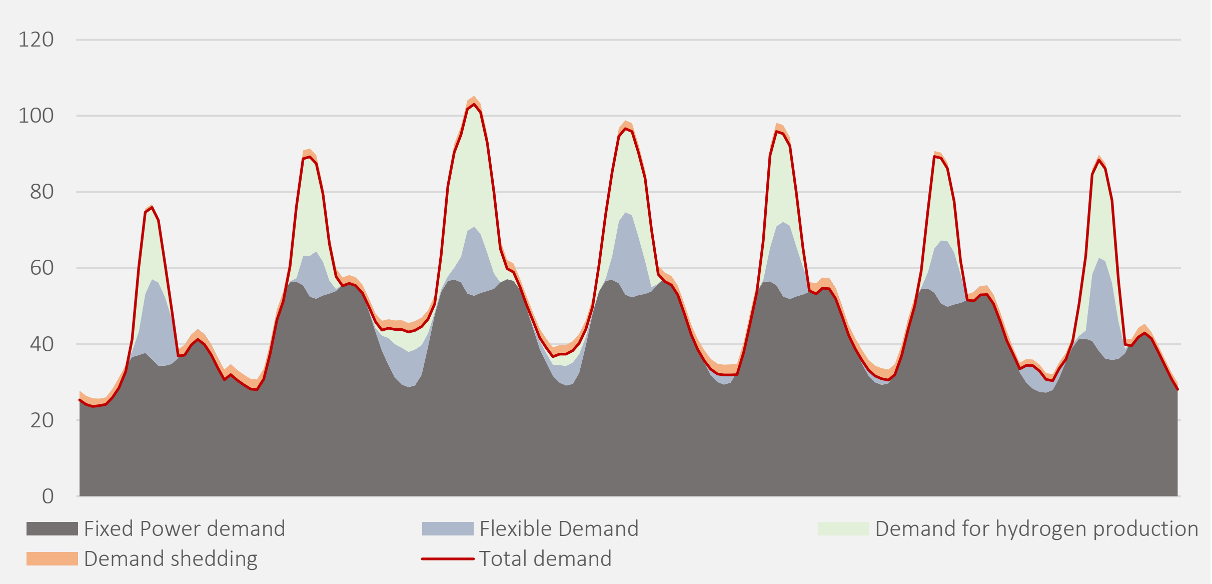


Figure 16 - Optimised power demand profiles during the first week of February of 2035 (GWh)[10]. Source: Artelys modelling.

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[9] The absolute net imports category corresponds to: net exports when the associated area is above of the total demand line, net imports when the area is below the total demand line. In the figure, the system exports power to neighbouring countries in the middle of the day, during the solar peak, and imports power the rest of the day.

[10] Flexible demand refers to the shiftable demand. The assumptions used for its modelling are described in section 4.1.1. It notably includes flexible demand for domestic hot water.

These flexible production and demand assets will be supported by storage assets. The associated storage capacities are shown in Figure 17.

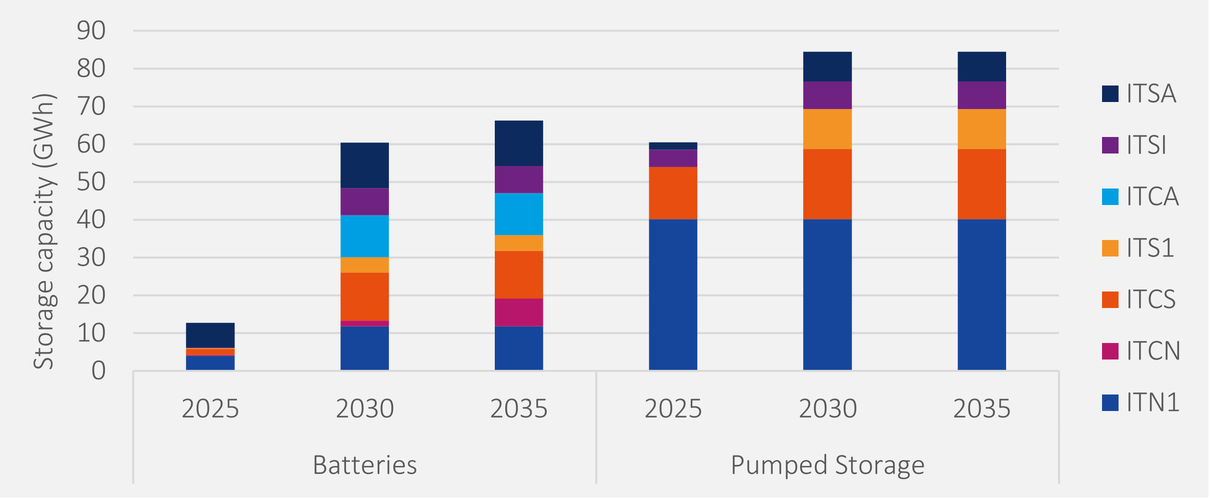


Figure 17 - Projected evolution of storage capacities for batteries and pumped storage assets (GWh). Source: Artelys modelling.

3.2.2 Evolution of flexibility needs and of the provision of flexibility services

The need for assets bringing flexibility services to the power system will significantly increase, driven both by the decrease of thermal generation capacities and the strong increase in solar and wind generation capacities.

Flexibility needs

As the share of variable wind and solar production will need to strongly increase to reach a close to net-zero production mix, flexibility needs will increase. As shown in Figure 18, solar and wind generation is expected to reach a major share of total production by 2035. In parallel, controllable generation will account for a lower share of production, as a consequence of the phase-out of thermal assets[11].

As a result, the way flexibility will be handled must evolve considerably in the coming decades, notably by leveraging demand-side flexibility potentials and by incentivising a system-friendly way of operating electrolysers.

[11] One should however note that the system will continue to require thermal dispatchable assets to be available. As these assets are not expected to reach high full load hours (FLH), a fit-for-purpose market design must be put in place to ensure such assets can recover their fixed costs. This point is even more crucial if measures such as the limitation of wholesale revenues are prolonged.

Figure 18 - Evolution of supply and demand balance within Italy (TWh). Source: Artelys modelling.

Flexibility needs are expected to increase on all timescales, with a substantial increase of daily flexibility needs because of solar PV integration.

The flexibility needs for each region are illustrated in Figure 20. Show the aggregated flexibility needs at the Italian level. Both the regional flexibility needs and the aggregated needs are broken down by year and by timescale.

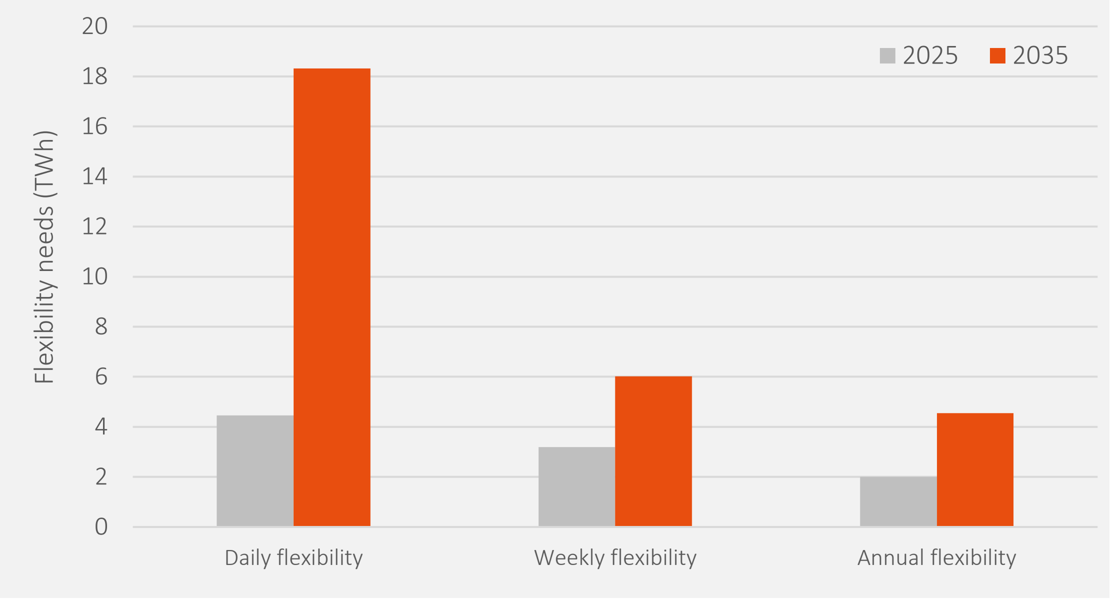


Figure 19 Evolution of daily, weekly and annual flexibility needs within Italy (TWh/year)[12]. Source: Artelys modelling.

Flexibility needs are expected to substantially increase on all timescales. The most notable increase (and challenge) is the increase of daily flexibility needs due to solar PV deployment. The way the needs for flexibility evolves significantly varies from a region to the next: the largest increases occur in ITCS, ITS1, ITSI and ITSA. Moreover, the northern region ITN1, which features the highest demand, also faces an increase in its daily flexibility needs, but to a lesser extent compared to the southern regions as the deployment of solar PV is not as important in that region. The increase in flexibility needs in the south is notably due to a significant increase in the amount of renewable generation in these regions as illustrated in Figure 9 and Figure 10.

[12] The flexibility needs illustrated on the graph correspond to the sum of regional flexibility needs.

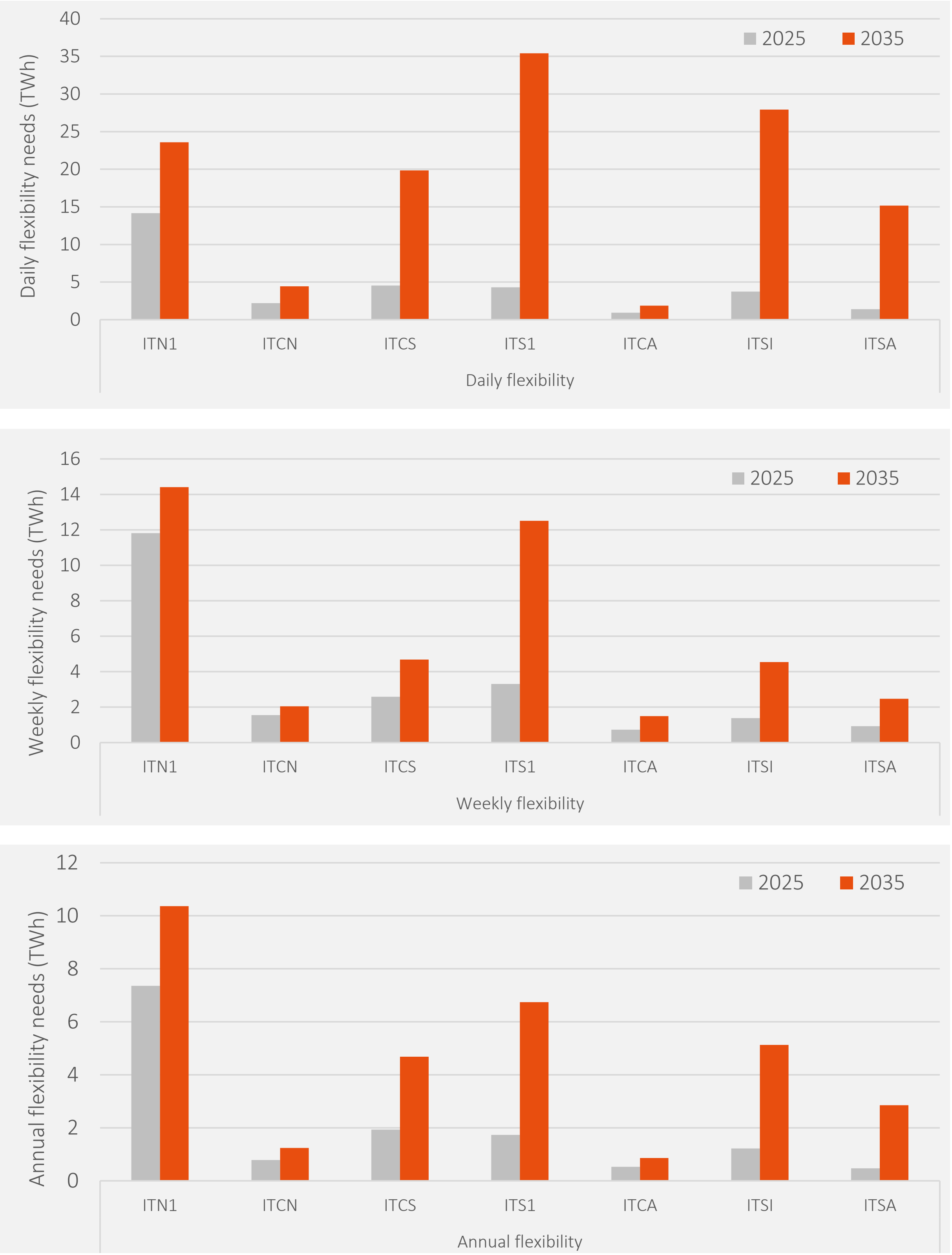


Figure 20 Evolution of daily, weekly and annual flexibility needs for each bidding zone from 2025 to 2035 (TWh/year). Source: Artelys modelling.

Contribution to flexibility

The contributions of each technology to flexibility needs at daily, weekly, and annual timeframes are shown in Figure 22, Figure 23 and Figure 24 for each bidding zone. The aggregated contributions for Italy are illustrated in Figure 21.

The contribution of gas power plants to daily, weekly, and annual flexibility services largely decreases. It is progressively replaced by new contributions from shiftable demand, electrolysis, hydrogen plants, hydropower, batteries, and imports/exports.

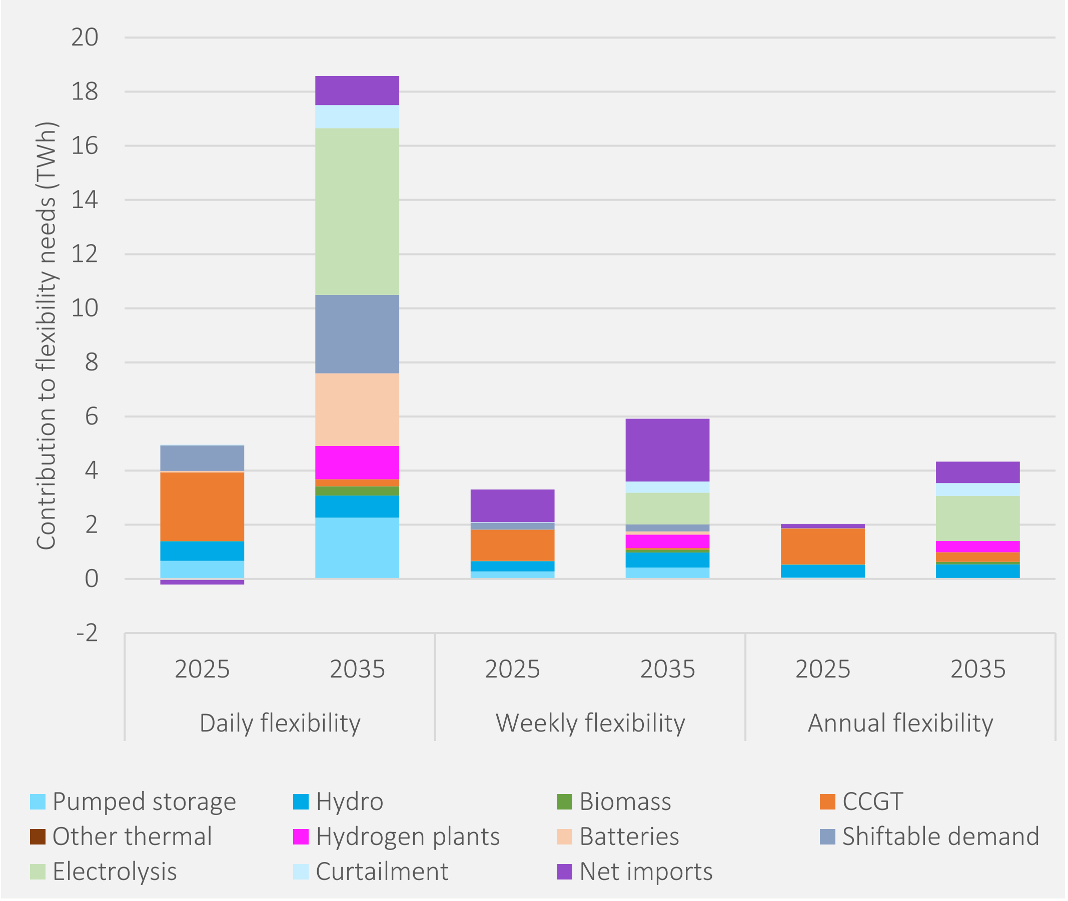


Figure 21 Contribution of each technology to daily, weekly and yearly flexibility needs at the Italian level (TWh/y)[13]. Source: Artelys modelling.

In the southern regions, electrolysis largely contributes to providing flexibility on all timescales. In the North, shiftable demand brings an important share of daily flexibility, while imports mainly contribute to providing weekly flexibility. The role of hydro and pumped hydro storage in providing flexibility is reinforced, especially on the daily and weekly timescales.

[13] The contributions of each technology illustrated on the graph are calculated as the sum of regional contributions to flexibility needs.

Provision of daily flexibility services

As shown in Figure 22, electrolysers are foreseen to become major contributors to daily flexibility by 2035, most notably in the Southern Region, in Sicily and in Sardinia. The role of shiftable demand is strongly strengthened, especially in the North, where it is foreseen to cover a major part of daily needs by 2035. The role of batteries, hydro and pumped storage is reinforced over time, both in the South and in the North.

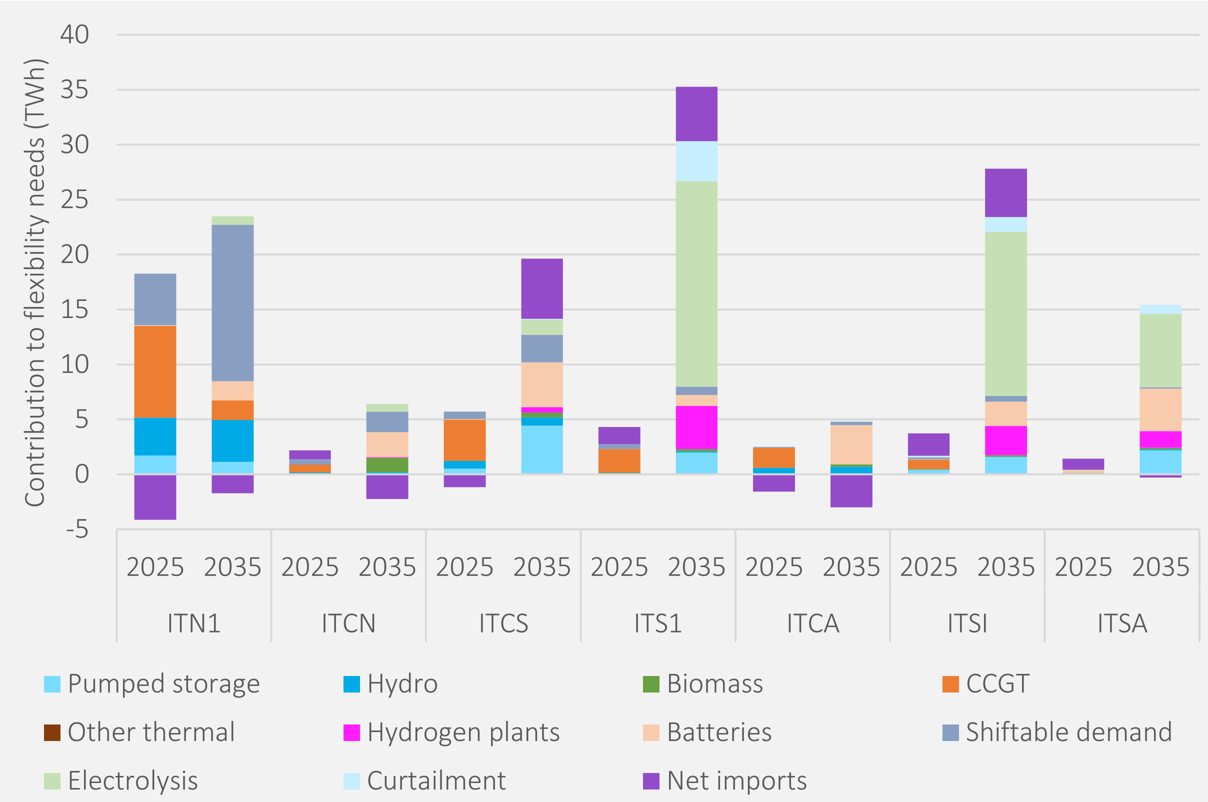


Figure 22 Contribution of each technology to daily flexibility needs (TWh/y). Source: Artelys modelling.

The role of imports and exports can be seen to differ between regions and time horizons: when it appears as a negative contribution, it translates the fact that import/export patterns increase the regional need for flexibility (this can be due to the fact that a given region provides daily flexibility services to a neighbouring region).

Provision of weekly flexibility services

Power exchanges between regions and with neighbouring countries will play a major role in providing weekly flexibility needs from 2025 to 2035. By 2035, electrolysers are foreseen to contribute to weekly flexibility needs, mainly in the south. To a lesser extent, battery storage, curtailment of renewable electricity production and hydrogen turbines will contribute to the provision of weekly flexibility services. Demand shifting contributes much less to weekly flexibility than to daily flexibility, as demand flexibility is mostly offered with a constraint that the energy has to be recovered during the same day (e.g. for EV charging, heat pump operations, etc.).

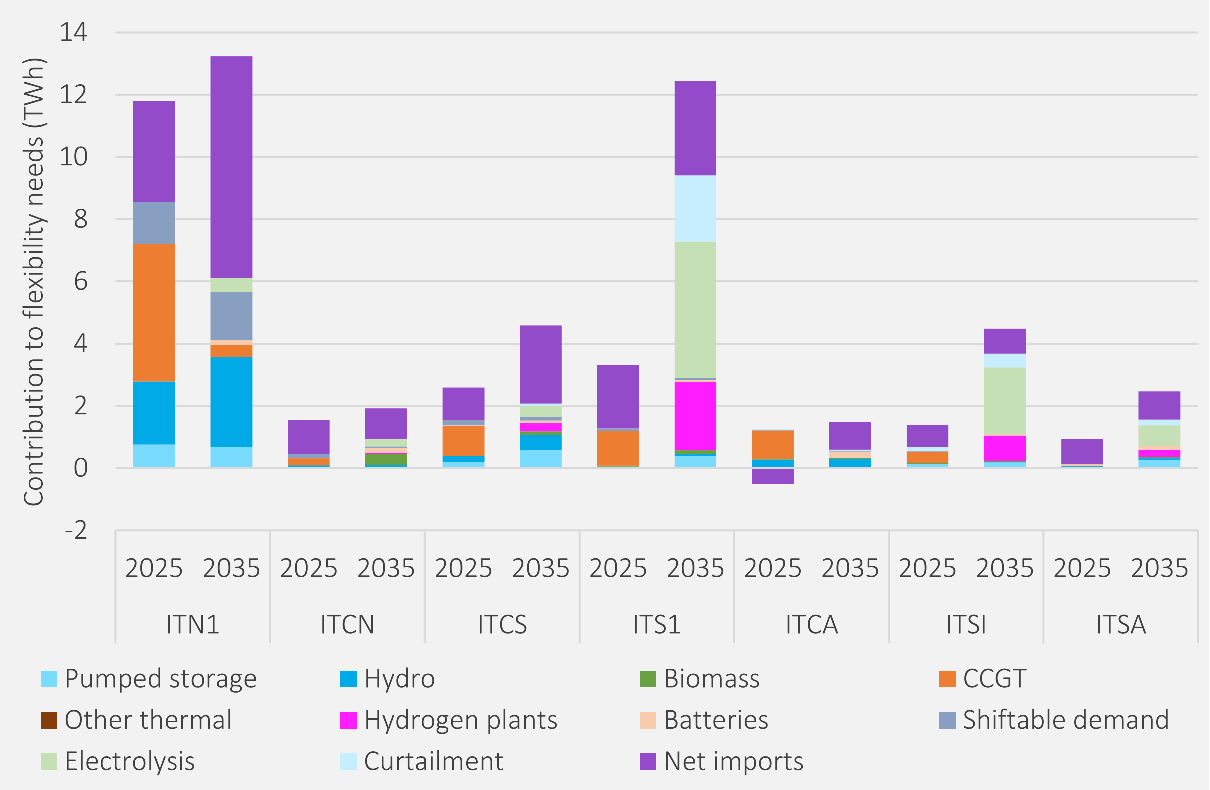


Figure 23 Contribution of each technology to weekly flexibility needs (TWh/y). Source: Artelys modelling.

<u>Provision of annual flexibility services</u>

As for the daily flexibility, the annual contribution of imports in ITN1 are negative for 2025. This phenomenon also happens in 2035 for ITS1 an ITSI. It means that the net imports of ITN1 does not contribute to its own regional flexibility needs and instead, its local flexible assets provide flexibility to other regions. As a result, the net imports are beneficial (positive) for other neighbouring regions, such as ITCN and ITCS. This shows the crucial role of electricity networks in the mutualisation of flexibility provision. Finally, the annual flexibility increases in ITS1, ITSI and ITSA are mainly addressed by electrolysers and hydrogen plants.

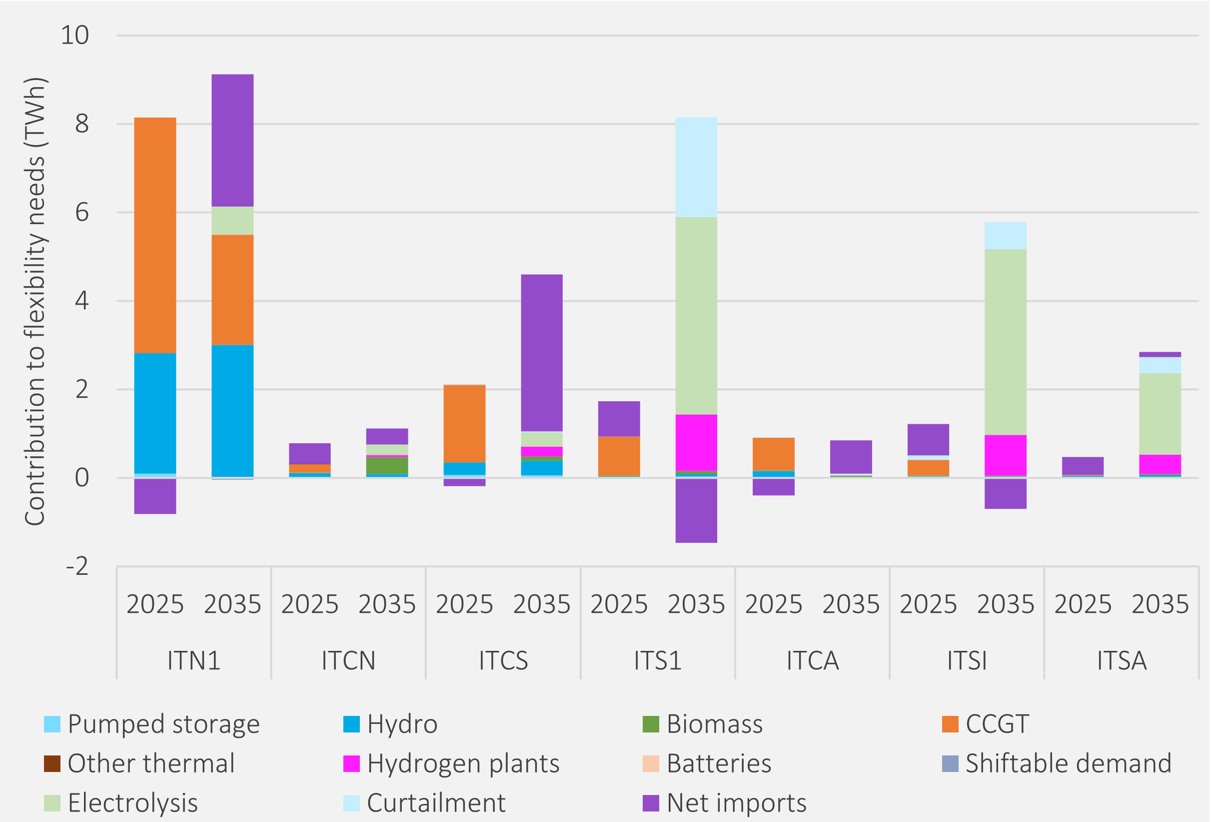


Figure 24 Contributions of each technology to annual flexibility needs (TWh/y). Source: Artelys modelling.

3.3 Electrolysis will not only enable hydrogen production for end-uses, but also to provide flexibility to the power system

Hydrogen production will strongly develop, to provide feedstock to end-uses, and to provide flexibility services to the power sector

As described in Section 4.1.2, both the hydrogen demand for non-electrical end-uses as well as demand for the electric system are modelled. Whilst the demand for non-electrical uses is exogenous assumptions, the model endogenously decides whether to produce additional volumes for its use in the power sector and to invest in hydrogen-fired gas turbines.

The volumes of hydrogen produced in each region are provided in Figure 25. The total demand for non-electrical uses (mainly industrial and transport uses) is an input of the model (in red in Figure 25) while its distribution (in dark green in the figure) and the volumes of hydrogen produced for the flexibility of the power system (in light green in the figure) are a result of the cost-optimisation simulation.

As shown in Figure 25, the production of hydrogen for the power sector strongly increases by 2035, and represent a major part of the production by 2035.

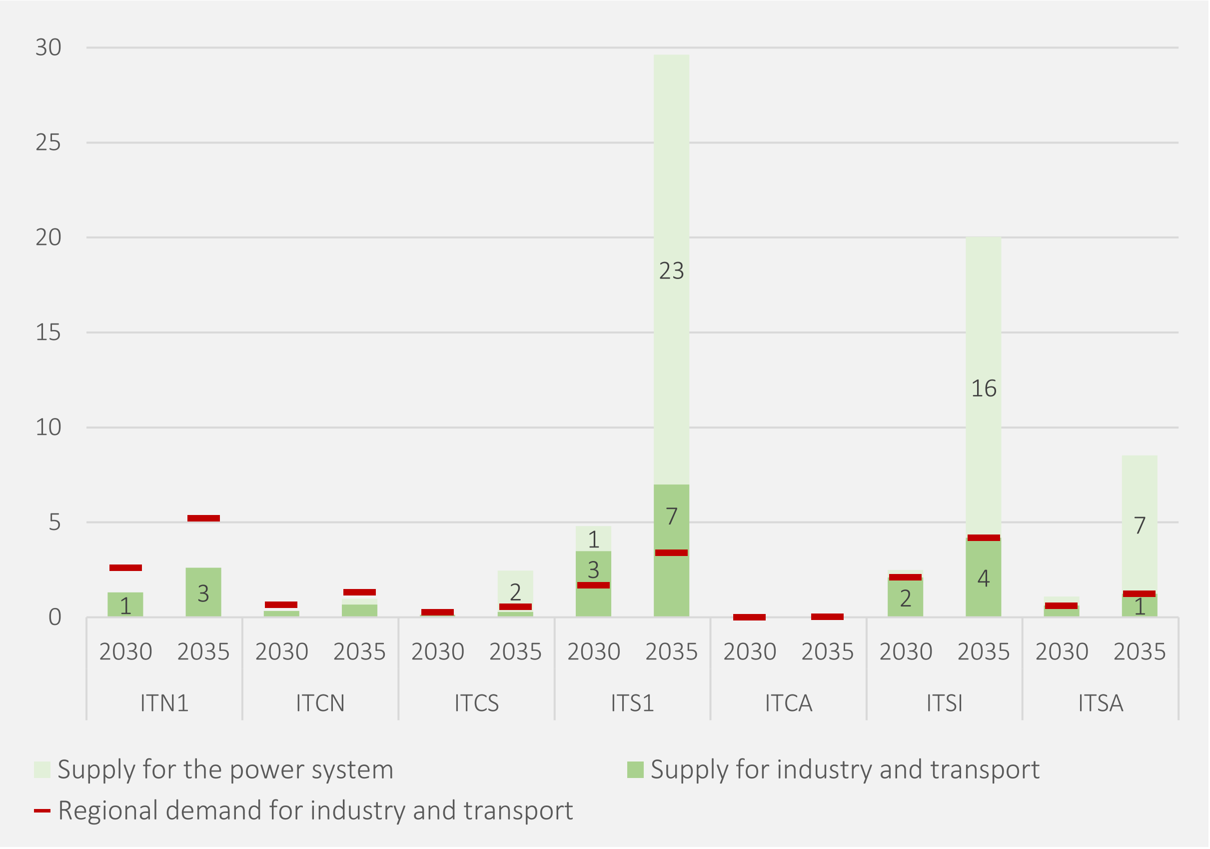


Figure 25 Volumes of hydrogen produced (in green) and volumes of demand for industry and transport (in red) for each zone within Italy (TWh/y)[14]

Hydrogen production is foreseen to become more important in the south where renewable potentials and load factors are higher than in the north.

The installed capacity of electrolysis (see Figure 26) and the total production of hydrogen is the highest in the Southern region, in Sicily and in Sardinia. In these regions, the modelling results indicate that the hydrogen production for P2H2P (Power to Hydrogen to Power) to be higher than the hydrogen production for industry and transportation, despite its low overall efficiency.

[14] Values are provided for the hydrogen volumes higher than 1 TWh.

These results are dependent on the assumptions made for hydrogen and electricity exchanges between regions, and the resulting trade-off between electricity and hydrogen exchanges[15].

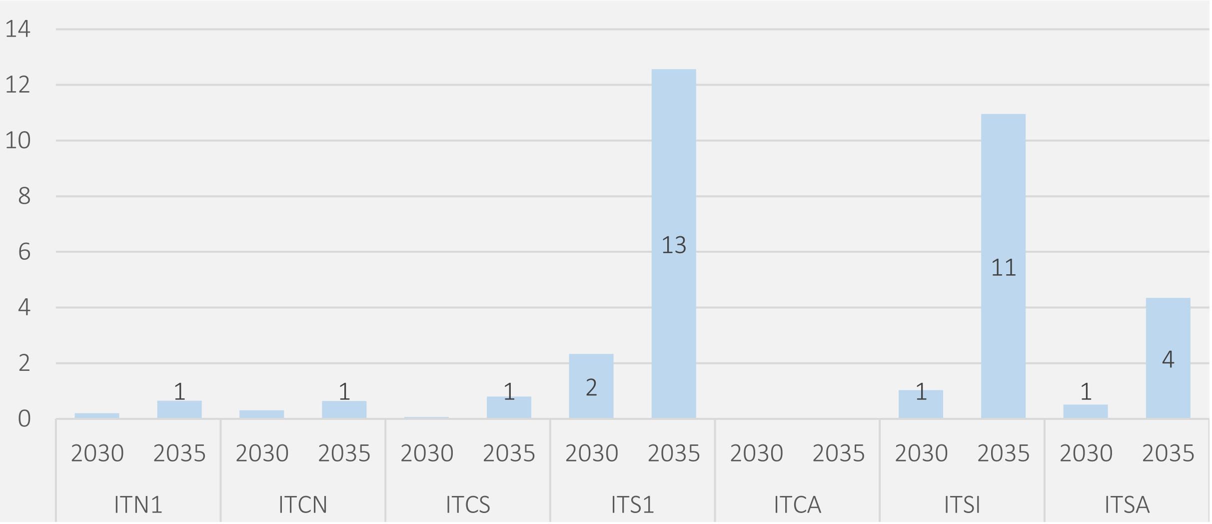


Figure 26 Evolution of the installed electrolysis capacity within Italy (GW). Source: Artelys modelling.

3.4 Investing in additional electricity exchange capacities within Italy and interconnectors with neighbouring countries minimises system costs

The investment in new interconnection with neighbouring countries reduces the costs of the system, even in situations where a limited amount of annual net imports is imposed

The transmission capacities do not evolve significantly between 2025 and 2030, they are based on already planned projects. Investments in new interconnection capacities are allowed from 2030 to 2035[16]. For all transmission lines except the import line from Switzerland, the installed capacity reaches the maximum limit (described in the assumption section), as shown in Figure 28. Investing in these transmission lines, and unlocking additional investment potentials would thus result in further reducing the overall system costs.

[15] The assumptions for hydrogen exchanges are described in Section 4.1.2, and the assumptions for the expansion of power transmission capacities are described in Section 4.2.3. At least half of the regional hydrogen demand must be produced locally, and hydrogen flows are only allowed within continental Italy. Electricity exchange capacities can up to double between regions.

[16] The methodology for interconnexion capacity expansion is described in Section 4.2.3.

Country	Code
Austria	AT
Swiss	CH
France	FR
Greece	GR
Montenegro	ME
Malta	MT
Slovenia	SI

Figure 27 Country codes

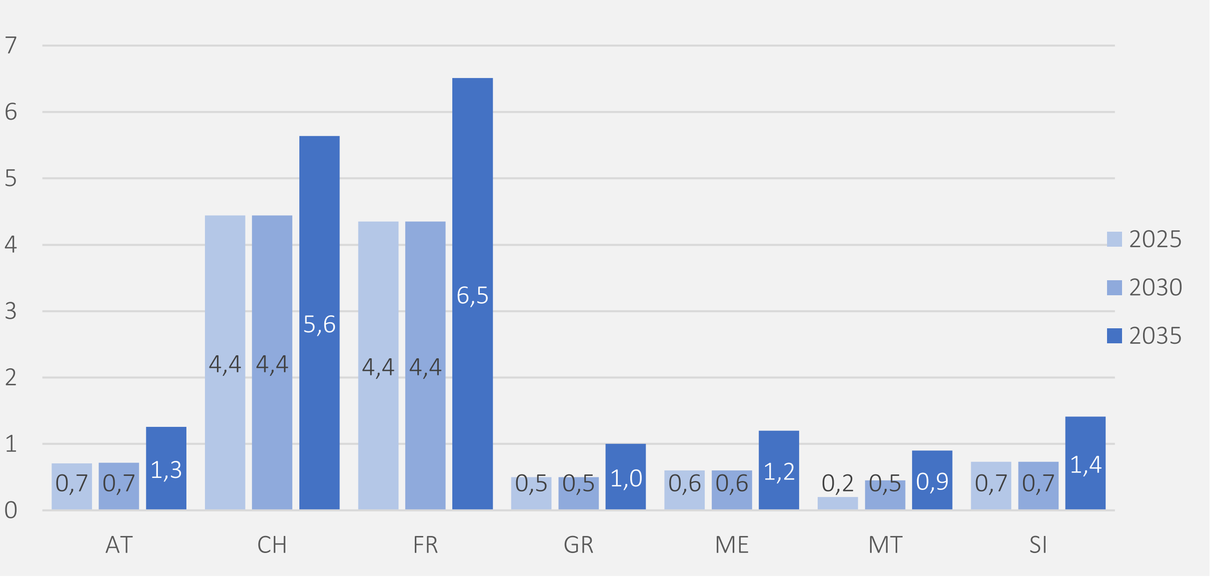


Figure 28 Evolution of transmission capacities from 2025 to 2035. Source: Artelys modelling.

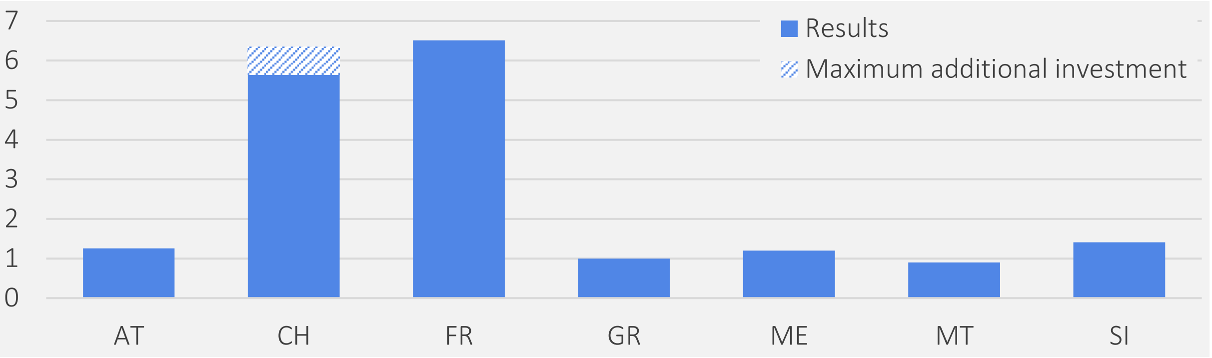


Figure 29 Projected installed transmission capacities from neighbouring countries in 2035 and additional investment available (GW). Source: Artelys modelling.

The annual net imports have been limited to 40 TWh to ensure that the Italian power generation is sufficiently independent from imports from neighbouring countries. The evolution of import volumes depending on the exporting country is provided in Figure 30. The impacts of relieving the 40 TWh constraint are discussed in the next section.

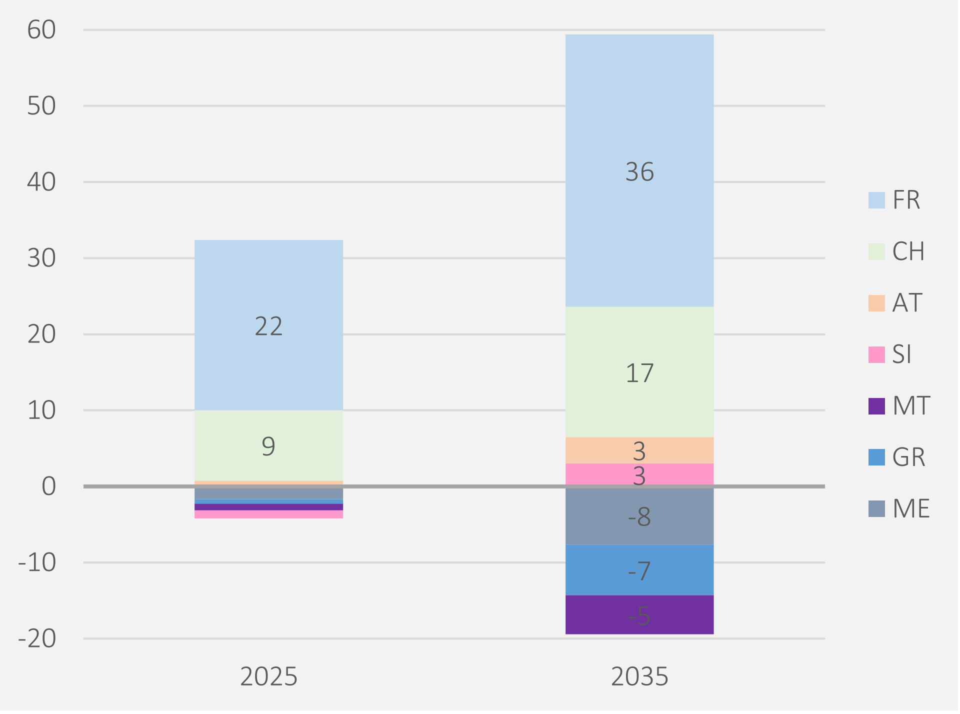
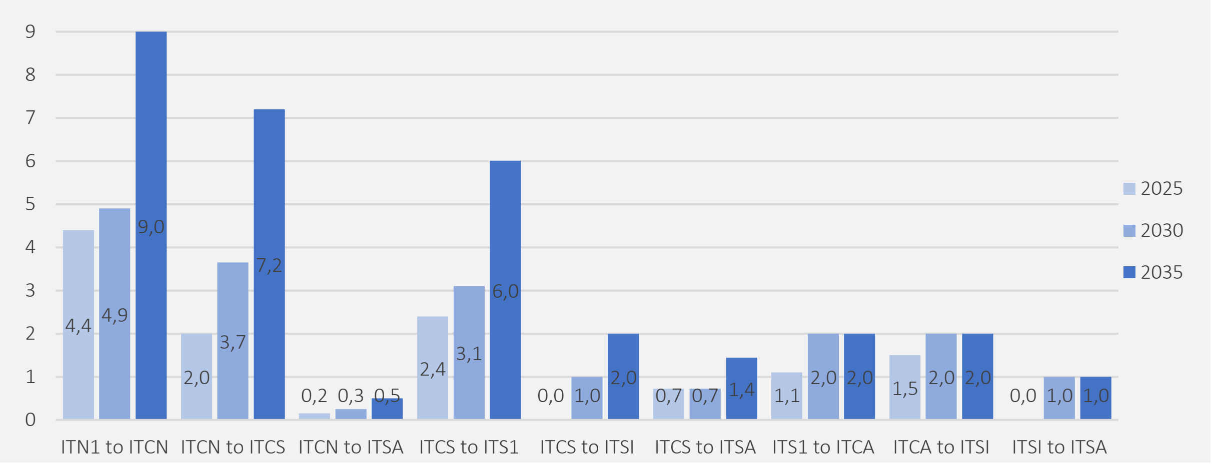


Figure 30 Evolution of net imports from neighbouring countries (TWh/y). Source: Artelys modelling.

The development of additional capacities between specific Italian regions is expected to decrease system costs. These lines notably enable the flow of renewable generation from southern Italy to northern regions.

As shown in Figure 31, transmission capacities are expected to increase between the Northern Region and Central North, Central North and Central South, Central North and Sardinia, Central South and the Southern Region, Central South and Sardinia.



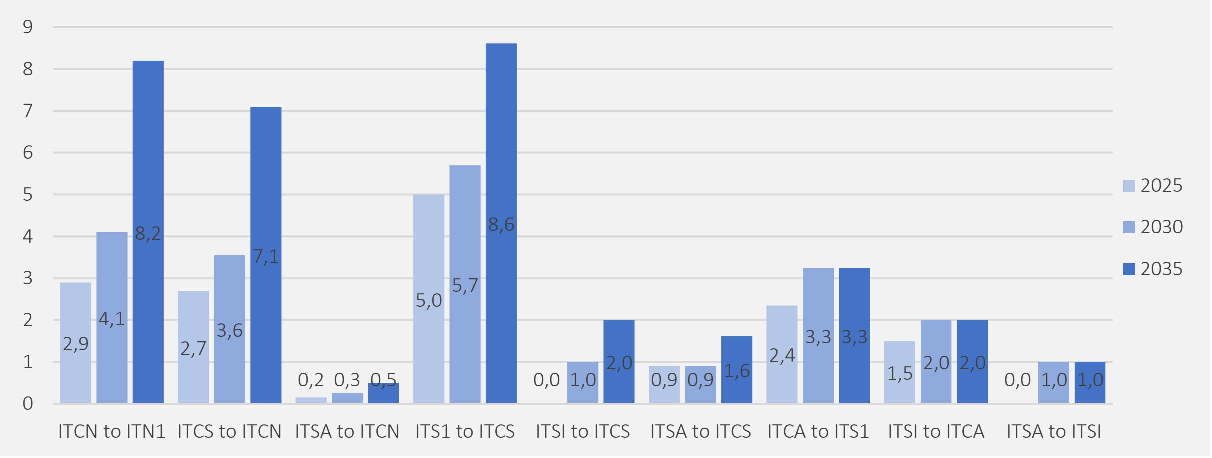


Figure 31 Evolution of internal transmission capacities from 2025 to 2035 (GW). Source: Artelys modelling.

For part of these capacities, the maximum input limit is reached: most transmission lines between continental Italian zones reach the maximum investment limit. The maximum additional investment available is illustrated in Figure 32.

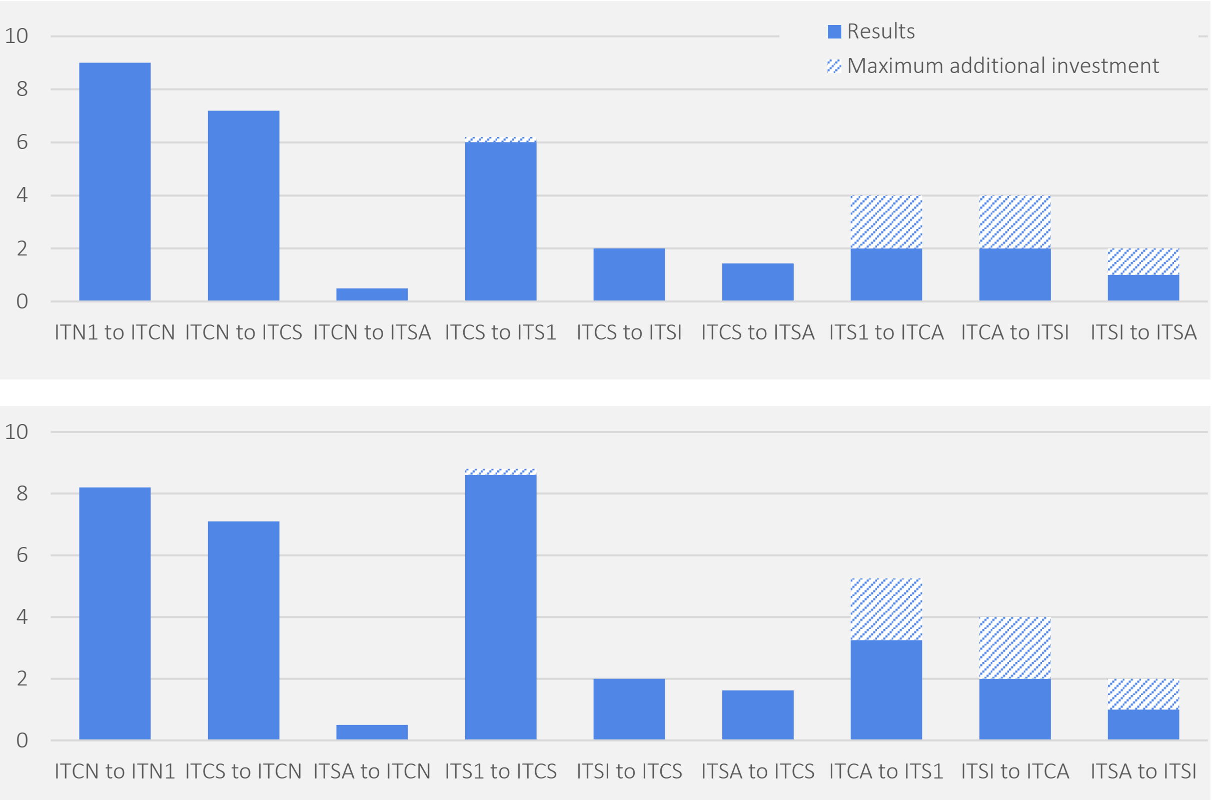


Figure 32 Projected installed capacities of internal transmission lines in 2035 and additional investment available (GW). Source: Artelys modelling.

As shown in Figure 7, the overnight investment costs associated to the installation of new transmission lines is projected to account for a small share of the total investment costs (around 2% from 2025 to 2030 and 6% from 2030 to 2035 for both internal and international lines).

3.5 An increased reliance on imports would reduce solar PV installations and P2H2P

Whilst the report has until now concentrated on a situation where the net imports were limited to a maximum of 40 TWh per year, we explore in this subsection a situation where we relieve this constraint and allow for a maximum annual net import of 60 TWh.

Allowing for an increased reliance on imports leads to a decrease in solar power production, and in hydrogen production for the provision of flexibility services to the power system

In a situation where net imports reach 60 TWh, the solar production is found to decreases from 234 TWh to 187 TWh in 2035, and electricity production from hydrogen plants reduces from 24 TWh to 8 TWh. In other words, part of the additional solar production required when the constraint on net import of 40 TWh is active is stored in the form of hydrogen which is used later to produce electricity.

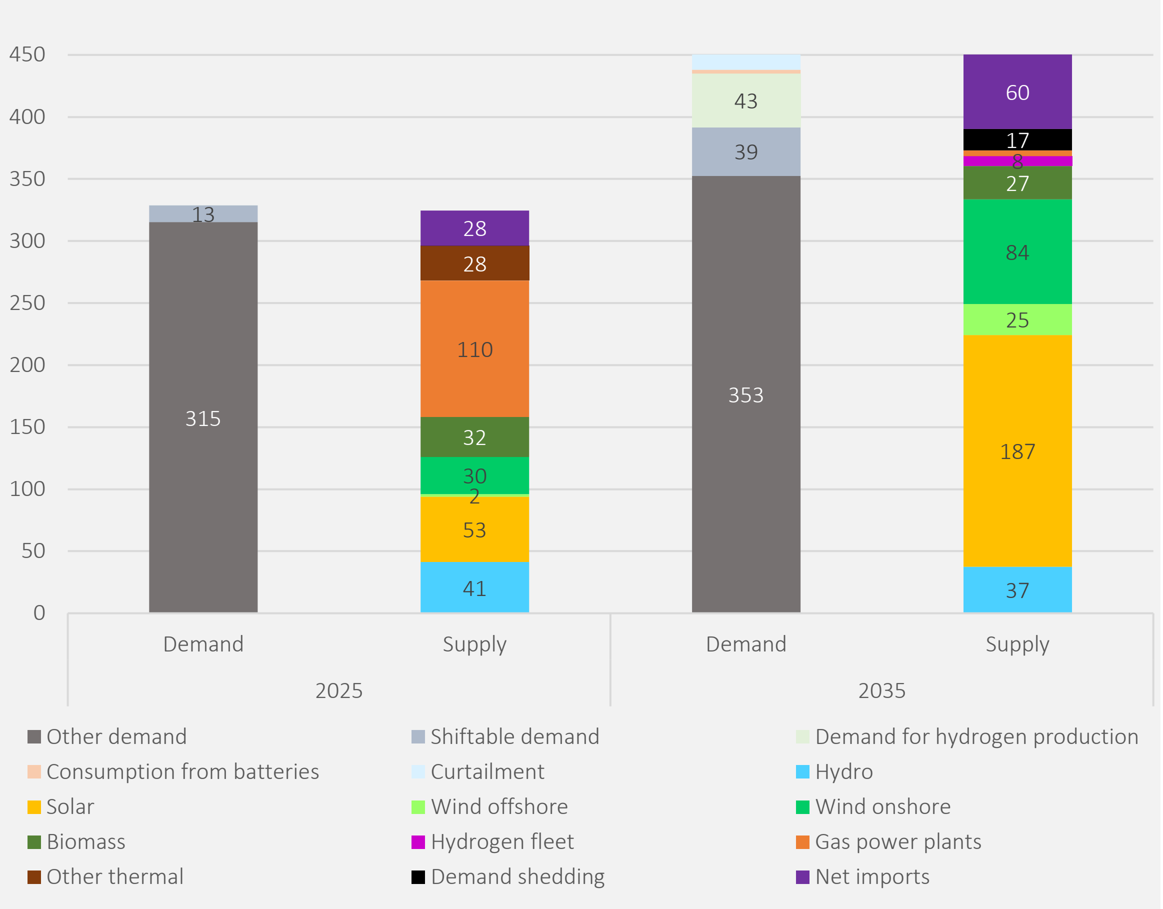


Figure 33 Demand and supply balance from 2025 to 2035 with an increase in the net import limit to 60 TWh (in TWh). Source: Artelys modelling.

The optimal investment in new solar capacities, hydrogen turbines, and electrolysers is lower when the net import limit is increased (see Figure 34). By 2035, the difference reaches 33 GW of solar PV, 5 GW of hydrogen turbines and 16 GW of electrolysers. This notably eases the pressure on the rate of solar installation from 2030 to 2035, as shown in Figure 35: from 2030 to 2035 the required installation rate is below 8 GW/y, compared to above 14 GW/y in the central scenario.

Regarding wind turbines, relaxing the constraint on net imports has only a moderate impact on the required investments: the investments remain close to those for imports at 40 TWh.

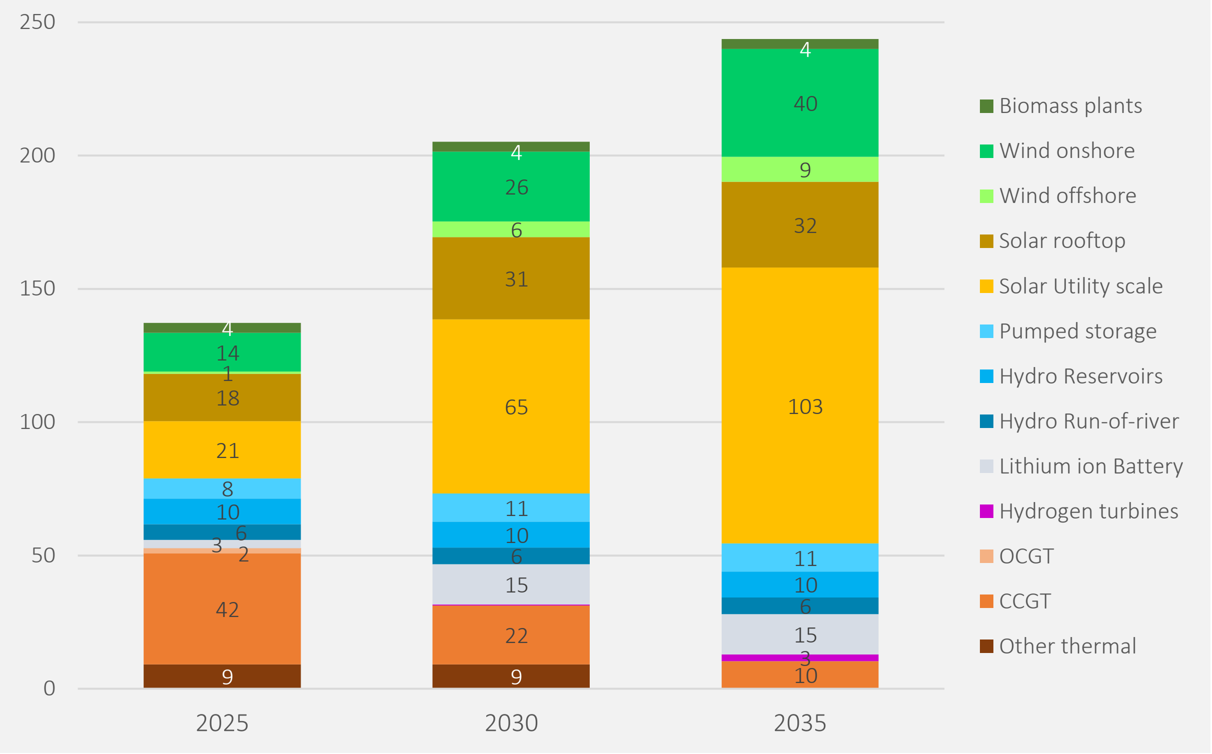


Figure 34 Evolution of installed capacity with an increased level of net import of 60 TWh (in GW). Source: Artelys modelling

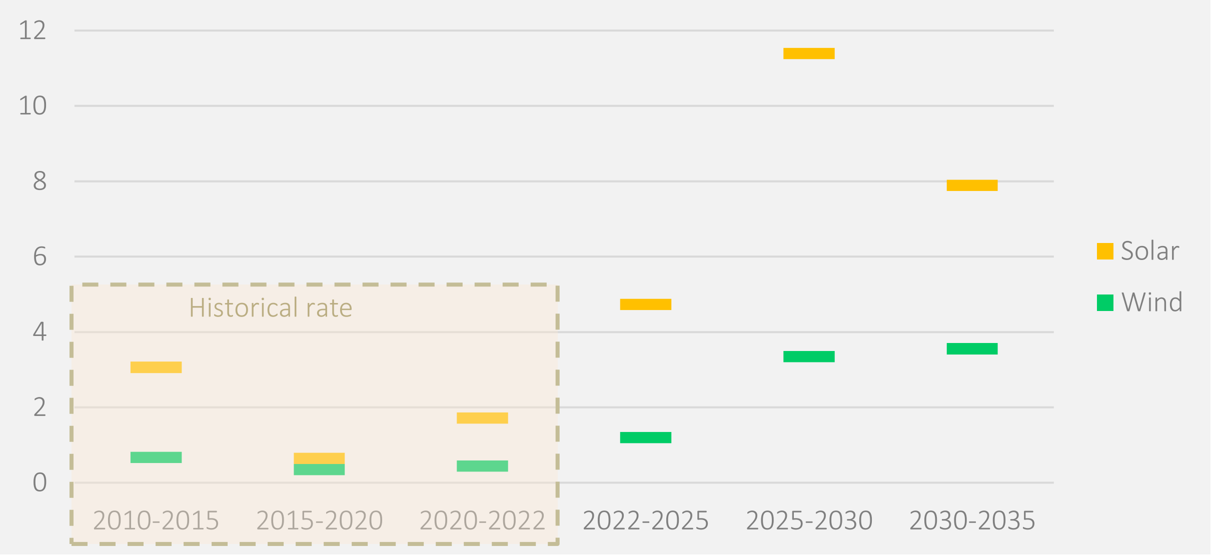


Figure 35 Projected and historical installation rate for wind and solar (GW/year) with a relaxed constraint on net imports. Source: Artelys modelling.

As shown in Figure 36, relaxing the constraint on net import relaxes the pressure on solar installation mainly in the southern regions (in the South, in Sicilia and in Sardinia) in 2035. The solar installed capacities within the other regions are not impacted by the augmentation of the imports.

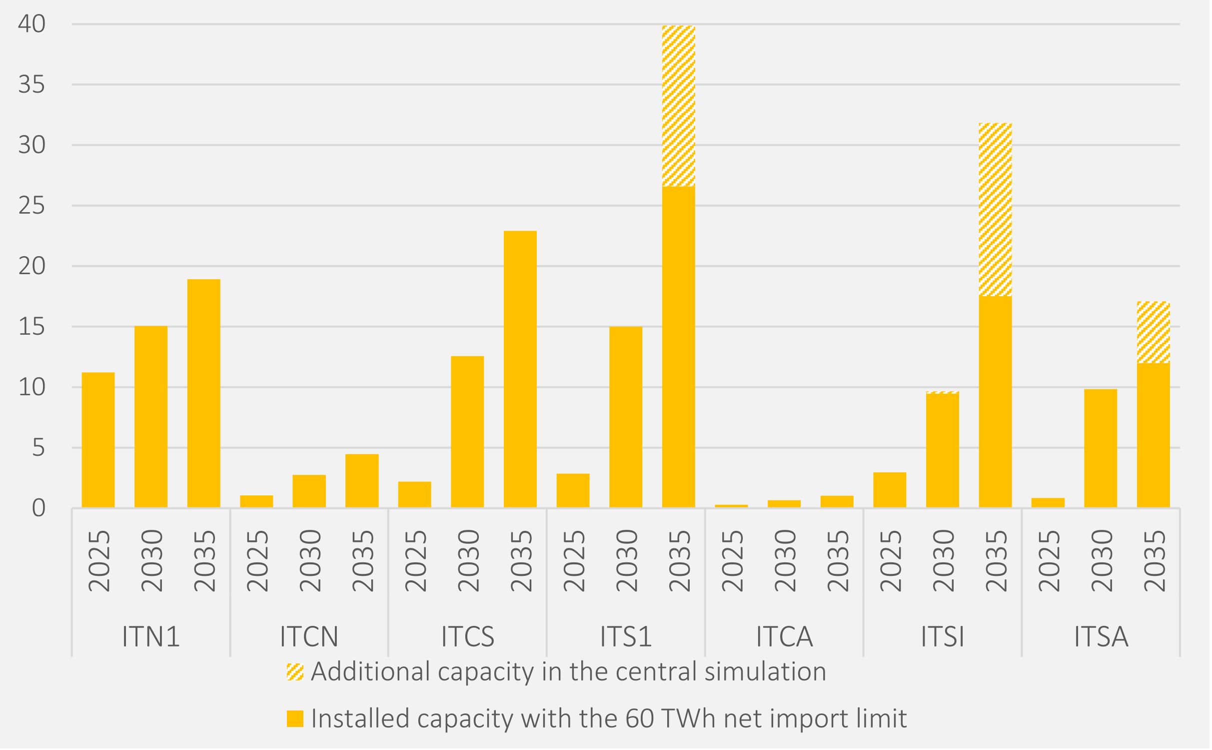


Figure 36 Impact of an increase of the net import limit on the local installed capacity of solar utility scale (GW). Source: Artelys modelling.

Finally, a higher level of national net imports also increases the optimal investments in transmission lines with neighbouring countries, as illustrated in Figure 37. When relaxing the constraint, we find that all the transmission lines with neighbouring countries reach the investment limit we have set: the transfer capacity with Switzerland is thus increased compared to the capacity we sound in the central simulation.

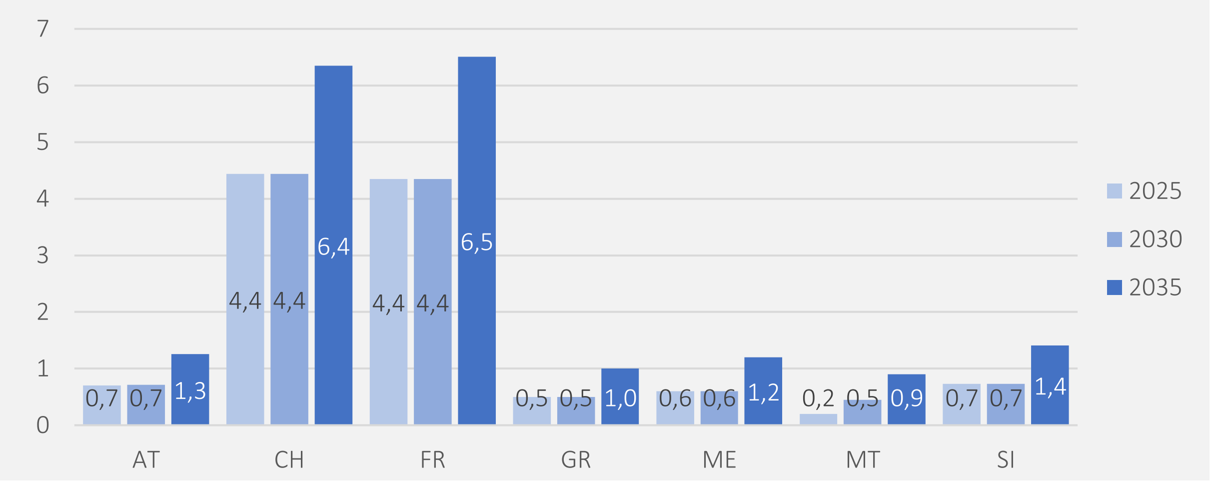


Figure 37 Evolution of transmission capacities from 2025 to 2035 with an increased level of net imports (GW). Source: Artelys modelling.

4 Key assumptions

The assumptions related to the evolution of the demand, the investment potentials in generation, flexibility solutions, and transmission networks are based on a review of recent publications and scenarios.

The model optimises the investments in and the operations of the different generation, demand flexibility, storage and transmission assets in order to ensure the supply-demand balance can be met at the lowest cost, subject to a series of constraints that are also presented in this section.

The model uses a regional granularity within Italy (corresponding to the current set of bidding zones), and a country-level granularity for the other European countries. We provide below the key assumptions used in this modelling work, with a focus on Italy.

4.1 Demand

The model considers the final demand for electricity and for electrolytic hydrogen, which both need to be taken into account when dimensioning the electricity generation mix and the set of flexibility solutions that are required to ensure the supply-demand equilibrium can be met on an hourly basis.

To this end, the demand is broken down into:

- The demand for electrolytic hydrogen production, excluding the production of electrolytic hydrogen for the power system flexibility (this part of the hydrogen demand is endogenously optimised by the model)
- The final electricity demand, excluding electricity for hydrogen production.

We provide an overview of the assumptions related to these components of the demand in the following sections.

4.1.1 Final electricity demand

The electricity demand is key to the modelling as, together with RES ambitions, it heavily impacts the structure of the optimised power mix and the need to deploy flexibility solutions. The final electricity demand profiles are based on time-series built by ENTSO-E for the 2022 edition of the European Resource Adequacy Assessment (ERAA), (ENTSO-E, 2022). The ENTSO-E profiles have been rescaled to reflect the projected evolution of the total power demand volume being assumed in this study. Demand-side flexibility is included into the modelling through load shedding and load shifting capabilities. The volumes that can be shed or shifted are region-dependent and based on the ERAA.

Regional power demand profiles

The electricity demand is modelled via a time-series that adopts an hourly time resolution (8760 time-steps for each year being modelled). Within Italy, the demand profiles differ from bidding zone to bidding zone, based on the data provided by ENTSO-E in the datasets accompanying the ERAA 2022 publication.

The assumptions related to the evolution of final electricity demand volumes (in TWh/year) are based on a review of scenarios and publications. An extensive review of scenarios describing the evolution of the final electricity demand in Italy has been performed. Based on this review, the assumptions for electricity final demand volumes have been set to:

- In 2025, the final electricity demand adopts the value published in ENTSOE's ERAA (ENTSO-E, 2022).
- In 2030 and 2035, the final electricity demand volumes are fixed based on Ember's System Change scenario. This choice is in line with the Fit-for-55 scenario, published by Terna (Terna, Snam, 2022), and the REPowerEU scenario published by Elettricità Futura and Accenture (Accenture, Elettricità Futura , 2022)

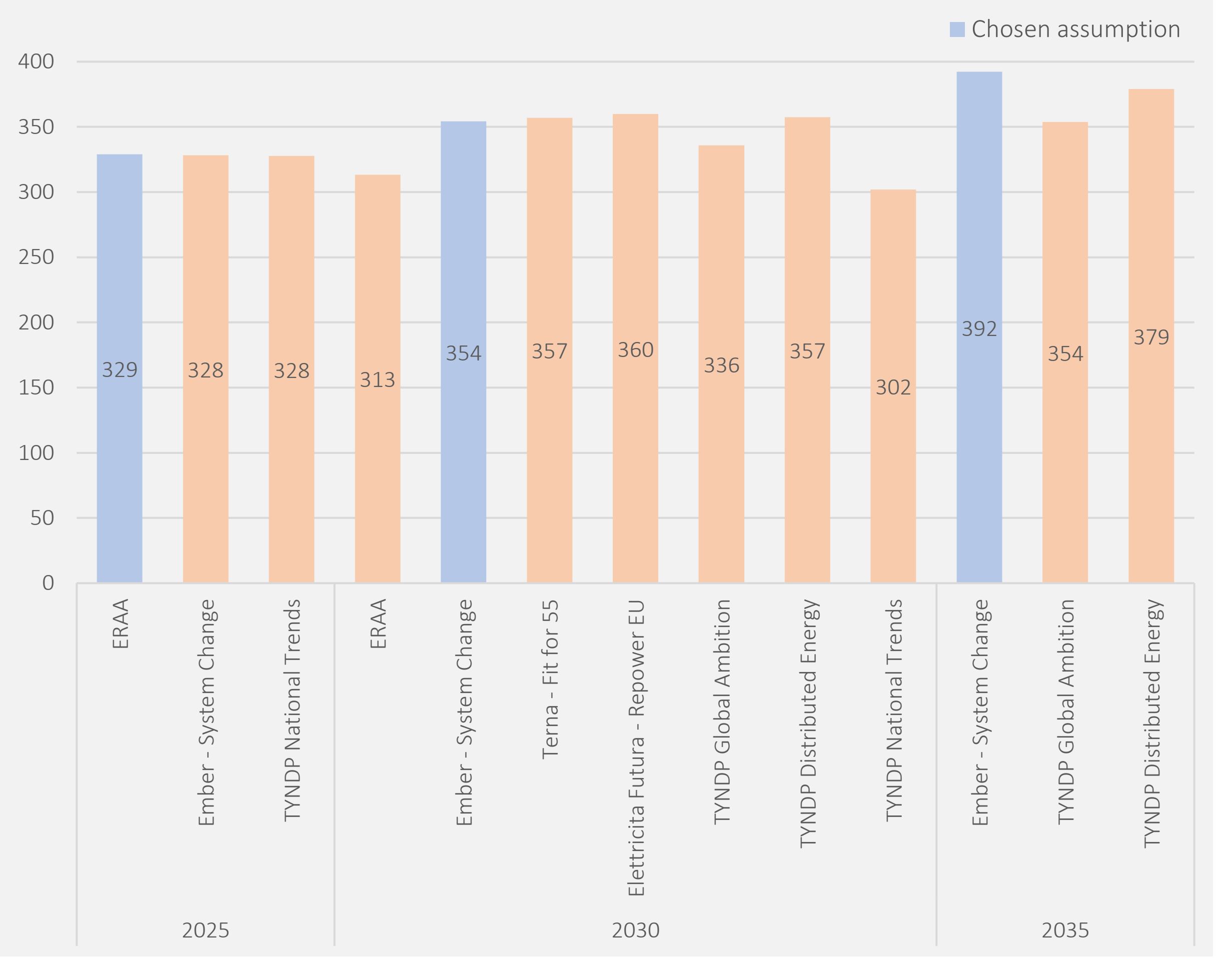


Figure 38 Final power demand excluding the power demand dedicated to the production of electrolytic hydrogen (TWh/year)

The total domestic final electricity demand is regionalised between the different bidding zones, based on the volumes published by ENTSO-E in the latest ERAA (ENTSO-E, 2022).

Zone	2025	2030	2035
ITN1	183	196	217
ITCN	29	31	35
ITCS	56	61	68
ITS1	24	26	28
ITCA	6	7	7
ITSI	20	22	24
ITSA	9	12	13
Total	**329**	**354**	**392**

Figure 39 Final electricity demand (without electrolysis) - Our assumption (TWh/year)

Demand side response

Two ways of providing demand-side flexibility to the system have been modelled: load-shedding and load-shifting. They represent incentives for consumers to change their consumption behaviour, based on price signals.

Load-shedding refers to the reduction in the power demand of specific consumers when the price of electricity exceeds a certain limit. These consumers are usually industries who temporarily reduce their consumption in response to an increase in the market price. The limit price (set to 250 €/MWh) and associated volumes are based on ERAA 2021 (ENTSO-E, 2021). These power volumes that can be shed differ depending on the bidding zone.

Zone	Volume (MW)
ITN1	2178
ITCN	221
ITCS	221
ITS1	155
ITCA	30
ITSI	121
ITSA	28
Total	**2954**

Figure 40 Maximum demand that can be renounced when the power price is over 250 €/MWh

Load-shifting refers to the shifts in demand from specific uses between times of stress on the power system, and times with lower demand or higher production. This scheme can apply to different uses, most notably to the consumption of domestic hot water and heating, or to the consumption of certain industries. The demand that can be shifted is limited, in compliance with the latest edition of ERAA (ENTSO-E, 2022).

Zone	2025	2030	2035
ITN1	1093	2152	3211
ITCN	131	257	384
ITCS	169	332	496
ITS1	78	154	230
ITCA	15	30	44
ITSI	31	61	91
ITSA	7	13	20
Total	**1524**	**3000**	**4476**

Figure 41 Demand that can be shifted (MW)

4.1.2 Hydrogen demand

Currently in Italy, around 500 000 tH2 (circa 17 TWh) are produced each year for industrial consumption, around 3/4 are used by refineries, and 1/4 by the chemical industry (RSE, 2021). Almost all hydrogen consumed today is produced from fossil sources via processes such as steam methane reforming (without CCS). In 2020, the Italian government published preliminary guidelines for the National Hydrogen Strategy (Ministero dello Sviluppo Economico, 2020). This document sets out a series of sectors in which the development of green hydrogen should be supported, in particular the use of hydrogen as a feedstock for industrial end-uses (for the chemical and refining industries notably), and as a fuel for specific transport applications.

Overall methodology

The demand for electrolytic hydrogen is broken down into two parts:

- The hydrogen demand per region for *industry and transport*, which is set *exogenously*, and
- The hydrogen demand for the *power system*, which is *determined endogenously*. This part of the hydrogen demand is a result of the simulation: the model optimises the volume of hydrogen produced for the flexibility of the power system and the investments in H2-fired power plants to provide long-term flexibility to the overall system.

The model only includes the demand for electrolytic hydrogen produced with grid-connected electrolysers. Therefore, the deployment of renewable power plants shown in our results does not include the potential additional deployment of renewables dedicated to off-grid hydrogen production.

Our projected total Italian demand for grid connected electrolysed hydrogen for industry and transport is based on a benchmark of a series of scenarios[17]. This projected total Italian demand was then broken down between the bidding zones based on considerations related to the use of various fuels by the industry.

Regional hydrogen demand

The projected demand for grid-connected electrolytic hydrogen in industry and transport is set at 0 TWh in 2025, 8 TWh in 2030 and 16 TWh in 2035. These domestic volumes have then been regionalised based on the current distribution of the fuel demand for the industry. The current fuel demand is based on the dataset published within the sEEnergies project, and co-constructed by Aalborg Universitet, Halmstad University, TEP, Utrecht University, Europa-Universität Flensburg, KU Leuven, Norwegian University of Life Sciences, SYNYO and Fraunhofer ISI (sEEnergies, 2020). This allocation provides a plausible idea of the future distribution of hydrogen demand for industry and transport. Indeed, around 80% of the current industrial fuel demand in Italy comes from refineries, the steel and iron industry and the chemical industry. Refineries and the chemical industry are the main industries currently consuming hydrogen. The steel and iron industry should drive the demand for new hydrogen applications, notably through the DRI-based steelmaking route.

[17] The System Change scenario published by Ember (New Generation, Ember, 2022), the Fit for 55 scenario published by Terna (Terna, Snam, 2022), the Global Ambition and the Distributed Energy scenarios of the TYNDP 2022 (ENTSO-E/ENTSO-G, 2022) and the scenarios published by RSE (RSE, 2021) were reviewed.

The resulting projected exogenous hydrogen demand for industry and transport is shown in Figure 42.

Zone	2025	2030	2035
ITN1	0	2,6	5,2
ITCN	0	0,7	1,3
ITCS	0	0,3	0,6
ITS1	0	1,7	3,4
ITCA	0	0	0
ITSI	0	2,1	4,2
ITSA	0	0,6	1,3
Total	**0**	**8**	**16**

Figure 42 Hydrogen demand in LHV for industry and transport - Our assumption (TWh/year)

Exchanges between regions

Exchanges are allowed between regions of continental Italy, but no imports or exports are allowed for Sicily and Sardinia. In such a configuration, all the hydrogen demand in Sicily and Sardinia must be produced locally. Regarding continental Italy, up to half of the regional demand must be produced within the region, the rest can be imported from other regions.

4.2 Production, storage and interconnections

4.2.1 Framework for the capacity expansion planning

Overall methodology

The modelling covers the years 2025 to 2035, with five years-time steps, which means that the years 2025, 2030 and 2035 are explicitly modelled. The year 2025 is used as a basis, both the demand and the installed capacities are exogenous, the hourly production of these exogenous capacities is optimised to meet the demand. After 2025, the investments of power generation, flexibility solutions and transmission capacities are optimised within predefined limits[18].

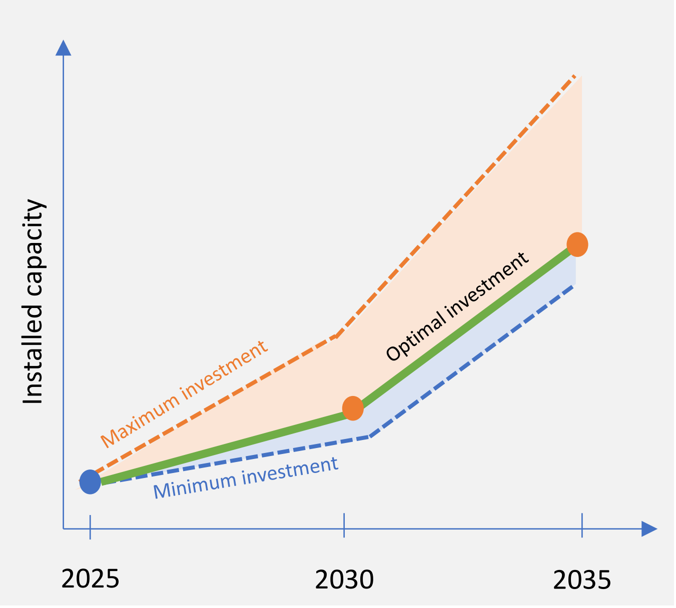


Figure 43 Schematisation of the framework for the capacity expansion planning

Installed capacities in 2025

In 2025, the installed capacities are based on the capacities published in the ENTSO-E's latest version of ERAA (ENTSO-E, 2022). After consultation with stakeholders, the assumption that there is no lignite, coal, or oil capacity left in the Italian power system in 2025 has been adopted.

[18] Decommissioning decisions can also be a result of the optimization process, see section 0 for more details.

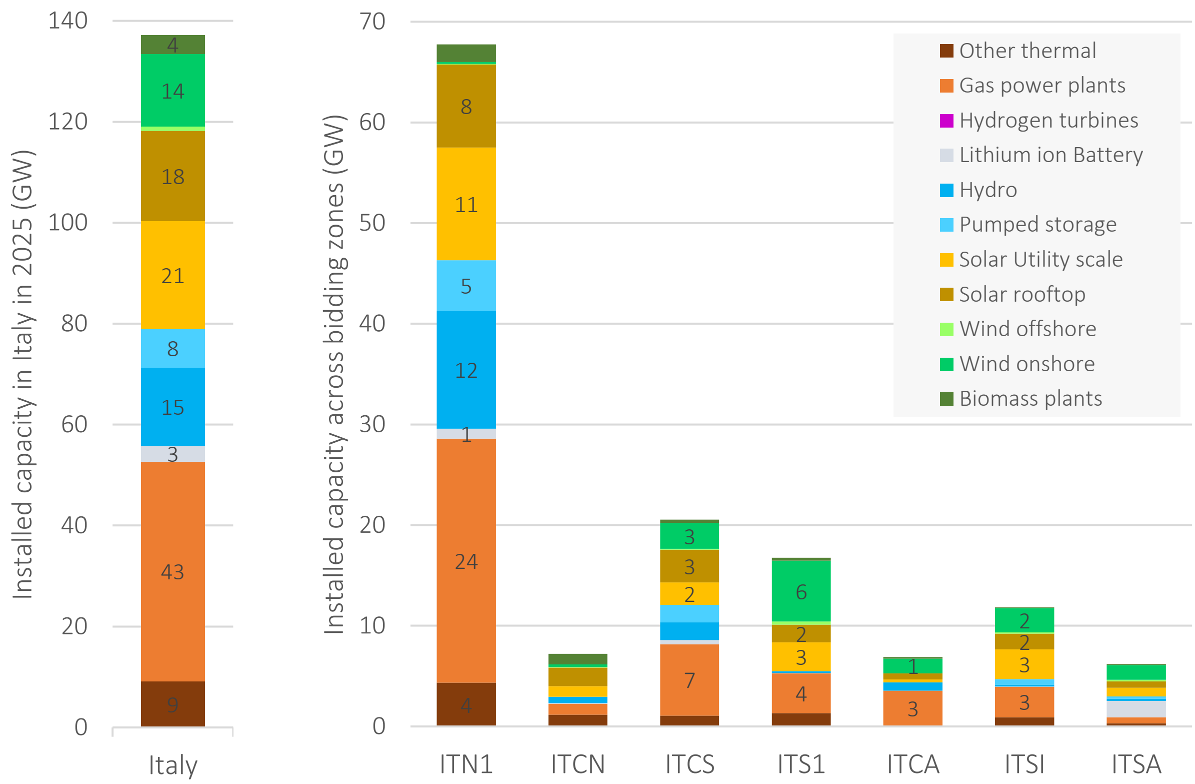


Figure 44 Assumptions for installed capacity in 2025 in Italy and across bidding zones (GW)

Investment limits

After 2025, the overall evolution of installed capacities is endogenous. The limits on investments and decommissioning depend on the technologies. The breakdown is detailed in Figure 45.

The key assumptions are:

- No investments are allowed in nuclear power plants, and in carbon and capture for power production,
- The evolution of biomass capacities and that of hydro capacities are both set exogenously,
- OCGT and CCGT can be decommissioned by the model, and new OCGT can be installed,
- The installation of new wind, solar, batteries, eletrolysers, hydrogen turbines and transmission capacities is endogenous. Limits (e.g. based on technical potentials) have been imposed in the model to ensure the plausibility of the results. These limits are described in the next sections.

Exogenous capacities

No installed capacity

× Nuclear power plants
× Carbon Capture and Storage
× Oil, coal and lignite power plants

Scenario-based investments

✓ Hydro reservoirs
✓ Run of river hydro
✓ Pumped storage (7,6 GW in 2025, and 3 GW additional capacities from 2030)
✓ Biomass power plants

Endogenous capacities

Decommissioning and investments allowed

Gas power plants: both OCGT and CCGT can be decommissioned by the model (investment in peaking gas power plants are also allowed)

New investments allowed

✓ Interconnections within Italy and with neighbours
✓ Solar Utility Scale
✓ Solar rooftop
✓ Wind onshore
✓ Wind offshore
✓ Batteries
✓ Hydrogen turbines
✓ Electrolysis

Figure 45 Distribution of the different technologies between exogenous and model-optimised capacities

4.2.2 Wind and solar

The deployment of solar and wind capacity is constrained by a minimum and a maximum limit. The *minimum limits* have been built from existing scenarios, mainly the ENTSO-E's ERAA (ENTSO-E, 2022), and the Fit-for-55 scenario published by Terna (Terna, Snam, 2022). The *maximum limits* depend both on regional technical potentials and on maximum installations rates.

- The technical potential of rooftop solar is based on an analysis of the residential and industrial roof area. The regional technical potentials used for solar utility scale are from the study *100% Renewable Energy: An Energy [R]evolution for ITALY* (Teske, S., Morris, T., Nagrath, K, 2020) prepared by the Institute for Sustainable Futures for Greenpeace Italy. The total Italian technical potentials for wind onshore and wind offshore were derived from the same study, and the regionalisation is based on the current distribution of connection requests to Terna (Terna, 2023)[19].

- Regional limits on the yearly installation rates have been added in the model for wind onshore and solar utility scale. These maximum yearly installation rates were derived from a presentation published by Elettricità Futura (Elettricità Futura, 2022), and the current distribution of connection requests to Terna (Terna, 2023). The regional installation rate limits are shown in Figure 46.

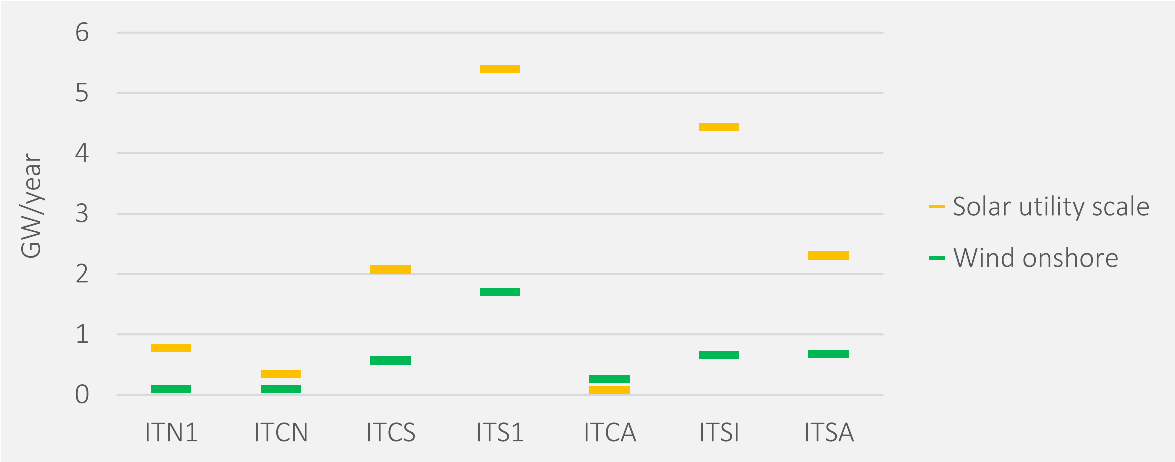


Figure 46 Maximum yearly installation rate of solar utility scale and wind onshore for each bidding zone (GW/year)

The combination of these maximum annual installation rates and technical potentials results in maximum installed capacities in 2030 and 2035. Figure 47 provides an overview of the maximum capacities that can be installed in 2035 in each of the zones.

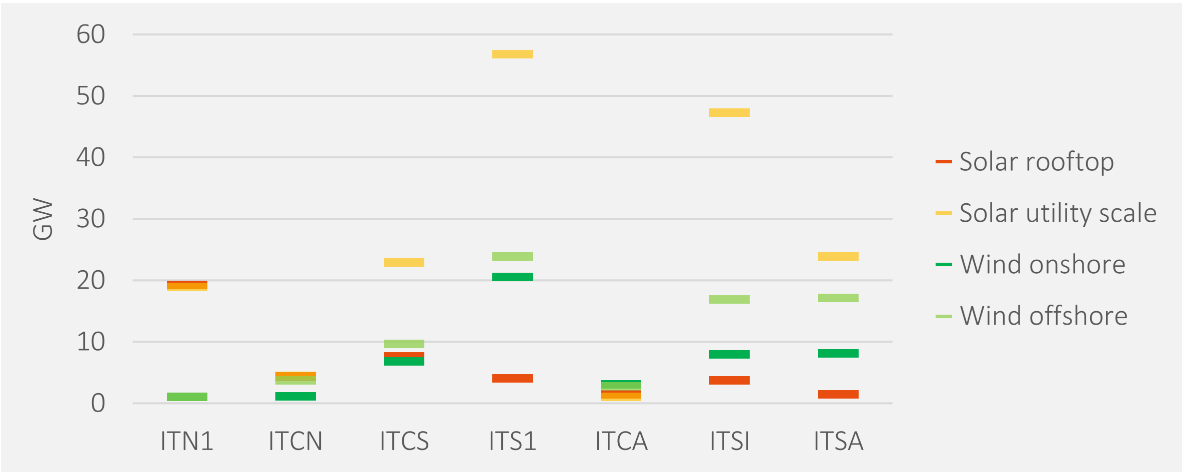


Figure 47 Maximum installed capacity in 2035 (GW)

[19] A benchmark of other published onshore technical potentials and existing scenarios was carried out to ensure the consistency of the figures used.

The comparison of the results with these constraints input in the model for wind and solar is described in Section 3.1.

4.2.3 Other investment and decommissioning options

Gas capacities

Both peaking gas (OCGT) and baseload gas capacities (CCGT) are modelled. Different categories of peaking gas and baseload gas are included in the model, to capture the range of efficiencies of these plants. The share of each of these categories is derived from the TYNDP 2022 (ENTSO-E/ENTSO-G, 2022).

In 2025, gas capacities are fixed based on the installed capacities published in the ENTSO-E's adequacy assessment (ENTSO-E, 2022) and in the TYNDP 2022 (ENTSO-E/ENTSO-G, 2022). After 2025, baseload gas capacities can be decommissioned by the model. The maximum capacities for baseload gas categories correspond to the ones published in the ENTSO-E's adequacy assessment, and in 2035 the oldest categories are forced to be decommissioned. For peaking gas, existing capacity can be decommissioned by the model, as for baseload gas, and the model also allows the investment in new peaking gas capacities[20].

Batteries

Batteries will play several roles in a future decarbonized power system, and notably they will participate in the provision of balancing services. To capture the minimum investment required to ensure balancing needs are covered, minimum investments limits are set on the deployment of batteries. Minimum deployment limits for batteries are based on the capacities published in the ERAA (ENTSO-E, 2022). The maximum deployment of batteries is not constrained.

Electrolysers

Investments in electrolysers are decisions taken by the model to enable the system to meet the hydrogen demand for industry and transport set in our assumptions (see Section 4.1.2), as well as additional endogenous flexibility needs of the power generation system. No limit on the deployment of electrolysers is set in the model, which means that the electrolysis capacity is the result of a techno-economic trade-off between costs on one side and values brought by electrolysers on the other.

Hydrogen fleet

Hydrogen turbines can be installed by the model to provide flexibility services to the power system. In practice, the presence of hydrogen turbines enables the following process to materialise: electrolysers

[20] As described in Section 0, the outcome is that there is no new investment in gas power plants, even if it is allowed by the model.

consume additional electricity, mostly during periods during which electricity prices are low, the hydrogen produced is then stored, and consumed at a later time by hydrogen turbines when the availability of other electricity production assets is insufficient to meet the demand (e.g. during low wind cold periods).

Interconnections

The evolution of transmissions capacities between regions and with neighbouring countries is fixed in the model before 2035, and additional endogenous deployments are allowed from 2035.

- The fixed capacities in 2025 and 2030 are based on the current deployment plans of Terna.
- In 2035, additional investments are allowed. The transmission capacities can up to double. Furthermore, the assumption is that when investing in new transmission capacity, the transfer capacity increases by the same amount in both directions.

The evolution of inter-regional capacities in 2025 and 2030, and the maximum limit set in 2035 are shown in Figure 48.

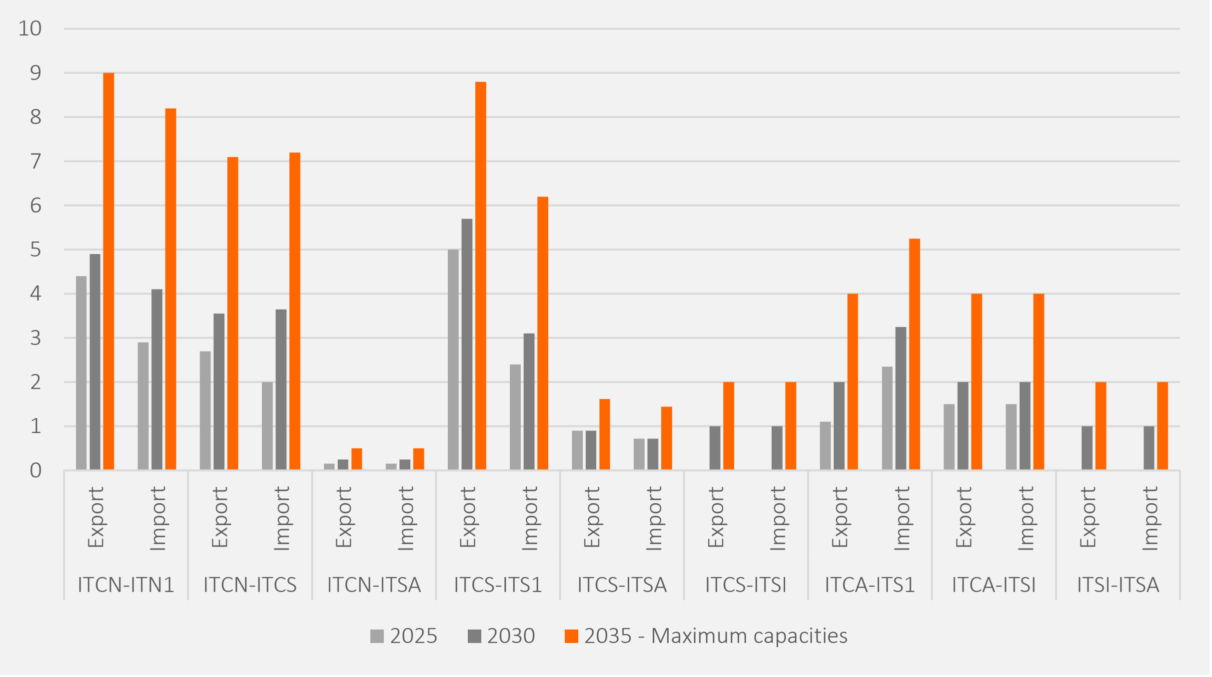


Figure 48 Evolution of nominal NTC for inter-regional interconnections (GW)

The evolution of interconnection capacities between Italy and neighbouring countries in 2025 and 2030, and the maximum limit set in 2035 are shown in Figure 49.

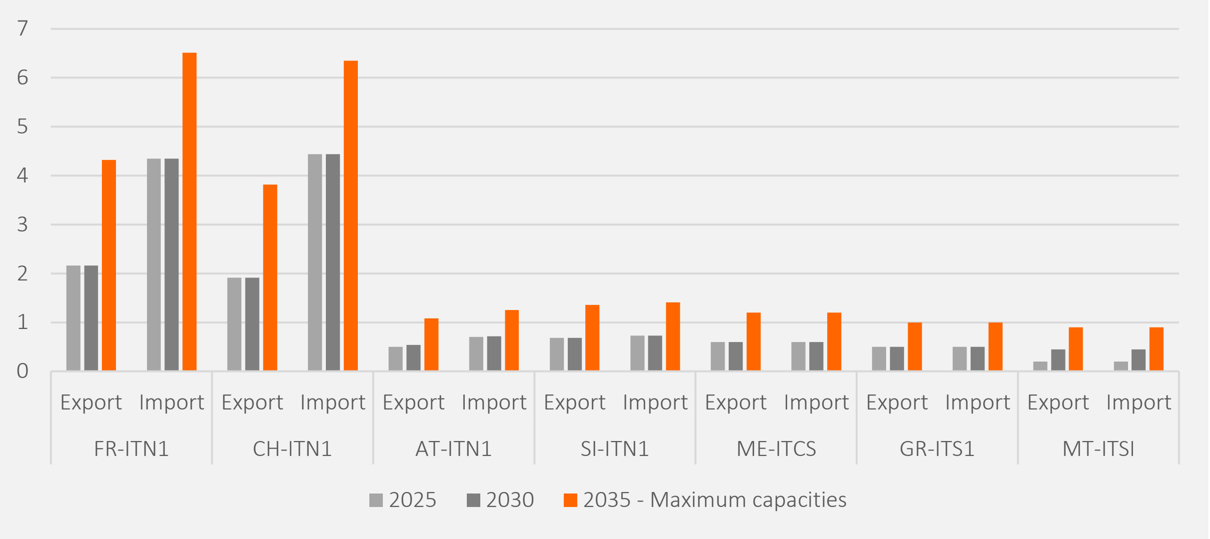


Figure 49 Evolution of nominal NTC for international interconnections (GW)

In order to dimension the Italian system without relying on imports from Tunisia, no flows on that interconnector have been considered on this interconnector

4.2.4 Scenario-based capacities

Hydro power plants

The capacities of hydro reservoirs, run-of-river hydro and pumped storage are scenarised based on existing scenarios. 400 MW of run-of-river hydro plants are installed between 2025 and 2030 (mainly in the Northern region and in Central North regions), based on the ENTSO-E's latest adequacy assessment (ENTSO-E, 2022). No additional hydro reservoir development is foreseen in our scenario. 3 GW of additional pumped storage are projected, as described in a scenario published by RSE (RSE, 2019). These new investments are regionalised based on the amount already proposed by investors, and on the land-based technical potential of pumped hydro. As shown in Figure 50, the new deployed plants are localized in Central South, South, Sardinia and Sicilia.

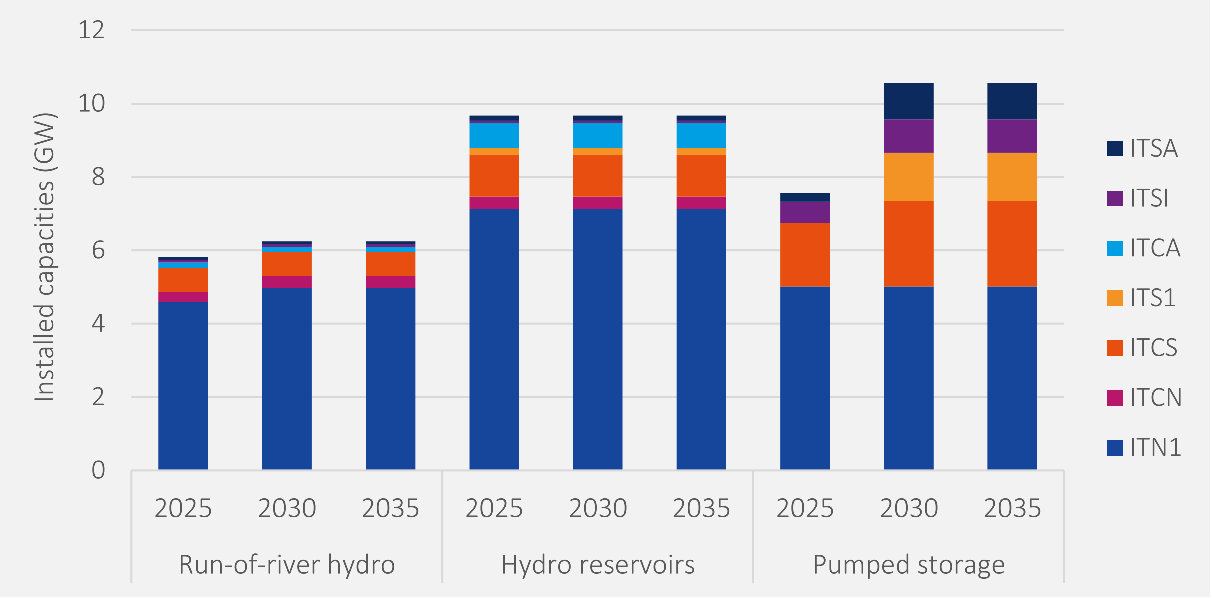


Figure 50 Projection for the evolution of installed capacity for run-of-river hydro, hydro reservoirs, and pumped storage (GW)

Biomass capacities

Biomass capacities are fixed exogenously, based on the datasets provided by ENTSO-E in their latest adequacy assessment (ERAA 2022). These capacities are assumed to stay constant from 2025 to 2035.

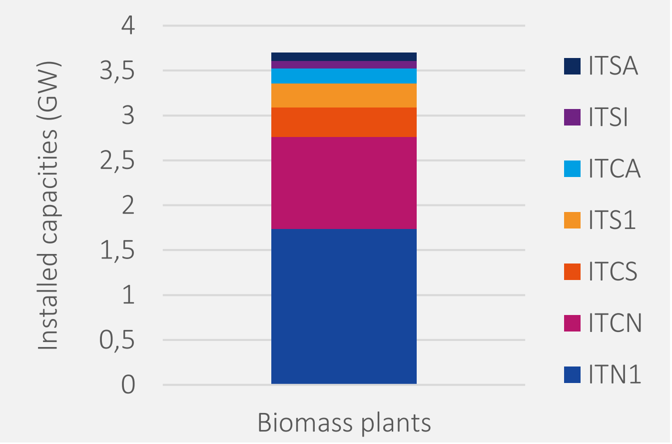


Figure 51 Projection for the installed capacity of biomass power plants (GW)

4.2.5 Additional constraints

The sections 4.2.2, 0, and 4.2.4 describe technology-specific constraints. Additional constraints covering several technologies were set into the model, to model more global limits:

- A limit on the *CO2 emissions* in 2035 was set to achieve a close to net-zero power production mix[21]
- In addition, a limit on the *maximum yearly net import volume* was also set into the simulations. The aim of adding this constraint was to reach a technology mix that ensures a sufficient independence and resilience of the Italian generation mix can be reached. The simulation thus constraint the maximum net imports to be below 40 TWh per year. This level was chosen to reflect the average over recent year of the yearly net import volumes.

4.3 Cost assumptions

4.3.1 Investment and operation costs

The investment and fixed operating costs are based on the ones used for the Ember's New Generation report which models pathways towards a decarbonisation of the European electricity system by 2035 (EMBER, 2022).

Most of these costs are based on the ASSET database, published by the European Commission, and used for PRIMES modelling in 2018 (European Commission, Directorate-General for Energy, De Vita, A., Kielichowska, I., Mandatowa, P., et al., 2020)[22]. As the cost projection dates from 2018, some costs have been updated with other sources to better reflect current cost evolution[23].

4.3.2 Commodity prices

Gas prices

The short-term evolution of gas prices has been adapted to reflect the current situation. The 2025 gas price used in the modelling is based on the average 2-year TTF Gas Futures. And from 2030, gas prices are assumed to be in line with pre-crisis projections. The 2030 and 2035 gas prices are based on the same prices as the one used within the ENTSO-E's adequacy assessment (ENTSO-E, 2022). Given the strong emission constraint in 2035, the impact of the gas price on the final generation mix in our simulation is limited.

[21] The level of this limit is set to 5 gCO2 per kWh of direct power demand (i.e. a maximum of 1,96 MtCO2 in 2035).
[22] See https://data.europa.eu/doi/10.2833/994817. These estimations were performed in 2018.
[23] See Ember's technical report for details on the costs' choices: https://ember-climate.org/insights/research/new-generation/#downloads (EMBER, 2022)

Year	2025	2030	2035
Projected evolution of gas prices (€/MWh LHV)	100	24,8	24,8

Table 4 Projected evolution of gas prices, from 2025 to 2035, used for the modelling (€/MWh LHV)

CO2 prices

The carbon prices are based on the assumptions made in the EMBER's New Generation study (EMBER, 2022).

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