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# Modelling the Italian power system: carbon free scenarios to 2050

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# Abstract

Nowadays, national decarbonisation strategies and policies aim to address climate change, defining pathways for the transition towards a net-zero emissions energy system. In this energy transition, all sectors must contribute. However, the electricity sector has the greatest potential to decarbonise: a fully decarbonised power sector is expected by 2050.

To support policymakers in planning the evolution of energy systems, optimisation modelling tools are needed to capture key challenges and opportunities. In this thesis, long-term scenarios for Italy are analysed to achieve the imposed targets of emission reduction for the power sector. An hourly resolution power system spanning three years is modelled. Future outlooks for 2030, 2040, 2050 are evaluated, optimising power generation and electricity storage investments by utilising greenfield planning and overnight investment methods. Electricity trading is allowed between neighbouring countries, and electric vehicles are also introduced into the model, resulting in a modification of the power demand profile.

Results show that a low-carbon electricity system is possible and that emissions can be cut by 80-90% with respect to 1990 levels. This target achievement can be enabled by the high penetration of intermittent renewables coupled to the growing deployment of storage and technologies such as Carbon Capture and Sequestration (CCS), able to withstand the growing demand for electricity while meeting the stringent targets reducing $CO_2$ emissions. In addition, a scenario dedicated to the exploitation of nuclear energy is explored, revealing how this technology could prove a valuable aid in the fight against climate change.

Future developments of the model could account for more detailed modelling of the transmission grid and take into account cross-sectoral interactions, investigating the development of low carbon pathways at a whole-energy system scale.

# Abstract

Attualmente, diverse strategie e politiche nazionali di decarbonizzazione mirano ad affrontare il cambiamento climatico, definendo percorsi di transizione verso un sistema energetico a zero emissioni nette. In questa transizione energetica, tutti i settori devono contribuire. Tuttavia, il settore elettrico presenta il maggior potenziale di decarbonizzazione: un sistema elettrico completamente decarbonizzato è previsto entro il 2050.

Per supportare i responsabili politici nella pianificazione dell'evoluzione dei sistemi energetici, sono necessari modelli di ottimizzazione per catturarne le sfide e le opportunità chiave. In questa tesi, vengono analizzati scenari a lungo termine per l'Italia, con lo scopo di raggiungere gli obiettivi imposti di riduzione delle emissioni per il settore elettrico. Viene modellato un sistema elettrico a risoluzione oraria che copre un arco temporale di tre anni. Sono valutate le prospettive future per il 2030, 2040, 2050, ottimizzando la generazione di energia e gli investimenti per lo stoccaggio dell'elettricità utilizzando metodi di pianificazione greenfield e investimenti overnight. Lo scambio di elettricità è permesso tra paesi confinanti e nel modello sono introdotti anche i veicoli elettrici, con una conseguente modifica del profilo della domanda di energia.

I risultati mostrano che un sistema elettrico a basse emissioni di carbonio è possibile e che le emissioni possono essere ridotte dell'80-95% rispetto ai livelli del 1990. Il raggiungimento di questo obiettivo può essere permesso dall'alta penetrazione delle rinnovabili intermittenti accoppiate alla crescente diffusione dello stoccaggio e di tecnologie come la Cattura e il Sequestro del Carbonio (CCS), in grado di sostenere la crescente domanda di elettricità, soddisfando allo stesso tempo i severi obiettivi di riduzione delle emissioni di $CO_2$. Inoltre, viene esplorato uno scenario dedicato allo sfruttamento dell'energia nucleare, rivelando come questa tecnologia potrebbe rivelarsi un valido aiuto nella lotta al cambiamento climatico.

Gli sviluppi futuri del modello potrebbero tenere conto di una modellazione più dettagliata della rete di trasmissione e prendere in considerazione le interazioni fra differenti settori, indagandone lo sviluppo sull'intero sistema energetico.

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# List of Abbreviations

| | | |
|---|---|---|
| $C_{technology}$ | [MW] | capacity of the selected technology |
| $C_{RES,2019,t}$ | [MW] | capacity of wind and solar power in 2019 |
| $C_{RES,t}$ | [MW] | scaled capacity of renewable power |
| $C_{SMR}$ | [MW] | capacity of installed SMR |
| $E_{s,t}$ | [MWh] | electricity storage level at hour t |
| $E_{s,init}$ | [MWh] | electricity storage at the beginning of the modelling |
| $P_{B,t}$ | [MWh/h] | power balance at hour t |
| $P_{CL,t}$ | [MWh/h] | curtailed power at hour *t* |
| $P_{chargecap}$ | [MW] | maximum charging power of the electricity storage |
| $P_{d,historical}$ | [MWh/h] | historical power demand at hour t |
| $P_{dischargecap}$ | [MW] | maximum discharging power of the storage |
| $P_{D,t}$ | [MWh/h] | electricity demand used in the model at hour $t$ |
| $P_{GRES,t}$ | [MWh/h] | power generation at hour t |
| $P_{Gnuclear,t}$ | [MWh/h] | power generated by (all) nuclear power at hour t |
| $P_{Ghydro,t}$ | [MW] | power generated by variable hydropower at hour *t* |
| $P_{Gsolar,t}$ | [MWh/h] | power generated by solar power at hour t |
| $P_{Gwind,t}$ | [MWh/h] | power generated by wind power at hour t |
| $P_{I,t}$ | [MWh/h] | power import at hour *t* |
| $P_{S,t}$ | [MWh/h] | power consumed by storage (negative for supplied) at hour *t* |
| $P_{SL,t}$ | [MWh/h] | storage losses at hour *t* |
| $P_{chargecap}$ | [MW] | maximum charging power of the electricity storage |
| $P_{Vestas}$ | [MWh/h] | power profile of single offshore turbine |
| $P_{wind,off}$ | [MWh/h] | scaled wind offshore power profile used in the model |
| $C_{transmission}$ | [€/MW] | total cost of imported energy |
| $C_{total}$ | [€] | total system investment cost |
| $c_{fixed\ O\&M\ ,techn.}$ | [€/MW] | fixed O&M cost of selected technology |
| $C_{technology}$ | [€/MW] | investment cost of the selected technology |
| $C_I$ | [€] | yearly energy import cost |
| $c_{variable\ O\&M,techn.}$ | [€/MWh] | variable O&M cost of selected technology |
| $CO_{2\ emitted}$ | [t] | total amount of $CO_2$ emitted |
| $CO_{2\ cap}$ | [t] | maximum amount of $CO_2$ emission allowed |
| $CO_{2\ content}$ | [$tCO_2$/MWh] | carbon emission per MWh of electricity produced |
| $CO_{2\ price}$ | [€/$tCO_2$] | carbon price per tons of emitted $CO_2$ |
| $Carbon_{t,n}$ | [€/MWh] | cost of emission per MWh of electricity produced |
| $Fuel_{t,n}$ | [€/MWh] | cost of imported fuel |
| $d$ | [TWh] | electricity demand |
| $n_{technology}$ | [-] | lifetime of the specific technology in years |
| $r$ | [-] | Discount rate |
| $t$ | [h] | time set used in the modelling; values include [1,2…,26280] |
| $x$ | [-] | scaling constant for power demand |
| $X_{EV}$ | [-] | parameter used in (4) |
| $\mu$ | [-] | parameter used in (4) |
| $\sigma$ | [-] | parameter used in (4) |
| $\tau_{RES}$ | [-] | scaling factor for wind and solar power |
| $\tau_{offshore}$ | [-] | scaling factor for wind offshore power |
| $\tau_{thermal}$ | [-] | scaling factor for thermal power |
| $\eta_{s,charging}$ | [-] | charging efficiency |
| $\eta_{s,discharging}$ | [-] | discharging efficiency of the electricity storage |

# Chapter 1

# Introduction

Climate change has already caused the increasing of 1 degree of the planet temperature compared to the pre-industrial era (European Commission, Climate action, 2021). The scientific community agrees that the main cause of this event lies in the human activity. In particular, the greenhouse emissions are recognized as the main responsible, $CO_2$ especially. This creates the urgent need to abandon the exploitation of fossil fuel and the need to rely on more sustainable resources. With this thesis, the possibility of reaching a carbon free power system for Italy before 2050 will be analysed. Sustainability is generally not considered convenient, compared to fossil fuel, but since agreements are taken between European countries and lot of incentives has already been distributed, the right direction is being pursued.

Compared to the other European countries, Italy is positioned at the bottom for the installed capacity of renewable technology and the Italian electricity sector is indeed the main responsible of the $CO_2$ emissions of the country (accounts for 81% of the total emissions). This is explained by the fact that more than half of the entire generation is produced with non-renewable energy sources like coal, natural gas, and others solid fuels. There is an urgent need to accelerate the decarbonisation process by setting 2030 as an interim milestone for achieving the objectives of reducing greenhouse gases agreed at European and international level and reaching full decarbonisation of the energy sector by 2050. Paris agreement set the goal of the decarbonization, while COP26 set the path to achieving it.

Factors contributing to this goal include: the phasing out of coal, scheduled by the end of 2025, a higher $CO_2$ price level than in recent years, and a significant acceleration of renewables and energy efficiency in manufacturing processes. This development will be guided by a constant focus on efficiency and facilitated by cost reductions for some renewable technologies, including photovoltaics, which will take on growing significance due to their modularity and the fact that they use a source that is widely available on all the country.

# Chapter 2

# Overview on the Italian electricity system

Greenhouse gases (GHG) and suspended pollution particles in the atmosphere caused by the burning of fossil fuels are responsible for the majority of the warming documented over the last century. The ability of these gases to absorb and redirect terrestrial radiation as infrared radiation, indeed, reduces the amount of radiation sent back to space, inducing a rise in the world temperature (IPCC, 2014). The research has led to increased certainty that global warming could bring very severe impacts and risks worldwide. These advances provide a much more solid base of evidence on which climate change policy can be further developed.

The principal anthropogenic GHG and one of the most present in Earth's atmosphere is, according to IPCC, the carbon dioxide ($CO_2$), especially because it can remain in the atmosphere for hundreds of years. The amount of $CO_2$ in atmosphere reached 419 parts per millions, according to calculations by the National Oceanic and Atmospheric Administration (NOAA, 2021), and this rise happened despite an estimated 7% reduction in global emissions due to the pandemic, reaching a levels 50% higher than it was just prior to the industrial revolution.

The Kyoto Protocol adopted in December 1997 (UNFCCC, 1997), has established emission reduction objectives for industrialised countries and countries with economy in transition: in particular, the European Union was committed to an 8% reduction within the period 2008-2012, in comparison with base year levels. For Italy, the EU burden sharing agreement, has established a reduction objective of 6.5% in the commitment period, in comparison with 1990 levels. A new global agreement was reached in Paris in December 2015, (United Nations, 2015) for the period after 2020. The agreement aims to limit the temperature increase to 1.5 °C above pre-industrial levels to strengthen the global response to the treat of climate change, recognizing that this would significantly reduce its risks and impact. The EU and its Member States have committed to this second phase of the Kyoto Protocol and established to reduce their collective emissions to 20% below their levels in 1990. The energy sector is the largest contributor to national total GHG emissions with a share, in 2020, of 81% of total emissions in $CO_2$ equivalent. Emissions from this sector decreased by 19.4% from 1990 to 2020 and by 29% compared to 2005, as can be seen in Figure 1, and predictions show that it will continue to decline.

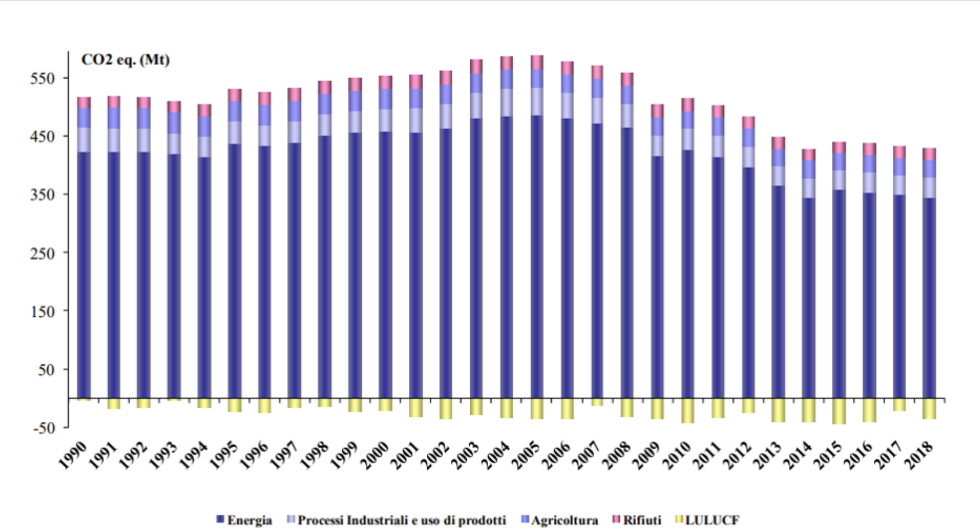



*Figure 1: $CO_2$ equivalent emission by sector since 1990, the dark blue column refers to the energy sector. (TERNA, s.d.)*

The share of the different sectors, in terms of total emissions, remains nearly unvaried over the period 1990-2020. Specifically for the year 2020, the greatest part of the total greenhouse gas emissions is to be attributed to the energy sector, followed by industrial processes and agriculture, accounting for 8.1% and 7.1%, respectively, and waste contributing with 4.3% to total emissions. The main drivers for the reduction of $CO_2$ emissions can be found in the sectors of energy, manufacturing, and construction; in the period 2005-2020, emissions from energy industries decreased by 23.9% while those from manufacturing industries and construction show a decrease of 48.8% (ISPRA, 2021).

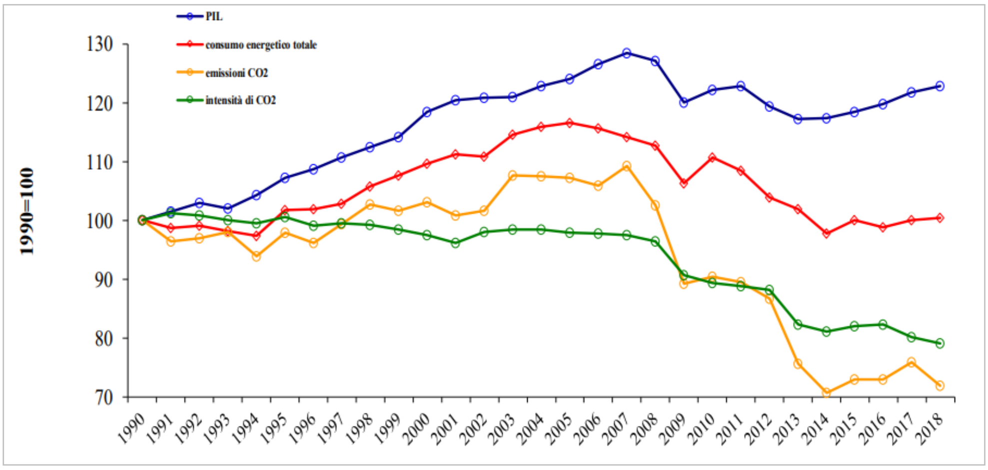



*Figure 2: Italian GDP, $CO_2$, and total consumption trend (ISPRA, 2018).*

In the 1990s, $CO_2$ emissions essentially mirrored energy consumption. A decoupling between the curves is observed only in recent years, mainly because industries and electric energy production, begin to substitute high carbon intense fuels with methane gas; in the last years, moreover, the increase in the use of renewable sources has led to a notable reduction of $CO_2$ intensity. From 2005, GHG emissions from the energy sector are decreasing because of the policies adopted at European and national level to implement the production of energy from renewable sources. From the same year, a further shift from petrol products to natural gas in producing energy has been observed as a consequence of the beginning of the EU greenhouse gas Emission Trading Scheme (EU ETS). From 2009, a further drop of the sectoral emissions is due to the economic recession.

Given the seriousness of the current situation, the main energy and climate targets indicated in the "Integrated National Plan for Energy and Climate" (PNIEC) to 2030 and characterising the policy scenario are:

- A 33% reduction in greenhouse gas emissions compared to 2005 levels for all non-ETS sectors (transport, residential, tertiary, industry not included in the ETS sector, agriculture and waste).
- A 43% reduction in primary energy consumption with respect to the PRIMES 2007 reference scenario11.
- Achieving a 30% penetration of renewables in gross final energy consumption. This target is then broken down into three different sectors, electricity, thermal and transport, as listed below:
  - for the electricity sector, the achievement of a share of about 55.4% of gross final electricity consumption.
  - for the thermal sector, a minimum RES share of 33.1% of gross final consumption, i.e., in heating and cooling.
  - for the transport sector, the attainment of a minimum share of renewables of 21.6% of the sector's energy consumption.
- An interconnection target of 10%, calculated as the ratio of Net Transfer Capacity (NTC) of interconnections to net installed generation capacity.

Furthermore, in the Integrated Plan, the main objectives and the related measures necessary to achieve them include

- the total phase-out of coal from electricity generation by 2025 (at the moment there are 7 GW installed)
- promoting the uptake of electric vehicles, with a target of 6 million electrically powered cars by 2030, including 1.6 million pure electric vehicles.
- an important development of new centralised storage systems, both hydroelectric and electrochemical, for a total of at least 6 GW.

## 2.1 Demand of electricity

The electric demand in Italy followed a growing trend since 1990, when the demand was of 235 TWh, reaching its maximum level in 2008 with 339 TWh (TERNA). Subsequently, with the economic recession, the demand decreased sharply to 317 TWh in 2009, trying to recover from the crisis in the following years. From 2012 on, however, the trend changes, undergoing a slow decreasing, due to the improvement of the technologies and their efficiency, reaching the lowest value of 304 TWh in 2014, until the advent of the COVID pandemic in 2020, when a new recent low of 301 TWh was reached.

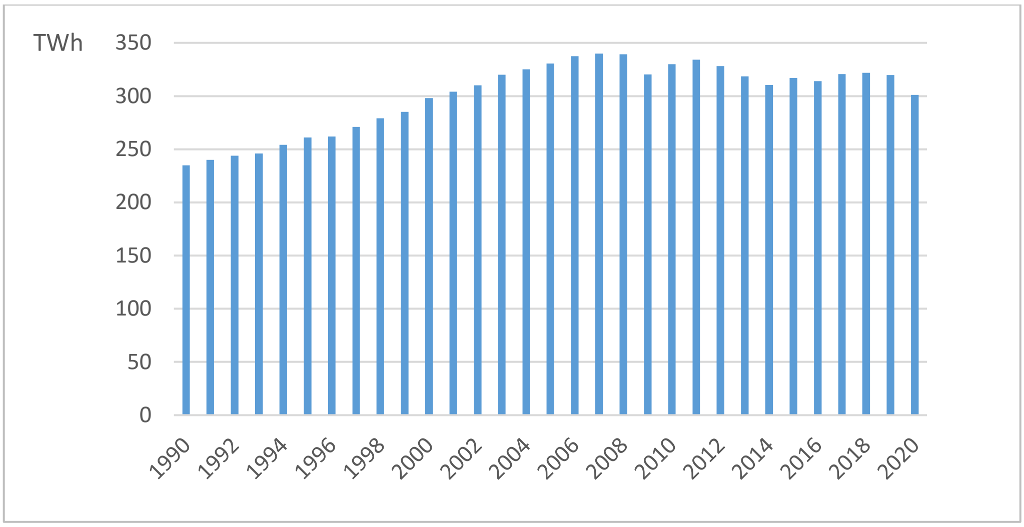



*Figure 3: Italian electrical demand trend (TERNA,2020)*

Given the considerable reduction in demand in 2020, it was hence decided to consider the period prior to the pandemic (2017-2019) as the range of data collection of the model developed in this thesis. This was done so that the forecasts obtained by the model were not distorted by extraordinary events and were instead capable to predict future scenarios, consistent with the rest of the historical data.

The electrical demand of the country varies throughout the year mainly due to external temperature. From Figure 4, it can be seen that the highest monthly demand is usually in June and July, during summer, when the cooling requirement is maximum, then usually followed by a sudden decrease in the central weeks of August, when most companies remain closed due to the summer break. Similarly, demand tends to increase in winter, given the high heating requirement, especially in the north of Italy. Conversely, during spring and autumn, it can be noticed a gradual decrease, of the electrical demand.

The peak value of power demanded in 2019 was 59.3 GW, which occurred on 27 June at 4pm. The trend in monthly demand over the year shows that summer weather has a significant effect on energy demand: air conditioners and refrigeration systems have a significant impact on energy consumption, much greater than electric heating systems in winter.

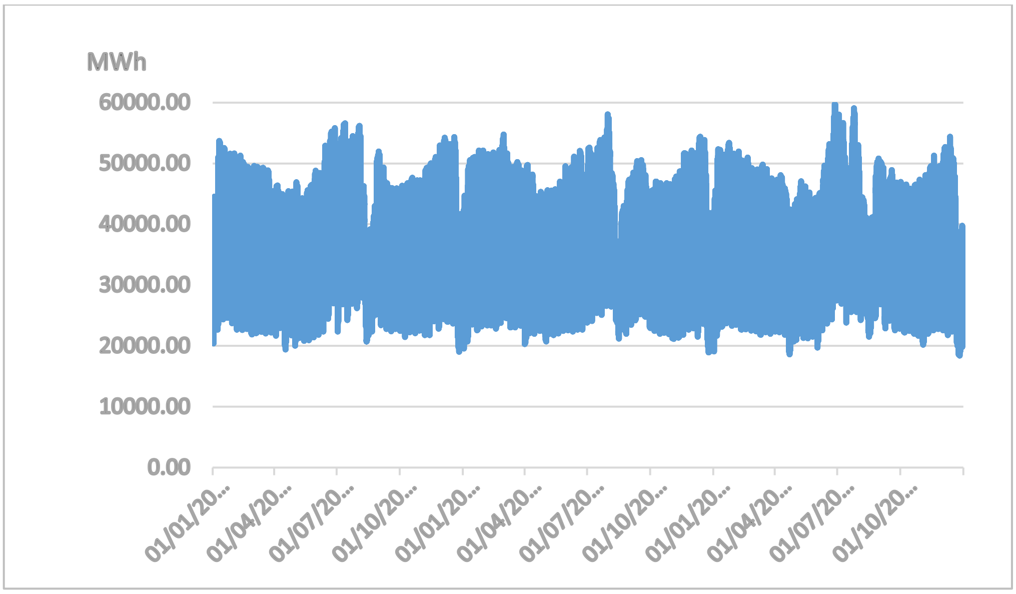



*Figure 4: Hourly electricity demand in Italy between 2017-2019 (TERNA, 2020)*

## 2.2 Supply of electricity

The mix of resources contributing to national electricity production has varied considerably in recent years, as can be seen in Figure 5: Electricity generation by source, Italy 1990-2020 (IEA).

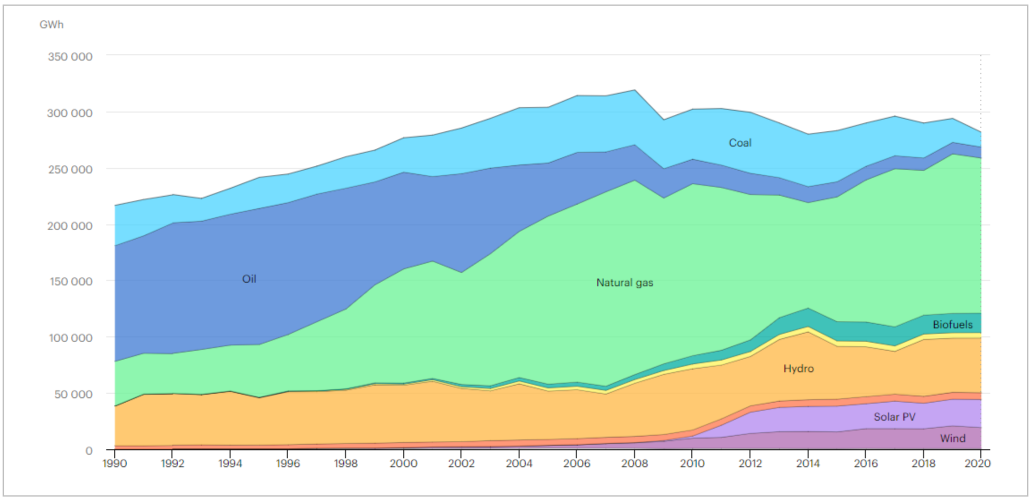



*Figure 5: Electricity generation by source, Italy 1990-2020 (IEA)*

In terms of total size of the Italian electricity generation fleet, the gross efficient power has progressively reached a peak in 2012, and then decreased in recent years. This phenomenon can be explained by analysing the trends that have driven installations of RES plants and the decommissioning of conventional plants. As for the traditional generation fleet, Italian thermoelectric capacity underwent a phase of modernisation and development until 2012, driven by expectations of growth in demand and energy prices, reaching 77 GW of installed power. From 2013 onwards, however, the installation trend came to a sudden halt, and in the following years the overall thermoelectric fleet has been reduced sharply as a result of numerous divestments that brought the actual available capacity below 60 GW. The share of production from non-renewable installations in national production decreased from 84% in 2005 to 58% in 2019 (Figure 7). In absolute terms, this reduction is even more pronounced with generation from non-renewable plants, from 236 TWh in 2005 to 163 TWh in 2019 (approx. -30%).

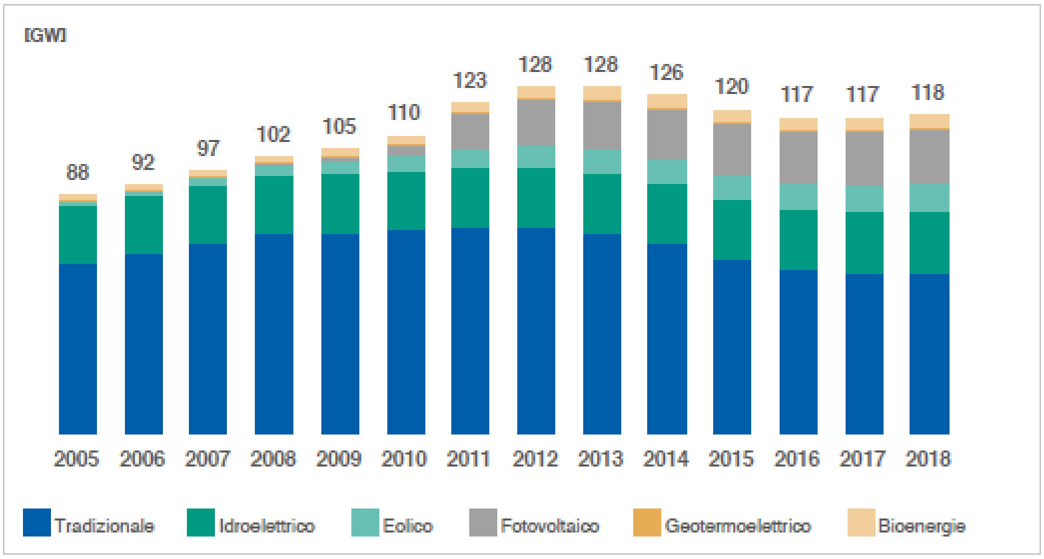



*Figure 6: Installed capacity by source (TERNA, 2019)*

The divestment of a large share of the thermal generation is mainly linked to the reduction in the profitability of these plants in recent years, caused on one hand by the slowdown in demand for electricity, and on the other hand, by the growth of the renewable energy sector, which has displaced the plants from the market, by reducing their equivalent production hours. Specifically, the evolution of the thermoelectric fleet since 2005 can be summarised in the following three phases:

- up to 2007: the growth in consumption and in commodity prices, led to significant investments in new efficient gas-fired production capacity, also to replace plants fuelled by petroleum products.
- between 2008 and 2014: the sharp reduction of electricity consumption caused by the economic crisis, combined with the market share gains by RES, led to a growing overcapacity of the thermoelectric fleet. This has caused a significant reduction in the equivalent production hours and held back investment.
- from 2013 onwards: the prolonged reduced profitability of many thermoelectric plants led to a phase of decommissioning for a large proportion of them. This, together with a partial recovery in demand and the slowdown in the installation of RES plants, led to an increase in equivalent hours of the conventional fleet, but with a lower level of profitability than in the past, due to the reduction in the clean spark spread (difference between the price of electricity and the variable cost of a gas-fired power plant).

For what concerns renewable sources, at the contrary, the main trend over the last decade has been the unprecedented development, accounting for around 41% of national net production in 2020, of which 17% from hydroelectric plants and the remaining 24% from geothermal, wind, photovoltaic and biomass sources, as can be seen in Figure 7. In particular, wind generation capacity has tripled between 2008 and 2018, reaching over 10 GW (3.5 GW in 2008), while the photovoltaic installed capacity reached a total of 23 GW in 2020, (0.5 GW in 2008), with a grew of 95% of annual production, reaching in 2019 a value of about 23 TWh.

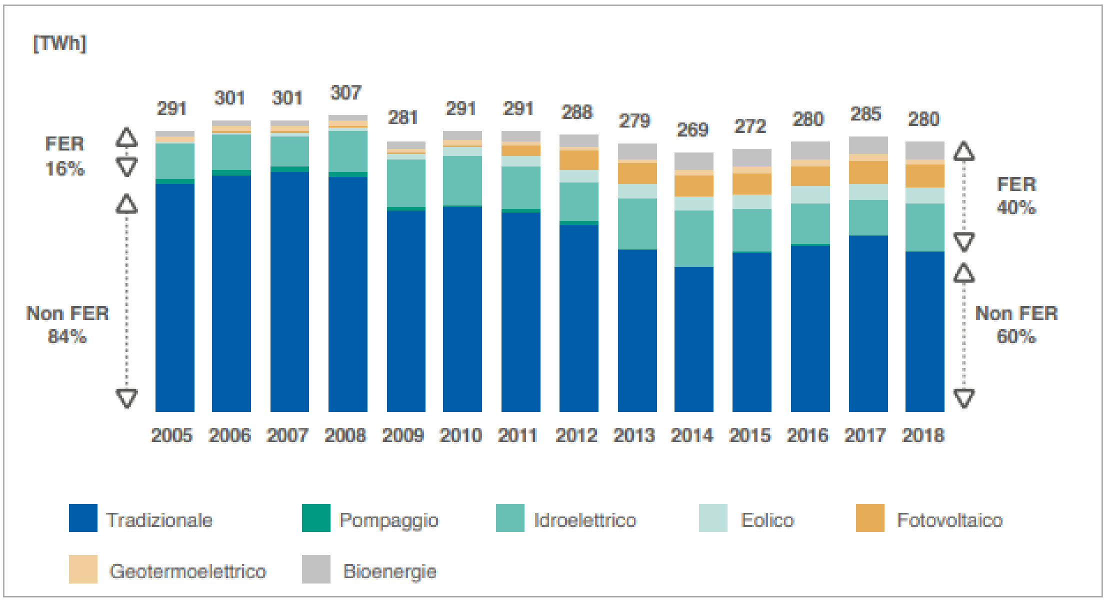



*Figure 7: Evolution of net power production by source (TERNA, 2019)*

Overall, the growth of the renewable fleet has been supported by a particularly incentivising legislation promoted between 2008 and 2013. In this timeframe, installed wind and photovoltaic installed capacity grew exponentially, by more than 6 times. This phenomenon stopped in the following years, when growth rates were much lower. In general, the construction of RES plants has been uneven on the Italian territory. Wind power plants, for example, have been heavily concentrated in the South and Islands, where about 80% of national wind power is installed. Photovoltaics, on the other hand, is more widely distributed throughout the country, with a higher concentration in the North, where more than 40% of power is installed, as shown in Figure 8. The installation takes place according to a logic that in areas that offer the best conditions of producibility, availability and availability of areas and simplicity of the authorisation process, taking little account of the potential of the grid to dispatch the power to places of consumption.

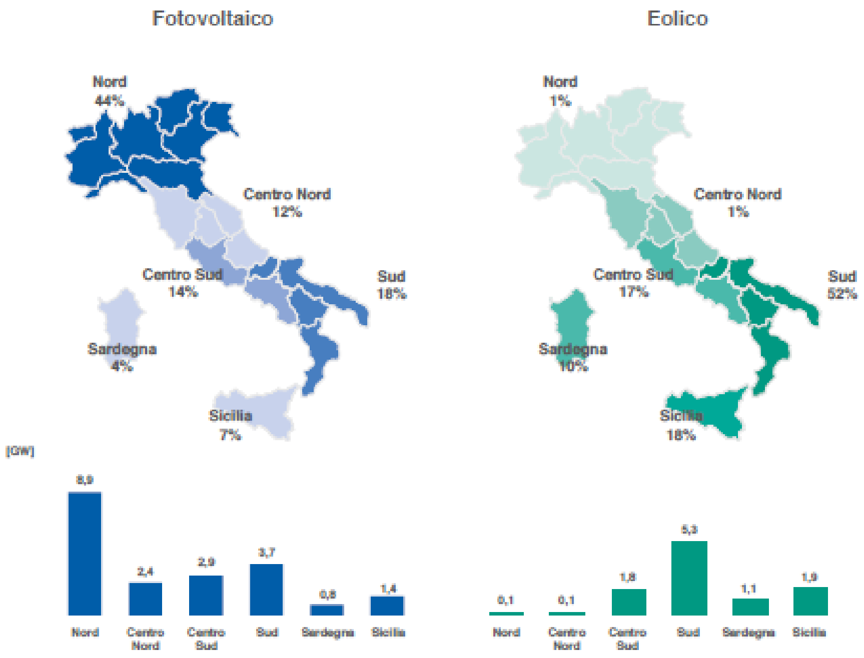



*Figure 8: PV and wind installed capacity by market zone (TERNA, s.d.)*

The role of distributed generation in the electricity system will grow in the coming years, especially in view of the evolution scenarios envisaged in the proposed National Integrated Energy and Climate Plan (PNIEC), which foresee a significant development of RES plants, many of which will be installed on MV-LV networks. This phenomenon of decentralisation of generation brings with it a series of important implications for the security of the electricity system, that will not be analysed in this thesis.

In 2020, renewable energy sources (RES) confirmed their leading role in the Italian energy panorama, finding widespread use both for the production of electricity (Electricity sector) and heat production (Thermal sector) and as biofuels (Transport sector). In the future, this role must be further strengthened: the new National Energy Strategy adopted in November 2017, in fact, identifies RES as a central element for the sustainable development of the country, setting growth targets to 2030 more ambitious than those currently proposed at EU level.

## 2.3 Transmission of electricity

Italy's electricity demand since 2005 has been met by an almost constant mix of domestic production and foreign imports, in particular, about 85% of demand is met by domestic production, equal to the net national production of the generation park reduced by the energy for pumping. Although this share has remained practically constant over time, the contribution of the different sources to domestic production has varied considerably in recent years, as will be seen in detail in the next paragraph. The share of demand not covered by domestic production, 14% in 2018, is covered by foreign trade, which, as mentioned above, has maintained a substantially constant percentage share in recent years. Historically, Italy is an importer of electricity, with exchange associated with the Swiss and French borders (more than 80% in

2018), where interconnection capacity is greater. The interchange with foreign countries in 2019 ensured a net electrical input of 32,2 TWh which represents the balance between a contribution of 39,8 TWh of imported energy and 7,6TWh of exported energy.

Italy's dependence on electricity imports from neighbouring countries continues to be perceived, for this reason, an investment policy is being implemented for the development of new transport assets and the connection with Malta, used in particular on the export side, is now to be considered fully operational (TERNA, Contesto ed evoluzione del sistema elettrico, 2019). According to the PNIEC, the projects under construction that will contribute to the achievement of the 10% interconnection target are:

- Italy-France HVDC link, with a nominal capacity of 2x600 MW, leading to an increase of 1200 MW in imports and 1000 MW in exports. The pre commissioning phase of the plant was initiated in June 2021.
- Italy-Montenegro HVDC connection: two ±500 kVcc pole lines, partly in land cable and partly in sea cable, with a transport capacity of 2 x 600 MW.

Currently, the interconnection capacity is mainly located on the northern border of the country (4 lines with France, 12 with Switzerland, 2 with Austria, 2 with Slovenia). The total value of trading capacity on the northern border for the year 2017 is between 6,300 MW and 8,435 MW in imports and between 3,010 MW and 3,895 MW in exports with 7 lines of 380 kV, 9 lines of 220 kV and 3 lines of 150/132 kV. There is also a direct current link with Greece and one connecting Sardinia and the peninsula with Corsica. Sardinia is also connected to Corsica by an alternating current cable. A 220 kV twin-triad cable connects Sicily with Malta.

The programme of interconnections envisaged in the medium and long term will increase the transmission capacity with the northern border up to more than 12 GW, with an increase in the short term for a total of about 1500 MW. In particular, by 2030, the interconnection capacity is expected to increase of about 6 GW of total import capacity, of which 500 MW are due to the new HVDC interconnection project with Greece and 1000 MW due to the interconnection project with Switzerland (Rationalisation Valchiavenna project).


*Figure 9: Interconnection capacity (GW) with foreign countries (TERNA, 2021)*

The contribution of imports is mainly driven by two fundamental factors: the price differential between Italy and neighbouring countries and the capacity of cross-border interconnections. Italy has had a positive electricity price spread with northern border countries for years. In 2018, the average spread with respect to these countries was over 11 €/MWh, with a maximum differential on the Austrian border (around 15 €/MWh) and a minimum differential of over 9 €/MWh with the French border.

This price difference is mainly due to the presence of a generation park characterised by technologies with generally lower variable costs in the northern border countries compared to Italy: in France more than 70% of the electricity production comes from nuclear power, Austria covers 60% of the energy produced by hydroelectric power, while Slovenia is characterised by a production mix where 2/3 of the energy produced from hydro and nuclear power. Switzerland also has a negative spread with Italy, being a bridge linking Italy with France and Germany (which has high levels of production from lignite and wind power).

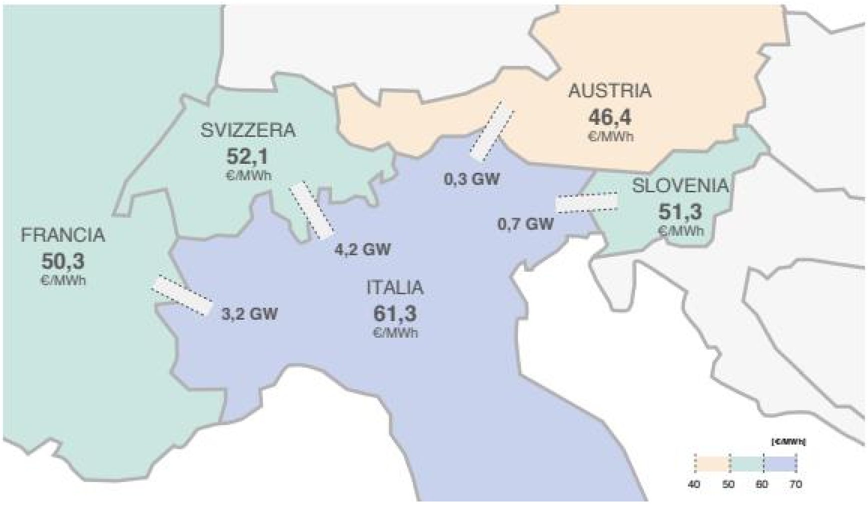



*Figure 10: Yearly average price of electricity and interconnection capacity in 2018*

At national level, the National Transmission Grid, owned by Terna, has over 66,000 km of lines (corresponding to about 73,000 km of electrical circuits), in particular, the Italian transmission grid is characterised by five voltage levels: 380 kV, 220 kV, 150 kV, 132 kV and 60 kV.

This electricity system has some unique characteristics, deriving from geographical configuration. The country is characterised by the fact that it confines with continental Europe only via the northern border, being crossed longitudinally by mountain ranges and has two large islands. As a result, almost all the interconnection capacity with foreign countries is located on the northern border, while at national level there are structural bottlenecks between different areas of the country, which cause difficulties in optimising energy flows, particularly towards islands and between northern and southern Italy. The low level of transmission capacity determines the need to separate the electricity system into different "market zones".

The possible exchanges of energy between adjacent market zones are appropriately limited in order to implement in the algorithms the constraints arising from the limited transport capacity of the grid. On the other hand, energy trading within each zone is unconstrained. The capacity of exchange between the different zones depends on the availability conditions of the grid elements, as well as load and generation conditions. Terna takes into account signals from the electricity market in the planning process, with a view to resolving issues related to grid congestion. In this regard, the planning objectives consist mainly of the reduction of congestion between market zones and intra-zonal congestion, in order to allow better use of the national generation pool and greater integration and competitiveness of the national grid.

# Chapter 3

# Modelling a power system with high VRES

Energy system models for long-term planning are widely used to study the increasing complexity of the electricity system and they help policy makers choosing among several possible scenarios of energy transition. Many new models and modelling features are emerging in the literature in recent years, due to the need of better address challenges of integrating VRES. Their greatest usefulness. rather than predicting a future scenario, is to be used to support strategic choices, considering that it is not guaranteed that that scenario will be reached, since there are considerable uncertainties associated with the evolution of demand. The energy system is undergoing to an increasing electrification and a significant share of variable renewables will be part of it, therefore it is needed to face some challenges such as how to represent short-term variability, incorporate the impact of climate change and ensure transparency in modelling studies. In this context, larger shares of VRES bring multiple challenges, especially in terms of the electricity grid that requires a balance between consumption and generation.

The main challenges related to the integration of VRES can be investigated depending on the temporal scale: on a short timescale (seconds or minutes), the main issues concerns the grid management and operation, in particular the reduction of inertia of the power system, the rate of frequency change, the increasing number of curtailment events, as well as the reactive power capability of the system (Van Hulle F, 2014). Therefore, if renewable generating technologies aim to replace much of the conventional plants, it is necessary to provide the correct support service to maintain a stable and reliable grid. The help of electrochemical batteries could be fundamental with a large penetration of VRES to increase the flexibility of the system and address ramping events, periods of oversupply as well as periods of deficit of supply, where the renewables are not able to meet the demand. Moreover, future power systems may require flexible power plants, demand response and extensions of the transmission grid (Huber M, 2014).

On a longer timescale, the study of future scenarios is needed to identify trajectories to a renewable and carbon free energy system, assessing the impact of different policies. For example, by evaluating the impact of a carbon tax, the evolution of fuel and electricity prices or how much the population growth and change in habits or standards of living will affect the energy demand (Hans-Kristian Ringkjøb, 2018). For an efficient integration of renewable, energy storage, grid expansion and demand side management are predicted to be crucial technologies. Moreover, sector coupling (i.e. considering not only the power sector, but also heat and mobility sectors as well as their interaction), is an important feature for the development of a national whole-energy deep decarbonisation transition. A more interconnected energy system, where energy sectors are closely linked, can support the integration of variable renewables as well as abate emissions. It is thus evident that the larger the share of VRES in the energy mix, and the more central the variability and operational aspects will become in present modelling.

## 3.1 Modelling classification

Després et al. (Després J, 2015) provided a complete model categorisation which consists of a distinction based on the following aspects: the general logic, the spatiotemporal resolution as well as the technological and economic parameters of the models. For what concerns the general logic, energy models generally follow two approaches: either a top-down or a bottom-up approach. Bottom-up models are based on detailed technological descriptions of the energy system and are characterized by regressive predictive logic and switching mechanism depending on the specific technology. Most of the models are bottom-up optimisation models with the aim of giving not only investment but also operational decision support. On the other hand, top-down logic ensures that certain targets are met in an iterative process, meaning that the parameters are modified until an acceptable combination is found, in terms of achieving the imposed targets considering macroeconomic relationships and long-term changes. When dealing with the integration of a high share of variable renewables, both long-term changes and technological properties may prove to be relevant issues of the model. Therefore, to capture both aspects, hybrid models could be useful (Fortes P, 2014).

Moreover, according to Després et al, four different purposes can be identified when characterizing a model:

- Tools developed for studying power systems with a high degree of detail, usually including power flows, dynamic stability, fault level studies etc. (Power System Analysis Tools).
- Tools developed for optimising the operation/dispatch of the energy/electricity system. These models operate on short-term timescales, but on a larger scale than power system analysis tools, e.g. on a national or European scale (Operation Decision Support).
- Tools that optimise the investments in the energy/electricity system (Investment Decision Support model). These models are usually long-term models, since they address long investment cycles in the energy sector.
- Tools that investigate future long-term scenarios in the energy/electricity sector (Scenario model)

Regarding the model methodologies, they can be divided into three main categories: simulation, optimisation or equilibrium techniques. The first typology of models simulates an energy-system based on specified characteristics and equations while the second optimises a given quantity. The majority of optimisation models uses a linear programming (LP) approach, with an objective function which is either maximised or minimised. Lastly, equilibrium models take a more economic approach, modelling the energy sector as a part of the whole economy and studies its relationship with the rest of the economy.

In terms of spatiotemporal resolution, time-steps can range from milliseconds in power system analysis tools to several decades when it comes to long term economic equilibrium models. This aspect limits which kind of processes can be appropriately modelled and becomes especially important in systems with a large penetration of VRES, as the variability of the solar and wind resources must be captured. In some models the time-steps are fixed, while in others the time-step is given by the input data. Likewise, the geographical resolution can vary from analysing single projects or individual buildings to modelling the energy system of the entire world.

Technological and economic properties of a model can be crucial when modelling the impact of high shares of VRES in the European energy system. They can be summarized in:

- Generation: renewable and/or conventional.
- Energy Storage typology.
- Grid: alternating current (AC), direct current (DC) or Net transfer capacities (NTC)
- Commodities: many models have a specific focus on the power sector alone, some models also include other commodities such as heat and transport.
- Demand sector: many models concern only the electricity systems and uses an aggregated demand based on the consumption of electricity in all of the sectors combined.
- Demand elasticity: how the demand changes due to price fluctuations.
- Demand side management.
- Costs: Investment, operation & maintenance, fuel, $CO_2$, taxes and balancing costs.
- Market: Most of the models assess the market by simply balancing supply and demand under perfect market conditions.
- Emissions: In some models, any pollutant can be modelled as its own commodity whereas some models treat greenhouse gas emissions by $CO_2$ equivalents.

## 3.2 Models that investigate the Italian energy system

In this section are summarized the most relevant deep decarbonisation studies regarding Italy– i.e. studies defining pathways to deeply reduce GHG emissions and highly increase RES penetration. Among the most recent deep decarbonisation studies, developed with currently available and actively used energy models, 13 focus on the Italian energy system. The main modelling framework used in these studies is TIMES/MARKAL, followed by EnergyPlan, OSe-MOSYS and Energy Scope. Although with different focuses, all these studies find that the deep decarbonisation of the Italian energy system is feasible and emission targets as high as 80%–100% GHG reductions compared to 1990 can be reached. Looking at relevant aspects for deep decarbonisation. Out of these works, 6 adopt a whole-energy system approach, while the others focus only (or mostly) on the electricity sector; 4 subdivide the energy system into subregions, while the remainder consider national level data. (M. Borasio, 2021)

The MARKAL/TIMES (Markal, 2019) energy model family is the most widely used in the context of decarbonisation studies at a national/regional scale. MARKAL (acronym for MARKet ALlocation) is a bottom-up model representing both the energy supply and demand sides of the energy system. The TIMES (The Integrated MARKAL-EFOM System) model is an evolution of MARKAL. It is a linear programming (LP) economic model generator that can be adapted to different energy systems at a national and regional level over a long, multi-period time horizon (usually 20–50 or 100 years); the model is mostly suitable for optimising investment decisions, while operation is represented in a coarser way using time slices (Connolly D, 2010). Another widely used modelling tool in the European context is EnergyPLAN, which can assist in the design of energy systems with high-RES penetration. EnergyPLAN optimises the hourly operation of regional and national energy systems – including not only heat and electricity supply but also the industrial and transport sectors – given the investment strategy as an input. As such, the model can be used to analyse and compare different investment strategies (EnergyPlan, 2018).

OSeMOSYS is an open-source energy planning tool, bottom-up, least-cost energy system optimisation framework for long-run integrated assessment and energy planning from the scale of continents down to the scale of countries and regions. It has a high sector-coupling representation and a low resolution in technology characterisation; it is one of the very few open-source models which can be taken into account for serious use (S. Moret, 2021).

EnergyScope is a long-term planning of large-scale energy systems framework which exploits a bottom-up LP modelling approach. The model configures an energy system over a certain time horizon by minimising the total discounted system cost which is an aggregation of capital costs, fixed and variable operation and maintenance costs (FOM and VOM), fuel costs, taxes, decommissioning costs, exogenous import costs, revenues from exogenous exports, subsidies, and salvage values of processes and commodities, for the entire time horizon, discounted to a selected base year (M. Borasio, 2021).

*Table 1 Review of national/regional deep decarbonisation studies. Abbreviations: hours (h), days (d), years (y), time slices (TS), power (P), heat (H), mobility (M).*

| Study | Model | Temporal target | Time resolution | Objective | Sectors |
|---|---|---|---|---|---|
| Virdis (2015) | TIMES | 2050 | 12 TS | 80% GHG reduction | P, H, M |
| RSE (2017) | TIMES | 2050 | 12 TS | 80% CO2 reduction | P, H, M |
| Lanati and Gaeta (2020) | TIMES | 2050 | 12 TS | 100% CO2 reduction | P, H, M |
| Calise et al.(2017) | EnergyPLAN | 2050 | h | 80% GHG resolution | P, H, M |
| Prina et al. (2019) | EnergyPLAN | 2050 | h | 40 % CO2 reduction | P, H, M |
| Gardumi et al. (2019) | ESeMOSYS | 2050 | 16 TS | High RE | P |
| Moret et al. (2021) | EnergyScope | 2050 | h | | P, H, M |
| Jafari et al. (2019) | GenX | 2050 | h | 100% RES | P |
| Bompard et al. (2020) | GenX | 2050 | h | 68% CO2 reduction | P, H, M |
| Lombardi et al. (2020) | Calliope | 2050 | h | 100% RE | P |
| Colbertaldo et al.(2018) | Developed by the authors | 2050 | h | 80% GHG reduction | P, M |
| Colbertaldo et al. (2020) | Developed by the authors | 2050 | h | 50% low-C mobility | P, M |
| Teske et al. (2020) | Developed by the authors | 2050 | h | 100% RE | P, H, M |
| Vellini et al. (2020) | Developed by the authors | 2030 | y | 47% GHG reduction | P |

# Chapter 4

# Modelling data

This thesis is based on the model of Tero Koivunen, a doctoral student at Aalto University who modelled a carbon-free power system for Finland in 2050 in his master's thesis (Koivunen, 2020). A carbon-free power system is defined, in his thesis, as a system which uses only such generation technologies, which emit neither fossil nor biogenic $CO_2$ emissions. The model was then adapted to the Italian case, requiring some changes due to the different initial energy mix, different demand and different power technologies in use at the moment.

Based on the classification reported in the previous paragraph, the model developed in this thesis consists of:

- Purpose: the model investigates future long-term scenarios in the electricity sector with the goal of a carbon free power system.
- Approach: top-down approach, with the target of a maximum carbon emission allowed.
- Methodology: optimization model with a linear programming approach that minimize an objective function (LCOE).
- Temporal resolution: hourly resolution, spanning three years.
- Spatial resolution: national, Italy.
- Modelling software: Excel solver.

## 4.1 Description of data sets

For the development of an Italian power system model, reference was made to the Finnish model, which used the following data sets as the main ones:

- Wind power generation - hourly data
- Solar power generation forecast - updated hourly
- Hydro power production – hourly data
- Electricity consumption
- Measured transmission of electricity between foreign countries
- Nuclear power production - real time data

In addition, differently from the Finnish model, also other two generation technologies were included, as they are relevant in the Italian generation mix:

- Geothermal power generation - hourly data
- Biomass power generation - hourly data

The corresponding Italian data sets were obtained using TERNA open data service (TERNA, Transparency Report: la piattaforma, s.d.). From there, different data sets were downloaded as excel files, and later these files were then combined as needed. All data sets above had the unit of MWh/h, and a resolution of one hour, except the electricity transmission, which had a resolution of 15 min. Referring to the nuclear data set, since there is no plant in Italy that uses this technology, a special data set has been constructed to recreate a hypothetical scenario that would exploit, among other technologies, also nuclear power. This aspect will be explored in more detail in the next paragraph. The data was obtained for years 2017-2019 for the current model. This latter choice, as already mentioned, was made to avoid including the covid pandemic period in the model, since it caused significant and unexpected reductions in energy demand and generation as can be seen in the figures below:

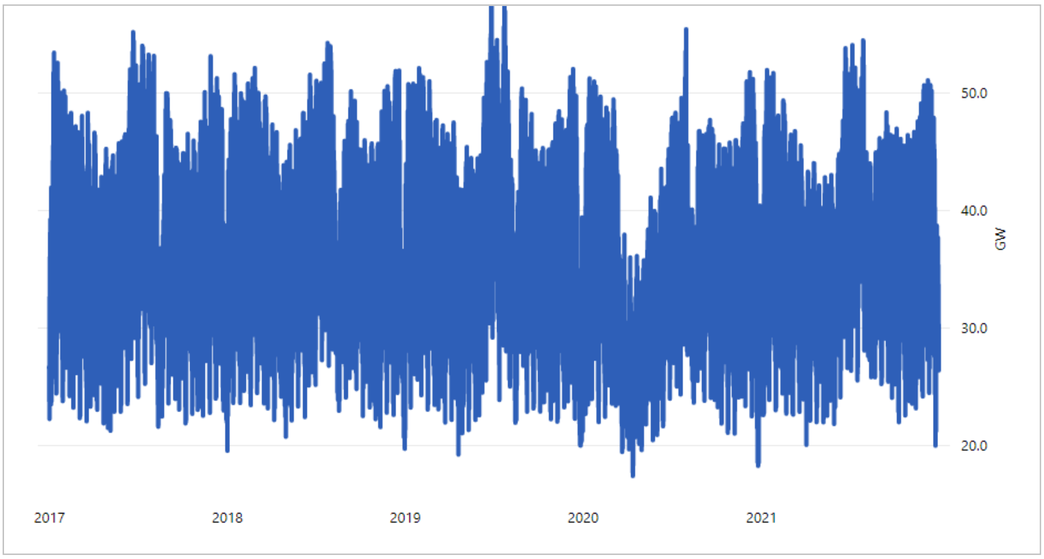



*Figure 11: actual Italian electricity demand profile during 2016-2021, TERNA*

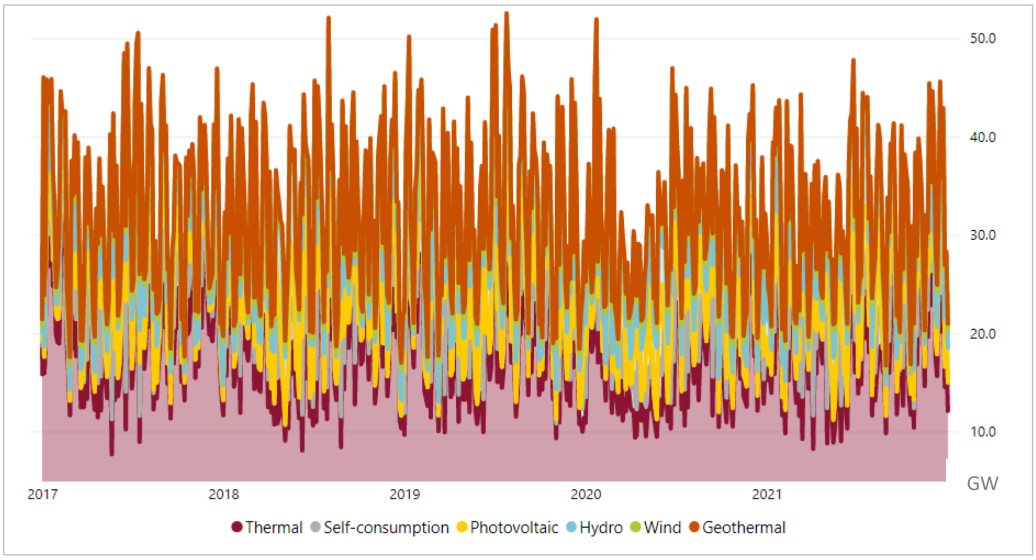



*Figure 12: actual Italian generation profile during 2016-2021, TERNA*

The decision to use the pre-pandemic period as the reference period was taken with the aim of recreating the usual operating conditions in the country, in the hope that such a phenomenon will not happen again.

The query dates for the procurement of this data were input in the system as follows:

- Start date: 1.1.2017
- End date: 31.12.2019
- Time zone (UTC+01:00)
- File format xml

### 4.1.1 Electricity demand

Electricity demand is one of the key inputs to the model. Literature is abundant with different electricity demand projections considering factors such as population growth, economic development, technology spill over, national and EU policies, amongst others.

The predicted electricity demand used for the current analysis is taken from the reference scenario of ISPRA (ISPRA, 2015), where three different scenario was simulated. A base scenario, which is a trend scenario at current legislation, a scenario with the maximum use of energy efficiency technologies with the same demand for energy services, and finally a scenario of high demand for these services. The resulting final electricity consumption are shown in Figure 13.

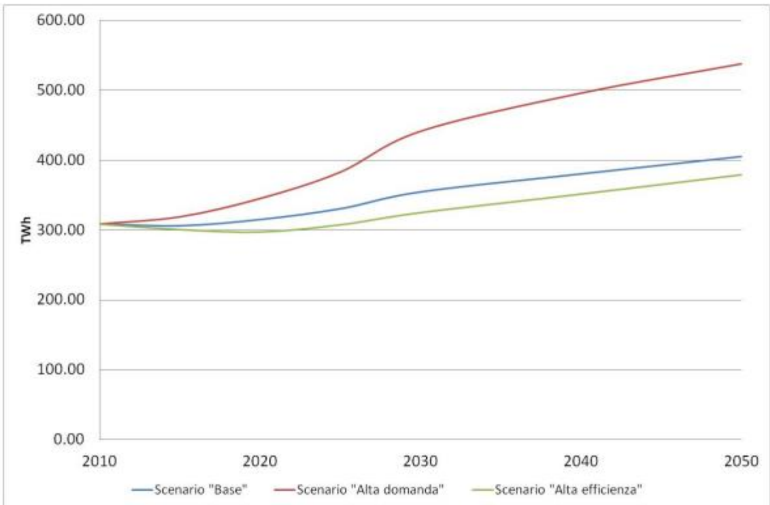



*Figure 13: predicted final electrical consumption*

It should be noted that the high demand scenario also incorporates consumption resulting from the hypothesis of the spread of electric cars and heat pumps for heating, both in the residential and tertiary sectors. These are three new "markets" for electricity with total consumption in addition to the increase in industrial production and demand for services. It should also be remembered that the "high efficiency" scenario does not only concern electrical consumption technologies but also thermal technologies, with a view to reducing overall energy consumption and emissions of greenhouse gases and pollutants. In the residential sector, in the tertiary sector and in part also in industry a possible strategy for reducing the consumption of fossil fuels is to replace them with electricity. The increase in electricity demand that is also seen in the "high efficiency" scenario is due to the implementation of this type of strategy. The reduction in overall emissions is achieved through production from renewable sources and CCS.

It should be noted that demand responses are not explicitly represented, with demand side measures expected to be captured in the assumed electricity demand growth rate.

*Table 2: National electrical consumption [TWh]*

| | 2010 | 2015 | 2020 | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|---|
| Base scenario | 309.2 | 306.5 | 315.4 | 330.7 | 354.6 | 380.2 | 404.9 |
| High demand scenario | 308.7 | 319.0 | 345.2 | 383.1 | 441.6 | 496.2 | 538.2 |
| High efficiency scenario | 308.0 | 300.3 | 296.9 | 307.2 | 324.6 | 351.2 | 378.8 |

For the purpose of this thesis, the demand of the base scenario was used as a reference, therefore demands of 354, 380 and 404 TWh in 2030, 2040 and 2050 are chosen as the electricity demands to which is then added a demand related to electric vehicles that will be explained in the next paragraph. The modelling of a separated EV demand allows the analysis of possible scenarios with a higher share of electric vehicles and for this reason it was chosen to refer to the base scenario, more conservative if compared to the high efficiency scenario, however more flexible than the high demand one. This assumption does not take into account, for example, the potential increase in electrification of space heating applications, which could significantly alter future load curves.

For the intra-annual variations in electricity demand, electricity load curves are implemented for the entire modelling horizon. To match the wanted electricity demand in the model it was necessary to scale the hourly electrical demand from the historical values (2017-2019).

By scaling the demand with appropriate constant, the sum of the electricity demand was scaled to the predicted value. The main concept of this scaling process is shown in (5):

$$\sum_{t=1}^{n} P_{d,historical} * X = D \quad (1)$$

Where:

- $P_{d,historical}$ is the original demand series [MWh/h]
- X is the scaling constant [-]
- D is the target future electricity demand, yearly [MWh]

The scale constant is calculated directly from the known sum of the historical hourly electricity demand (for the period 2017-2019) and the given predicted electricity demand value. This value is referring to a single year, so it is necessary to consider it three times in order to match the original demand series range, and it is an input of the model.

$$X = \frac{3 * D}{\sum_{t=1}^{n} P_{d,historical}} \quad (2)$$

For each individual hour it was then assigned a scaled demand, referring to the same scaling constant, as shown in (3):

$$P_{d,historical} * X = P_{D,t} \tag{3}$$

Where:

- $P_{D,t}$is the electricity demand used in the model at hour t

In the following subsection, the construction of the EV charging patter is described.

### 4.1.2 EV pattern

The EV charging distribution was based on (7) which was described by Quian et al (2011). This result is a generic charging distribution

$$f(x_{EV}, \mu, \sigma) = \frac{1}{\sqrt{2\mu\sigma^2}} e^{-(X_{EV}-\mu)^2/(2\sigma^2)} \tag{4}$$

Where:

- $x_{EV}$ is the time of the day, ranging from -11 (corresponding to 1 pm) to 12 (corresponding to noon)
- μ is the maximum charging starting time, which was 1 corresponding 1 am in the previous exercise model
- σ determines the shape of the function, which was set as 5 to correspond EVs, as in Qian et al. (2011)

The graph given by (4) is drawn in Figure 14.

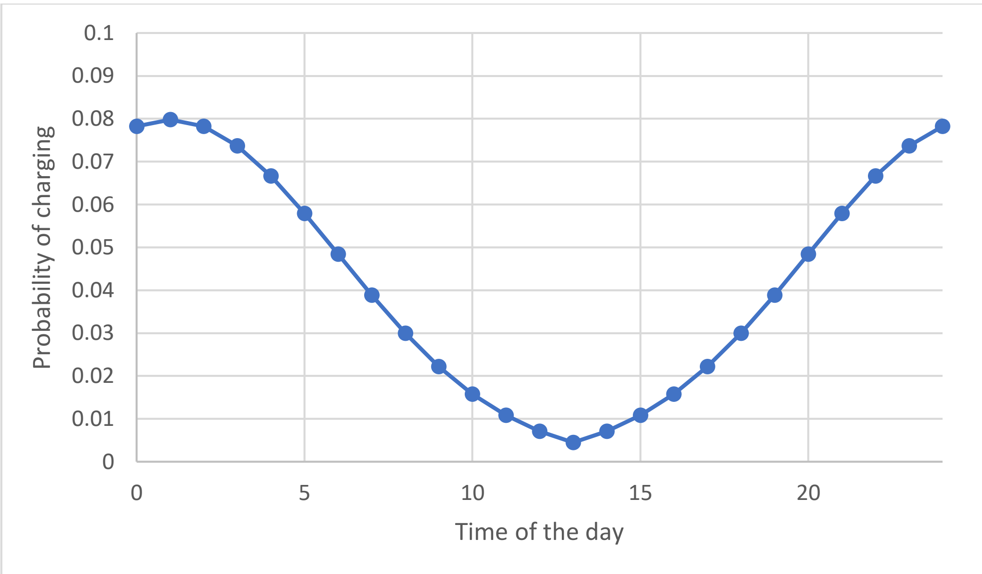



*Figure 14: The EV charging pattern*

By manipulating the density function variables manually, the EV demand profile has been constructed in such a way that, when added to the base demand, it would be distributed in the flattest way possible. This means that most of the recharges have been assigned during the evening and night, when the base load is lower.

The number of EVs was set to different numbers, depending on the scenario. The PNIEC foresees the investments in electric vehicles in 5-7 years, hence an overall diffusion of roughly 6 million of EVs, of which 4 million of pure EVs and 2 million of hybrid EVs, by 2030. Assuming this target is achieved, there will be 44 million vehicles circulating with 14% made up of EVs in 2030 (PNIEC, 2019).

The average charging time with a normal household charging power capacity of 3.3 kW was assumed to be around 1 hour, therefore, the charging power consumed per car at a given hour is given by multiplying the charging distribution profile of the car with the corresponding hourly energy need, i.e. 3.3 kWh. This description is a simplification and might not be very accurate since it is trying to predict the behaviour of a technology still scarcely used in Italy, and the actual usage could vary from the statistic regarding the internal combustion vehicles.

The final hourly EV demand is gained by multiplying the needed electrical energies obtained with the EV charging profile, with the amount of EVs in the scenario.

In Figure 15 it is possible to see how the total demand varies with the addition of the EV charging demand. It has been taken as an example an average summer day (both week and weekend day), period in which in Italy there is the highest demand for electricity.

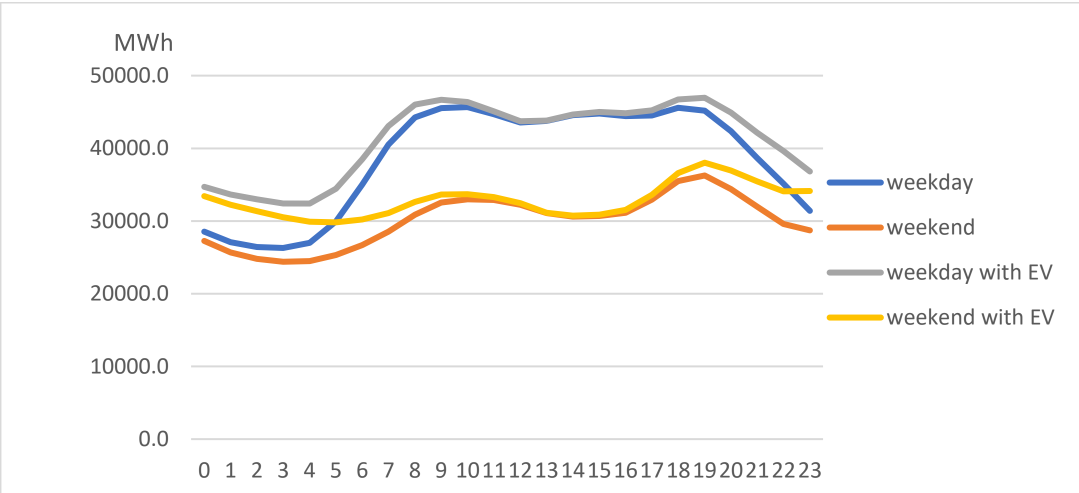



*Figure 15 electricity consumption with and without the addition of EV, on an average summer day*

Regarding the total amount of EVs in the different future scenarios, a value corresponding to 50% of the total Italian car fleet has been assumed for the 2040 scenario, and, for 2050, a complete coverage of the car fleet has been assumed (40 million), in order to evaluate the influence of an extreme distribution of this technology.

*Table 3: summary of the EV parameters used in the model*

| | 2030 | 2040 | 2050 |
|---|---|---|---|
| Number of EVs (mill) | 6 | 20 | 40 |
| EV charging demand (TWh/year) | 7 | 24 | 42 |

### 4.1.3 Power generation

This section describes how historical power generation data were used in the base model. Terna provides hourly data for each individual generation technology, and these data are used as the source data for the model. Then, for solar and onshore wind, these data set are multiplied by the corresponding scaling variable as follows:

$$P_{GRES,t} = (P_{GRES,2019,t} * \tau_{RES}) \quad (5)$$

$$RES \ni \{wind, solar\}$$

Where:

- $P_{GRES,t}$ is the power generation used in the model for wind and solar [MWh/h]
- $P_{GRES,2019,t}$ is the scaled input power generation for wind and solar [MWh/h]
- $\tau_{RES}$ is the scaling factor for wind onshore and solar [-]

The corresponding final capacities of installed wind and solar power generation are:

$$C_{RES,t} = (C_{RES,2019,t} * \tau_{RES}) \quad (6)$$

$$RES \ni \{wind, solar\}$$

Where:

- $C_{solar,2019}$ is the installed solar capacity in Italy in 2019, 22 GW
- $C_{wind,2019}$ is the installed wind onshore capacity in Italy in 2019, 10.8 GW

### 4.1.4 Wind offshore power production

The development of offshore wind in Europe has so far focused on the low-depth regions of the North Sea and Baltic Sea, with bottom-fixed turbines while the deployment of offshore technologies in the Mediterranean region is currently very limited and in Italy no offshore wind plant is installed yet. The current advances in floating offshore wind technology open up possibilities in regions of deeper waters, e.g., the Mediterranean Sea. An overview of the sea depth in Europe is visible in Figure 16. Significant exploitation of offshore wind resources in Italy is expected after 2030, using floating wind turbines, suitable for water depths greater than 50 m.

This technology is at the demonstration phase at present. Deployment in deep water is currently costly, but in this context, floating wind offers great potential for the development of marine renewable energy in the Mediterranean Sea (Soukissian TH, 2017). The accurate assessment of the wind climate is fundamental for the selection of potential areas given its considerable spatial variability in the region.

A particular area of interest for the development of marine renewable energy in the Mediterranean Sea, as can be seen in Figure 17, is its many islands, which are typically overdependent on fossil fuels. (Martinez, 2021).

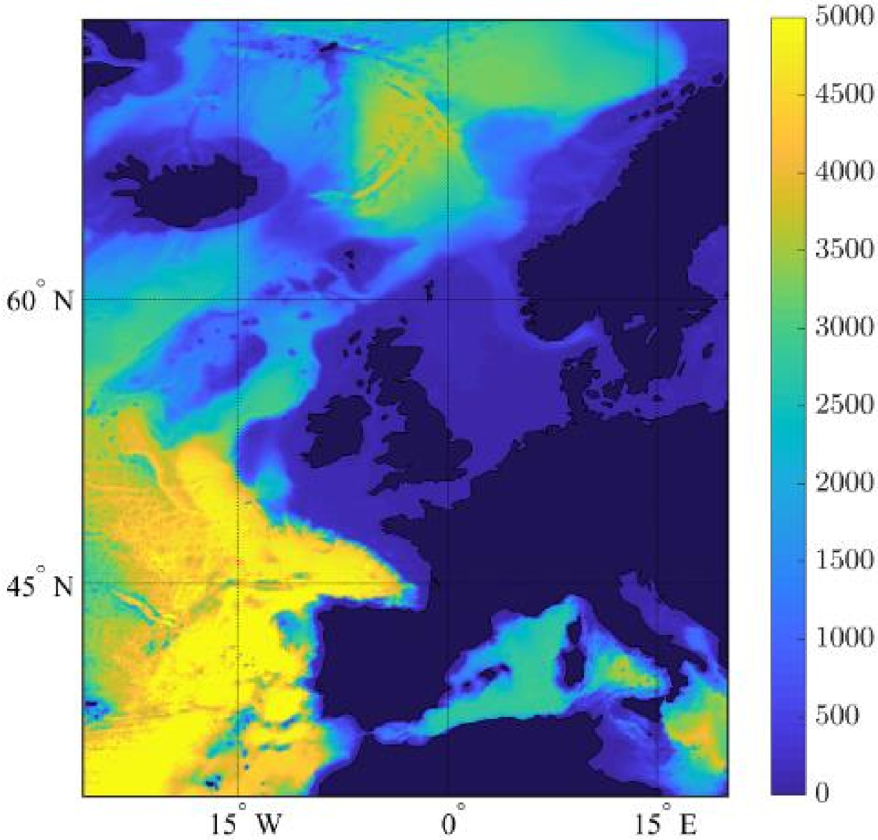



*Figure 16 Water depth (m) in Europe (Martinez, 2021)*

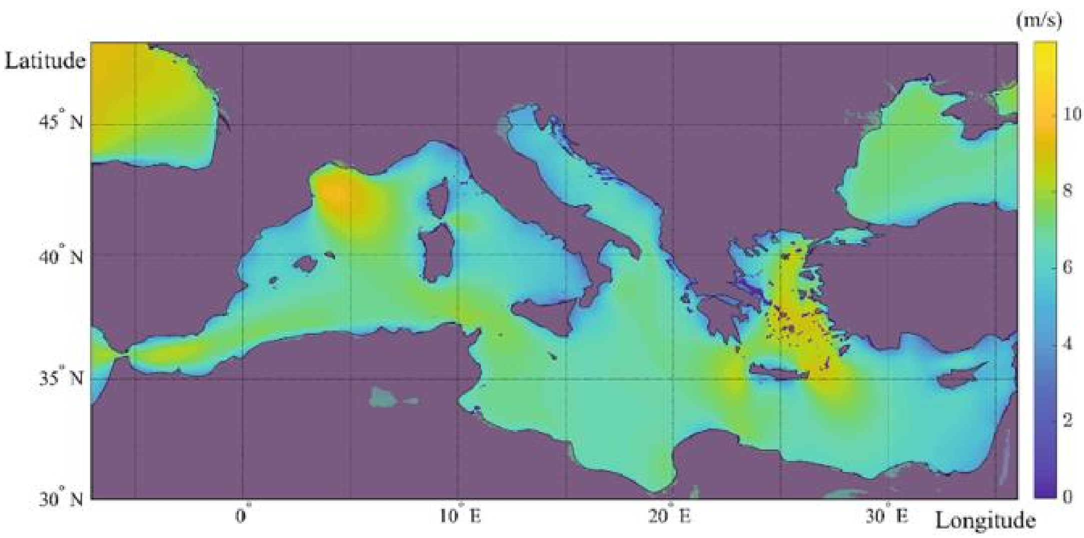



*Figure 17 mean wind speed (m/s) at 100 m height in the Mediterranean Basin (Martinez, 2021)*

In 2019 The PNIEC, Integrated National Energy and Climate Plan, has defined the ambitious goal of 300 MW of installed offshore wind power by 2025, to then triple in 2030 (PNIEC, 2019), however, despite this relatively limited target, as of December 2020 there were more than 5 GW of requests for connection to the high voltage electricity grid, some of these requests have yet to be processed and others have already been accepted, in particular in Emilia-Romagna, Puglia, Sardinia and Sicily. (TERNA, Piano di SViluppo, 2021).

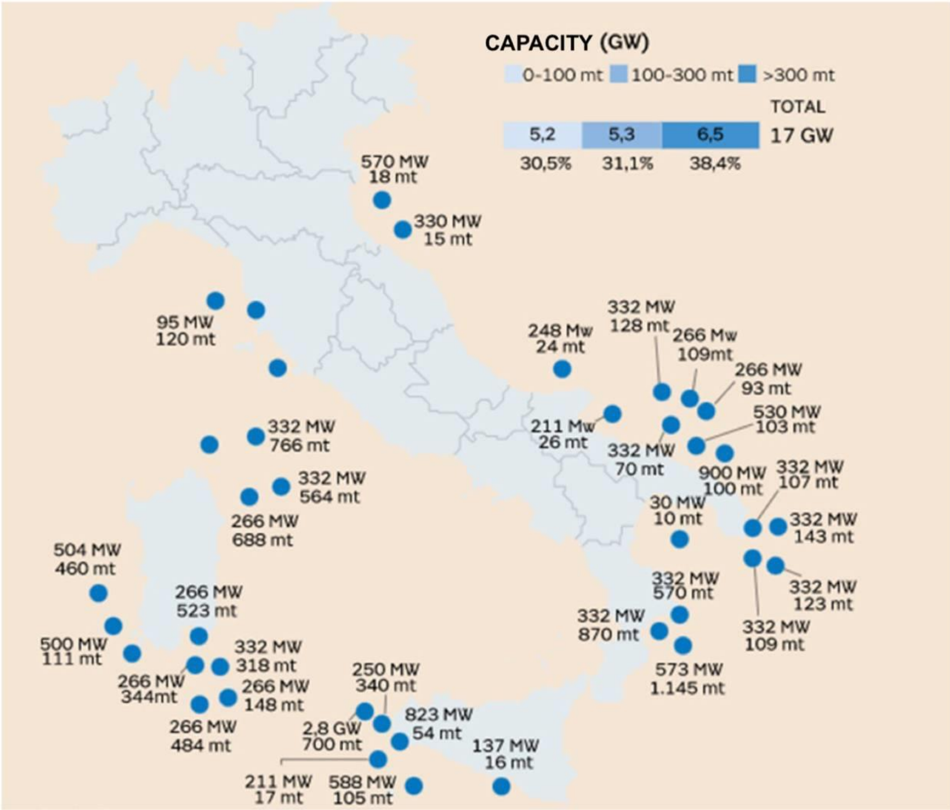



*Figure 18 detail location, power and depth of offshore requests (TERNA, 2019)*

The only Italian project currently under construction, involves the construction of ten 3 MW turbines off the port of Taranto. The wind farm will be made of bottom-fixed structures, since water depths varies between 3 and 18 m (Italian Ministry of the Environment, 2022). The first floating wind farm project involves the construction of a 250 MW wind farm, consisting of 25 turbines of 10 MW each, in the Sicilian channel, off the coast of Marsala, in one of the windiest areas of Italy. The wind farm will not be visible from the Sicilian coast as it will be installed in the direction of Tunisia 40 km from the coast, in order to reduce the environmental impact and visual pollution (Italian Ministery of Environment, 2022). Another project instead involves the construction of a 504 MW wind farm, consisting of 42 turbines of 12MW each, in the southwestern part of Sardinia, 35 kilometres from Portoscuso, in the province of Carbonia-Iglesias (Italian Ministry of the Environment , 2022). The project is currently undergoing administrative verification by the Italian Ministry of the Environment. Despite the high offshore potential available in Italy, there are several obstacles in the spread of offshore wind: first of all, the need for large capital investments, given the high costs of construction and maintenance of the wind farms; second, the time required to obtain the authorizations, which often require a very long time for approval. Furthermore, as the largest specialized companies in the sector are foreign, a major obstacle is the lack of a local supply chain capable of supporting the construction and development of new wind farms (Ghigo A., 2020).

For the purpose of this thesis, the Sicilian project was taken as a reference as representative of the Mediterranean situation. To implement in the model an hourly profile of generation from offshore wind, it has been identified the exact location dedicated to the installation of the wind farm and, with a dedicated online software, it has been downloaded the hourly power output by setting the technical characteristics of one single turbine with technical specifications corresponding to the project turbine. The selected turbine was the Vestas V164, 9.5 MW and its data sheet is reported in the Table 4 (Vestas, 2021).

*Table 4 technical specification of the selected floating wind turbine*

| **Vestas V165- 9.5 MW** | **Description** |
|---|---|
| Turbine | Horizontal axis |
| Power of a single turbine | 9.5 MW |
| Cut-in speed | 3 m/s |
| Cut-off speed | 25 m/s |
| Rotor diameter | 164 m |
| Swept area | 21 124 m$^2$ |
| Wind class | IEC S |

After developing the generation profile from a single offshore turbine, this hourly data set was used as well as for the historical onshore wind and solar data sets. Consequently, a dedicated offshore scaling variable is introduced to scale the newly created generation profile according to the needs of the model as follows:

$$P_{wind\ off} = (P_{Vestas} * \tau_{offshore}) \tag{7}$$

Where:

- $P_{wind,off}$ is the power generation used in the model for wind offshore [MWh/h]
- $P_{vestas}$ is the scaled input power generation obtained from the single offshore turbine [MWh/h]
- $\tau_{offshore}$ is the scaling factor for wind offshore [-]

Concerning the scaling factor $\tau_{offshore}$, it should be noticed that, since the downloaded profile is referring to a single turbine, it was necessary to set as a starting value greater than one, to simplify the model the finding of an exact solution that could take into account the existence of multiple wind farms. A coherent starting value was identified in 500, from which the model then started to search for the optimum. The related capacity for offshore wind is then calculated similarly to (6).

Wind and solar power capacities are therefore scaled using variables, which are changed during the modelling. These are determined for each scenario and, after being identified by the model, remain constants for whole temporal evolution of the scenario (3 years). Therefore, the wind and solar variables multiply the respective scaled time series, which results in the actual wind and solar generation within the model. In this way the capacity factors and consequently the hourly generation profile for wind and solar are assumed to remain the same also in future decades, with the only difference of being scaled to higher value, under the assumption of a perfect forecast.

### 4.1.5 Hydro power production

For hydro power, the power production as well as the installed capacity is assumed equal to the historical data across all the scenarios and the capacity is kept constant at 22.5 GW, (TERNA, 2020). This is considered to be constant since in Italy a significant growth of installed hydroelectric power is not foreseen in the next decades. It has to be noticed that in this historical production it is included also the net production from hydro pumped storage, that in Italy accounts for 4.4 GW installed and a yearly total production of around 2 TWh.

### 4.1.6 Nuclear power production

The Finnish model envisaged the use of only renewable resources and a large proportion of nuclear power to reach the carbon neutral target by 2050. For the Italian case nuclear power is a controversial topic and, given the current social and political position in this regard, it is not realistic to foresee the installation of such plants in the near future. Italy has had four operating nuclear power reactors with a total installed capacity of almost 2 GW, but all four plants were closed by 1990 following the Chernobyl accident. In addition, in June 2011, Italian nuclear referendum proposed to generate 25% of the country's electricity from nuclear power by 2030 (Ministro dell' Interno, s.d.), but was rejected by the population. Italy is now one of the few countries that completely phased out nuclear power for electricity generation after having operational reactors.

However, it was decided to try to include this technology in a separate dedicated scenario to study the behaviour of the model when there is a possibility of nuclear installation. In this scenario, as it will be better explained in the following chapter, a constant capacity of generation of Small Modular Reactors (SMR) can be added and it is included in the model variables so that the solver can determine how much capacity is needed. It is assumed that the SMRs run with a 95% efficiency of the nominal capacity during all hours.

### 4.1.7 Flexible power production

Bearing in mind that the objective of the thesis is to move towards a carbon neutral power system, as far as Italy is concerned, it is necessary to address the current significant production from fossil fuels. For this reason, it was deemed necessary to include this generation in the model, as it is currently covering around half of the total electrical production. The model was therefore given the ability to choose how much thermal capacity to install for each scenario and consequently the relative production while complying with the increasing targets for limiting $CO_2$ emissions. The upper limit of this kind of capacity was imposed equal to the installed capacity at 2020 (56 GW) from the perspective of reducing capacity rather than adding it. In this

way it is possible to see the gradual decrease in the use of this technology. This was done through a scaling variable similarly to the wind and solar generation. In addition, as will be better explained later, a dedicated scenario will be developed in which the use of carbon capture technology is included among fossil fuel plants. In this way, it is still possible to take advantage of the benefits offered by these plants in terms of flexibility without, however, failing to comply with GHG reduction constraints.
Concerning the installed capacities for geothermal, since Italy has an excellent availability of this resource an increase capacity from this technology is expected in the coming decades (Enel Green Power, 2021) as shown in Table 5, while for biomass the installed capacity (3760 MW) has been maintained the same for all scenarios, as a significant increase in this resource is not expected (TERNA, 2021).

*Table 5 expected installed capacity of geothermal technology*

| Year | Installed capacity [MW] |
|---|---|
| 2020 | 770 |
| 2030 | 1100 |
| 3040 | 1800 |
| 2050 | 2300 |

Regarding the production of these technologies (biomass, geothermal and thermal from fossil fuels), it has been decided to consider them as deferrable generations. This has been done since the major advantage of these technologies is their constant availability and most importantly their flexibility; in this way the model is able to modulate the production according to the need, up to a maximum established by the already mentioned installed capacity.
The mathematical approach for modelling the power production from these flexible technologies will be better explained in the next paragraph.

### 4.1.8 Electricity import and export capacity

Import and export capacities determine the maximum hourly values for electricity import and export. These values differ according to the year in question in the scenarios. The values of transmission capacities concerning 2030, 2040 and 2050 are increased according to the values presented in the "Piano di Sviluppo 2021" where the import capacity is expected to grow of 1500 MW in the short term and of 12 GW in the long term (Arera, 2021).
The import and export capacities are shown below in Table 6.

*Table 6 import capacities assumed for different years*

| Year | Import Capacity [MW] | Export Capacity [MW] |
|---|---|---|
| 2020 | 10000 | 5000 |
| 2030 | 16000 | 10000 |
| 2040 | 20000 | 15000 |
| 2050 | 23000 | 18000 |

### 4.1.9 Storage

This variable defines what the electrical storage size is, in terms of the maximum amount of electrical production [GWh], that can be utilized in the modelling. This variable is also changed while the modelling is done and checked whether the storage size results in a feasible solution.

For the purpose of this thesis, the storage is assumed to consists entirely of electrochemical batteries. this assumption was made for the sole intention of simplifying the model, allowing a single cost assumption to be made for this type of technology. In reality, multiple types of storage are currently available on the market, each with their own limitations and advantages.

The energy storage technologies can be divided into mechanical, electrical, thermal, and chemical energy storages. Electrochemical storage options include batteries such as lead-acid batteries, sodium-sulphur batteries, and lithium-ion batteries. These mature technologies can be very useful in the short term but have not yet been developed on a large scale, as they have several limitations such as short life cycles and resource consumption. An alternative storage technology could be represented by the flow batteries; however, they are still under development for what concerns large-scale but might be suitable in the future (IEA, 2016).

Among the electrochemical storages, fuel cells are a valid option for long-term storages of electricity. This technology consists into the production of hydrogen from electricity, in order to storage in a different form the surplus of electricity that could be present in a significant amount if a high share of variable renewable capacity is installed. Moreover, due to the reversibility of fuel cells, it is also possible to generate again electricity again from hydrogen, but this process will be affected by a low round-trip efficiency.

For what concerns mechanical storages, instead, a valid option is represented by Compressed Air Energy Storage (CAES). This technology consists into exploiting the surplus of electricity to compress air into an underground cavern or another storage container. The main limit of this very promising and efficient technology is however the dependency on the location, as it is preferable to employ an already existing natural storage which would allow to significantly reduce the capital cost.

# Chapter 5

# Modelling approach

The components of the model are both fixed and dynamic. The fixed objects are such, that they are calculated instantly after the initial parameters are input, and only depend on the initial data. The fixed components in the model are the fixed generation and the power demand. The dynamic components on the other hand are such, whose values depend either directly or indirectly on the values of the fixed components. These are the flexible production, power import, and the operation of the electricity storage.

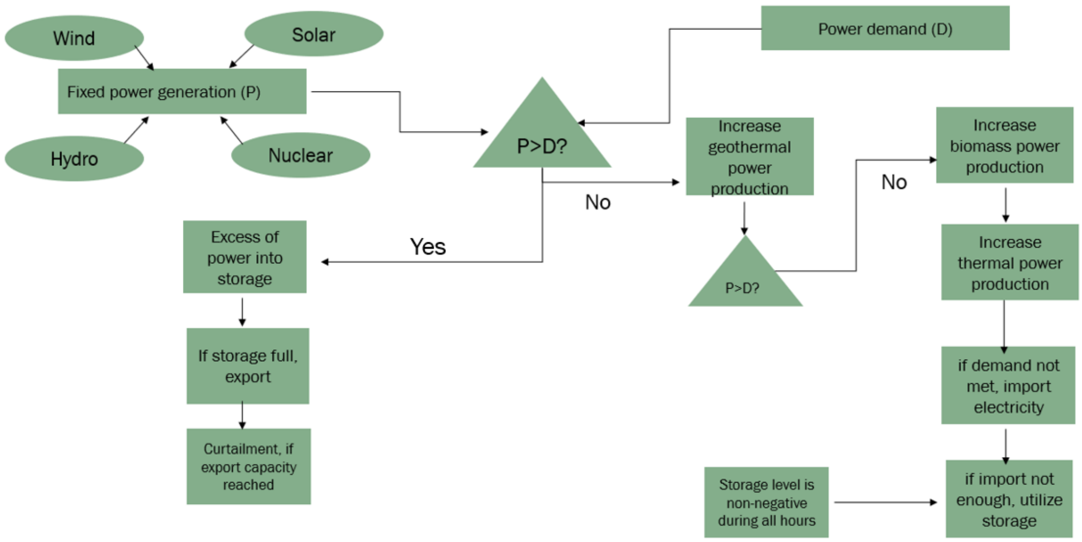



*Figure 19 flow chart of the model, representing the main concept behind it*

The fixed generation, consisting of hydro, solar and wind is initially compared to the energy demand. Subsequently, if the demand is not satisfied by the fixed generation, we draw on the variable production, with priority given to geothermal and biomass over thermal, in order to meet the limits dictated by the maximum amount of CO2 emissions allowed for each scenario.

If not even with the use of all deferrable generations the energy demand is met, then electricity is imported from abroad, limited by the transmission capacity imposed in each scenario. In the case the equilibrium is not reached even with the import, then it is used the electrical storage, which will be sized accordingly by the model.

On the contrary instead, if the production of energy exceeds the demand, the excess of energy can be transferred to the storage, until its complete recharge. Finally, if the storage is not able to accommodate all the production surplus because the limit charge level has been reached, energy is exported.

In this model, however, the export has not been considered because the aspect related to the export market and the related revenues is highly variable and complex, especially in the case of

Italy, which is historically not an exporting country. Consequently, the surplus of energy has been considered curtailed. It could be discussed later, on the basis of the consistency of the latter, the possibility of export or sector coupling.

## 5.1 Variables

In the following Table the summary of used variables is shown. These are variables, which are solved in the Excel solver in order to produce the scenarios.

*Table 7: summary of used variables*

| Variable | Symbol |
|---|---|
| Solar scaling variable | $\tau_{\mathrm{solar}}[-]$ |
| Wind On-shore scaling variable | $\tau_{\mathrm{wind,on}}[-]$ |
| Wind Off-shore scaling variable | $\tau_{\mathrm{wind,off}}[-]$ |
| Thermal scaling variable | $\tau_{\mathrm{thermal}}[\mathrm{MW}]$ |
| Electricity storage variable | $\mathrm{E}_{\mathrm{s,max}}[\mathrm{MWh}]$ |
| SMR variable | $\mathrm{C}_{\mathrm{SMR}}\ [\mathrm{MW}]$ |

## 5.2 Mathematical equations

In this section, the mathematical description of the model is shown, and the different constraints are explained, highlighting how the variables can be manipulated.

The main constraint for the power system model is the hourly power balance that establishes the equivalence of electricity supply (storage, generation and transmission) and electricity demand at each hour (and possible curtailment for excessive generation). Therefore, for each hour the following equation must hold:

$$P_{D,t} + P_{S,t} + P_{SL,t} + P_{CL,t} = P_{G,t} + P_{I,t} \qquad \forall\, t \tag{8}$$

Where:

- $P_{D,t}$ is the power demand at hour *t* [MWh/h]
- $P_{S,t}$is the power consumed by storage (negative for supplied) at hour *t* [MWh/h]
- $P_{SL,t}$ is the storage losses at hour *t* [MWh/h]
- $P_{CL,t}$is the curtailed power at hour *t* [MWh/h]
- $P_{G,t}$ is the total power generation for hour *t* [MWh/h]
- $P_{I,t}$ is the power import [MWh/h]

Also, an hourly power balance expression is considered in the model, where the storage is not considered. The balance is expressed as shown in the equation below

$$P_{B,t} = P_{I,t} + P_{G,t} - P_{D,t} \qquad \forall\, t \tag{9}$$

Where:

$P_{B,t}$ is the power balance at hour *t* [MWh/h]

The power generation is composed of fixed power generation and dispatchable power generation. The fixed generation is determined at the beginning of the modelling and is the sum of power from wind, solar, hydro and nuclear (when admitted) at hour t. Dispatchable power generation instead is calculated depending on the resulting power balances and it consists in the power generation from biomass, geothermal and thermal from fossil fuel

Mathematically, power generation at hour *t* is defined as follows:

$$P_{G,t} = P_{Gwind,t} + P_{Gsolar,t} + P_{Gnuclear} + P_{Gbiomass,t} + P_{Ggeothermal,t} + P_{Gfossil,t} \quad \forall\, t \tag{10}$$

Where:

- $P_{Gwind\ On,t}$ is the onshore wind power production at hour *t* [MWh/h]
- $P_{Gwind\ Off,t}$ is the offshore wind power production at hour *t* [MWh/h]
- $P_{Gsolar,t}$ is the solar power production at hour *t* [MWh/h]
- $P_{Gnuclear,t}$ is the nuclear power production at hour *t* [MWh/h]
- $P_{Gbiomass,t}$ is the biomass power production at hour *t* [MWh/h]
- $P_{Ggeothermal,t}$is the geothermal power production at hour *t* [MWh/h]
- $P_{Gfossil,t}$ is the thermal from fossil fuel power production at hour *t* [MWh/h]

Later, the sum of the fixed power generation (wind, solar, hydro, nuclear) is referred to as $PG_{fixed,t}$ [MWh/h].

For what concerns the flexible power generation from biomass, geothermal and natural gas, it is calculated accordingly to the need, up to the maximum capacity defined by the scenario, as explained in section 4.1.7. The mathematical expression is the following:

$$\begin{cases} P_{geo,t} = MIN\,(P_{D,t} - PG_{fixed,t}\,; P_{max,geo})\ if\ PG_{fixed,t} \le P_{D,t} \\ P_{biom,t} = MIN\,(P_{D,t} - \left(PG_{fixed,t} + P_{geoth,t}\right); P_{max,biom})\ if\ PG_{fixed,t} + P_{geo,t} \le P_{D,t} \\ P_{therm,t} = MIN\,(P_{D,t} - \left(PG_{fixed,t} + P_{geo,t} + P_{biom,t}\right); P_{max,therm}) \\ \quad if\ PG_{fixed,t} + P_{geo,t} + P_{biom,t} \le P_{D,t} \end{cases} \tag{11}$$

Where:

- $PG_{flexible,t}$ is the energy production from flexible technology [MWh/h]
- $P_{geo,t}$is the energy production from geothermal technology [MWh/h]
- $P_{biom,t}$ is the energy production from biomass technology [MWh/h]
- $P_{therm,t}$ is the energy production from thermal (NG) technology [MWh/h]
- $P_{max,geoth}$ is the maximum geothermal capacity, according to the scenario [MW]
- $P_{max,biom}$ is the maximum biomass capacity, according to the scenario [MW]
- $P_{max,therm}$ is the maximum thermal capacity at 2020 [MW]

With regard to thermal production from natural gas, a rump up time equivalent to 50% of the installed capacity has also been considered, in order to make the production profile more realistic and to avoid going from zero to full load in consecutive hours.

### 5.2.1 Electricity storage

This framework allows to model the electricity storage behaviour and describes how it charges and discharges for each hour. The only constraint is that the electricity storage cannot be negative, and that it cannot store more electricity than it has the capacity for.

The electricity storage equations are as follows:

$$\begin{cases} P_{S,t} = MIN\left(P_{B,t} * \eta_{s,charging}, P_{chargecap}\right) \ if P_B \geq 0 \\ P_{S,t} = MAX\left(\frac{P_{B,t}}{\eta_{s,discharging}}, P_{dischargecap}\right) \ if P_B < 0 \end{cases} \quad \forall\, t \qquad (12)$$

Where:

- $\eta_{s,charging}$ is the charging efficiency: 85%
- $\eta_{s,discharging}$ is the discharging efficiency of the electricity storage: 95%
- $P_{chargecap}$ is the maximum charging power of the storage [MW]
- $P_{dischargecap}$ is the maximum discharging power of the storage [MW]

The charge and discharge limits could be manually imposed by the user, if wished, in this thesis no charge or discharge capacity was imposed on the model directly so they can be considered as infinite. In this way the capacity of the electricity storage is determined as a variable in the model. The level of stored energy at time *t* is equal to the level at time *t-1* plus the charging power absorbed by the storage at hour *t* (negative if supplied), considering charging and discharging efficiencies. The level of the electricity storage is determined by the following electricity storage charge level equations

$$E_{S,t} = \begin{cases} MIN\ (E_{S,max}; E_{S,initial} + P_{S,t} * 1h)\ if\ t = 1 \\ MIN\ (E_{S,max}, E_{S,t-1} + P_{S,t} * 1h) \end{cases} \quad \forall\, t \qquad (13)$$

Where:

- $E_{S,t}$ is the electricity storage level at hour t [MWh]
- $E_{S,initial}$ is the electricity storage level at the beginning of the modelling [MWh]
- $E_{S,max}$ is the capacity of the electricity storage [MWh]

### 5.2.2 Electricity import and export

Import takes place only if power generation is not adequate to meet the demand, therefore electricity is imported during that hour. The amount of electricity import is determined by the electricity deficit, and it is limited by the import capacity.

The decision to prioritize import over storage usage was also made on the basis of the Regulation on the Governance of the Energy Union (2018/1999) in which EU set an interconnection target of at least 15% by 2030 to promote EU countries to interconnect their installed electricity production capacity (European Commission, 2019). This means that each country should allow at least 15% of the electricity produced in its territory to be transported by electric cables across its borders to neighbouring countries. As already addressed however, the targets of installed interconnection capacity used in the model has been limited by the values presented in section 4.1.8.

For what concerns the export, priority has been given to the charging of the storage, and only when storage reaches maximum capacity, the export is allowed. The term $\delta$ ensures exactly that the electricity storage is fully charged if there is enough power to do so, and only subsequently the amount of export can be calculated. the electricity export is also limited by the export capacity mentioned in section 4.1.8. Hourly electricity import or export values are determined by (13).

$$P_{I,t} = \begin{cases} MIN\ (P_{D,t} - P_{g,t}\ ; P_{importcap})\ if\ P_{g,t} \leq P_{D,t} \\ MAX\ \left(MIN(P_{G,t} - P_{D,t} +\ \delta; 0)P_{exportcap}\ \right)\ if\ P_{g,t} > P_{D,t} \end{cases} \quad \forall t \tag{14}$$

Where:

$$\delta = (E_{S,t-1} - E_{S,max}) /\ \eta_{s,charging}$$

## 5.3 Objective function

The objective function of the model is chosen to be the minimization of the levelized cost of energy (LCOE), also referred to as the levelized cost of electricity. The National Renewable Energy Laboratory states that LCOE is a measurement used to assess and compare alternative energy-producing projects and to determine whether a project will be a worthwhile venture, determining if it will break even or be profitable. The LCOE of an energy-generating asset can be thought of as the average total cost of building and operating the asset per unit of total electricity generated over an assumed lifetime. Alternatively, the levelized cost of energy can be thought of as the average minimum price at which the electricity generated by the asset is required to be sold in order to offset the total costs of production over its lifetime (NREL, 1995).

The objective function is therefore:

$$\min_{\tau_{solar}, \tau_{windON}, \tau_{wind\ OFF}, \tau_{thermal}, C_{storage}, C_{SMR}} LCOE \tag{15}$$

Where:

- $\tau_{solar}$is the scaling factor for solar [-]
- $\tau_{wind\ ON}$is the scaling factor for onshore wind [-]
- $\tau_{wind\ OFF}$is the scaling factor for offshore wind [-]
- $\tau_{thermal}$is the scaling factor for thermal from fossil fuel (NG) [-]
- $C_{storage}$is the capacity of the electricity storage. Sets the value of $E_{S,max}$[MWh]
- $C_{SMR}$is the total capacity of the Small Modular Reactor [MW]

## 5.4 LCOE

The LCOE for individual technologies is based on the equivalence of the present value of the sum of discounted revenues and the present value of the sum of discounted costs. The discount factor is made up of discount rate, and technology-specific lifetime. All variables are real, i.e. net of inflation and residual dismantling and decommissioning costs are not considered in this analysis. The LCOE was determined for each generation technology as formulated by the International Energy Agency (IEA, Projected cost of generating electricity, 2020):

$$\sum P_{MWh} * E_{t,n} * (1+r)^{-n} = \frac{\sum_n (Capital_t + O\&M_{t,n} + Fuel_{t,n} + Carbon_{t,n}) * (1+r)^{-n}}{\sum E_{t,n} * (1+r)^{-n}} \tag{16}$$

$technology \ni \{wind, solar, hydro, geothermal, biomass, thermal, nuclear, storage, transmission\}$

Where:

- LCOE: levelized cost of electricity of the selected technology [€/MWh]
- $P_{MWh}$: the constant lifetime remuneration to the supplier for electricity [€/MWh]
- $Capital_t$: overall capital cost of the selected technology [€/MW]
- $O\&M_t$: overall operational and maintenance cost of the selected technology [€/MWh]
- $Fuel_t$: fuel cost of the selected technology [€/MWh]
- $Carbon_t$: emission cost of the selected technology [€/MWh]
- $E_t$: yearly power production of the selected technology [MWh]
- n: lifetime of the selected technology [years]
- t: corresponding technology
- r: discount rate in percentage [-]

Because $P_{MWh}$ is a constant over time, it can be brought out of the summation, and Equation (1) can be transformed into:

$$LCOE_t = P_{MWh} = \frac{\sum_n (Capital_t + O\&M_{t,n} + Fuel_{t,n} + Carbon_{t,n}) * (1+r)^{-n}}{\sum E_{t,n} * (1+r)^{-n}} \tag{17}$$

In this equation, it is not the MWhs that are being discounted; it is the revenue from those MWh that is being discounted. Revenue today has more value to the investor or owner than revenue tomorrow. It is not output per se that is discounted, but its economic value. This is standard procedure in cost-benefit accounting.

For what concerns the LCOE of the entire system, it was calculated by summing up the technology-wise LCOE costs weighted among the yearly electrical demand of the scenario. In this way the share of each technology was relative to the actual energy dispatched, net of curtailed energy. This thesis assumes a uniform discount rate of 5% for all technologies This was analysed in further details in the sensitivity analysis section.

The final LCOE of the total system is calculated as following:

$$LCOE_{system} = \sum_{technology} \left( \frac{C.annual_t + O\&M_{t,n} + Fuel_{t,n} + Carbon_{t,n}}{d * 10^6} \right) \tag{18}$$

Where:

- C. annual: is the annuity of the capital cost, calculated throughout the lifetime of the technology by means of the discount factor as following:

$$C.annual = Capital\ cost * \left(\frac{r(1+r)^n}{(1+r)^n-1}\right) \tag{19}$$

- d is the total yearly demand [TWh]

All the different costs are influenced by the size of the individual units, with economies of scale typically reducing costs at larger scale. Despite the very modular nature of solar PV and wind turbines, costs can typically be reduced by building wind or and solar farms. This modularity aspect leads to a large range of LCOE values for renewable technologies. Although utility-size power plants often have plant-level costs that are comparable to conventional power plants, smaller plants can still be several times more expensive. In Europe, both onshore and offshore wind as well as utility scale solar installations are competitive to gas and nuclear energy.

Contrary to the increasing price of fossil and nuclear fuels, the levelized cost of electricity (LCOE) from renewable energy is continuously decreasing. This is due to innovative technological development, more efficient materials and production processes and a general reduction of costs related to the renewable industry, of which solar photovoltaics is a part.

## 5.5 Costs of components

In this next section the individual costs for each technology will be analysed.

### 5.5.1 Capital cost

In this thesis, capital cost is considered as "greenfield" and "overnight" investment cost, comprising the construction of a power plant**.** More specifically, greenfield is the planning assumption, meaning that there is no existing capacity, and everything is built. Overnight refers to the fact that the building time is not considered.

This thesis makes no assumption about financing cost and sources of capital as these are highly specific to the individual investor. Deconstruction of a plant is not included in the cost estimate, an exception is made for nuclear power, where deconstruction is more complicated and therefore is included in capital cost as upfront deposit payment. The capital cost of each generating technology was calculated as the total installed capacity for each technology (MW) multiplied for the specific cost of the selected technology (€/MW). These costs are scenario dependent as they are expected to decrease within decades. The capacities for hydro power and biomass are mostly the same in all scenarios, as they are not expected to vary much in the near future, geothermal capacity was made to grow slightly according to forecasts of ENEL (Power, s.d.) in order to study a system that would best exploit the Italian potential of this generation technology, whereas nuclear capacity depends on the scenario. Wind, solar, thermal and electricity storage capacity are variables, so their capacities are determined directly by the model. The investment cost is determined as following:

$$C_{total} = \sum_{technology} C_{technology} * c_{technology} \quad (20)$$

$technology \ni \{wind, solar, hydro, geothermal, biomass, thermal, nuclear, storage, transmission\}$

Where:

- $C_{total}$ represents the total system investment [€]
- $C_{technology}$ represents the capacity of the selected technology [MW]
- $c_{technology}$ represents the cost of the selected technology [€/MW]

The technology costs are scenario dependent, and they will be described below in great details. The capacities for hydro and biomass are the same for all scenarios while wind (both onshore and offshore), solar, nuclear, thermal and storage capacity are variable, therefore they are determined directly by the model.

Variable capacities for wind and solar are calculated based on the installed capacity referred to the 2020 as already explained in paragraph 4.1.3.

The installed transmission capacity varies according to the scenarios and is referred to in the table in the section 4.1.8. An additional transmission capacity, related to the storage, is however to be taken into account and refers to the largest charge or discharge value for the storage system, needed to sustain the power balance. If a storage capacity is installed, the transmission capacity is also increased.

Mathematically this can be described as follows

$$C_{transmission} = C_{scenarios} + MAX\left(\left|E_{s,t} - E_{s,t-1}\right|\right) \quad (21)$$

Where:

- $C_{transmission}$ is the total transmission capacity needed to be installed [MW]
- $C_{scenarios}$ is the transmission capacity related to the grid only, according to the predicted scenarios [MW]

A detailed description of the different costs utilized in the model is given:

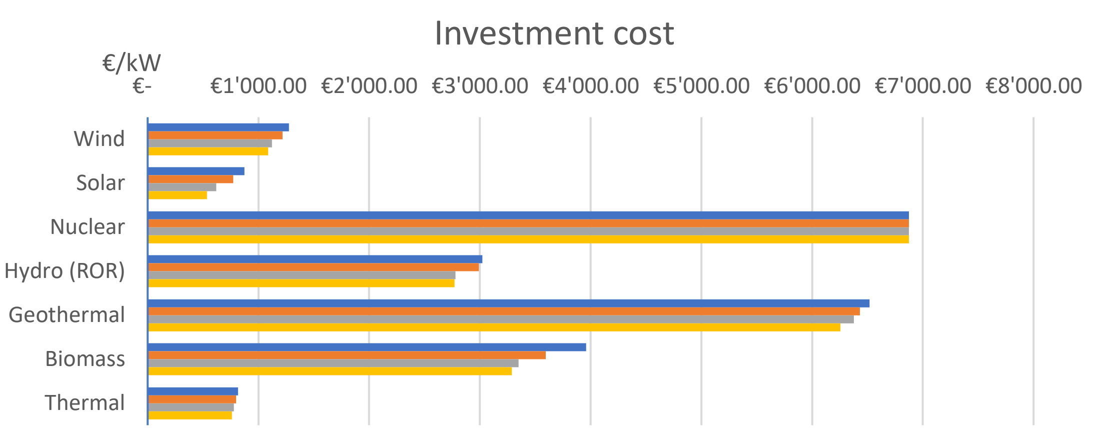
- Concerning solar PV generation, according to IEA (IEA, 2020), the global capacity weighted-average total installed cost of utility-scale projects commissioned in 2020 was 870 €/kW (13% lower than in 2019 and 81% lower than in 2010). Solar PV total installed cost reductions are related to various factors, the key drivers of lower module costs are the optimisation of manufacturing processes, reduced labour costs and enhanced module efficiency. The Joint Research Center predicts the PV costs to decrease to around 536 €/kW in 2050 (JRC, 2017)
- For wind generation, the total installed cost of onshore wind projects fell by 74% between 1983 and 2020, from 4507/kW to 1300 €/kW, based on data from the IRENA Renewable Cost Database. With no fuel costs, the capacity factor and cost of capital have a significant impact on LCOE, according to the JRC predictions, the capital cost in 2050 should fall to 1088€/MWh.
- The deep waters of the Mediterranean Basin impede the large-scale deployment of bottom-fixed technologies. Far less constrained by water depth are floating offshore

wind technologies; spar-buoys, tension-leg platforms and semi-submersible platforms; these technologies, however, have a higher cost compared to the bottom-fixed.

- Hydropower is a capital-intensive technology, often requiring long lead times, with this especially true for large capacity projects. The construction of hydropower projects varies in size and properties, influenced by the location of the project. There are also key technical characteristics which determine the type and size of turbine used. For the Italian case, it was assumed an average cost regarding the run of a river kind of technology of about 3000 €/MWh, according to IEA, since it is the most exploited hydro generation plant in the nation. This price is predicted to slightly decrease to 2770 €/kW in 2050, as stated by JRC.
- Geothermal plant installed costs are highly site-sensitive, having more in common in this respect with hydropower projects. Geothermal power projects costs are heavily influenced by the reservoir quality, the type of power plant and the number of wells required. The nature and extent of the reservoir, the thermal properties of the reservoir and its fluids — and at what depths it lies — will all have an impact on project costs. The total installed costs of geothermal power plants also include the costs of exploration and resource assessment (including seismic surveys and test wells), as well as drilling costs for the production and injection wells. Total installed costs also include field infrastructure, geothermal fluid collection and disposal systems and other surface installations. Based on the data available in the IRENA Renewable Cost Database, (IRENA, Power Generation Cost , 2020) (Hanward, 2017) installed costs from 2010 onwards have generally fallen within the range of 1720 €/kW to 6820€ /kW, and, according to IEA, for the Italian case, the average cost could be assumed as around 6500 €/MWh. The predicted cost in 2050 is supposed to decrease slightly to 6255 €/MW, according to JRC.
- The main categories in the total investment costs of a biomass power plant are: planning, engineering and construction costs; fuel handling and preparation machinery; and other equipment (*e.g.,* the prime mover and fuel conversion system) whom costs tend to dominate. Additional costs are derived from grid connection and infrastructure. For what concerns Italy, according to IEA an average value was identified as 3960 €/kW. In the power sector, bioenergy projects are predominantly small scale, with the majority of projects under 25 MW in capacity. There are, however, clear economies of scale evident for plants roughly above the 25 MW level. The predicted cost in 2050 is supposed to decrease slightly to 3290 €/MW, according to JRC
- According to Terna's statistics, most of Italy's thermoelectric power plants are fired by natural gas (75% of total thermoelectric power in 2020) and coal (15%). For this thesis, a capital cost relative only to natural gas plants has been considered, given that the complete phase-out of coal is expected within the next decade. the technology most present in Italy is the combined cycle (CCGT), for which steam and combustion turbines are combined in sequential cycles. Total capital costs for agas-fired combined cycle plant range between 625 EUR/kW for conventional types and 1210 EUR/kW for advanced CCGT plants. For the Italian case, a value of 815 €/KW was assumed, according to the IEA, expected to decrease to 760 €/kW in 2050, according to JRC.

- For nuclear power, construction costs of the Finnish nuclear plant Olkiluoto 3 are used as a reference, with a price of nuclear of 6875 €/kW. This price is very conservative, as this includes the total costs incurred by the project.
- The predicted cost of batteries, according to Hanward & Graham (Hanward, 2017) is expected to be 260€/KWh in 2030, 212€/KWh in 2040 and 173 €/KWh in 2050. It should be noted that the values are for batteries which may not be suitable for large-scale deployment in all scenarios.
- In order to estimate the costs of new electricity transmission capacity, the construction costs of the Finnish transmission line Rannikkolinja were used as a reference (Fingrid, 2017), as in the thesis of the doctoral student, Tero Koivunen. This choice was made because among the few Italian projects in construction at the moment, concerning the transmission network, they all included additional costs such as the dismantling of old lines or the construction of submarine lines, which caused an increment of the cost of about 4 times and thus compromise the validity of the model. Therefore, transmission was assumed to cost 325 €/kW.

The predicted costs reduction for the next decades are summarized in Figure 20:




| | Thermal | Biomass | Geothermal | Hydro (ROR) | Nuclear | Solar | Wind |
|---|---|---|---|---|---|---|---|
| 2020 | €815.43 | €3'960.00 | €6'520.00 | €3'023.45 | €6'875.00 | €874.79 | €1'275.00 |
| 2030 | €799.00 | €3'596.00 | €6'432.00 | €2'990.00 | €6'875.00 | €772.50 | €1'219.00 |
| 2040 | €779.68 | €3'350.00 | €6'378.00 | €2'781.00 | €6'875.00 | €620.00 | €1'123.00 |
| 2050 | €762.13 | €3'290.00 | €6'256.00 | €2'771.00 | €6'875.00 | €536.00 | €1'088.00 |

*Figure 20: summary of the capital cost prediction for each generation technology.*

### 5.5.2 Operation and maintenance costs

Operation and maintenance costs (O&M) can be divided in two categories: fixed and variable costs. Fixed operational and maintenance cost (O&M costs) are incurred regardless of the plant generating electricity; they are comprised of personnel salaries, security costs, insurance etc. and they are proportional to the installed capacity.  Variable O&M costs are directly linked to the generation of the power project and for this reason they vary with the power production, therefore they are typically calculated per unit of electricity generated (per MWh). For such renewable generation technology as solar, wind, hydro and geothermal it was assumed a null variable cost. These costs are determined as follow

$$C_{O\&M} = \sum_{techn.}\left[\sum_{t=1}^{26280}\left(P_{Gtechn.} * c_{variable\ O\&M,techn.}\right) + C_{techn.} * c_{fixed\ O\&M\ ,techn.}\right] \quad (22)$$

$$technology \ni \{wind, solar, hydro, nuclear, thermal\}$$

Where:

- $P_{Gtechn.}$ is the power production with selected technology at hour t [MWh/h]
- $C_{techn.}$ is the capacity of the selected technology [MW]
- $c_{variable\ O\&M,techn.}$ is the variable O&M cost of the selected technology [€/MW]
- $c_{fixed\ O\&M\ ,techn.}$ is the fixed O&M cost of the selected technology [€/MW]

A summary of the different costs assumed for every technology is shown in Table 8:

*Table 8: summary of the O&M cost for each generation technology.*

| Technology | Variable O&M [€/MWh] | Fixed O&M [€/MW] |
|---|---|---|
| Solar PV | 0 | 35000 |
| Wind Onshore | 0 | 15300 |
| Hydro | 0 | 40000 |
| Geothermal | 0 | 96000 |
| Biomass | 0 | 91000 |
| Nuclear | 10 | 100000 |
| Thermal | 5 | 25000 |

Fixed O&M costs of utility-scale solar PV plants have declined in recent years, driven by module efficiency improvements, which have reduced the surface area require per MW of capacity. At the same time, competitive pressures, and improvements in the reliability of the technology, these costs are mostly dominated by preventive maintenance and module cleaning.

For onshore wind energy, these costs often make up a significant part (up to 30%) of the LCOE for this technology (IRENA, 2018). For offshore wind farms, costs per kW are higher than those for onshore wind, this is mainly due higher costs for access to the wind site for performing maintenance on turbines and cabling. The latter is heavily influenced by weather conditions and the availability of skilled personnel and specialised vessels. However, given the higher capacity factors offshore, O&M costs are also amortised over a larger output, meaning offshore wind O&M costs typically constitute 16-25% of the LCOE for offshore wind farms deployed in the G20 (Group of Twenty) countries. Technology improvements, greater competition among service providers, and increased operator and service provider experience, however, are driving down these prices.

O&M costs for geothermal projects are high relative to onshore wind and solar PV, in particular, because over time the reservoir pressure around the production well declines. Well productivity therefore reduces over time and eventually power generation production as well, if remedial measures are not taken. The O&M cost assumption of 90 €/kW therefore includes two sets of wells for makeup and re-injection over the 25-year life of the project, in order to maintain performance.

O&M costs for biomass plant include labour, insurance, scheduled maintenance and routine replacement of plant components (*e.g.,* boilers and gasifiers), feedstock handling equipment, and other items. In total, these O&M costs account for between 2% and 6% of the total installed costs per year. Large bioenergy power plants tend to have lower fixed O&M costs, due to economies of scale. Variable O&M costs, at an average of 0.005€/kWh, are usually low for bioenergy power plants, when compared to fixed O&M costs. Replacement parts and incremental servicing costs are the main components of variable O&M costs, although these also include non-biomass fuel costs, such as ash disposal. Due to its project-specific nature and the limited availability of data, in this thesis, variable O&M costs have been merged with fixed O&M costs.

For what concerns thermal power plant, an average of the O&M costs was taken between the values of the most present plants on the Italian territory. In this case, according to IEA, it was assumed a cost of 25 €/KWh, related to combined cycle plants, fuelled by Natural Gas.

Electricity storage and grids were assumed to have no operation and maintenance costs. For what concerns nuclear plants, nuclear variable costs are comprised entirely of only fuel costs, while all nuclear waste and such costs were assumed to be included in the initial investment costs.

### 5.5.3 Fuel cost

Fuel prices are in most cases not stable but being negotiated in international markets and varying depending on the global economy and short- and long-term outlook of supply and demand. Additionally, prices may be subject to long-term supply contracts as well as seasonal fluctuations. This is true to different extents for the different fuels: whereas coal and gas prices can vary significantly even within a year, nuclear fuel costs can be considered as being relatively stable. For this reason, fuel costs vary not only in proportion to the energy production, but also in relation over the life of the generating equipment as well, due to the mentioned factors. While these costs may be zero for renewables, they are higher for fossil fuel and biomass sources. The share of fuel expenditures on total costs varies largely between technologies: whereas nuclear plants are characterised by high investment but relatively low fuel costs, this ratio is typically reversed in the case of natural gas plants.

The following table, taken from report World Energy Outlook (IEA, 2016) shows the predicted trend of importing fossil fuel in the next decades, comparing the New Policies Scenario (which reflects both currently adopted measures and, to a degree, declared policy intentions) and the Current Policies Scenario (without implementation of any new policies or measures beyond those already supported):

*Table 9: EU fuel import data predictions*

| EUR/MWH | 2015 | 2030 | 2050 |
|---|---|---|---|
| **NEW POLICIES** | | | |
| **N.GAS** | 29.43 | 43.30 | 53.39 |
| **OIL** | 34.21 | 74.46 | 91.90 |
| **COAL** | 10.10 | 13.11 | 14.17 |
| **CURRENT POLICIES** | | | |
| **N.GAS** | 29.43 | 46.66 | 62.63 |
| **OIL** | 34.21 | 85.19 | 110.69 |
| **COAL** | 10.10 | 14.17 | 17.00 |

Regarding biomass power plants, the cost of feedstock per unit of energy is highly variable, too. This is because the feedstock can range from onsite processing residues that would otherwise cost money to dispose of, to dedicated energy crops that must pay for the land used, the harvesting and logistics of delivery, and storage on site at a dedicated bioenergy power plant. Prices for biomass sourced and consumed locally, however, are difficult to obtain.

The majority of the biomass used for power generation comes from sources such as wastes and residues from agricultural and industrial processes, forestry arisings, etc. that are consumed locally. This cost can be zero for waste which would otherwise have disposal costs or that are produced onsite at an industrial installation, however they may be modest where agricultural residues can be collected and transported over short distances. For non-traded biomass, the only costs for the raw material are often the transport, handling and storage required to deliver the biomass wastes or residues to the power plant. For the purpose of this thesis, an average cost of 15 €/MWh was assumed between the most common biomass feedstock costs according to IRENA (IRENA, 2014).

The share of fuel expenditures on total costs varies largely between technologies: whereas nuclear plants are characterised by high investment but relatively low fuel costs, this ratio is typically reversed in the case of natural gas plants. Important for the interpretation of the results is also to keep in mind that the technologies are to different extents exposed to competition (assuming the power plant dispatch is done according to least cost considerations). Whereas the variable costs of nuclear technologies are relatively low and even a significant increase would hardly affect its short-run competitive position, coal and natural gas plants – depending on the market – are frequently competing for market shares. Thus, an increasing or decreasing price for one of them can also affect their capacity factor, which additionally affects their average generation costs. At the contrary, total nuclear costs are being dominated by fixed costs. This aspect will be further analysed in the sensitivity analysis.

### 5.5.4 Carbon cost

Carbon pricing is a method for nations to reduce global warming, applying a taxation to greenhouse gas emissions in order to encourage polluters to reduce the combustion of fossil fuels– the main drivers of climate change. The Carbon Pricing Score (CPS) answers the question of how far countries have attained the goal of pricing all energy related carbon emissions at the three benchmarks for carbon costs or more. The more progress a country has made towards the relevant benchmark value, the higher the CPS. An intermediate CPS between 0% and 100% means that some emissions are priced, but that not all emissions are priced at a level that equals or exceeds the benchmark. For Italy the carbon price score is 24% (electricity sector) considering a price of 60€/tonCO2 (OECD, 2021).

However, this model attempts to include a realistic cost of emissions on the assumption that all the emissions from thermal production are taxed. The corresponding carbon cost in the calculation of the LCOE was calculated as shown:

$$CO_{2\,emitted} = \sum_{source} CO_{2\,content} * CO_{2\,price} \tag{23}$$

$$source \ni \{NG, biomass, import\}$$

Where:

- $CO_{2,emitted}$ is the total amount of $CO_2$ emitted by the power system [t]
- $CO_{2,content}$ is the carbon emission per MWh of electricity produced with NG plant [$tCO_2/MWh$]
- $CO_{2\,price}$ is the price applied per tons of $CO_2$ emitted, no costs for emissions other than $CO_2$ were included [€/$tCO_2$]

Concerning the national gross thermoelectric production, according to the "Istituto Superior per la Protezione e Ricerca Ambientale" (ISPRA, 2021), the emission factor per MWh decreases steadily from 1990 to 2018 from 709.1 g CO2/kWh to 415.5 g $CO_2$/kWh as can be seen in Figure 21. The decrease is mainly due to the increasing share of natural gas and the continuous reduction of the specific emission factor of this fuel. More specific predictions regarding these emissions are not available, but it can be assumed that this value will steadily decrease as the efficiency of the technology increases. Furthermore, this aspect will be further investigated in the scenario where carbon capture technology is coupled with thermal production.

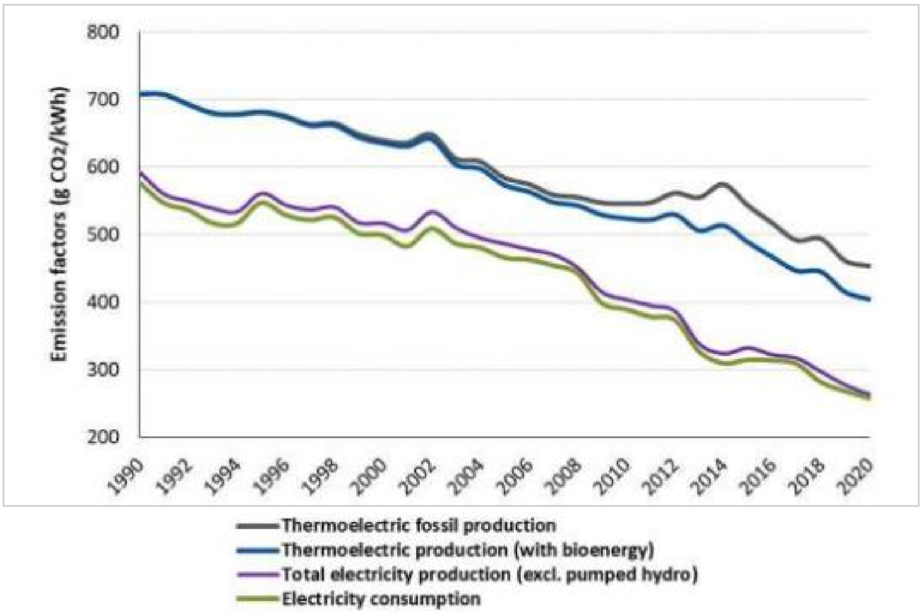



*Figure 21: $CO_2$ emissions trend in the Italian electricity production.*

For the purpose of the thesis a value of 376 g $CO_2$/kWh is assumed, concerning NG plants only while concerning carbon emission from biomass plant they were assumed equal to 217 g $CO_2$/kWh. (ISPRA, 2021)

It was decided to also take import emissions into account, as it is unrealistic to assume that all imported electricity comes from renewable energy only. Therefore, it has been assumed that the carbon emission for each imported MWh will be comparable to the average emission given by the Italian electricity production at each scenario, assuming that the latter will be within the European average for what concerns greenhouse gas emission intensity.

The carbon price of the EU ETS, which had never consistently traded for more than €30, has currently jumped up to more than €60 in the beginning of 2022, as can be seen in Figure 22. This is a huge increase from the €18 price in 2020, and prices are expected to continue to rise as the EU strives to meet its emissions reduction goals and carbon allowances become less available (European Commission, 2021). The influence of this price on the generation from fossil fuel will be further discussed in the sensitive analysis section.

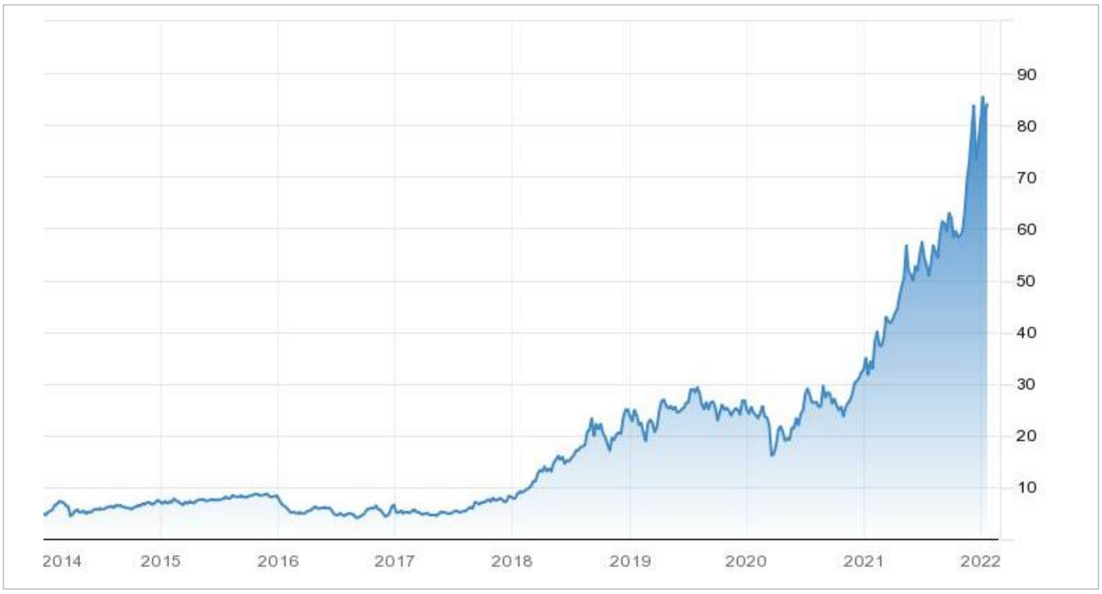



*Figure 22 Carbon permits price in €/ton$CO_2$*

## 5.5.5 Import and export costs

For what concerns import costs, they are again proportional to the actual imported energy. For the import price it was assumed a price equal to the "Prezzo Unico Nazionale" (PUN), with a value of 55 €/MWh related to 2019 (TERNA, s.d.). TERNA's forecasts suggest that between 2030 and 2050 the price of electricity will rise slightly, at a rate of 20%. This price assumptions reflects in a very general way the reality of the import and export world as these prices are dictated by the daily market rules. The value of the PUN as the import price of the model is therefore to be considered as a reference value. Regarding a possible gain from export, it was decided not to include it in the model for two reasons: firstly, the price of export is as well subjected to daily price fluctuation, depending on a large amount of different factors such as the amount of electricity surplus availability and the location and timing of the foreign demand; secondly, it has to be considered that Italy has never been an exporting country, therefore all the electricity produced in surplus by the model, is considered as curtailed.

Electricity trading cost is therefore determined as follows

$$C_{trading} = \sum_{t=1}^{26280} P_{I,t} * C_I, \quad if\ P_{I,t} \geq 0) \tag{24}$$

Where:

- $C_{trading}$ is the yearly energy import cost [€]
- $P_{I,t}$ is the imported power at hour t [MWh/h]
- $C_I$ is the cost of imported energy [€/MWh]

## 5.6 Constraints of the model

The first constraint is related to the reduction of emissions. for each scenario the same maximum of $CO_2$ emissions from polluting resources (such as natural gas and biomass) has been set. This constraint increases over the years.

For 2030, the value indicated by PNIEC has been taken as a reference, i.e. a reduction of 43% compared to the 1990 value has been taken as reference. For the years 2040 and 2050, a reduction value equivalent to 68% and 90% has been set. The variation of results according to the amount of $CO_2$ reduction will be further analysed in the following paragraphs.

- $CO_{2,emitted} \leq CO_{2\ cap}$ (25)

Where $CO_{2\ cap}$ is the maximum amount of carbon emission allowed in each scenario, the corresponding values are shown in Table 10:

*Table 10 summary of the carbon emission targets*

| | 2030 | 2040 | 2050 |
|---|---|---|---|
| **$CO_{2\ cap}$ [mil. t$CO_2$]** | 72 | 40 | 13 |
| **% of $CO_2$ reduction** | -45% | -68% | -90% |

The second constraint is related to storage, so that in any given hour, the storage cannot be negative and cannot accumulate more storage than its capacity.

- $E_{s,t} \geq 0\ for\ \forall\ t$ (26)

The third constraint is related to the technical potential of wind and photovoltaic power that can be installed by 2050. According to the technical limitations and the amount of resources present on the Italian territory, the maximum value of installable capacity for onshore wind can be estimated of around 50 GW while for PV is around 100 GW (Paolo Colbertaldo, 2018). As far as offshore wind is concerned, the assessment of the potential is still rather complex, one study states that considering offshore floating, it could reach up to 180 GW (GWEC, 2020). For the purpose of the thesis, these values were therefore used as an upper limit, and the results will be discussed in more detail in the results section.

- $$C_{RES} \leq C_{RES,potential} \qquad (27)$$
  $$RES \ni \{wind\ onshore, wind\ offshore, solar\}$$

# Chapter 6

# Scenarios description

Common technical and economical parameters used in all the developed scenarios are presented for each decade in Table 11 and Table 12.

*Table 11: Parameters for basic scenarios. These parameters were also used in other scenarios, unless otherwise specified.*

| Parameter | 2020 | 2030 | 2040 | 2050 |
|---|---|---|---|---|
| Electrical demand [TWh/y] | 320 | 354 | 380 | 404 |
| EV amount | 400000 | 6 mil. | 20 mil. | 40 mil. |
| Import capacity [MW] | 10000 | 16000 | 2000 | 23000 |
| Export capacity [MW] | 5000 | 11000 | 15000 | 18000 |
| Geothermal capacity [MW] | 770 | 1100 | 1800 | 2300 |
| Biomass capacity [MW] | 4200 | 3760 | 3760 | 3760 |
| Wind cost [€/kW] | 1275 | 1219 | 123 | 1088 |
| Solar PV cost [€/kW] | 875 | 773 | 620 | 536 |
| Hydro [€/kW] | 3023 | 2990 | 2781 | 2771 |
| Biomass cost [€/kW] | 3960 | 3590 | 2780 | 2770 |
| Geothermal cost [€/kW] | 6520 | 6432 | 6378 | 6256 |
| Nuclear cost [€/kW] | 6800 | 6800 | 6800 | 6800 |
| Thermal cost [€/kW] | 815 | 799 | 779 | 762 |
| Storage cost [€/kWh] | 317 | 260 | 2121 | 173 |
| Grid cost [€/kW] | 325 | 325 | 325 | 325 |
| Import cost [€/MWh] | 52 | 56 | 67 | 81 |
| Emission cost [€/tonCO2] | 25.8 | 80 | 100 | 120 |

*Table 12 Common parameters used in all basic scenarios and other scenarios, unless otherwise mentioned.*

| Parameter | Value |
|---|---|
| Lifetime of wind [y] | 25 |
| Lifetime of solar [y] | 25 |
| Lifetime of hydro [y] | 80 |
| Lifetime of nuclear [y] | 60 |
| Lifetime of biomass [y] | 30 |
| Lifetime of geothermal [y] | 40 |
| Lifetime of thermal [y] | 35 |
| Lifetime of transmission [y] | 50 |
| Lifetime of storage [y] | 10 |
| Initial state of electric storage | O,5* Emax |

## 6.1 Base scenario

In the Base scenario there is the possibility to install renewable capacity up to the maximum potential for each source; in addition, a share of power from thermal plants fuelled by natural gas is also allowed, while still meeting the requirements imposed by the gradual reduction of $CO_2$ emissions for each decade as already mentioned in section 5.6. The purpose of this scenario is to analyse how the model will behave if only the technologies currently in use in Italy are exploited in 2050.

## 6.2 CCS scenario

In the CCS (carbon capture and sequestration) scenario, in addition to the installation of NG thermal plants, it is also possible to install plants coupled to the CCS technology, with which it is possible to absorb the $CO_2$ emitted from large point source. This innovative technology allows the production of energy from fossil fuels or biomass while meeting emission requirements. This technology can play an important role in meeting global energy and climate goals.

At the moment, to make installations of CCS plants profitable, the prices of carbon tax should be significantly higher than current prices, but existing estimates of the social cost of carbon claim that they are expected to grow rapidly in future decades allowing CCS plants to achieve a cost advantage (IEA, 2020). Hence, CCS might become a valuable option that would make deferrable low-carbon generation available, and with sufficiently high carbon prices and competitive fuel prices, CCS may represent a possible complement in some low-carbon energy mixes. Currently there are three different technologies on how to capture carbon dioxide:

A. Pre-combustion: the $CO_2$ can be captured before burning the fuel. It is required a complex chemical process and alternative burning equipment (IGCC-process).
B. Post-combustion: the $CO_2$ can be captured after burning the fuel by cleaning the flue gas, this process has been practiced for a long time.
C. Oxyfuel-process: the fuel is burned in a pure oxygen environment. It is much more expensive, but it leads to cleaner flue gases.

For what concerns the capture rate, it is maximum in oxyfuel-combustion processes which guarantee high purity $CO_2$, with capture rates of around 92% and higher, and no post-treatment is needed, in contrast with pre- and post-combustion technologies. $CO_2$ capture rates of post- and pre-combustion are slightly lower at around 88% and 89%. For the porpoise of this thesis, an average value of 90% was assumed (IEA, 2020).

However, one aspect to consider when coupling power plants with these CCS technology is the efficiency of the plants. Fossil fuel plants with CCUS are on average 10% (coal) and 14% (CCGT gas) less efficient than without CO2 capture (IEA, 2019) and consequently it determines the use and associated costs of fuel as well as the emission intensity of electricity production. Figure 23 clearly outlines the general stages involved in the Carbon Capture Utilisation and Storage process. The captured $CO_2$, if not used in situ, is compressed and transported by ship, pipeline, rail or truck to be exploited for several applications as, for example, being converted into fuels, chemicals and raw materials. Otherwise, the captured $CO_2$ can be stored by injection into deep geological formations, trapping $CO_2$ permanently underground. The geological formations could be represented either by depleted hydrocarbon reservoir or saline aquifers, allowing the exploitation of otherwise unused areas. Regarding the transportation to the storage site, an efficient transportation can be implemented through pipeline (onshore or offshore), or ship transport.

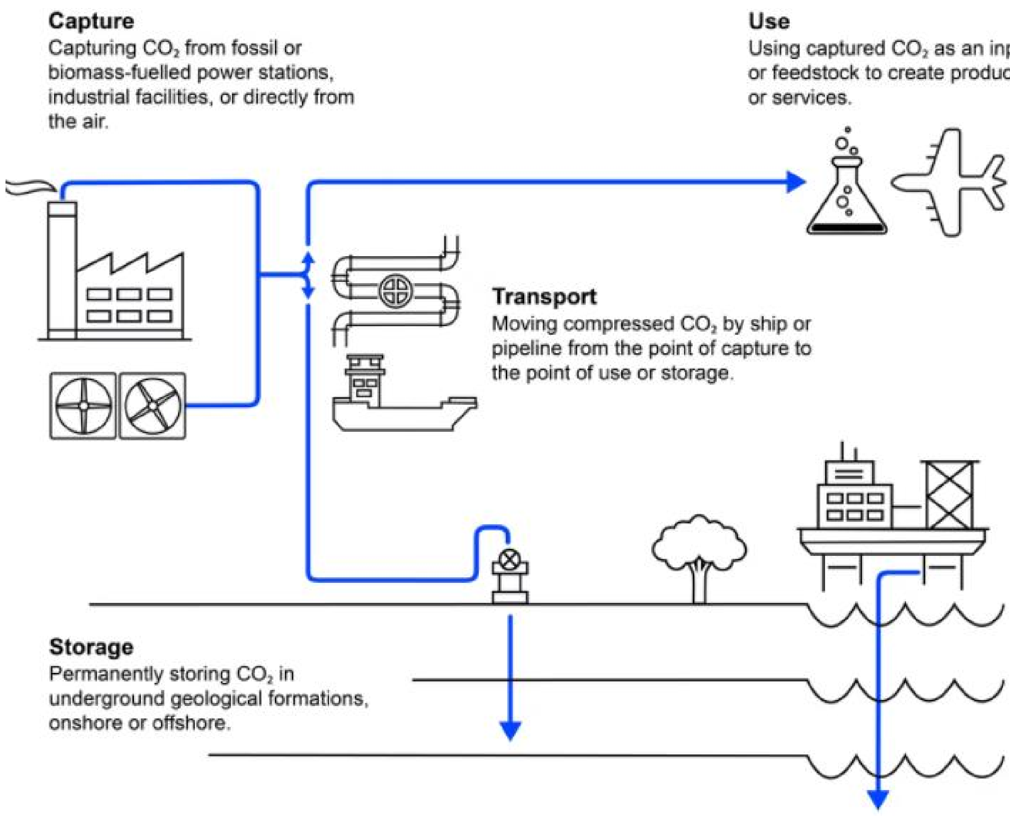



*Figure 23 Carbon Capture Utilisation and Storage process diagram (IEA, 2021).*

Since no large-scale installation of this technology exists, it is difficult to assess capture costs, and all cost data produced thus far are highly case-specific. Consequently, all estimates should be treated very cautiously. The predicted costs concerning the capture technology only were assumed accordingly to the Joint Research Centre (JRC, 2017) while for storage and transmission they are described in details in Table 14 and Table 15 (Edward S. Rubin, 2007) .

*Table 13 Carbon Capture technology cost predictions*

| | **2020** | **2030** | **2040** | **2050** |
|---|---|---|---|---|
| NG plants [€/kW] | 2250 | 1560 | 1540 | 1510 |
| Biomass plants [€/kW] | 5526 | 4860 | 4600 | 4420 |

*Table 14 transport cost on a common basis (2013 USD/t$CO_2$/250 km) for onshore and offshore pipelines at different capacities*

| **Study** | **On/offshore** | **3 Mt$CO_2$/y** | **10 Mt$CO_2$/y** | **30 Mt$CO_2$/y** |
|---|---|---|---|---|
| IEPCC (2005) | On-shore | 4.3 - 7.2 | 2.2 - 3.7 | 1.2 – 2.2 |
| ZEP (2011) | On-shore | 10.9 | 3.3 | - |
| IEPCC (2005) | Off-shore | 7.2 - 8.9 | 3.4 - 4.3 | 1.9 - 2.4 |
| ZEP (2011) | Off-shore | 14.8 | 4.8 | - |

*Table 15 storage cost in 2009 EUR/t$CO_2$ (Zero Emission Platform, 2011)*

| **Reservoir type** | **On/Offshore** | **Range** |
|---|---|---|
| Depleted O&G Field- reusing wells | Onshore | 1-7 |
| Depleted O&G Field- no reusing wells | Onshore | 1-10 |
| Saline Formations | Onshore | 2-12 |
| Depleted O&G Field – reusing wells | Offshore | 2-9 |
| Depleted O&G Field- no reusing wells | Offshore | 3-14 |
| Saline Formations | Offshore | 2-20 |

In order to include the wide variety of possibilities offered by transport and storage of co2, an average of the values described above was used. i.e. 8€ and 9€ per ton of $CO_2$ respectively for transport for storage.

## 6.3 SMR scenario

Nuclear plants, among the various dispatchable low-carbon technologies, proves to have the lowest expected costs in 2025 (IEA, 2020). The only other comparable technology is to be found in large hydro reservoirs plants but remain highly limited by natural constraints of individual countries. Even if gas-based combined-cycle gas turbines (CCGTs) can be competitive in some regions, their LCOE is very much dependant on the prices for natural gas and carbon emissions and these may vary greatly in future decades, due to geopolitical crises and climate change related actions.

According to the IEA Sustainable Development Scenario (SDS), a significant contribution of nuclear power is indispensable in order to meet the objectives of reduction of greenhouse gas emissions under the 2015 Paris Agreement (IEA, 2020). This increasing role of nuclear power to achieve decarbonisation targets is also confirmed by the Intergovernmental Panel on Climate Change (IPCC, 2018). Small Modular Reactors (SMRs) are defined as nuclear reactors with a power output between 10 MWe and 300 MWe (IEA, 2020). These reactor concepts, due to their technical characteristics, may provide further cost reduction and therefore increase interest in nuclear power. Nevertheless, there are some challenges which should be overcome in order to achieve commercial profitability._SMRs take advantage of the benefits of economies of series, to be transported and assembled on site, resulting in shorter construction times. This is one of the key elements that might prove to make SMRs cost competitive compared to other energy options, however, this brings a negative effect on the economic competitiveness of the unit. With an increase of the rector size, the related fixed costs exhibit a rather slow growth, encouraging to maximize the output of the reactor to reduce as much as possible the cost per unit of electricity produced. As shown in Figure 24 the diseconomies of scale, is on the other hand counterbalanced by the benefits of serial construction, which in turn relies on design simplification, standardisation and modularisation.

While some of these positive aspects have been reported in other industries, they have to be proven yet in the nuclear sector. The construction of first prototypes may bring some of the claimed advantages of SMRs and hence accelerate their commercial viability.

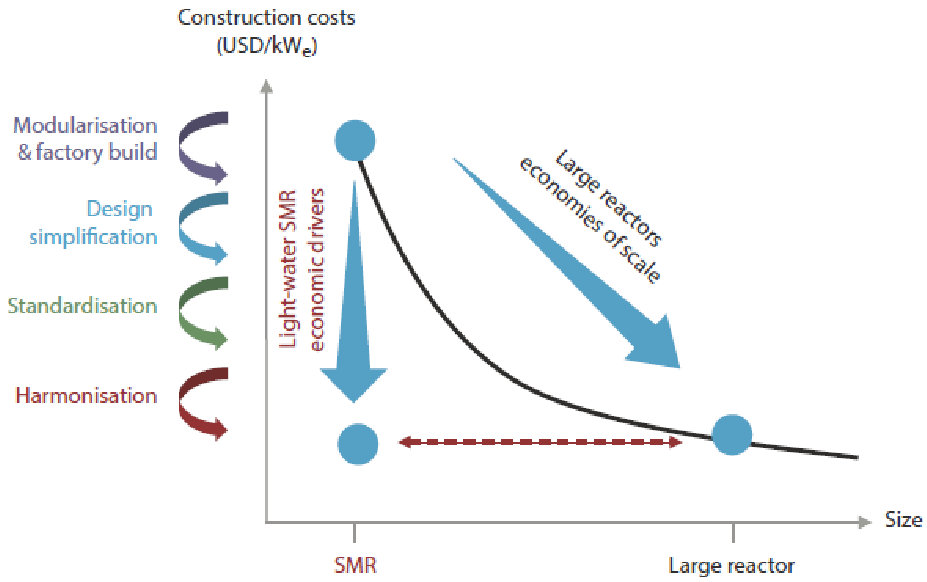



*Figure 24 SMR economic drivers that helps compensate diseconomies of scale (NEA & EOCD, 2020)*

In the development of the scenario the possibility of installing SMR as a variable was initially introduced, allowing the model to install as much capacity as needed without upper limits. for simplification no maintenance period was foreseen for these types of plants which consequently operate constantly for every hour and a 95% production efficiency was set. the cost related to capex was however considered equivalent to that of the nuclear plant, using a very conservative value: 6875 €/kW for the cost of capex the model was considered to be equivalent to that of the

Finnish Olkiluoto 3 nuclear plant, using a very conservative value: 6875 €/kW (Koivunen, 2020). As far as operating and maintenance costs are concerned, reference is made to Table 8.

The introduction of this additional degree of freedom to the model led to results that were rather different from those of the previous scenarios. For this reason, it was considered necessary to proceed with the scenario analysis by setting a fixed SMR capacity that is gradually increased to 2050 so that the effect on the whole system can be analysed. The impact of the installation of up to 15 GW of nuclear capacity is analysed, according to the study of the University of Pisa (B. Vezzoni, 2009), in which several future scenarios for the Italian case were assumed.

In Figure 25 the different scenarios and their characteristic features are summarized:

**Base scenario**

- **Power production from solar, wind, hydro, geothermal and biomass is admitted**
- **Thermal power production from fossil fuel is admitted**
- **No nuclear capacity installed**


**Carbon Capture and Sequestration scenario**

- **Power production from solar, wind, hydro, geothermal and biomass is admitted**
- **The CCS technology can be coupled with the thermal from fossil fuel power production**
- **No nuclear capacity installed**

**Small Modular Reactors scenario**

- **Power production from solar, wind, hydro, geothermal and biomass is admitted**
- **Thermal capacity, coupled with CCS technology, is admitted**
- **The possibility to install nuclear capacity (SMR) is admitted**

*Figure 25 summary of the different scenarios analysed in the model*

The common targets of $CO_2$ emission reduction for each decade are summarised in Table 16:

*Table 16 common targets of $CO_2$ emission reduction %, compared to the 1990 value*

| | 2030 | 2040 | 2050 |
|---|---|---|---|
|  | -45% | -68% | -92% |

# Chapter 7

# Results and discussion

In the following table, the results obtained from the model are summarized, reporting the most significant values. For the purpose of comparison with the other scenarios, results are also included for an SMR scenario referred to the 2050 horizon, where the SMR capacity is kept as a variable.

*Table 17 main model results for the different scenarios*

| **Scenario** | **Base Case** | | | **Carbon Capture Case** | | | **SMR case** |
|---|---|---|---|---|---|---|---|
| **Year** | **2030** | **2040** | **2050** | **2030** | **2040** | **2050** | **2050** |
| **Installed capacities [GW]** | | | | | | | |
| Wind Offshore | 3.5 | 20.6 | 77.7 | 0.6 | 1.4 | 12.1 | 3.7 |
| Wind Onshore | 31.3 | 40.1 | 50.0 | 12.3 | 14.7 | 34.7 | 45.0 |
| Solar PV | 26.4 | 73.9 | 100.0 | 25.8 | 58.9 | 62.4 | 58.5 |
| Nuclear SMR | 0 | 0 | 0 | 0 | 0 | 0 | 4.05 |
| Hydro | 22.6 | 22.6 | 22.6 | 22.6 | 22.6 | 22.6 | 22.6 |
| Geothermal | 1.1 | 1.8 | 2.3 | 1.1 | 1.8 | 2.3 | 2.3 |
| Biomass | 3.7 | 3.7 | 3.7 | 0 | 0.1 | 0 | 0 |
| Biomass CCS | 0 | 0 | 0 | 3.7 | 3.6 | 3.7 | 3.7 |
| Thermal (NG) | 23.5 | 25.4 | 4.9 | 18.1 | 11.4 | 0.6 | 1.8 |
| Thermal CCS (NG) | 0 | 0 | 0 | 10.5 | 16.9 | 27.9 | 22.4 |
| Storage | 10.4 | 48.4 | 99.7 | 1.2 | 3.5 | 6.1 | 3.8 |
| **Electricity import and curtailment [TWh]** | | | | | | | |
| Import | 12.2 | 15.2 | 40.7 | 15.4 | 22.2 | 33.7 | 15.4 |
| Import % | 3% | 4% | 10% | 4% | 6% | 8% | 6% |
| Curtailment | 1.76 | 30.6 | 148.5 | 0.6 | 0.9 | 2.6 | 1.8 |
| Curtailment % | 1% | 7% | 26% | 1% | 1% | 1% | 1% |
| Storage utilization GWh | 6 | 102 | 650 | 2.2 | 2.4 | 28 | 2.5 |
| % of renewable generation | 62% | 82% | 92% | 41% | 50% | 57% | 66% |
| **LCOE €/MWh** | | | | | | | |
| Investment LCOE | 37.2 | 53 | 100 | 26.3 | 31.1 | 38.9 | 40.1 |
| O&M LCOE | 24.3 | 30 | 20.5 | 43.2 | 44.5 | 46.8 | 43.3 |
| Total LCOE | 61.5 | 83.8 | 120.5 | 69.5 | 75.6 | 85.7 | 83.4 |

## 7.1 Results

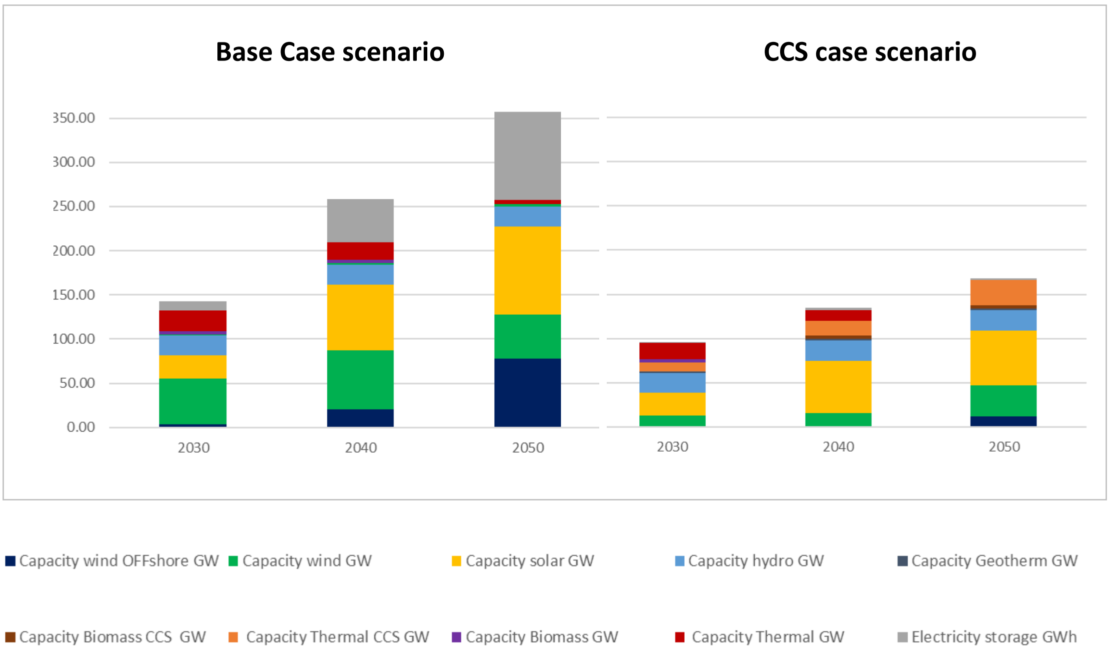



*Figure 26: results of installed capacity by scenario*

From the results obtained by the model, it can be seen how the baseline scenario differs from the CCS one for the extent of the installed capacities. In the basic scenario in particular, the installed renewal capacities increase significantly over time, until reaching the maximum potential set for 2050. This upper limit corresponds to the technical potential that can be exploited in the Italian territory, as mentioned in section 5.6, so it cannot be exceeded. Removing this limit, however, the model would tend to install more power if allowed. In this way instead it can be seen how the storage is increased, going to make up for the lack of electricity generation.

As the decades progress, the limitations set by the model on $CO_2$ emissions become more and more restrictive up to a set target of 90% reduction from 1990 levels. As a result, in the base scenario the installed capacity of thermal plants from fossil sources such as natural gas is drastically reduced from 56 GW in 2020 to around 5 GW in 2050.

By contrast, the renewable capacity grows proportionally, giving priority to the installation of solar photovoltaic, the cheapest technology, and to the wind technology secondly. Onshore wind is significantly increased in the 2030 scenario compared to current capacity (10.8 GW), while its growth remains modest in the following decades if compared to the solar PV trend. As regards offshore wind, on the other hand, its installation is not simply due to the achievement of the maximum potential of other renewables, given its still quite high cost when compared with onshore and PV. However, even without setting the maximum potential limit for renewables, offshore wind is still chosen by the model. This is explained by the fact that its capacity factor is considerably higher than onshore (with an annual average of 41% compared to 23% of the latter) and also demonstrates a significantly different generation profile, which is better distributed to cover the Italian electricity demand.

Figure 27 and Figure 28 show the different electricity generation profile in the case of 10 GW of installed capacity for onshore and offshore. It is evident that in the case of offshore, especially in winter, there is a higher and more constant output, and since PV solar production is also reduced in winter, offshore installation may be preferable compared to onshore.

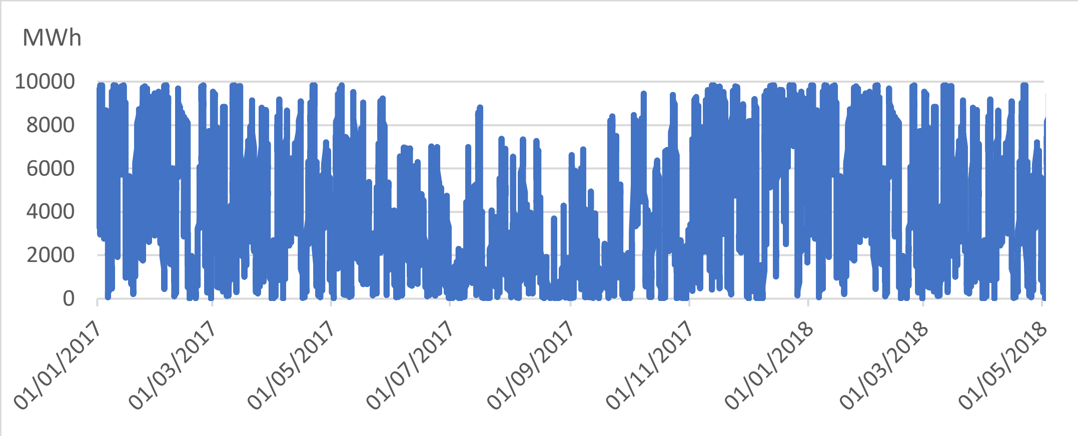



*Figure 27 Offshore wind power production profile, 10 GW of installed capacity*

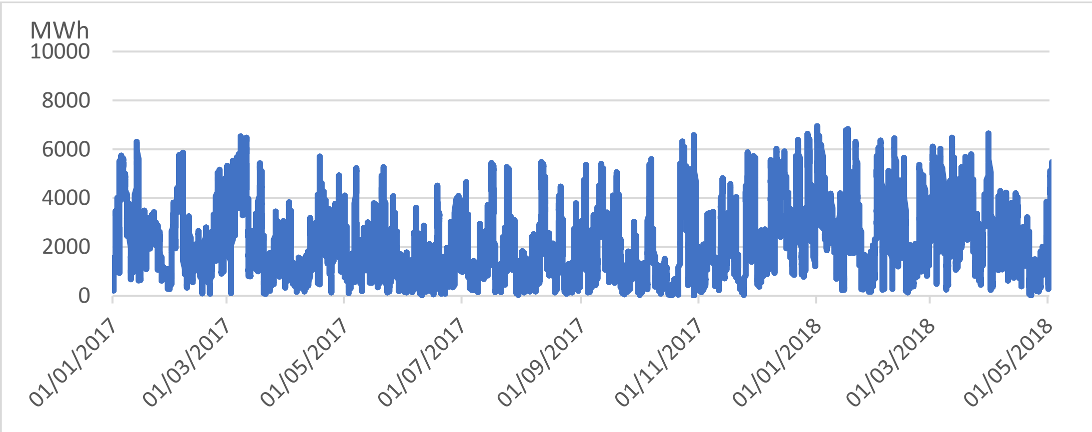



*Figure 28 Onshore wind power production profile, 10 GW of installed capacity*

It should also be noted that the import share in the baseline scenario is higher than in the CCS scenario, reaching an import of 40 TWh compared to 33 TWh in the CCS case. these values are in any case within the indicative ranges of the European Union, which indicates an interconnection between countries in 2050 of up to 15%. (European Commission, 2019)

Concerning the storage, it is clear that this becomes a capacity becomes an essential element for the feasibility of the baseline scenario. As the capacity of wind and solar increases substantially, it is then necessary to balance the intermittency related to these renewable energy sources, ensuring immediate availability of electricity from storage if needed. As can be seen from the results, the size of the storage grows considerably from 2030, up to a maximum of about 100 GW installed, with a producibility of about 650 GWh. The feasibility of this installation can be debated since in the model it is considered to come only from batteries and these kinds of technologies are not yet able to guarantee these performances.

Turning to the CCS case, however, it can be seen that the scenario changes considerably, in which, in general, the installed capacities are much smaller. The only exception is the capacity of thermal from NG coupled to CCS, which is also the reason for the reduction in all other generation technologies. The use of this technology allows around 30 GW to remain, compared to the 56 GW currently installed, while achieving the target imposed by $CO_2$ emission reduction. This technology therefore allows great flexibility and covers the base load for all decays in the CCS scenario. The model, moreover, decides to install thermal first without CCS and only when the emission limits become more stringent, it decides to install thermal coupled with CCS, keeping the total installed thermal capacity around 30 GW. This choice is mainly dictated by the much higher costs of CCS, both in terms of capex and opex.

With regard to imports, it can be seen that in the CCS scenario to 2050, less electricity is imported from abroad (30 TWh) compared to the base case (40 TWh), representing an advantage from the point of view of energy independence.  This aspect, however, is better analysed in the next section as, on the other hand, more fuel has to be imported to power gas-fired plants. In Italy, approximately 92% of the total natural gas supply is imported from abroad (IEA, 2022).

Concerning the storage, it can be clearly seen from the results that the installed capacity required is drastically reduced in the case of CCS and does not increase particularly with the decades. This can be explained because, as already said, total NG thermal generation remains almost constant, distributed between thermal with and without CCS. So, there is no need to install more storage to cover the base load shortage.

A further aspect to be analysed is the amount of curtailed energy. In the base case this amount increases to a share of 26% of the entire production, compared to 1% in the CCS case. This significant difference is clearly due to the large amount of renewable capacity installed, whose production is neither predictable nor deferrable as for fossil fuel plants. The possibility of sector coupling could be discussed here, in order to make the most out of the clean energy production offered by renewables, but this aspect is not covered in this thesis

A further analysis was carried out to better analyse the development of the scenarios for varying $CO_2$ emission reduction targets. The results of the sensitivity analysis can be seen in Figure 29 and Figure 30 . It should be noted that the baseline scenario is significantly more affected by this variation. Firstly, it can be seen that the LCOE increases rapidly, due to the significant need to install a lot of renewable capacity from wind and photovoltaics. consequently, the need for storage also increases dramatically as these intermittent technologies increase, to ensure that demand is covered even when these resources are not available. Offshore wind is the technology with the lowest growth since it has the highest cost compared to other renewables. On the other hand, installed thermal capacity from natural gas is progressively decreasing, in line with the imposed emission limits, until almost no capacity installed, in order to achieve the 92% $CO_2$ reduction target.

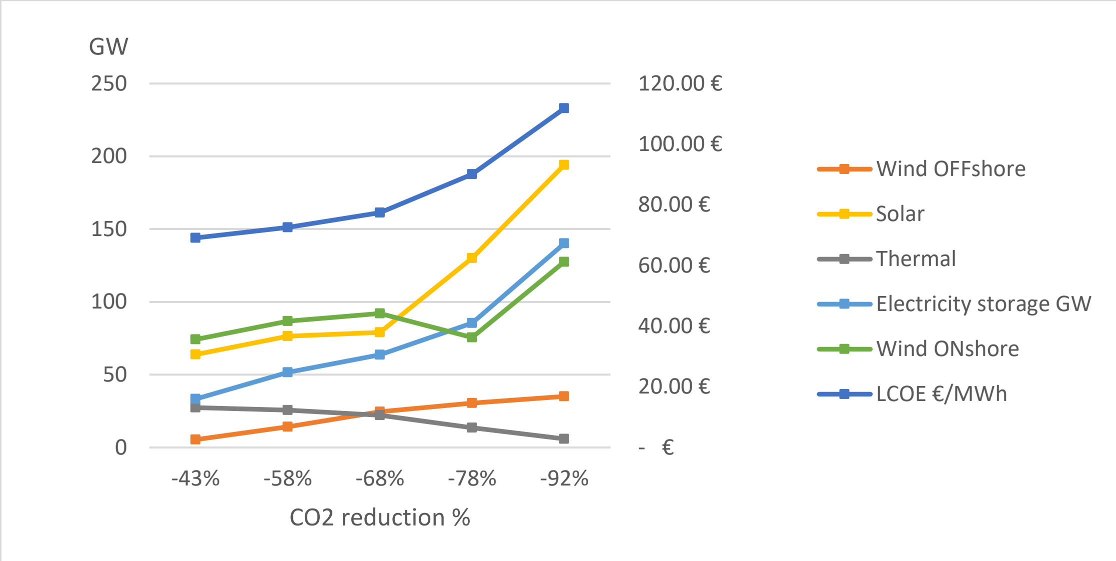



*Figure 29 $CO_2$ emission reduction influence on the LCOE and the different generation capacities, base case, 2050 scenario*

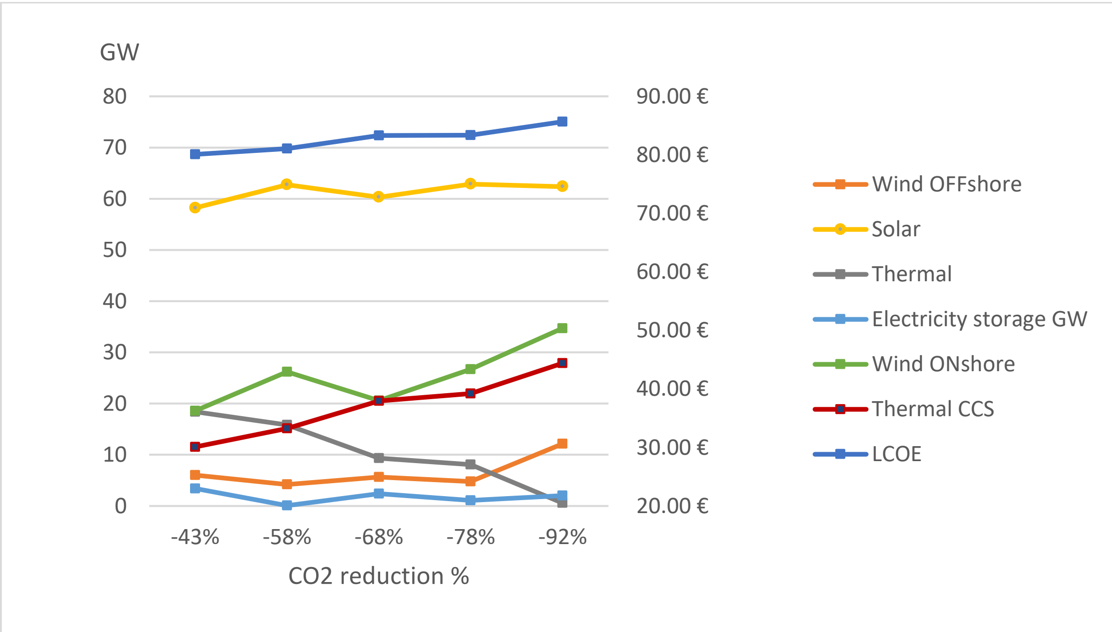



*Figure 30 $CO_2$ emission reduction influence on the LCOE and the different generation capacities, CCS case, 2050 scenario*

In the case of the CCS scenario, on the other hand, it can clearly be seen that the increase in LCOE is much less pronounced than before. As the limits on emissions increase, the trend is again to install more renewable capacity, but the extent of this growth is more limited than in the base case. This behaviour is explained by the presence of thermal power production coupled with CCS technology. In fact, it can be seen from the red line in the graph that this technology is the one with the predominant growth, since it allows high production all year round, without being affected by climate variations as renewables are. The coupling with CCS technology makes it possible to exploit these plants even though they are powered by fossil fuels (in the model by Natural Gas only), allowing up to 90% of emissions to be captured. Unlike renewables as wind and photovoltaics, which are currently very mature and increasingly economical, the CCS technology is however still very expensive and underdeveloped on a large scale. This aspect could explain why the model still prioritises the installation of traditional renewables, which, as the graph shows, have a significantly higher installed capacity, particularly photovoltaic and onshore wind. Finally, the amount of storage to be installed remains almost constant as the $CO_2$ reduction targets change, since the variability of renewables is compensated for by thermal plants.

As regards the SMR scenario, it was decided to analyze it with a different approach since the introduction of a further degree of freedom in the model made it difficult to find a global optimum when varying the initial values. This issue will be further discussed in the next paragraph. From the Figure 31 it can be seen how the introduction of nuclear plants, despite representing a very expensive investment, allows a global economic advantage. LCOE is slightly but gradually reduced as nuclear capacity increases, reaching values below 80 €/MWh. Moreover, all the remaining capacities, including the thermal one, generally undergo a gradual reduction, while keeping constant proportions between them. Storage remains almost constant, as nuclear capacity increases.

The introduction of this technology is currently at the center of political and social debate in Italy. It could help fighting climate change and reduce energy dependence on natural gas from foreign countries, but at the same time the majority of the population is still highly opposed.

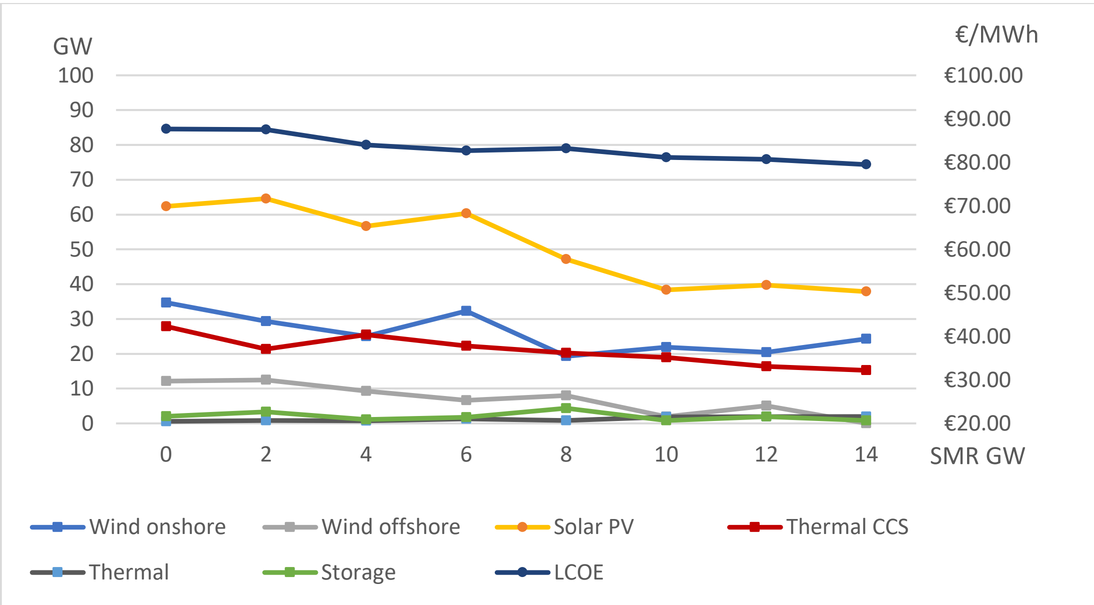



*Figure 31 SMR installed capacity influence on LCOE and the different generation capacities*

In Figure 32, Figure 33 and Figure 34 you can see a comparison between the behaviour of the different storages installed in the 3 different scenarios at 2050. In the base case it is evident from the number of peaks, how the storage is discharged very quickly. For this reason, a high capacity is required to be installed, especially in winter, when the demand for energy is greater and and renewables are unable to meet it. By contrast, in the other two scenarios it can be seen how the storage is rarely used for the whole simulation period, remaining full for most of the time. The feasibility of installing some GW of electrochemical storage may be debated, since it is not convenient to use it so infrequently. in the CCS scenario, however, the storage demand becomes more critical since the 28 GW of storage required derives from the presence of a single peak in which almost all the power is discharged within a few hours.

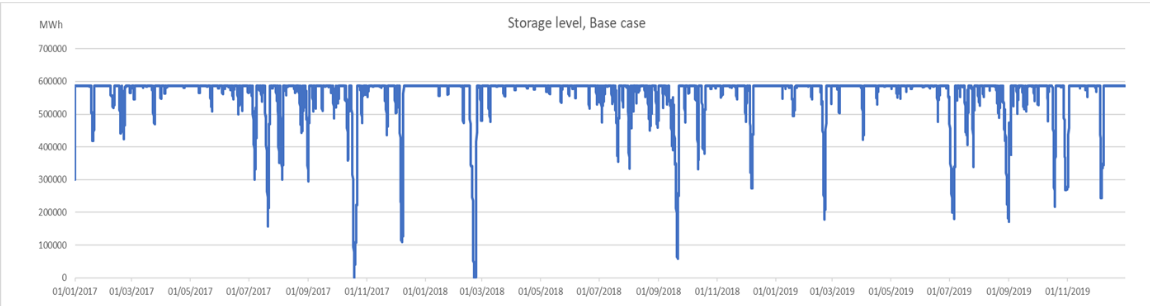



*Figure 32 storage level profile in the base case, 2050 scenario*

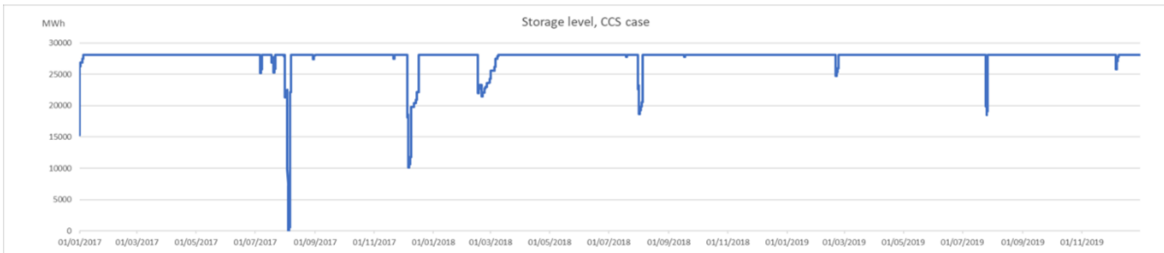



*Figure 33 storage level profile in the CCS case, 2050 scenario*

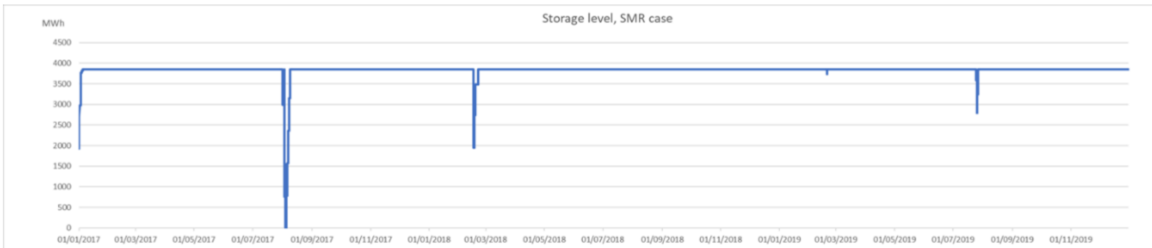



*Figure 34 storage level profile in the SMR case, 2050 scenario*

# 7.2 Comparison of the scenarios

## 7.2.1 Land use assessment

The integration of RES into landscapes have been a persistent cause of opposition against renewable energy projects, resulting in a development delay for this kind of technologies. Land use could be considered one of the most objective quantitative metrics of landscape impact, since it measures the area that is directly occupied by turbines or photovoltaic panels. Moreover, visibility analyses with geographic information systems (GIS) can estimate the area from which a RE project is visible but, unlike land use metrics, however, it also includes subjectivity related to individual perception (Rodrigues M, 2010). In literature, land use of solar and wind energy is measured in two forms: direct land use and total land use. The first one is the area that is directly occupied by RE equipment, facilities and works of infrastructure while total land use, which is the most extensive of the two types of land use, was preferred as a metric, in the context of landscape impact (Denholm P, 2009). In the case of solar energy, direct and total land are almost equal. For major solar photovoltaic projects direct land use constitutes of approximately 90% of the total land use area. This is to be expected since solar panels do not have extensive spacing requirements like wind turbines, therefore it is reasonable to assume that the panels are dominant from a landscape perspective within the totality of the used area (Romanos Ioannidis, 2020). In the case of wind energy, the difference between direct and total land use is larger. This difference is justified by the fact that wind turbines are sited in distances of 3 to 10 rotor diameters apart (120–900 m for 40–90 m blades) to optimize the absorption of wind energy. This generates the requirement for larger and more complex land properties for wind energy projects. In Table 18 it is possible to see the estimation of the specific land use requirement value used for this assessment, the values for land use are referred to an official Italian report (SNPA, 2021).

*Table 18: Estimates of total land use requirements of wind and solar energy.*

| Type of renewable technology | Total land use per unit installed capacity |
|---|---|
| Wind onshore > 20 MW | 340 000 $m^2$/MW |
| PV (utility scale) > 20 MW | 15 000 $m^2$/MW |

Using the above values, the land use assessment for the additional capacity to be installed in 2050 is calculated and the results are shown in Figure 35 and Figure 36.

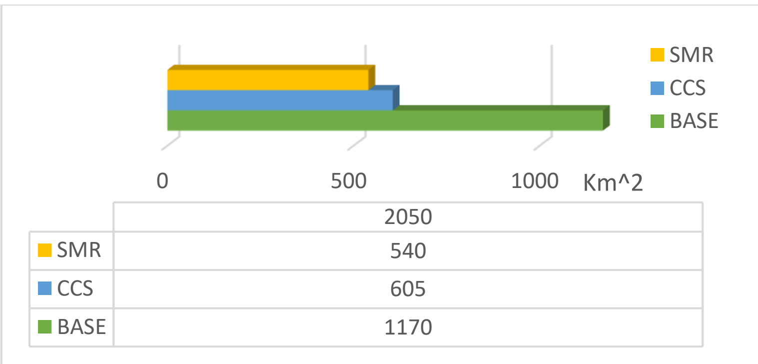
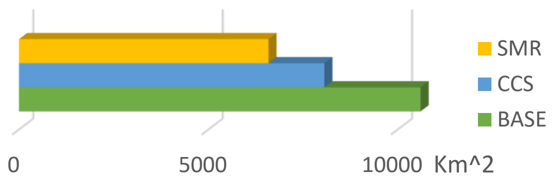



*Figure 35 occupied land by photovoltaics in different scenarios, 2050 horizon*




| | 2050 |
|---|---|
| SMR | 6583 |
| CCS | 8060 |
| BASE | 13260 |

*Figure 36 occupied land by onshore wind in different scenarios, 2050 horizon*

It is clear from the results of the analysis that the land requirement in the base case is significantly higher than in the other two scenarios, especially regarding photovoltaic installations.

An estimate was made of the area potentially available for photovoltaic rooftop installations and assumptions about the photovoltaic capacity that can be installed. It has been estimated that the percentage of roofs suitable for PV systems can vary between 49 and 64% across Europe (SNPA, 2021). Taking into account also the distance between panels to allow for maintenance, the results show that the net area available from the Italian buildings can vary from 682 to 891 km$^2$, with an estimated power of 66 to 86GW that could be installed on existing buildings. Assuming that 10% of all roofs are already installed, it can be concluded that there would be between 600 and 800 km$^2$ of available surface from buildings that could fully accommodate the additional capacity to be installed in the case of the CCS and SMR scenarios.

It is not easy to predict how many of the incremental GW that will need to be installed will be on the ground and how many on buildings; nowadays the distribution of this technology is around 42% on land and 58% on building (Confagricoltura & Elettricità Futura, 2021). To encourage self-consumption and to reduce the impact on land consumption, installations on buildings will be favoured, however, there will also be a need for large installations on the ground (giving priority to non-agricultural and non-greenfield land).

The PV demand for available terrain in the base case is almost twice than the base case and, although a limit to the technical potential of this resource has been set in the model, this scenario may reveal practical limitations related to the installation of the panels**.** Nevertheless, to the surface available from buildings, it can be added power that could be installed in parking areas, on brownfield sites or in other abandoned, degraded or marginal areas, without increasing land consumption. Another particularly interesting and innovative solution that is being developed lately is the agro-photovoltaic technology that would not result in the subtraction of used land.

The evaluation of the available terrain in Italy for onshore wind installation is much more complicated than that just described for photovoltaics. it is necessary to assess the land and wind conditions, the distance between the turbines and limitations regarding the landscape impact. All these aspects require the identification of large suitable areas of land, not easy to detect.  Even in this case, however, the land demand in the base case is higher compared to the other scenarios, as the capacity of renewables to be installed reaches its maximum technical potential.

### 7.2.1 Primary Energy Self Sufficiency

IEA defines energy self-sufficiency (or dependency) as the “ability of a country or region to fulfil its own energy needs” and it is calculated dividing the total primary energy supply of a country by its energy production (IEA, 2022). If the index is lower than 100%, the country or region is not self-sufficient and depends on imports from foreign countries.

In this paragraph is therefore evaluated the primary energy self-sufficiency of Italy in the different identified power systems projected to 2050. This is done primarily to assess the energy dependency of the country from the import of both electricity and fuel, the latter consisting mainly of natural gas and uranium in the case of nuclear power.

To do that, it is firstly needed to define the concept of “Total Primary Energy Supply” (TPES). It is defined by IEA as the total amount of primary energy that a country has available internally, and it is usually thought of as the sum of all energy extracted from natural resources. A coherent principle used to calculate the primary energy of different sources is the “Physical Content Method” (IEA, 2022). The principle of the method, in line with Eurostat also, is based on the evaluation of the “Primary energy equivalent” of the sources by considering the first flow downstream of the production process that has a practical energy use (Eurostat, 2022). Depending on the energy sources, the application of this principle leads to different situations:

- Regarding energy products form fossil fuels or directly combustible renewable fuels such as natural gas, gasoline, lignite and combustible municipal waste, the primary energy is defined as the heat generated during the combustion.

For non-conventional energy products that are not directly combustible this principle is differentiated into:

- Regarding geothermal and nuclear energy sources, heat is chosen as the main primary energy equivalent form. Certain conventions may be adopted in the following cases: if the amount of heat generated from a geothermal plant is unknown, the primary energy equivalent is evaluated from the generation of electricity with a thermal efficiency of 10% (low quality steam is generally exploited). If heat production is the main product, an efficiency of 50% can be assumed. If the amount of heat produced from a nuclear reactor is unknown, the primary energy equivalent is evaluated from the generation of electricity, assuming a thermal efficiency of 33%, derived as the average of European nuclear plant efficiencies.
- Regarding wind, hydro and solar energy sources, electricity is chosen as the main primary energy equivalent form.

After the evaluation of the primary energies, the final IEA energy balance is carried out adopting the same unit for each energy content: the tonne of oil equivalent (toe), defined as $10^7$ kilocalories (41.868 gigajoules). This quantity is equal to the net heat content of 1 tonne of crude oil.

In Table 19, energy productions obtained by the model for the different scenarios in 2050 are shown, broken down by different energy sources.

*Table 19 Electricity production by soruces in the different modelled scenaros [TWh]*

| | 2020 | 2050 Base | 2050 CCS | 2050 SMR |
|---|---|---|---|---|
| **Thermal from NG** | 162.8 | 14.8 | 167.1 | 120.8 |
| **Hydro** | 45.4 | 45.4 | 45.4 | 45.4 |
| **Wind (Offshore and Onshore)** | 20.1 | 281.8 | 103.7 | 105.5 |
| **Solar PV** | 23.3 | 112.5 | 60.2 | 65.8 |
| **Geothermal** | 17.9 | 10.9 | 15.1 | 18.6 |
| **Biomass** | 5.9 | 12.7 | 18.1 | 19.5 |
| **Nuclear** | 0 | 0 | 0 | 33.7 |

For the calculation of the heat generated during the combustion of NG, reference has been made to the average amount of fuel used to generate a kWh of electricity estimated by EIA in 2020 (EIA, 2022) for which 7.43 cubic feet are needed per kWh. It has to be highlighted, however, that the exact amounts of fuel per unit of electricity generated depends on the efficiency of the power plant and the heat content of the fuel which could vary by types of generators, heat content of fuels, power plant emission controls, and other factors. In this context, an average efficiency of 45% and an average gross calorific value of 38 MJ/m$^3$ were assumed, considering that:

$$E = m * LHV_{net} * \eta \tag{28}$$

Where:

- E is the amount of electricity produced [kWh]
- m is the amount of fuel consumed for the production of electricity [m$^3$]
- $\eta$ is the efficiency of the plant
- $LHV_{net}$ is the net calorific value (Lower Heat Value) of the NG [MJ/m$^3$]

It has to be considered that the IEA energy balance approach is based on the “net” instead of the “gross” LHV, in which the latent heat of vaporisation of the water produced during the combustion of the fuel is excluded. In this way comparability is ensured among all the elements of the energy balance, which are therefore expressed on the same net basis. Regarding the conversion of most forms of natural gas, the difference between “net” and “gross” calorific value is 9-10%, while for electricity and heat there is no difference as they are not combusted.
Regarding the category of biomass, it should be considered the calorific value of the feedstock based on the underlying scenario data. However, given the wide variety of biomass available for electricity production (organic fraction of municipal solid waste, agricultural waste, lignite etc.), it is difficult to identify a single LHV value, therefore the primary energy equivalent is evaluated from the generation of electricity assuming an average plant conversion efficiency equal to 33% is used. This corresponds to the net calorific value of the biomass needed to produce 1 kWh of electricity.

Having explained the previous assumptions, the evaluation of the Primary Energy Self-Sufficiency (PESS) is carried out as described by the formula (29):

$$PESS = \frac{Internal\ Primary\ Energy\ Supply}{Total\ energy\ production} \tag{29}$$

Specifically:

$$PESS = \frac{IPES\ (= El_{wind,solar,hydro} + \frac{El_{geot}}{10\%} + \frac{El_{biom}}{33\%})}{IPES + El_{import} + \frac{El_{Nucl}}{30\%} + \frac{El_{NG}}{45\% * LHV_{Net}}} \tag{30}$$

Where:

- $Internal\ Primary\ Energy\ Supply\ (IPES)$ is the sum of the primary energy that a country has available from internal resources such as wind, solar, hydro, biomass and geothermal. Each factor is calculated from the relative electricity production, following the IEA approach of the Physical Energy Content, as descripted above.
- $Total\ energy\ production$ is the sum of the internal primary energy and imported primary energy, considering both electricity import and electricity produced with imported fuel (Natural Gas and Uranium).

In Italy, 92% of the Natural Gas is imported from abroad (EIA, 2022) and, in the hypothesis of exploiting nuclear power, also the nuclear fuel would be imported, increasing the supply dependence of the country.

From these calculations, the Primary Energy Self-Sufficiency of the Italian power sectors in the different scenarios in 2050 are shown in the graphs below, by subdividing the primary energy within the country, i.e. all renewable resources, from the external primary energy, which is in turn subdivided into electricity imports and fuel imports: NG and uranium:

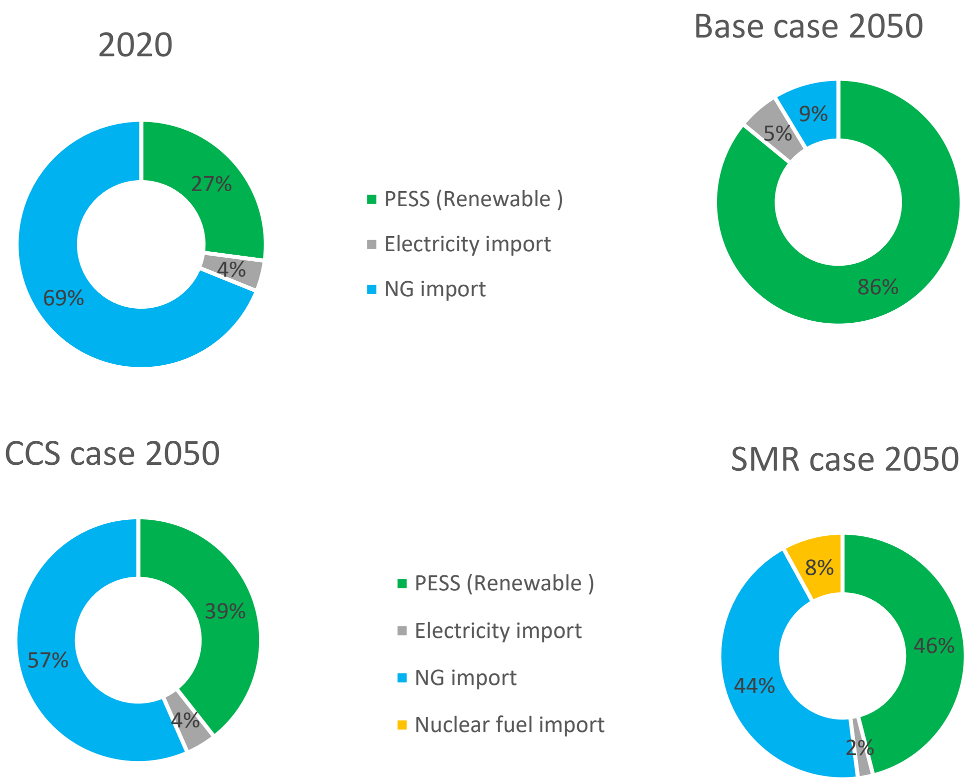



*Figure 37: PESS of the power system in the different scenarios, at 2050 horizon, compared to the 2020 situation.*

From the graphs, it can be seen how different the various scenarios are in terms of energy sufficiency. In the base case, it is evident that independence can be considered almost fully achieved since the resources used to produce electricity are almost entirely renewable (86%) and therefore internal to the country. These are wind, solar, hydropower, geothermal and biomass resources of energy, considering that the fuel used for biomass plants is internal to the country as well (organic waste fraction, agricultural and livestock residues, wood, etc..).

The remaining share of primary energy, 14%, is imported from abroad, distributed between 5% of electricity import and 9% of fuel import (NG). Among the 3 different scenarios, the import share of the base case scenario, is slightly higher, representing an increase compared to 2020. Although dependence on imports compared to today has decreased significantly, this aspect must be taken into account, pointing out that a large penetration of renewables needs more external support in terms of electricity import that can be harnessed at the moment of need, to deal with the high intermittency of renewables.

In the CCS scenario, the situation changes considerably. The use of natural gas becomes much more extensive, as CCS technology is widely exploited. For this reason, the import dependency of NG, in terms of primary energy, represents 57 % of the total, while the import is slightly reduced compared to the base case, representing 4 % exactly as it is currently. Imports from NG, despite making it possible to achieve emission reduction targets with respect to the 2020 situation, it still represents a significant share of the total, preventing Italy from increasing its energy independence, making it still highly reliant on external imports, both in terms of fuel and electricity. As far as renewables are concerned, they account for 39% of the primary energy of the Italian electricity sector, still representing a considerable increase compared to the situation in 2020.

The SMR case, on the other hand, with the addition of the possibility of installing nuclear power, makes it possible to further reduce the dependence of the country on the NG import to the 44%, leading to an increase of self-sufficiency in terms of internal primary energy of 46%. This scenario, however, providing the use of electricity from nuclear power, requires a related import of nuclear fuel, as Italy does not have significant internal reserves from which to obtain supplies. However, given the very high energy density offered by this fuel, the share related to nuclear power remains limited, allowing to obtain a rather different scenario from the CC. From these data, nuclear technology appears to be a valuable aid towards greater energy independence

Figure 38 represents the historical trend of the Italian self-sufficiency in the entire energy sector from 1970 to the present day, compared to the Finnish trend. as far as Italy is concerned, a fluctuation of around 18-20% can be noted, in particular it is evident a prolonged drop around due to the economic crisis of 2008, followed by a net recovery around 2012, a period in which the incentives for renewables allowed a massive installation of wind and solar PV energy plants, leading to an increase in self-sufficiency up to 27% in 2020. Despite the ups and downs, there is a general growth of up to 60% self-sufficiency in the entire energy sector.  This sudden rise can be explained by the fact that in 1980 2 nuclear plants (Loviisa, Olkiluoto), with a total of 4 reactors, were put into operation. The total installed capacity of almost 3000 MW is able to provide the 32% of the country's electricity in 2010 (World Nuclear Association , 2022).

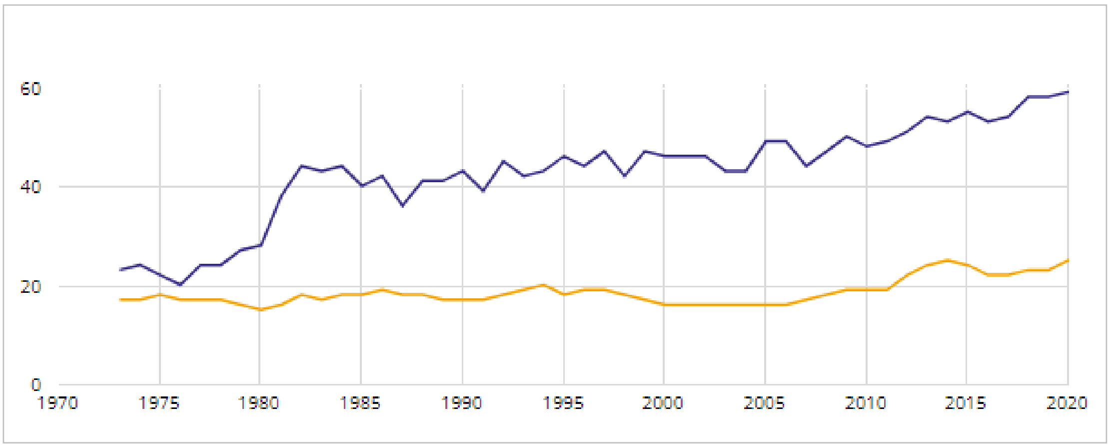



*Figure 38 Comparison between Italian and Finnish self -sufficiency (%) trend in the whole energy sector, (IEA, IEA Atlas of Energy, 2022).*

### 7.2.3 Renewable penetration

In Table 20 it is possible to see the share of renewable penetration in terms of how much electricity is produced from renewable sources (such as wind, solar, hydro, biomass and geothermal) compared to the whole electricity production of the different predicted scenarios.

$$RP = \frac{\sum Renewable\ electricity\ production}{Total\ electricity\ production} \tag{31}$$

*Table 20 Renewable penetration for the different predicted scenarios*

| | 2020 | 2050 base | 2050 CCS | 2050 SMR |
|---|---|---|---|---|
| Renewable production [TWh] | 112.6 | 463.3 | 242.0 | 254.8 |
| Fossil production [TWh] | 162.8 | 14.8 | 167.7 | 120.7 |
| Renewable penetration [%] | 41% | 97% | 57% | 68% |

The table shows how the penetration of renewables varies greatly in the different scenarios. The base scenario, where the share is 97%, represents a power system that would be almost entirely covered by renewables, with the related limitations linked to their intermittent nature, as for example the grid stability issue. The remaining two scenarios show a penetration of 57 and 68 % for the CCS and SMR scenario respectively. It should be noted, however, that fossil fuel production remains substantial and does not decrease considerably compared to the current situation. Particularly, in the case of CCS, production has even increased slightly, since CCS technology allows fossil fuel production without emissions. This aspect should be emphasised because, although emission targets are met in each scenario, a large share of the resources used in CCS and SMR cannot be fully considered sustainable.

## 7.3 Sensitivity Analysis

An economic sensitivity analysis was carried out for the different scenarios. All the main economic parameters were varied by 25% to assess their influence on the LCOE in the 2050 horizon. The results are shown below in Table 21.

From the table we can say, that generally, the discount rate is the most influent parameter, and this can be explained since the investment costs represent the main contribution to the LCOE in each scenario and discount rate has the greatest impact in calculating the LCOE of the investment cost. However, also solar and wind investment, both onshore and offshore, are important, especially in the base scenario in which, generally, capital investment is much more influential than in the other two scenarios, where the cost of fuel has a large impact on the final value of the LCOE.

The CCS case and SMR have modest variations referred to installed renewables capacities, except for the onshore wind, in which the variation is significant in the SMR case. However, the parameter that most affects these scenarios compared to the base case is the cost of natural gas. This aspect could be explored further as it creates a limit to the country's energy independence, binding Italy to geopolitical relations with countries such as Russia, Algeria, Azerbaijan, representing nowadays the main suppliers of natural gas (Statista, 2021).

Investment cost of storage is also a major contributor and has the largest impact in the base scenario, as it represents a substantial investment to counterbalance the variability of renewables.

*Table 21 Results of the economic sensitivity analysis. Change in % of LCOE varying the most influent parameters, 2050 horizon*

| | **Base Case** | | **CCS case** | | **SMR case** | |
|---|---|---|---|---|---|---|
| | **25%** | **-25%** | **25%** | **-25%** | **-25%** | **-25%** |
| **Cost of investment** | | | | | | |
| **Wind offshore** | 6.87% | -6.87% | 1.60% | -1.60% | 0.58% | -0.58% |
| **Wind onshore** | 2.45% | -2.45% | 1.71% | -1.71% | 3.08% | -3.08% |
| **Solar** | 2.09% | -2.09% | 1.79% | -1.79% | 1.65% | -1.65% |
| **Nuclear** | 0.00% | 0.00% | 0.00% | 0.00% | 1.09% | -1.09% |
| **Thermal** | 0.20% | -0.20% | 0.00% | 0.00% | 0.07% | -0.07% |
| **Thermal CCS** | 0.00% | 0.00% | 2.01% | -2.01% | 1.54% | -1.54% |
| **Storage** | 6.56% | -6.56% | 0.61% | -0.61% | 0.43% | -0.43% |
| **Cost of O&M** | | | | | | |
| **Wind offshore** | 0.90% | 0.90% | 0.70% | 0.70% | 0.20% | -0.20% |
| **Thermal** | 0.07% | 0.07% | 0.81% | 0.81% | 0.62% | -0.62% |
| **Nuclear** | 0.00% | 0.00% | 0.00% | 0.00% | 0.30% | -0.30% |
| **Import cost** | | | | | | |
| **NG import** | 0.40% | -0.40% | 8.02% | -8.02% | 6.78% | 6.78% |
| **Nuclear fuel import** | 0.00% | 0.00% | 0.00% | 0.00% | 0.08% | -0.08% |
| **Electricity import** | 1.88% | -1.88% | 1.58% | -1.58% | 1.28% | -1.28% |
| | | | | | | |
| **Discount rate** | 10.8% | -10.2% | 7.48% | -7.02% | 7.59% | -7.16% |

## 7.4 Limitations and future works

This model has the advantage of being very flexible and the temporal aspects are in general well treated, especially as it is an hourly modelling with three years of data, containing many different weather profiles which influence demand, PV and wind production. There are, however, some limitations, as well as applications for which the model is not designed for.

### 7.4.1 Excel limitations

The resolution method used in the search for solutions to the model is the Excel Solver GRG Nonlinear solver method. The Simple Linear resolution method available in Excel for Linear problems, is not suitable for the model presented in this thesis, since the non-linearity is most likely given by the operation of the storage. Therefore, running the problem with this kind of method, resulted in an error. The GRG method operates looking at the gradient of the objective function as the input values (or decision variables) change and when the partial derivatives equal zero, it determines the optimum solution. The completion time was generally around 1 hour or more. The obtained solution, however, presents some criticalities as it is highly dependent on the initial conditions and may not be the global optimum solution. More likely, instead, the solver stops at the local optimum closest to the initial values, reaching a solution that may or may not be globally optimized. Therefore, even small changes in initial values could have large impacts on results, while sometimes the solver would give results which were nearly identical to the original values. However, once the solution was found, an analysis of robustness was carried out, varying one at a time each of the initial values of the same quantity, checking how much the solution of objective function differed from the original simulations. This rough analysis revealed that in general the objective function did not deviate much from the original solution, reporting slightly different scenarios that could be defined suboptimal scenarios.

In general, the performance of Excel degraded with the addition of more features and due to its slowness, it was difficult to carry out several sensitivity analyses, and even performing simple tasks became problematic. In addition to technical performance issues, the results of the Excel Solver must be treated carefully.

### 7.4.2 Economic assumptions

The assumptions and data used have a major influence on modelling tools which may be highly sensitive depending on the different choices made. One of the main difficulties concerning the implementation of the objective function has been to assume a single price for each technology, which however differ greatly depending on the specificity of the installation. Electricity storages was assumed in the costs to consist entirely of batteries. This would not be realistic, especially in the base scenarios in 2050 that would need 650 GWh of electrical storage. This would not be possible using batteries; therefore, other storage technologies could be utilized as for example Compressed Air Energy Storage (CAES) or fuel cells.

Regarding the economical calculation, the investment part does not consider the hourly pricing of electricity, but rather only calculates a single LCOE value for the whole modelling. Critiques of LCOE are not scarce; a criticism could be for example, to disregard integration costs when the share of VRES becomes significant. The locational aspect adds significant costs to renewables that are in general less flexible compared to fossil fuel plants about where they can be sited. As a result, a larger grid is required to transport the electricity and associated grid costs are necessary to support the renewable system. Moreover, the balancing cost is not taken into account. i.e. cost incurred by the operator to overcome the uncertainty of the intermittent generation and ensure that supply and demand are always in balance. In addition, back-up costs, overproduction costs, and full-load hour reduction costs would need to be taken into account (Idel, 2021).While individual assumptions can be debated, it is necessary to emphasise the essential function of LCOE. The purpose of this thesis was to use a single economical parameter to compare different scenarios and LCOE remains a uniquely straightforward, transparent, comparable, and well understood metric. The usefulness of a tool such as the LCOE remains fundamental nowadays and it is widely adopted for modelling, policy making and public debate.

### 7.4.3 Modelling assumptions and future developments

The basic model for the realisation of this thesis was the one developed by doctoral student Tero Koivunen in the realisation of his master's thesis: "Modelling of a Carbon-free Finnish power system". His model pursued the same objectives of this thesis, adopting however a bottom-up approach, in which the target of an emissions-free electricity sector by 2050 was achieved without any emissions cap imposed. The main difference between the Finnish and the Italian model indeed, is the fact that only generation technologies such as renewables, and nuclear were adopted. In the original model, no fossil-fuelled plants have been included and, contrary to the Italian case, a massive presence of nuclear power is present. However, the possibility of varying this nuclear capacity, both by decreasing and increasing it, was analysed, as well as it was analysed the limitation of energy exchanges with neighbouring countries, in order to assess how the system would behave if it had to sustain itself almost autonomously. Moreover, hydroelectric production was simulated dynamically using a reservoir and hourly water inflow data.

In deep decarbonisation context, the model presented in this thesis represents a quite simplified version of the transmission grid, not considering the internal power network and assessment of transmission reliability and congestion risks. The expected large power flows from regions with high RE penetration and low demand (e.g. South) to regions with low RE potential and high demand (e.g. North) would require closer attention with dedicated grid modelling tools. Moreover, modelling only the power sector do not fully account for cross-sectoral synergies which are key aspects for capturing the dynamics of the energy transition. In this context, focusing on one sector only might lead to suboptimal solutions.

Another aspect that could represent a further development of the model, is the potential change of the demand pattern. Even if the volume change of the electricity demand is considered, the future electricity demand pattern is highly uncertain due to various factors, including climate change, e-mobility, electric heating, and electric cooling. Similarly, with regard to energy generation, using historical data to predict the future is also risky, especially considering climate change. The weather conditions could be drastically different, especially in 2050. Lastly, long time horizons make the comparison between future outcomes and real-world observations difficult, since unpredictable changes occurring over time and external events could affect the structure of the system, leading to different results.

# Chapter 8
# Conclusion

The main goal of this thesis was to develop a model of a carbon-free Italian power system, and to find out whether this type of power system is viable, both economically and technically. Results show that a low-carbon electricity system is possible and that emissions can be cut by 80-90% with respect to 1990 levels. Different scenarios were developed, and the two main scenarios of this thesis were the baseline scenario and the CCS scenario.

The CCS scenario turned out to be the most technically feasible since Italy is still rather dependent on fossil fuels such as NG but thanks to the introduction of CCS technology these plants would be still able to meet EU emission targets. The capacity of thermal power plants to be kept operational is indeed in line with predictions found in the literature, in which CCS technology is considered fundamental to the decarbonisation of the country and the required electricity storage could be implemented with EV batteries, thus requiring no dedicated electricity storage. The baseline scenario, however, proved to be less feasible considering the high capacity of renewables to be installed and the related problems caused by their integration and their intermittency. As a result, the storage demand needed for the system is rather consistent and unrealistic to be achieved with only electrochemical batteries. Curtailment was significant, but this could be due to sector coupling being not in the scope of this thesis. In addition, a scenario dedicated to the exploitation of nuclear energy revealed how this technology, despite presenting nowadays a very controversial technology with a large initial investment, could lead to an overall more cost-effective system. It could allow a generally lower installation of renewables and storage but especially it could be decisive in achieving greater energy independence in terms of fossil fuel and electricity imports.

The average cost of electricity in a decarbonised electricity sector would increase in the range of 40–120% by 2050 compared to today, depending on the scenario assumptions. The availability of CCS technology and the requirement for electricity storage are particularly important to achieve a complete decarbonisation of the electricity sector.

Future developments of the model could be implemented in some other modelling program rather than Excel, focusing on a more refined modelling of the transmission grid, taking into account also the internal power network and the assessment of transmission reliability and congestion risks. Another aspect to be implemented in the model could be the introduction of cross-sectoral interactions to better assess the feasibility of the proposed scenario, for instance by converting curtailed energy into gas, hydrogen or other fuel with power-to-x technology.

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