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"Impact of the investments foreseen in the Integrated National Energy and Climate plan 2030 on the electricity price."

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Abstract

This thesis aimed to estimate the impact of new investments in renewable energy sources, such as solar panels and wind turbines, on the electricity prices in Italy. The analysis is based on the Integrated National Energy and Climate Plan (INECP) adopted by the Italian Government in compliance with the European Union's Regulation (EU) 2018/1999. The research uses data from the 2018 day-ahead wholesale electricity market and focuses on four different hours on six days in March, July, and November. The analysis considered the production estimated for both sunny and windy days, and corrected for seasonal and zonal differences. The results showed that the future prices of electricity will be strongly influenced by the presence or absence of sun and wind. When the sun and wind are present, the price of electricity will potentially reach 0 €/MWh, especially in the southern zones, while on cloudy and not windy days, the price will return to 60/70/80 €/MWh, as in the status quo scenario. The study also estimate that the variability of prices will be higher in 2030 with the new investments in place. The findings of this research provide valuable insights for the energy industry and highlight the importance of stable infra-zonal connections for maintaining stable electricity prices.

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Introduction:

The Paris Agreement, negotiated by 196 parties at the 2015 United Nations Climate Change Conference, has led to the European Union's adoption of the Regulation (EU) 2018/1999. This regulation aims to ensure the implementation of a common European Union strategy concerning the energy market, decarbonization, energy efficiency, and research, with a temporary target of 2030. The Union-wide binding target is to achieve at least a 40% domestic reduction in economy-wide greenhouse gas emissions compared to 1990 and a level binding target of at least 32% for the share of renewable energy consumed in the Union[1].

In compliance with this regulation, the Italian Government has studied and published in December 2019 the final version of the Integrated National Energy and Climate Plan (INECP). The purpose of the thesis is to focus the analysis on the Investment foreseen by the Plan for Renewable Energy production and to try to estimate how this investment will impact the energy price in the electricity market.

The current research focuses strictly on the production curve of electricity. The INECP plan also comprises a broad group of investments: changes in the heating system; in the form of transportation; an increase in the efficiency of the energy-intensive sector; a new form of integration in the grid system; and more. Mostly all these topics covered in the plan will not be considered in the research but they will be taken into account in order to guarantee that the assumption we will need to take are the most realistic possible.

As it will better explain later the data we are using in the research are taken from the 2018 market. The specific market that we will take into consideration, at the wholesale level, is the day ahead market. We will analyze for this data four different hours, on six different days. The hours chosen to analyze are three in the morning, ten in the morning, noon, and six in the evening. The days chosen are one Wednesday and one Sunday, in March, July, and November. We will also distinguish in our analysis the different Italian market zones.

Since replicating the topology of the Italian grid it would be unworkable for the current thesis, we are taking as given all the zonal congestion, and we take as an assumption that other exchanges between zones are impossible, thus assuming full market congestion between zones. In our model, all the electricity that we expect will be produced in the various zones can only be dispatched there.

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[1] REGULATION (EU) 2018/1999 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 11 December 2018, Chapter 1, General provision, Article 2 (11). Website link

The thesis will be structured as follows: the first chapter will provide an introduction to the overall thesis topic and research question. The second chapter will present an overview of past studies related to the topic. The third chapter will explain the sources of the main data used in the study. The fourth chapter will detail the methods and models used in the analysis. The fifth chapter will present the results. The sixth chapter will explores the new equilibriums resulting from considering possible inter-zone exchanges. The final chapter will provide the conclusions and policy implications drawn from the research.

The impact of investment in renewable sources on the market price

The electricity market is interesting and has its particularities that are important to understand. It is a market where a product that no one can differentiate is sold. No one has the ability to distinguish from one Kilowatt-hour to another one. No matter how it has been produced, if it derives from the solar panel on your own roof, or from the coal plants situated a hundred km from your house. But one characteristic that everyone cares about in the production of electricity is when it has been produced. While no one cares if a normal product has been produced, one hour, one day, or even sometimes years before, no one would like to turn on the light and have to wait a given amount of time to have it. You want the electricity to be produced or at least dispatched exactly at the moment you need it[2].

To guarantee that everyone has access to electricity at the moment they need it, there are markets where electricity is sold for a given hour. The market we are studying is the Day-ahead market, where the negotiation takes place for the supply of electricity for the following day. The purchases and sales presented in this market are based on forecasts and estimations.

An additional characteristic that makes the electricity market so interesting to study is the coexistence of different production technologies. In the production of other goods and commodities, we are used to seeing the process that Schumpeter called “creative destruction”. A new technology with superior characteristics emerges and eventually replaces older, less efficient production methods, leading to their eventual displacement in the market. In the economy of electricity this not always happen, the coexistence of different methods of production is not only possible but it even helps to increase its efficiency. This is because different technologies have different fixed and variable cost mixes and production constraints. For example, the production of electricity through the solar panel or wind turbines has zero

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[2] Most of the time the production and the dispatching of electricity coincide because storing the electricity and dispatching it a second time it is really expensive.

variable costs, but it has a remarkable fixed cost; while on the other side, the production through gas plants has a lower fixed cost and higher variable costs – especially if we compare to 2022 market, where gas prices have reached unexpected peaks.

Once a solar plant or wind turbine has been installed, the cost of producing an additional kilowatt-hour is close to zero due to the low maintenance required. On the other hand, producing electricity through a gas-fired power plant incurs additional costs, including the cost of purchasing and burning the necessary gas, as well as labor and overhead expenses. Additionally, the emissions of carbon dioxide associated with producing that kilowatt-hour also add to the overall cost. Furthermore, while gas-fired power plants can be quickly brought online to meet energy demands, the availability of solar and wind energy is dependent on weather conditions, making gas-fired power plants a necessary component for ensuring grid stability, in addition to efficiency.

Given the existence of various power plants with varying costs and unique attributes. It is essential to understand the method used to select the power plants to purchase electricity from in the energy market.

In the maximization problem of producing the required amount of electricity at the lowest price, the most efficient solution is to order the power plants according to their increasing marginal costs. This model is called "Merit Order Dispatching".

Based on this cost-minimization solution:

- all the plants with a marginal cost of production lower than the System Marginal Cost[3] (SMC) will produce and sell at their maximum;
- the plant with a marginal cost equal to the SMC will produce only a fraction of its maximum;
- all the plants with a marginal cost higher than the SMC will not be producing.

Therefore in the Merit Order dispatching, Renewable Energy Sources (RES) are dispatched to the market with the highest priority. After that are dispatched all the other plants following that order, typically: Nuclear[4], Coal, Gas, and Oil[5].

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[3] Anna Cretì and Fulvio Fontini, 2019. "System Marginal Cost (SMC): the cost for the electricity system of serving one unit more of the load." *Economics of Electricity. Markets, competition and Rules,* Cambridge University press, page 102.

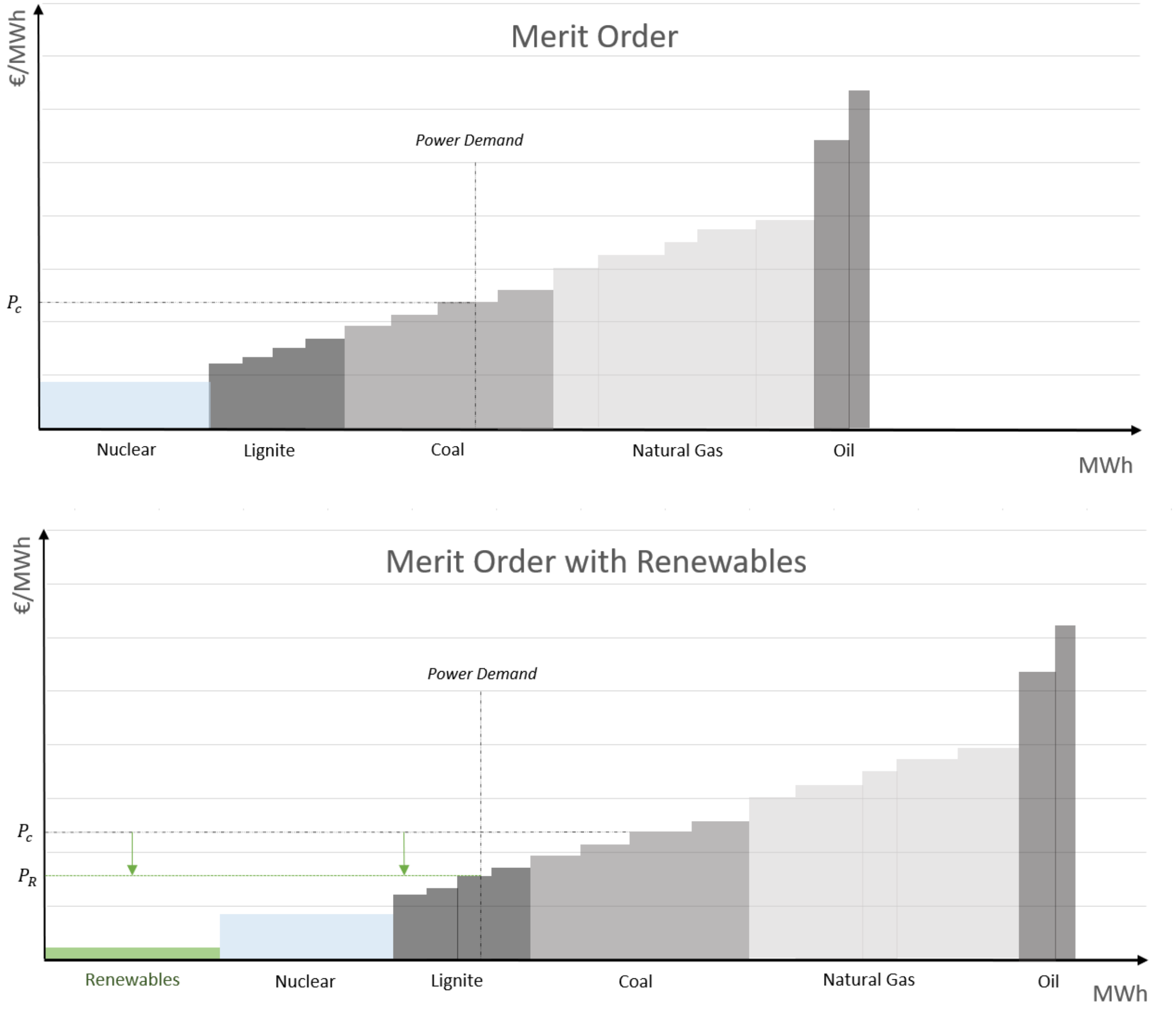
[4] Nuclear is not in the Italian energy production mix, but we import a not negligible amount of electricity from country where nuclear is in the energy mix, therefore we consider it meaningful to taking in account it.

[5] *"Project Costs of Generating Electricity",* International Energy Agency, Nuclear Energy Agency, 2020.

The increase in electricity production from RES results in displacing the conventional plants from the market, since as already said they have lower or even zero marginal cost. The outcome of that process is the decrease of pollution, thanks to the lower amount of fossil fuels needed to clear the market, which leads to a gain in social welfare due to positive externalities of lower CO2 emission[6]. This effect lowers the market-clearing equilibrium prices. It can be seen graphically in chart 1, reported below.

In the graph, the electricity demand is considered stable and inelastic to the price. In reality, the new production by RES can have such a strong impact on the price of electricity that will even be able to cover a higher demand. After the implementation of a high quantity of RES, the new equilibrium is, therefore, possible to have not only a lower price but also a higher amount of electricity dispatched.

Chart 1; Electricity price fluctuations due to the Merit Order Effect.



Source: Own elaboration

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[6] María PazEspinosa, CristinaPizarro-Irizar, 2018. *Is renewable energy a cost-effective mitigation resource? An application to the Spanish electricity market.* Renewable and Sustainable Energy Reviews. Website link

It is really meaningful to see that this is already happening today, last year - 2022 - gave us perfect proof of that. The Sunday of July 2022 reported in chart 2 shows that during the hours of high consumption, and pick production of solar panels, the prices decrease by more than half, and expensive fossil fuels production plants were crowded out by the production of solar panels.

The purpose of this thesis is to predict the impact on the price of electricity after the new plants will be installed, with respect to the price seen previously, our benchmark is specifically 2018 prices.

Literature review

The current chapter provide an overview of the existing research related to the impact of renewable energy sources to the electricity market prices. This chapter present and analyse the main previous studies and work that have been conducted in the field. The Merit Order Effect have been studied multiple times for different countries, the bibliography reported below contains study from Spain, Germany, Italy, Ireland and US. Most of the presented paper do study the impact ex post, but their analysis is fundamental to understand and consider all the implication, as, changing in the market behavior, new investments in fluctuation generation capacity, or on the analysis related to cycling costs.

Clò, Cataldi, and Zoppoli (2015) in their research, examined the effect of solar and wind generation on the Italian wholesale electricity prices in the day-ahead market. Their findings revealed the existence of the merit-order effect for both wind and solar. Over the period 2005-2013, an increase of 1 GWh in the hourly average of daily production from solar and wind sources, on average, resulted in a reduction of wholesale electricity prices by 2.3 €/MWh and 4.2 €/MWh respectively and implied volatility. However, they also found that the savings from solar were lower than the costs of the supporting schemes. On the other hand, the total savings from wind were greater than the related supporting schemes. Additionally, analysis on a year-to-year basis revealed that the impact of renewable energy sources on prices and the net monetary benefits decrease over time, in correspondence with the increasing degree of penetration of solar and wind sources.

Gullì and Lo Balbo (2015) investigate the impact of intermittent renewable energy sources, specifically photovoltaic (PV) production, on Italian wholesale electricity prices. The authors estimate that during the period 2010-2012, the merit-order effect of PV production was around 10€/MWh. However, this was almost offset by a rise in market power, resulting in prices remaining unchanged despite a significant drop in demand. The decrease in demand is likely due to the portion of electricity that is self-consumed on-site by customers. The authors identify a threshold of 50% of peak power demand as the level beyond which an increase of 1% in renewable energy sources induces a reduction of wholesale electricity prices by 0.88€/MWh. The authors note that when power markets are imperfectly competitive, PV generation may not provide significant direct benefits in terms of decreasing spot prices.

Beltrami, Fontini, and Grossi (2021) conducted a study on the role of renewable energy sources (RES) in the Italian power market exchange. The study used zonal hourly micro-data from the

Italian day-ahead electricity power market for 2018. The researchers found that large and small-scale wind and solar generation in 2018 resulted in nearly 19 billion euros in economic savings. The weighted average energy price in each mainland zone of Italy would have been more than double if RES production was not present. The study found that hydro played the most important role in balancing demand in the North zone and the absence of other RES sources would have only led to a 13% increase in the weighted average price. The North and Central zones were found to have the highest savings from RES, while the savings from RES in the Southern Italian zone were relatively small.

O'Mahoney and Denny (2011) conducted a study on the impact of wind generation on the Irish electricity market and its effect on merit order. Using an hourly Ordinary Least Squares (OLS) regression model for the year 2009, they estimated a positive impact resulting in a total saving of 141 million euros. They found that the total cost of electricity in Ireland would have been 12% higher without the presence of wind turbines. The savings were higher than the subsidies, even without considering the cost of carbon emissions.

Espinoza and Pizarro-Izar (2018) examine the overall effect of renewable energy policy in Spain from 2002 to 2017. The study calculates the net social cost which includes: the Merit Order Effect, resulting from the dispatching of renewable energy production; the cost of regulation that raises the final price of electricity; and the environmental benefit in monetary terms, due to the reduction of CO2 emissions. The results for the period studied (2002-2017) indicate that after 2010, the increase in regulatory costs had a negative impact on the economic savings from renewable energy sources. As a result, the promotion of renewable energy had a positive net unit social cost (estimated at around 20 €/MWh) which was ultimately passed on to consumers.

Gelabert, Labandeira, and Linares (2011) conduct a comprehensive ex post analysis of the impact of renewable energy on Spanish electricity prices. The study examines the utilization of technologies and hourly prices between 2005 and 2010, and provides an estimate of the actual Merit Order Effect of the integration of renewable sources and cogeneration on Spanish Wholesale electricity prices. The paper states that a marginal increase of 1 GWh of electricity production using renewable and cogeneration results in a decrease of nearly 2€ per MWh in electricity prices. Over the analyzed period, this reduction accounted for an average of 4% of total prices.

De la Nieto and Contreras (2020) analyzed the impact of renewable generation on day-ahead electricity market prices in Spain. They conducted a study over 16 days in 2015 and estimated the effect of renewable energy on the market. The results showed that the greater the participation of renewable generation in the electricity market, the greater the downward effect on prices. According to their study, the prices of electricity in the day-ahead market could have increased by 10 €/MWh if there were no production from renewable energy sources.

Senfuss, Ragwitz, and Genoese (2008) conducted an analysis of the merit-order effect of renewable electricity generation on spot market prices in Germany. They found that in the year 2006, the reduction of the unweighted average price reached 7.8 €/MWh. Furthermore, they discovered that the cumulative merit order effect increased each year, from 1 billion € in 2001 to 5 billion € in 2006, thanks to the new investments in RES. Additionally, the study highlighted the importance of CO2 and fuel prices, such as natural gas and coal, as drivers of final equilibrium prices.

Gurtler and Paulse (2018) conducted a study on the impact of wind and solar power forecasts on day-ahead and intraday electricity prices in Germany. Using a panel data analysis and a dataset with 24 daily observations of day-ahead and intraday prices from 2010 to 2016, they estimated that there was a price dampening effect of both solar and wind power, with approximately 0.6 €/MWh decrease in price per additional GWh. They also found that a decrease in forecasting errors for wind and solar power generation would lead to a decrease in price volatility. The estimated magnitude of the price effect of forecasting errors of 1000 MW was of 1 to 5 €/MWh. However, they estimated that increasing the flexibility of the existing power generation portfolio and adding more fluctuation power generation capacity would reduce the impact of ramping or rescheduling needs.

D. Mills, Levin, Wiser, Seel, and Botterud (2020) synthesize the available literature, data, and analysis on the impact of variable renewable energy on wholesale markets in the United States. According to their findings, in the US the main driver of the decrease in prices from 2008 to 2020 was the decrease in the price of natural gas. However, they observed a significant impact in areas where there was a high concentration of renewable energy sources (RES), nuclear or coal generation, along with limited transmission. Despite the expectation that wholesale energy prices will decline with increasing RES penetration, the studies surveyed by the authors show a general trend of increasing prices for regulation reserves with higher levels of RES penetration.

Haas, Lettner, Auer, and Duic (2013) reported that the introduction of a large number of solar panels into the electricity market in Germany has two important effects. Firstly, as seen in other studies, the new production with zero marginal price pushes out conventional electricity plants and decreases the market equilibrium price. Secondly, when renewable energy sources are scarce the cost at which electricity is offered by conventional plants is higher than in the previous market equilibrium. With new investments in renewable energy sources, natural gas plants have now reduced their full-load hours per year from 6000 to only 1000-2000, cause by the need to amortize fixed costs over fewer hours. The authors forecast that the market will adapt to these changes in the long term through the adoption of new forms of electricity storage and growth in balancing markets. They also anticipate an increase in price volatility and overall higher prices for electricity produced by fossil fuels and storage.

Data

Data used to replicate the 2018 electricity market

In our analysis we have built our database using various sources. To replicate the day ahead market, with hourly precision, we have extracted our data from two different sources, the Italian "Gestore del Mercato Elettrico" (GME) and the European "Network of Transmission System Operators for Electricity" (ENTSO-E). Six different days, and four different hours from 2018 have been taken as period of observation. In order to have a representative sample we have chosen to take one typical working day, in our case Wednesday, and one day of the holiday, Sunday, of three different months: March, July, and November. For these six different days, we have chosen to analyze four different hours: three in the morning, ten in the morning, noon, and six in the evening.

In this way we have analyzed the situation in three representative periods of the year, analyzing March and November we have two different months with similar behavior from industrial production, not linked to any holiday, with different solar radiation and wind impact. In July we have the maximum solar radiation and a high level of use of air conditioners. The choice to analyze a working day and a holiday is due to the fact that during holidays the consumption of electricity is strongly different from a working day: stops in industrial production strongly decrease the consumption of electricity.

As in the choice of the day and the month, we have taken into account four different specific hours that have a strongly different demand in the market. Three in the morning is the hour when typically there is a minimum in the electricity demand, homogenously in the different periods of the year, ten in the morning and six in the evening are the typical moments of high pick, especially in the working days, and noon[7] it has a high level of consumption and the pick in production for the solar panel technology.

In the graphs reported below, one can notice how electricity consumption changes during the different hours of the day, during the different days of the week, but also depending on the considered month. Working days have a higher use of electricity and also a higher variance between different hours. While we can note that in the three months reported, the greatest variance is found between Sundays. In particular, we can see how on Sunday in July there is little variance along hours, probably caused by the important use of air conditioners used independently from the hour of the day. While on the November Sunday reported below, we

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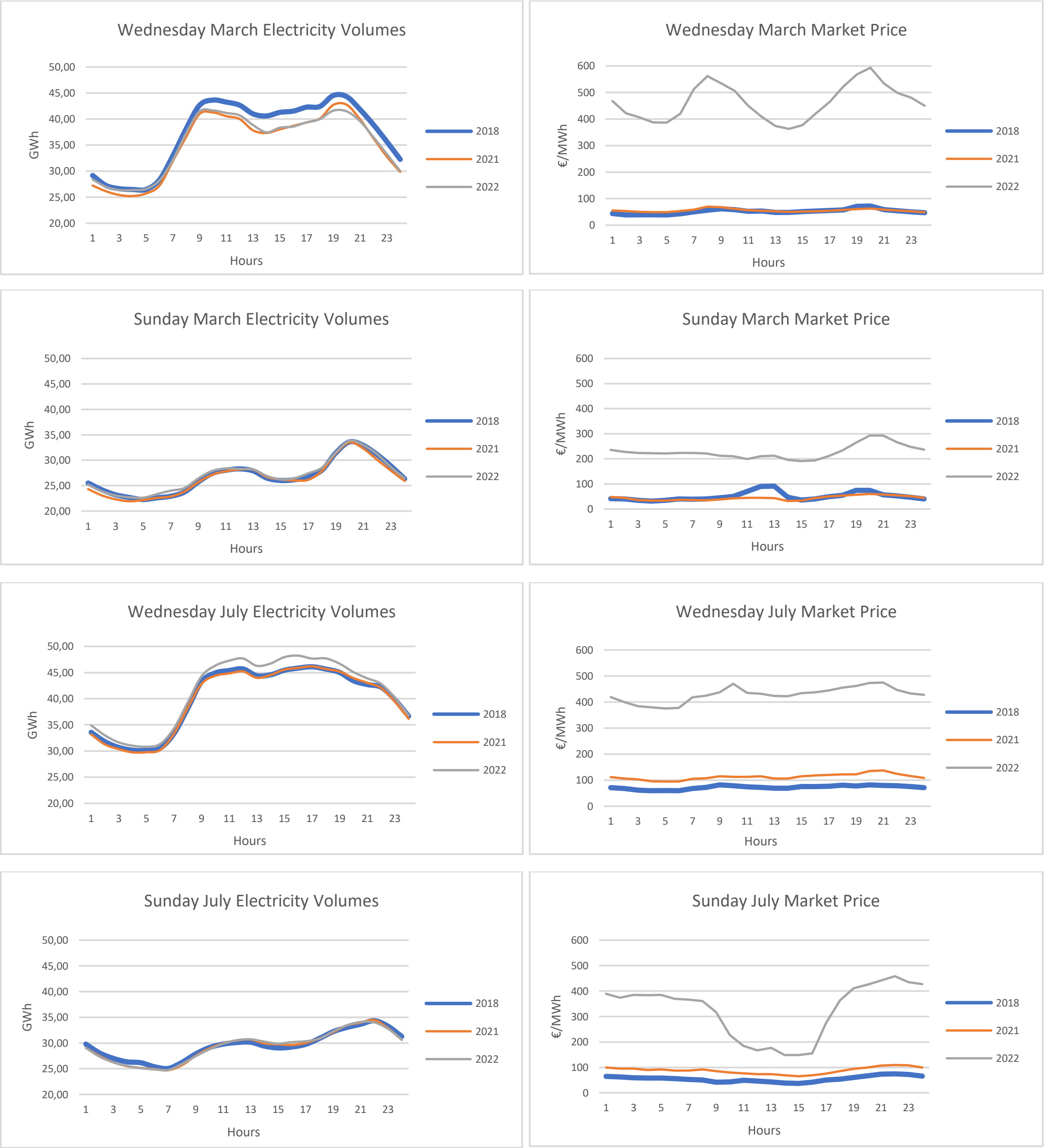
[7] In our analysis we have always considered solar time, in order to solve the problem of Daylight Saving Time applied in Italy in the Summer months.

can observe a particularly high peak in the evening hours plausibly caused by the lighting, November being a month in Italy when the sun sets earlier[8].

Chart 2; Eight-Day Analysis of Electricity Volume and Price Trends



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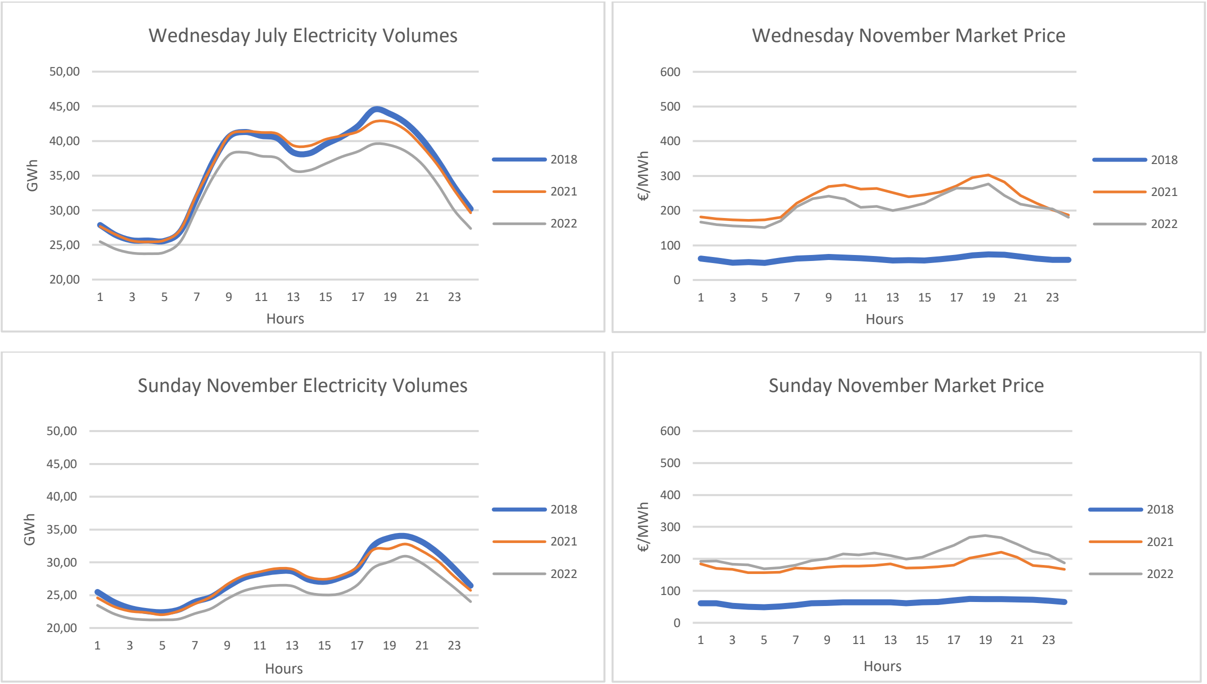
[8] In these graphs the time is not standardized on solar time, but is shown considering the time changes.



Source: Own elaboration [9]

Our data collected by the GME contains all the electricity supply and demand bids on the day-ahead market (MGP). The offers are disaggregated by zones and have an hourly frequency. The choice to analyze the year 2018 can be motivated by various reasons. As noticed by Beltrami et al. 2021[10], 2018 is a representative year of the previous four years and it is also representative of 2019. All the key indicators relevant for our analysis - plant position in the merit order, fuel mix, electricity consumption, and generation - can be considered similar.

The sequent year 2020, 2021, and 2022 have different problems that make us consider them not appropriate to base our forecast for the time horizon that we have.

- 2020: It is not considered suitable since the Covid-19 pandemic has strongly hit the Italian market. The temporary and mandatory closure of companies and production systems has decreased the consumption of electricity with no possible comparison in the past. Today we can be confident to say that even if some structural change could

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[9] The graph reported the data downloaded from the GME website, in the section where Results and Statistics are exposed - Website link.
The day to which the graphs refer for 2018 are: the 7th and 11th of March, the 4th and 8th of July, and the 14th and 18th of November.
The volumes (GWh) reported are all the volumes of Electricity purchased in the market for all Italy in the Day-Ahead Market. The Market prices (€/MWh) represents the hourly market price for the all Italian Market, since Italy is divided in 7 different Market Zones, due to constraint in the National Grid Electricity Transmission, the price presented can differ to the specific Zonal Market Prices.

[10] Filippo Beltrami, Fulvio fontina, Monica Giulietti, Luigi Grossi, 1 June 2021. *The Zonal and Seasonal CO2 Marginal Emissions Factors for the Italian Power Market*. University of Verona, Department of Economics.

have remained, the 2020 year cannot be considered in any way a good approximation of the future market.

- 2021: We have reported in the previous graph both the consumption and the prices of electricity during that year because both variables have been fundamental in considering which year was the most appropriate to analyze. During 2021 we know, and can see from the graph, that in the first part of the year, March in our analysis, the pandemic was still a problem, and certain regions and provinces were still in lockdown. The lockdown was not comparable to the 2020 one, but it had a structural impact on the consumption of electricity. The prices on the other side were completely comparable to the ones seen in 2018. We feel confident in saying that the impact of the decrease in consumption in that period can be considered temporary because looking at the following months when the lockdowns were no more in place, the amount of electricity consumed is consistent with the one consumed in 2018, even if the price of electricity was considerably higher.

  In November 2021 we had the opposite problem, the decrease in production caused by the pandemic was completely forgotten and prices started to raise. The increase in the prices was mostly driven by the increase in the price of Gas, which started to increase in the second quarter of the year. During that period, across the world there was an intention to forget the closure and to come back to the previous way of living, increasing not only traveling but also all the production system. However, as we have seen, the previous value chains were broken. Some time to erase the friction created by the stop was needed. We have seen the impact of it, not only on the price of gas but also on other products that have driven inflation back to a level not previously observed in western countries in the last 30 years.

  An interesting analysis published by The Oxford Institute for Energy Studies shows how the “European gas market in 2021 faced a ‘perfect storm’ of limitations on supply and a year-on-year rebound in demand in both Europe and elsewhere”[11]. The European production of Gas during that period decreased, and the import from Russia was already strongly lower. The demand for LNG from the Asian market was pushed by the increase in the production of China and Japan. Low output of hydro energy in Brazil and Chile, and lower production from Argentina increased the demand from south America and consequently the price of LNG. If we cannot bet that the price of Gas in 2030 is going

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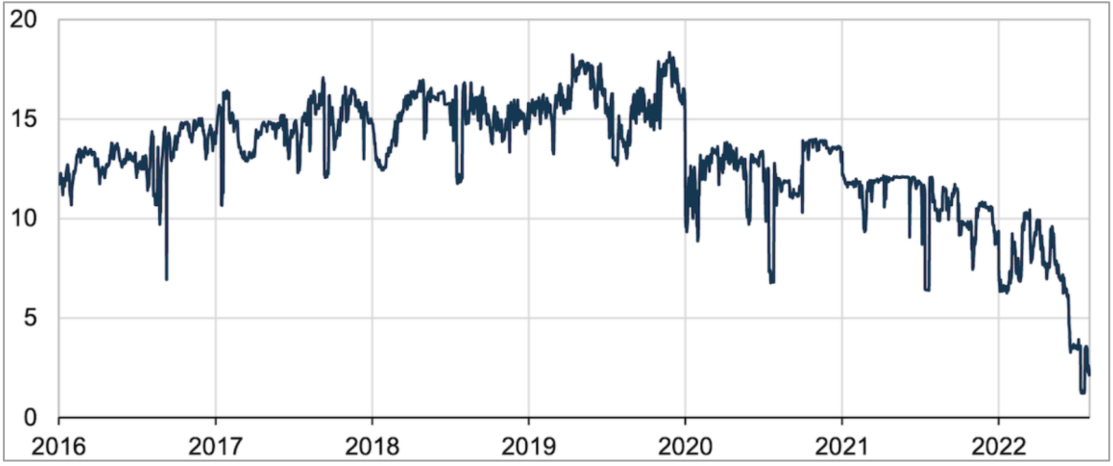
[11] Mike Fulwood, January 2022. *Surging 2021 European Gas Prices – Why and How?,* The Oxford Institute for Energy Studies. page 2.

to be as low as in November 2018 we can be convinced that with the proper investments and buffer it is not going to be as high as in November 2021.

We concluded that 2021 would not be a good starting point to forecast the future. Moreover, since we are interested in researching how the new investment will impact the price and production in the various period of the year, 2021 doesn't seem to be appropriate. Indeed, it had a period with low prices and low demand, and a period with similar demand to the previous year but with completely different prices.

- 2022: Following what happens at the end of the year 2021 the sequent year has been even worst for Gas and Electricity prices. The 24th February 2022, Russia started the invasion of Ukraine and prepared the war cutting its supplies of gas to Europe straight from the autumn of 2021.

Chart 3; Daily natural gas pipeline exports from Russia to Europe (Jan 1, 2016 – Jul 31, 2022)
Billion cubic feet per day



Source: U.S. Energy Information Administration - EIA[12]

According to Eurostat, Russia during the period 2016 to 2020 accounted for about one-third of European's and the United Kingdom's supply of natural gas via pipeline. During the year 2022, this value has been cut at the behest of Russia but not only. Europe and Italy have searched in any way different supplies of Gas. But the limitation in present pipelines for import from other countries, and limitation in importing GNL, has obliged all countries of Europe to accept all the gas possible from every source driving in this way gas prices really high. The main problem of the European government in 2022 was not the price of gas but the quantity of gas. Understandably risk of blackouts and the

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[12] Victoria Zaretskaya, Warren Wilczewski, August 2022. *Russia's natural gas pipeline exports to Europe decline to almost 40-year lows.* U.S. Energy information Administration. Website link. Data source: Refinitiv Eikon, based on data provided by the European Transmission System Operators. Note: Russia's natural gas exports by pipeline include exports to the European Union and the United Kingdom as measured by daily flow volumes at the main entry points in Germany, Slovakia, and Poland.

inability to provide gas for households heating were the two variables that were mainly considered in managing the market.

Furthermore, Europe after the invasion of Ukraine put an import ban on all forms of Russian coal and Russian Oil. They were not in force since the start of the year, but they progressively push the price of both commodities at a higher value, impacting in the same way electricity prices, as it happened with gas.

The last big impact on the European and Italian Electricity market in 2022 is due to the closure of several French Nuclear Plants for extraordinary maintenance. On November 2022 the cumulative output of the year from Nuclear was 23.7% lower than the previous year . France being the world's largest net exporter of electricity, this had a big impact on the European electricity market, and it has also directly increased the demand for gas due to the need to temporarily cover electricity production with gas power plants.

Italy imports nearly 14.5% of its electricity demand. In 2021, out of 319.9 TWh of electricity demand, 46.6 TWh were imported. Most of it is directly from France and Switzerland which is closely linked with the French electricity market.

To conclude the analysis of the past year we can optimistically say that in the future it is not so probable that all the constraints that occurred in the past year will be present, at least not simultaneously, making 2022 the year of bad records. On the demand side, we can notice that in 2022 we had a high demand in July, due to the heat wave that hit Europe, especially the Southern countries. In the rest of the year, in our graph for March and November, we can see that the population decreased strongly the consumption to manage the increase in prices.

We will try now to assess what can happen in the future, and if it can be reasonable to use the data of 2018 as a good approximation to base our forecast.

On the gas price side, we can say that the prices reported for gas in the INECP were already expected to increase by roughly 15% in the next 10 years[13], so it is reasonable to say that the prices we are going to use will be slightly lower than what is expected to be in 2030. We can also consider that a 15% increase in 10 years is lower than the inflation goal of the ECB, so it is not a strong variation for what we should consider in our analysis. Moreover, it is far less likely that Europe and especially Italy will be again hit so strongly by an external impact. The efforts made this year to guarantee supplies that are diversified from geopolitical risks will

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[13] Ministero dello Sviluppo Economico, Ministero dell'Ambiente e della Tutela del Territorio e del Mare, Ministero delle Infrastrutture e dei Trasporti, December 2019. *Piano Nazionale Integrato per l'Energia e il Clima.* Page 212.

guarantee more stability; new pipelines and gasifiers take time to be built, but once they are in place they guarantee to buffer for long periods of time.

On the estimation, the consumption of gas in Italy is expected to decrease from 74.5 billion cubic meters (BCM) in 2019 to 61.8 BCM and 54.4 BCM; in 2030 and 2040 respectively, this is due to an increase in energy efficiency and the expected use of modern technologies. The use of Biomethane and Hydrogen will then help to decrease Italy's dependence on gas imports. Biomethane is expected to grow from a production of 0.1 BCM in 2019 to 1.0 BCM and 7.0 BCM in 2030 and 2040 respectively; Hydrogen is estimated to be produced in 0.1 and 3.9 BCM of methane equivalent in 2030 and 2040 respectively[14].

Analyzing all this data together we can say that in the medium term, it is reasonable to expect prices similar to the one measured in 2018 plus some factors closely related to the overall Inflation.

The last variable that we have analyzed for the different years is the Installed capacity for the generation of electricity in the Italian market. The total installed capacity (GW) in 2018 was 115.22 GW, in 2021 increased to 117.16 GW, arriving in 2022 at 118.40 GW. The changes in different sources are shown in the graphs below.

The changes between the years 2018 and 2021 are not substantial. The increase by year of solar plants installed is about 0.8 GW, and the increase in wind turbines is about 0.3 GW a year. Therefore we can say it is only a slight change. Instead considering 2022 the change is much greater, but these new plants installed will be directly considered in our study among the plants already programmed in the INECP.

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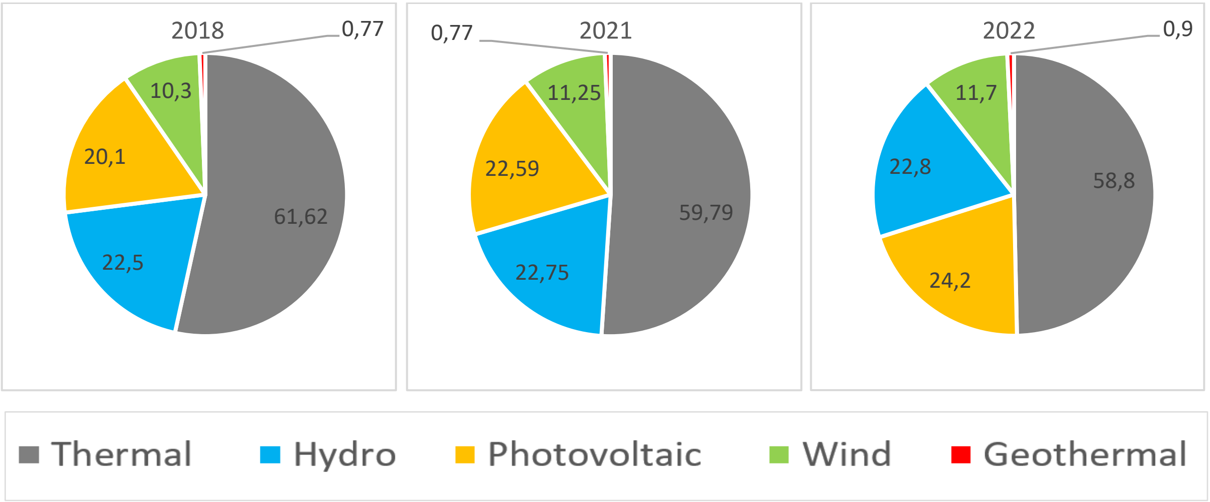
[14] Terna – Snam, 2021. *Scenario National Trend Italia.* Page 8. Website link.

Chart 4; Generation Installed Capacity.



Source: Own elaboration based on Terna data

One last constraint that we had to take into account using 2018 data was the zonal division of Italy. In 2018 the zonal configuration of the market comprised 10 zones, while today, and in the future, the Italian Market zones are seven: North, Centre-North, Centre-South, South, Calabria, Sicily, and Sardinia. From 2018 to today, four production hub have been eliminated: Priolo, Foggia, Brindisi, and Rossano; and one market zone have been added: Calabria. This has been done for optimizing the market negotiation and avoiding grid security problems, increasing in this way it's efficiency.[15] To solve these differences we had to make certain assumptions. We had added the plants of Foggia into the South zone, we had considered the coal plant of Brindisi as turned off, and we had considered Priolo and Rossano as they were in the past given their low output. It is important to underlain that given our previous assumption, we have maintained in the data all the zonal market exchanges that happened in 2018, in this way all the energy sold by Priolo and Rossano have been already taken into account in Sicily and Calabria – South in our analysis - zonal market exchanges.

Different assumptions have been done for the market zone of Calabria. Having all the data disaggregated for production and demand it would have been theoretically possible to divide the two market zones, South and Calabria, but without a correct replication of the topology of the grid, the results would have not been realistic at all. Given our assumption, we should have considered all the exchanges with Sicily as they happened, but we could not forecast the exact exchanges with the new South zone. Therefore the past exchanges between Sicily and Calabria, without considering possible mitigation with the exchange between Calabria and the South would have made an unrealistic prediction model.

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[15] Terna, 8 February 2021. *The new electricity market zones: what you need to know*. Terna Lightbox. Website link

In this case, the assumption that we have taken is to consider the two current markets as one united market, in reality, this assumption is realistic if the two markets are perfectly connected and do never have zonal congestion. If this happens all the electricity required or produced in one zone moves freely to the zone with the highest prices eliminating all the arbitrage possibilities.

Data used to forecast the changes.

The second group of resources from which we have drawn is the one used to forecast the quantity of electricity that will be sold in the market by the investment that we are studying.

First of all, we have taken from the National Plan the nominal power of production of the new investments, which are foreseen to be in the all-Italian market 39 new GW of renewable power plants. Moreover, to locate whether the investment is going to be implemented we have used the 2021 Development Plan published by Terna[16].

On the maps reported below it's possible to visualize the amount of power (MW) of the new investments and their distribution in the national territory. The distribution reported is the one used in our study.

Figure 5; New installed power capacity - Solar panels

Source: Own elaboration based on Terna data

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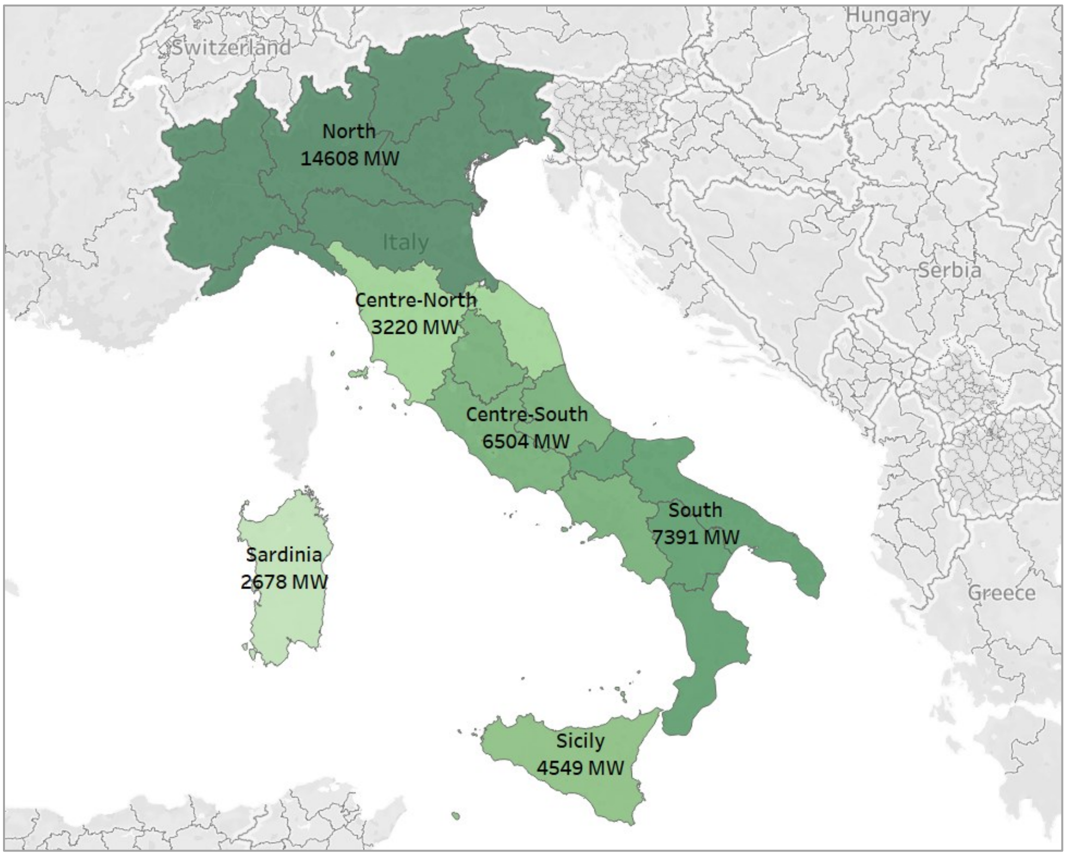
[16] *2021 Piano di Sviluppo Evoluzione Rinnovabile, Rinnovabili: scenario NT-Italia vs sensitivity NTSTMG al 2030,* Terna. Website link.

Figure 6; New installed power capacity - Wind turbines

Source: Own elaboration based on Terna data

Figure 7; Total New Installed Power Capacity



Source: Own elaboration based on Terna data

For our analysis differences in the period of the year and the hour of the day have a strong impact not only regarding consumption but also regarding the production of energy sources. Therefore we had to estimate for each hour the possible real production of the new investments.

The source that we have used to estimate these changes is the website Renewables.ninja[17]. This website allows running simulations of the hourly power output for solar and wind energy plants located in the world, with high precision for Europe.

The production of electricity through wind turbines does not have any correlation to the hour of the day, while the production of energy through solar panels is strictly correlated to it.

For solar panels, we have considered a capacity factor of 100% for noon, 60% for 10 a.m., 20% for 6 p.m., and of 0% for 3 a.m. These factors are not perfect but are a good approximation for our study. The production of solar panels also depends on the direction in which they are oriented and on their inclinations. We have assumed the best possible configuration for both factors: an orientation towards the south and an inclination of 35%. For wind turbines, we have considered a capacity factor of 100% for all the hours of the day.

On the other side, we have differentiated the capacity factor both for solar panels and wind turbines concerning the different periods of the year and the different geographic positions. Thanks to the Renewable.ninja source we have been able to select seven geographic positions related to the seven zonal markets.

Before analyzing the graphs shown, we believe it is important to define what the Capacity Factor is:

> *"The capacity factor (on an annual basis) is the ratio of the mean delivered power over the nameplate capacity (both in MW); alternatively, it is the ratio of actual yearly production over the theoretical maximum that would be achieved if perfect wind conditions lasted all year long (both in MWh)"*[18]

We can refer to this definition also for the solar panel. If there was sunshine for the whole day with a perpendicularity to the position of the panel always of 90°, with no clouds or overcast skies, the capacity factor of the panels would be 100%.

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[17] Website link. The graphs shown below were created through the website and refer to the 2019 dataset.

[18] N.Boccard, 2013. *Economic Implications of Wind Power Intermittency,* Encyclopaedia of Energy, Natural Resource, and Environmental Economics, Module in Earth Systems and Environmental Sciences, page 181.

In formula it can be written as:

$$CF = \frac{E_{ac}(\frac{kWh}{yr})}{P_{ac}(kW) * 8760\ (\frac{h}{yr})}$$

Where:

E_{ac} is the actual annual energy output in a given period – a year in the equation;

P_{ac} is the full-rated power;

Instead, especially for solar panels, the sun has an inclination of 90° only at midday, and also the day with the most hours of light of the year - the summer solstice - has about eight hours of darkness - in Italy - the capacity factor is therefore much lower than 100%. From the graphs, it can be seen that in Italy it never reaches 25% on a monthly basis.

First, we will analyze the graphs related to solar panels.

The output of solar plants is related to astrophysical conditions, therefore for all of Italy: in June and July there is the best possible condition, longer hours of light and high intensity of Solar radiation; in March there are about twelve hours of light and solar radiation is increasing; in November there are strictly fewer hours of light and the intensity of the solar radiation it's strongly lower than the other moths. But the second variable to which the capacity factor is related is the number of cloudy days and this is not only dependent on the period, but also on the region we refer to[19]. The cloudy day explains why April has in our graphs a lower Monthly capacity factor than March, and why November has an averagely lower monthly capacity factor. The geographic position makes slight differences that are considered in our analysis.

The expected output of solar panels and wind turbines for each zone and hour studied is presented at the conclusion of this chapter[20]. It is important to underline that both for solar panels and wind turbines we will use the best output possible. To compute the equilibrium it would make no sense to check whether, on a cloudy day, solar panels really make any difference. But on the other side, we don't want to consider that at all moments solar panels and wind turbines can have the maximum nominal output, it would not be realistic at all. Our

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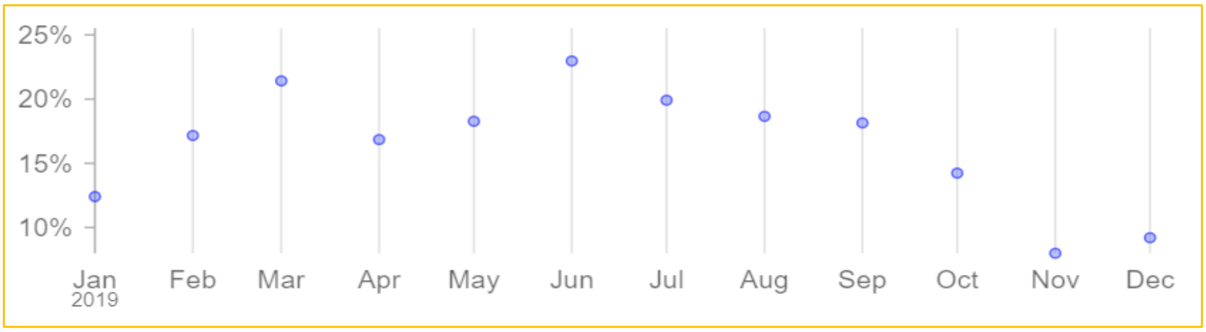
[19] The geographical position also make differences for the other variables, but considering only Italy we consider it negligible.

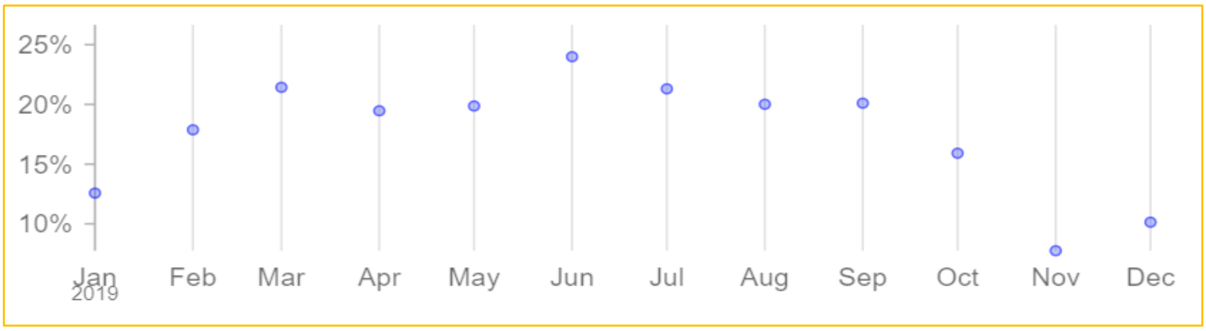
[20] All the capacity factors considered can be found in the Annex.

approximation can be considered as what can realistically happen on one sunny day in March, July, or November 2030.

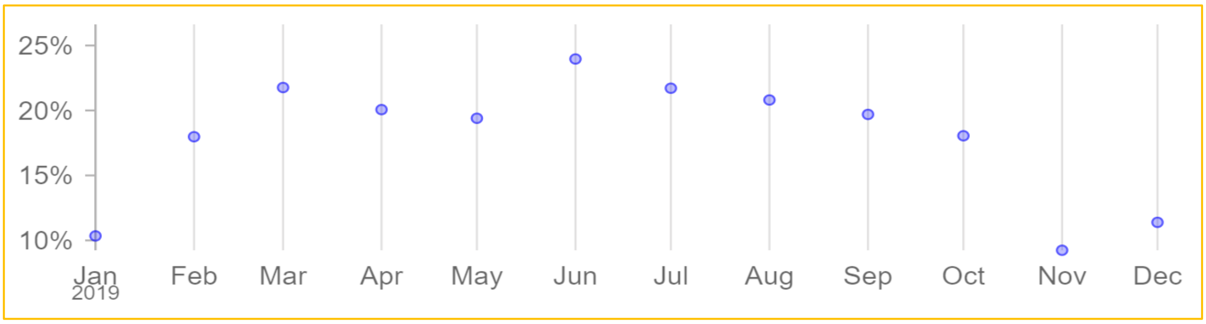
Chart 8; Solar Panel Capacity Factor



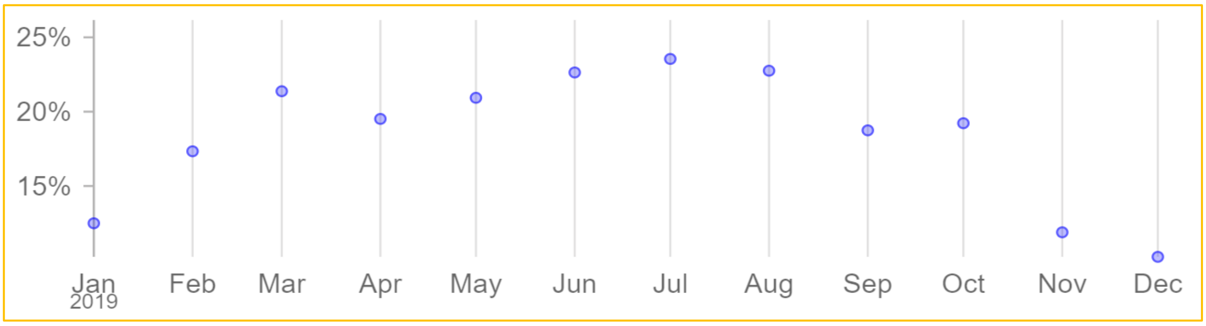
Solar PV. North. Monthly Capacity Factor. Lat 45,2183; Lon 10,4166. Capacity (kW): 14608000; System loss (fraction): 0.1; Tilt(°): 35; Azimuth (°): 180. Total mean capacity factor: 16.4%.



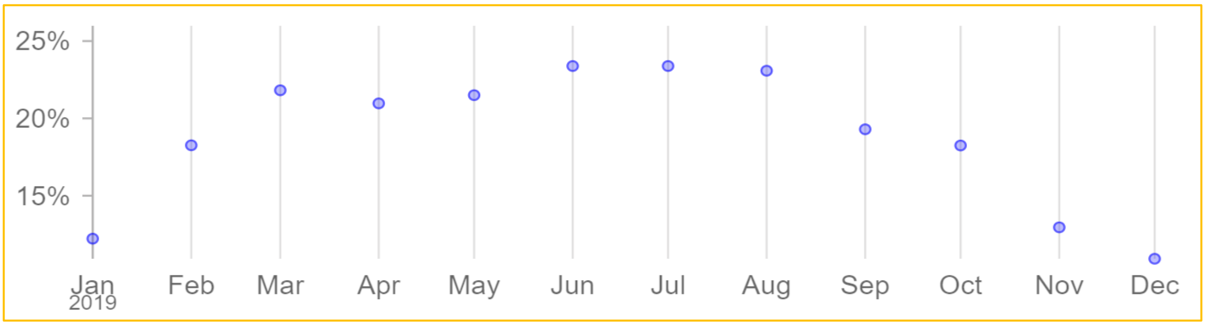
Solar PV. Centre-North. Monthly Capacity Factor. Lat 43,5300; Lon 11,0949. Capacity (kW): 3152000; System loss (fraction): 0.1; Tilt(°): 35; Azimuth (°): 180. Total mean capacity factor: 17.5%



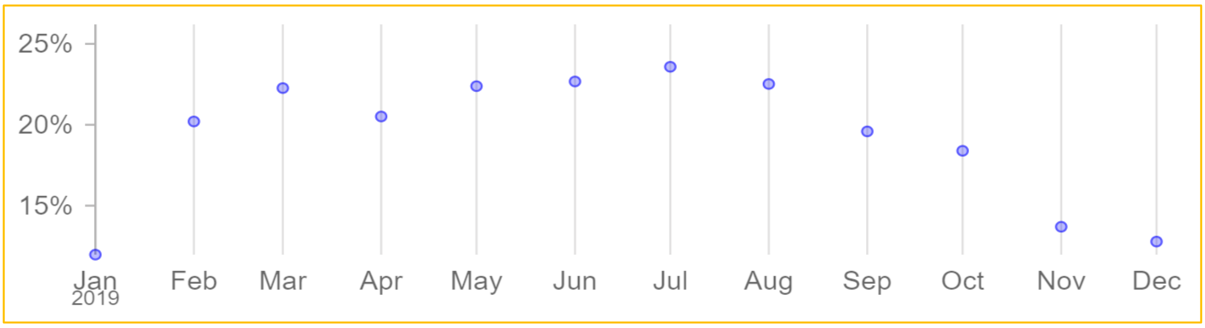
Solar PV. Centre-South. Monthly Capacity Factor. Lat 41,5078; Lon 14,2103. Capacity (kW): 4976000; System loss (fraction): 0.1; Tilt(°): 35; Azimuth (°): 180. Total mean capacity factor: 17.9%.



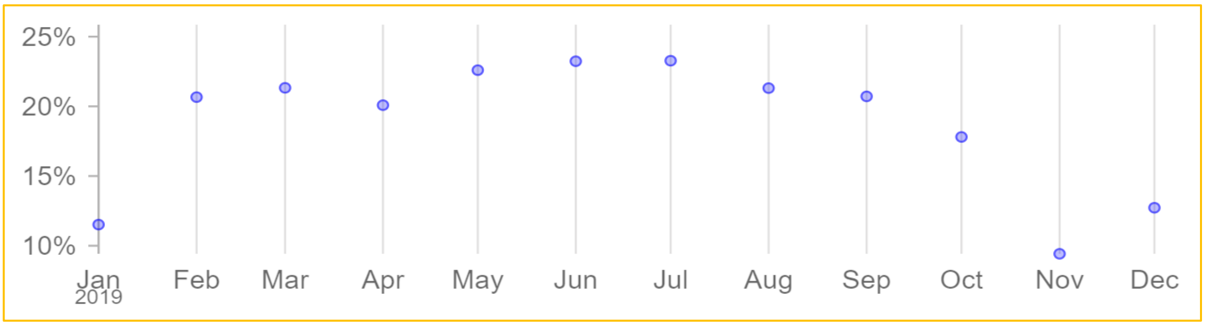
Solar PV. South. Monthly Capacity Factor. Lat 40,5724; Lon 17,6271. Capacity (kW): 3339000; System loss (fraction): 0.1; Tilt(°): 35; Azimuth (°): 180. Total mean capacity factor: 18.4%.



Solar PV. Calabria. Monthly Capacity Factor. Lat 39,1972; Lon 16,9628. Capacity (kW): 526000; System loss (fraction): 0.1; Tilt(°): 35; Azimuth (°): 180. Total mean capacity factor: 18.9%.



Solar PV. Sicily. Monthly Capacity Factor. Lat 37,2682; Lon 14,0020. Capacity (kW): 2571000; System loss (fraction): 0.1; Tilt(°): 35; Azimuth (°): 180. Total mean capacity factor: 19.2%.



Solar PV. Sardinia. Monthly Capacity Factor. Lat 39,6939; Lon 8,9412. Capacity (kW): 1310000; System loss (fraction): 0.1; Tilt(°): 35; Azimuth (°): 180. Total mean capacity factor: 18.7%.
Source: Renewable.ninja

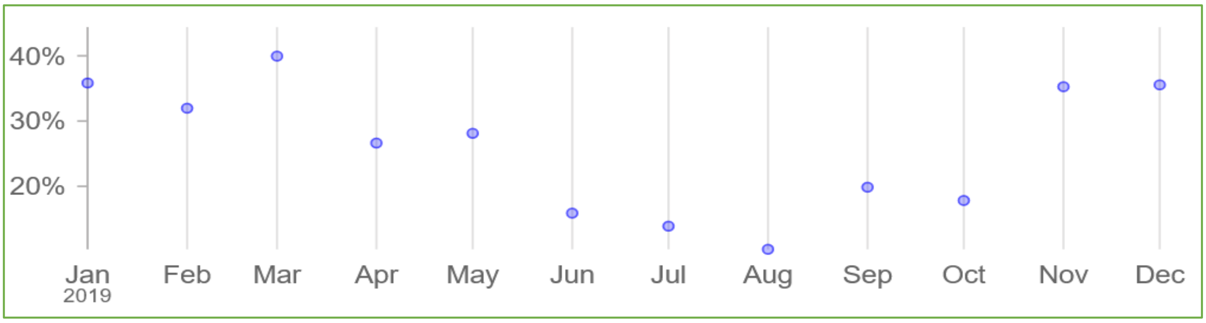
We will then shortly analyze the output of wind turbines.

The size of the wind blades can vary greatly, they can be from a few tens of meters, to 260 meters high, like the largest turbine that is being built while this thesis is being written. We have considered for our study as all the turbines that will be built will be 100 m. The turbine model considered is the Vestas V90 2000. As a more affecting variable, we have considered as most all the plants will be built Off-shore. We have approximately taking into consideration the windiest place in Italy. This approximation is not the most realistic one, as it will not be feasible to install all the power plants in the best locations, there is a real constraint in terms of space, but it is a useful approximation with a low impact given our goal.

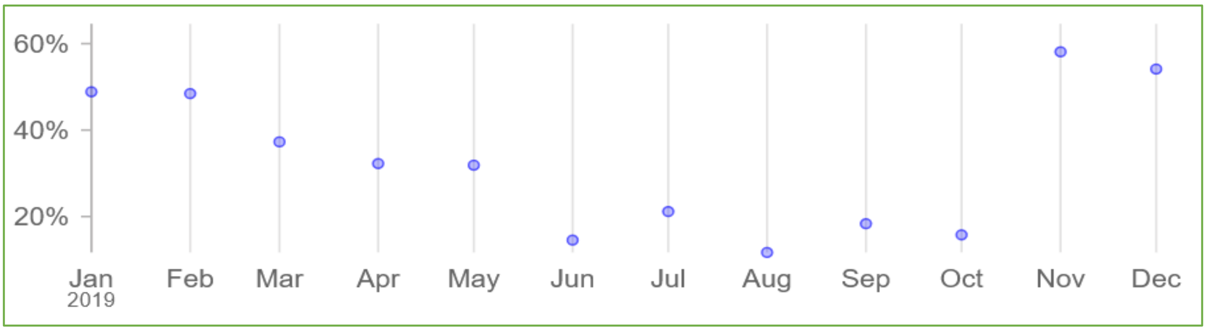
The last approximation that does have an impact is that not all years are the same, and wind does not have a precise seasonality as solar radiation. Using our source it is possible to see that the windy period of 2020 was different from the 2019 one - reported in our graph. We can, however, say that on average in summer there is less wind.

Whether the data reported are more realistic is in the differences between different zones. In the North of Italy, no investments are foreseen since the total mean capacity factor would be really low, while in the south the production is higher, arriving in Sardinia to have a total mean capacity factor for the year at 49.1%: meaning that 50% of the output possible will be produced.

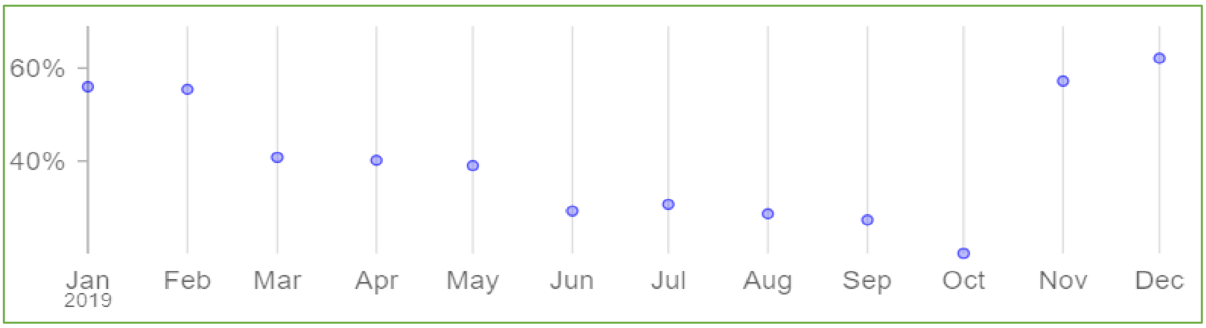
Chart 9; Wind turbines Capacity Factor



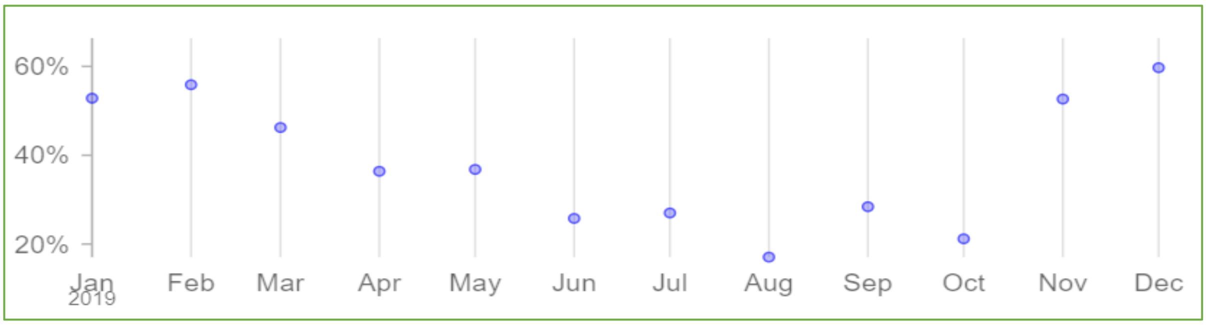
Wind. Centre-North. Monthly Capacity Factor. Lat 44.1926; Lon 12.6893, Off-Shore. Capacity (kW): 68000; Hub height (m):100; Turbine model: Vestas V90 2000. Total mean capacity factor: 25.8%.



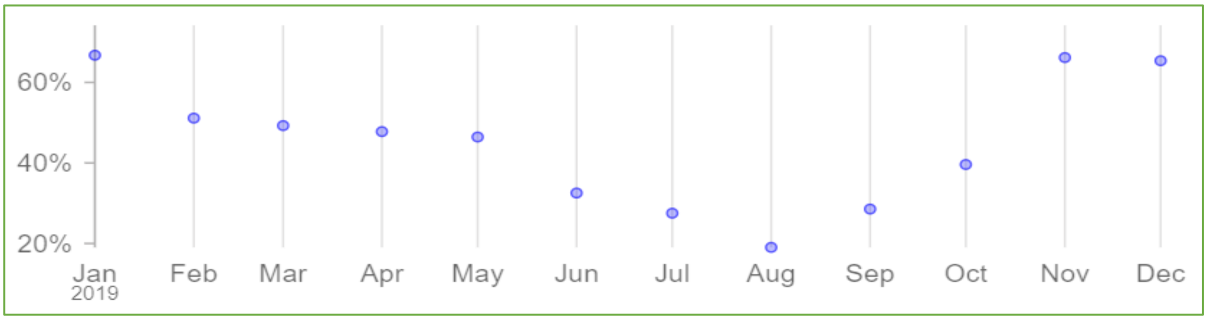
Wind. Centre-South. Monthly Capacity Factor. Lat 40.3077; Lon 13.8014, Off-Shore. Capacity (kW): 1528000; Hub height (m):100; Turbine model: Vestas V90 2000. Total mean capacity factor: 32.5%.



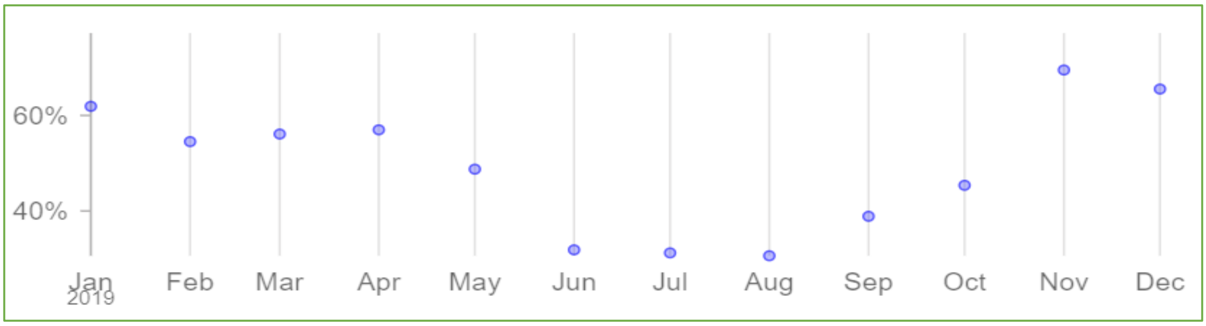
Wind. South. Monthly Capacity Factor. Lat 39,9907; Lon 18,3840. Capacity (kW): 2818000; Hub height (m):100; Turbine model: Vestas V90 2000. Total mean capacity factor: 40.5%.



Wind. Calabria. Monthly Capacity Factor. Lat 38,5386; Lon 16,9743, Off-Shore. Capacity (kW): 708000; Hub height (m):100; Turbine model: Vestas V90 2000. Total mean capacity factor: 38.2%.



Wind. Sicily. Monthly Capacity Factor. Lat 37,9075; Lon 12,0141, Off-Shore. Capacity (kW): 1978000; Hub height (m):100; Turbine model: Vestas V90 2000. Total mean capacity factor: 44.9%.



Wind. Sardinia. Monthly Capacity Factor. Lat 38,3633; Lon 9,3566, Off-Shore. Capacity (kW): 1368000; Hub height (m):100; Turbine model: Vestas V90 2000. Total mean capacity factor: 49.1%. Pick in November at 69.51%.
Source: Renewable.ninja

Solar Panels Production	Wind Turbines production	Total Production

Forecasted hourly production (MWh)

North

	Installed capacity = 14608MW				Installed capacity = 0MW				Installed capacity = 14608MW			
	3 a.m.	10 a.m.	12 a.m.	6p.m	3 a.m.	10 a.m.	12 a.m.	6p.m	3 a.m.	10 a.m.	12 a.m.	6p.m
March	0	6135	10226	2045	0	0	0	0	**0**	**6135**	**10226**	**2045**
July	0	7012	11686	2337	0	0	0	0	**0**	**7012**	**11686**	**2337**
November	0	876	1461	292	0	0	0	0	**0**	**876**	**1461**	**292**

Centre North

	Installed capacity = 3152MW				Installed capacity = 68MW				Installed capacity = 3220MW			
	3 a.m.	10 a.m.	12 a.m.	6p.m	3 a.m.	10 a.m.	12 a.m.	6p.m	3 a.m.	10 a.m.	12 a.m.	6p.m
March	0	1324	2206	441	35	35	35	35	**35**	**1359**	**2242**	**477**
July	0	1513	2522	504	13	13	13	13	**13**	**1526**	**2535**	**518**
November	0	189	315	63	31	31	31	31	**31**	**220**	**346**	**94**

Centre South

	Installed capacity = 4976MW				Installed capacity = 1528MW				Installed capacity = 6504MW			
	3 a.m.	10 a.m.	12 a.m.	6p.m	3 a.m.	10 a.m.	12 a.m.	6p.m	3 a.m.	10 a.m.	12 a.m.	6p.m
March	0	2090	3483	697	795	795	795	795	**795**	**2884**	**4278**	**1491**
July	0	2388	3981	796	397	397	397	397	**397**	**2786**	**4378**	**1193**
November	0	299	498	100	1192	1192	1192	1192	**1192**	**1490**	**1689**	**1291**

South and Calabria

	Net installed capacity = 3865MW				Net installed capacity = 3526MW				Net installed capacity = 7391MW			
	3 a.m.	10 a.m.	12 a.m.	6p.m	3 a.m.	10 a.m.	12 a.m.	6p.m	3 a.m.	10 a.m.	12 a.m.	6p.m
March	0	1739	2899	580	1880	1880	1880	1880	**1880**	**3619**	**4778**	**2459**
July	0	2087	3479	696	1009	1009	1009	1009	**1009**	**3096**	**4487**	**1705**
November	0	480	799	160	2704	2704	2704	2704	**2704**	**3184**	**3504**	**2864**

Sicily

	Net installed capacity = 2571MW				Net installed capacity = 1978MW				Net installed capacity = 4549MW			
	3 a.m.	10 a.m.	12 a.m.	6p.m	3 a.m.	10 a.m.	12 a.m.	6p.m	3 a.m.	10 a.m.	12 a.m.	6p.m
March	0	1234	2057	411	1286	1286	1286	1286	**1286**	**2520**	**3343**	**1697**
July	0	1388	2314	463	771	771	771	771	**771**	**2160**	**3085**	**1234**
November	0	386	643	129	1671	1671	1671	1671	**1671**	**2057**	**2314**	**1800**

Sardinia

	Net installed capacity = 1310MW				Net installed capacity = 1368MW				Net installed capacity = 2678MW			
	3 a.m.	10 a.m.	12 a.m.	6p.m	3 a.m.	10 a.m.	12 a.m.	6p.m	3 a.m.	10 a.m.	12 a.m.	6p.m
March	0	550	917	183	889	889	889	889	**889**	**1439**	**1806**	**1073**
July	0	629	1048	210	534	534	534	534	**534**	**1162**	**1582**	**743**
November	0	79	131	26	1245	1245	1245	1245	**1245**	**1323**	**1376**	**1271**

Methodology

To achieve the objective on forecast the possible price of equilibrium after the introduction of the investment foreseen in the Renewable Energy Sources (RES) we have replicated the Merit-order dispatching.

In the status-quo scenario, as we have explained in the introduction we have taken as given the prices and quantity of electricity dispatched in the 2018 market, during the hours that we are studying. The markets zones of the Italian markets have been individually analyzed by us, therefore we have taken as given all the exchanges that occur in the real market between the zones but we have considered their fix. Therefore in the status-quo scenario, we have zones where the production of electricity does not cover all the consumption of it, and the excess part is covered by exchanges with other areas or thanks to exchanges with other nations, and in the opposite side, we have zones that produce more than their cumulated consumptions. Nevertheless, thanks to the R code[21] used in this research, we have been able to replicate the real outcome of the market prices for all 2018 zonal markets, starting from the disaggregated data of the demand and supply of electricity.

In the alternative scenario, the RES is added to the supply curve. The new amount of electricity that is supposed to be produced by the new plants leads to a different equilibrium situation. This is due to the fact, as explained in the introduction, that the RES has a higher merit order, therefore RES are the first ones to be dispatched, and the conventional fossil-fueled power plants are crowded out to the market. The comparison of the two equilibrium outcomes allows us to measure the differences in electricity prices.

An important assumption that we have made, as already anticipated, is the full congestion of all the zonal markets. The production of electricity foreseen in the previous chapter, from the new investments, is added in the alternative scenario exclusively in the zonal market where it is expected to be produced. With this assumption, all the new equilibrium will be exclusive to each zone and will lead to, sometimes strongly, different prices for the same period. In reality, the market will not be always congested and electricity produced in one zone could be consumed in another one. For zones that were net importers in the status quo, we assumed that the new production will initially replace previously imported energy. Only after imports have

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[21] The R code used was originally created and kindly provided by Fippo Beltrami and used in the article *The value of carbon emission reduction induced by Renewable Energy Sources in the Italian power market*, Beltrami, Fontini, and Grossi (2021). It was originally created to simulate the market equilibria without RES, It has been adapted by the author of this dissertation to fit to the purpose of this research.

been reduced to zero will the new production impact the zonal supply curve and influence the equilibrium price.

It is important to notice that the distribution of the new plants is in favor of the Center and South of Italy; this is due to the fact that the capacity factor of the RES is dependent on the zones where the plants are situated. The Center and the South of Italy have a higher capacity factor both concerning solar plants and wind turbines. Knowing the distribution of the production and use of electricity the Italian Govern and Terna, the Italian operator that manages the Italian transmission grid, have already scheduled new investments to increase the connection between the zonal market. The investment expected can be seen in chapter 2.4 of the INECP.

However, since replicating the present and future topology of the Italian grid would be too computationally challenging, we have taken as an assumption that all the market zones will not have the possibility to exchange more electricity than what was already traded in the status quo scenario.

The model runs as follows:

1. Firstly, the program simulates the zonal day-ahead electricity market by replicating the supply bids submitted to the market. The supply curve is reconstructed using the merit order principle based on the actual bids submitted. The offers are ranked according to the asking prices, from lowest to highest. In case of multiple bids with the same price, they are ranked with the same merit;
2. The load, as assumed, is rigid. The model orders the demand bids based on the merit order principle, from highest to lowest price. It calculates the total electricity quantity of all accepted bids, referred to as Q_Real, and the price of the last accepted offer, referred to as P_Real. These represent the actual market equilibrium for the zone and hour under consideration;
3. The program then calculates the import and export of electricity between market zones, dividing the zones into net importing and net exporting zones. For the net importing zones, the program saves the net electricity imported as Q_Import, and for the net exporting zones, it saves the net exported electricity as Q_Export;
4. The program also saves the forecasted production of electricity as Q_RES
5. For net importing zones, the program compares Q_RES with Q_Import:

- If Q_RES is smaller or equal to Q_Import the new market equilibrium is assumed to be the same as the actual equilibrium, as the new production is insufficient to replace the imported electricity.
  In this case:
  Q_Forcasted = Q_Real
  P_Forcasted = P_Real
- If Q_RES is greater than Q_Import, the program calculates the new market equilibrium. It first checks if the new equilibrium can satisfy a bigger amount of electricity, that comprehend all the requested electricity from the market – previously accepted and not accepted bids – Q_Max:
- If there is an equilibrium with Q_Max, the program calculates its price, resulting in:
  Q_Forcasted = Q_ Max
  P_Forcasted
- If it's not possible to cover previously not accepted electricity at the price proposed in the offers, the program compute the price based on previously covered electricity, resulting in:
  Q_Forcasted = Q_ Real
  P_Forcasted

6. For the net exporting zones, a positive amount of new electricity will always affect the market equilibrium price. In this case we have also to consider in the equilibrium the amount of electricity produced in the market zone and sold in a different one. We have therefore summed Q_Export to the quantity of electricity that have to be satisfied[22].
   - The program calculates the new equilibrium by first checking if it's possible to satisfy Q_Max. If so, the new equilibrium will be:
     Q_Forcasted = Q_Max
     P_Forcasted
   - If not, the program calculates the equilibrium price based on Q_Real, resulting in:
     Q_Forecasted=Q_Real
     P_Forecasted.

---

[22] The exports could also have been considered as a decreasing quantity in the supply curve, since the electricity sold in a different zone cannot satisfy the internal market.

Note that there are some crucial assumptions that have been taken in modeling this problem.

One of the main assumptions made is the presence of zonal congestion, also referred to as "no import and export infra-zones" beyond what is observed in the current scenario. This means that the model assumes that the transmission capacity between different zones or regions within the electricity market is limited, and that this limitation affects the flow of electricity and can lead to congestion. This has important implications for the pricing of electricity, as well as for the planning and expansion of transmission infrastructure. Zonal congestion occurs when there is a mismatch between the supply and demand of electricity in different zones or regions, leading to an oversupply or undersupply of electricity in certain areas, and can lead to increased costs for consumers and reduced efficiency in the electricity market.The second important assumptions are “Zero demand flexibility” and “No storage”. In the model we created it is assumed that there will not be strategic bidding and neither storage. If this change, and the introduction of new forms of storage or different use of the storage already present - such as pumped-storage hydroelectricity – will impact strongly the load this assumption can fail. However, this is unlikely to happen by 2030;

On the side of the supply curve, we assume to have no “strategic bidding”, no “cycling restrictions”, and we do not count for “cogenerations plants”. All the three assumptions imply that the bidding linked to the new equilibrium should not change with respect to the old one.

- Strategic bidding implies mainly perfect competition in the market, no one should be able to change the results with new strategic bidding, which can be changed in prices or quantity offered;
- Cycling restrictions imply that the plants do not have a cost in turning On and Off, but this is usually not true. Plants especially coal and nuclear, do face high costs in turning On and Off or in moderating the output of electricity. However in the building of new plants, it’s given great importance to the ability to be flexible, coal plants in 2030 will be turned off, and nuclear plants do not impact this research. Therefore this assumption even if not strictly realistic is necessary for this study and have a small impact, we will in any case take it into account for the analysis of the policy implications;
- Congenators, imply the assumption for cycling restrictions cost turning Off the plants. If the plants do have as purpose both the generation of electricity and

heating for houses or waste incineration, the cost of turning Off the plants imply stops in the production of the second service, implying in this way social cost and fines to the plants.

The last strict assumption is that the production forecasted by us in the previous chapter of solar panels and wind turbines has to be equal to the real production. This assumption is related to the purpose of the research, we do not want to modelized a complete year but six days where solar plants and wind turbines could have a significant impact on the production of electricity. Knowing the purpose of the thesis, it would have been completely insignificant for us to study days with little sun and little wind, even if these days are present in the periods we studied. It must therefore be clear that considering the results we obtained as the average results for the period would be wrong. The results obtained by us must be considered as a good approximation of what will happen on a sunny and windy day, linked to the month studied, of March, July, and November

Case Study: North Italy, Wednesday 7 March 2018, 10 a.m.

In this analysis, we will delve into why even with a significant production from RES this does not impact our model of the price of electricity. As previously noted, we have taken the market exchanges as given and modeled the market prices solely based on exchanges within the focus zonal market.

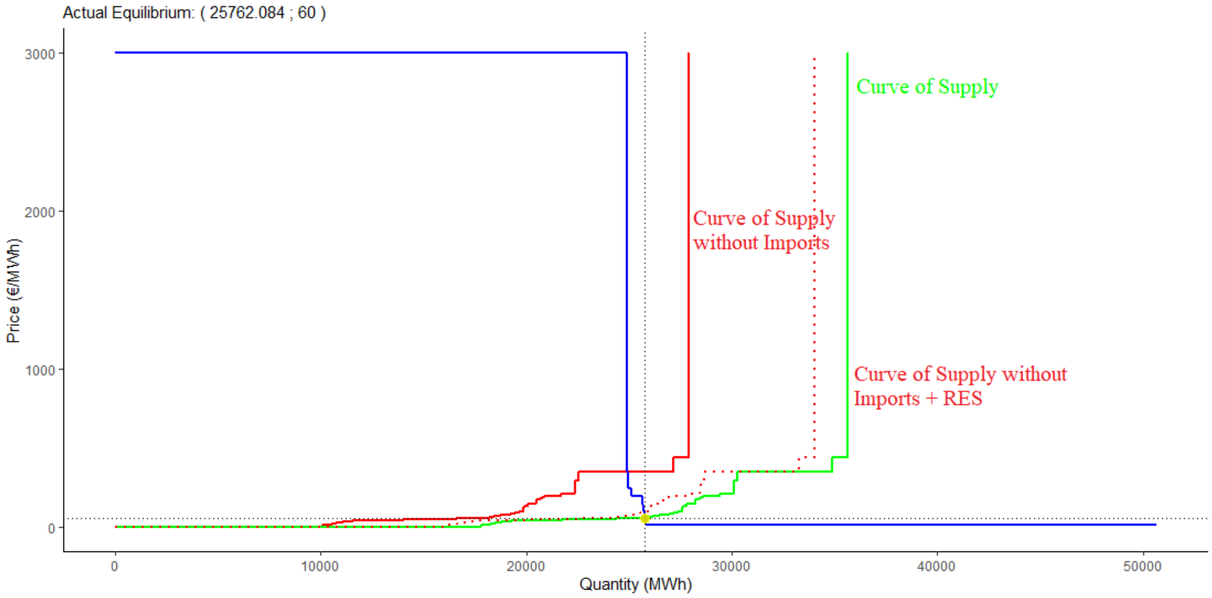
We will demonstrate why this constraint is not only reasonable, but also necessary due to the technical limitations of the research and its purpose. Additionally, we will show that it would have been impossible to model a comprehensive representation of the market, as this would have required forecasting not only the production in Italy, but also in all of Europe. The interconnections between Italy and foreign countries are substantial, and their exchanges can greatly affect the price, even when considering all the interconnections between the Italian market zones. This is especially true for the North zone, which is why we have dedicated a special section to this issue.

On Wednesday, March 7, 2018, at 10 a.m., the estimated day-ahead load was 25,762 MWh, and the equilibrium price was 60 €/MWh. The total electricity production within the zone was only 18,023 MWh, with the remaining 7,739 MWh imported from outside the zone and from the Central-North zone. The table below shows the net MWh imported from the North zone, with a 1 MWh discrepancy resulting from rounding.

Austria	France	Slovenia	Switzerland	Centre North	Sum
315	2497	540	3086	1300	7738

To show how this exchanges impact the price formation of energy and why in our model even a substantial production of energy from renewable sources do not impact the price equilibrium, we have reported in the graph all three curve, plus the curve of demand. In red is reported the curve of supply where it have been subtracted all the electricity imported, therefore it represents the solely zonal production. In green, is reported the curve of supply that comprehend also the electricity imported; since in this situation the marginal supply offer was the offer of imports, we have considered and shown as all the 7738 MWh imported had a price of 60 €. The last curve is the curve of supply without the MWh imported from a different zone, but with the renewable energy estimated production and this curve show how the new electricity produced will not be enough to substitute all the imported electricity. Therefore, the new equilibrium will be the same as in the status quo. The difference from it will be that the imported quantity of electricity will be lower. If in the status quo equilibrium it have been imported 7738 MWh, in the new equilibrium the electricity imported will be: Q_Import – Q_RES, in this case it would be 7738 - 6135 = 1603 MWh. Therefore in our model, the new electricity production it is not photographed in a decreasing in price, but it does have an impact on the zonal and foreign exchanges.

Chart: Case study, Zone North, hour 10, day 07 03 2018



Source: Own eleaboration

This is plausibly a false assumption, since also a decrease in imports would probably drive in a decrease of the price of imports, but if replicating the topology of Italian power lines would have been a titanic undertaking, being able to model and estimate future prices across all of Europe would have been technically impossible for the current study.

Results

The application of the methodology described has allowed us to compute and graphically show all the new equilibriums. Comparing the new equilibrium with the status quo scenario we have been able to understand whether and in which period the new investment will have the biggest impact on the price of electricity.

Before pursuing a deep analysis of the data, it is interesting to make some considerations.

First, in 2018 the North zone represented nearly 75% of the total national load and only generated 58% of the total national electricity. This difference will get even worse with the investments foreseen by the INECP, out of 39 GW of new investments only 14.6 will be in the North Italy zone, of which 100% will be in solar panels. As underlined previously this is due to the higher capacity factor of RES in the southern region of Italy. The distribution will imply to have in our research results a strong impact in the southern zone for all months and all hours of the day, thanks to the presence of wind turbines as well as solar panels. In the North zone, we can expect a zero impact in the night and evening due to zero or low production of electricity by solar panels, and a stronger impact at 10 a.m. and 12 a.m. in March and July.

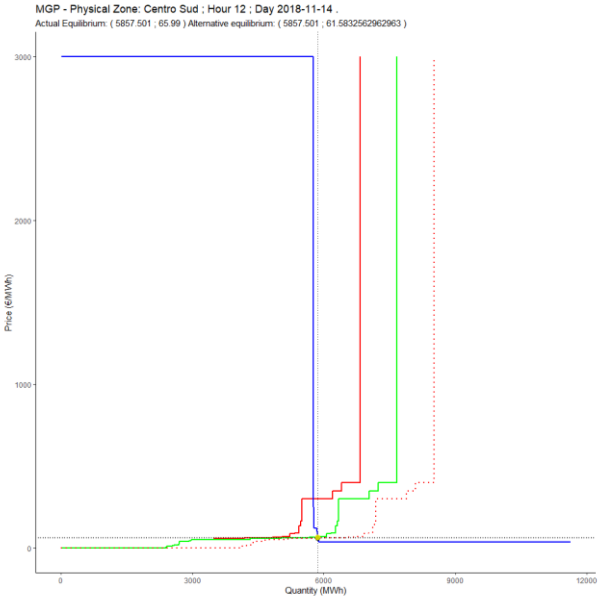
The second interesting consideration is the different impact of the production between the working day and the holiday analyzed of the same week. It is reasonable to expect that the RES production has a stronger impact on the holiday prices, due to the higher relative percentage of production out of the total load.

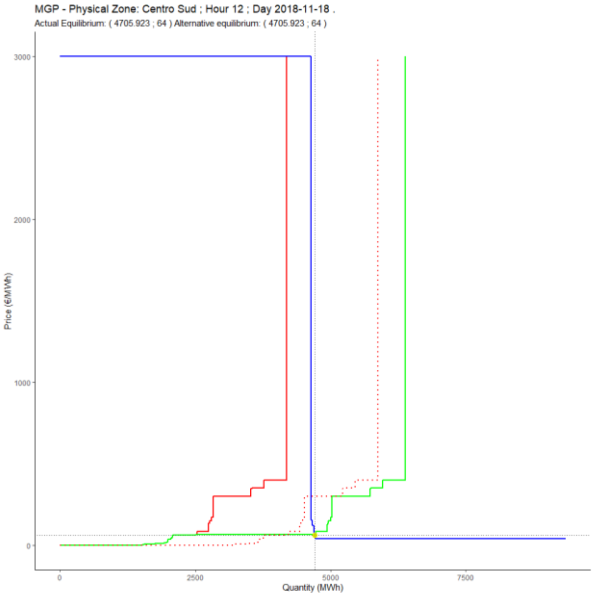
In the results, it appears that not always the RES impact was stronger during the holiday. We can analyze two reasons why this could happen.

- First, during high pick demand hours, which are typical during working days, also the less efficient production plants are called to produce following the Merit Order Dispatching. Usually, plants with a less efficient production price are also fewer and smaller. It can happen that with a small quantity of energy offered at a zero marginal price, the costly plants are pushed out of the market, making the price strongly lower. This can be seen graphically, the curve of supply is steeper when the quantity produced bigger;
- The second reason is linked to the technical assumption of this research. With a lower price and quantity required, it is probable to compete with infra-zone supply, having in

this case a higher supply of electricity from a different zone that we haven't modelized in this research.

Below have been reported two charts that can show an example of a zone where the price on Wednesday was impacted by the RES investment while on Sunday no impact was foreseen, comparing the same hour in the same week. On Wendensday 14 November in the zone Centre South we found that the price of electricity at noon will pass from 66 €/MWh to 62 €/MWh, we have instead found that Sunday 18 November the RES production will not have any impact on the price, and the it is foreseen to remain stable at 64 €/MWh. This difference is because on Wednesday the net import of the zone has been of 832 MWh, while on Sunday the zone was importing 2198 MWh. The foreseen production from the new RES was 1689 MWh, therefore it would cover the imports and impact the prices on Wednesday, while on Sunday the new production would not be enough to substitute all the electricity imported.





We will now deepen the analysis of the results by focusing on each month. The table below reports all the results that have been found, disaggregated by months, days, hours, and zones.

Let’s start analyzing the results of March. It is useful to remember that in our model we have used for the month of March on average a capacity factor of 73% for solar panels, and 44% for wind turbines.

As could be expected the zones North, Centre North, and Centre South do have a low or zero impact on the cost of electricity during night or evening. This is because in the North no wind turbines are foreseen and both in the Center North and South only a low percentage of the new plants will be wind farms. However, at 10 a.m. and 12 a.m., the foreseen production of solar energy is expected to have a strong impact on the prices. On Sunday 11 March in the North zone, we found the recond price decreasing where it will pass from 140 €/MWh to 0€/MWh, this is the highest fall between all the hours and zones studied. The 140 €/MWh was clearly due to constraining in the production of that day and was probably only a singular circumstance, but it is interesting to notice that RES production could have a positive impact also on price picks.

The South zone and the two islands on the other side benefit in March both from the presence of wind and sunny days. In Sardinia, the new RES forecasted production does even cover all the load in three of the four hours analyzed; the exception is at 6 p.m. of Wednesday where out of 1132 MWh of load, 1072 are expected to be covered by the production of the new plants. The production from the new plants installed is also expected to cover all the load of the South of Italy and Sicily at 10 and 12 a.m.

Therefore the prices of electricity in March, especially in the southern part of Italy, are not only expected to decrease but are expected to achieve 0 €/MWh, covering most of the time also the slight part of the demand that was not covered in the status quo scenario.

Considering all the country, out of a load of 42453 MWh at noon on a Wednesday in March the new production is estimated to be 26672 MWh. It is important to not overestimate the impact considering the forecast result as an average day in March, the estimated production is more than what will be produced in an average day. The results should be compared to a sunny and windy day in March.

🟩	lower price
🟦	higher quantity
🟧	higher difference

			Prices €/MWh and Quantity MWh variability							
			North				Centre North			
			3 a.m	10 a.m	12 a.m.	18 a.m.	3 a.m	10 a.m	12 a.m.	18 a.m.
March	Wednesday	**P Real**	39	60	57	57	39	60	57	57
		P Forecasted		60	51	57	39	60	24	57
		Q Real	15302	25762	25367	24443	2803	4715	4643	4655
		Q Forecasted		25762	25367	24443	2803	4715	4643	4655
	Sunday	**P Real**	35	56	140	54	35	47	47	54
		P Forecasted		46	0	54	35	0	0	54
		Q Real	12686	15230	15762	15418	2330	2745	2901	2921
		Q Forecasted		15230	15878	15418	2330	2802	2963	2921

			Centre South				South			
			3 a.m	10 a.m	12 a.m.	18 a.m.	3 a.m	10 a.m	12 a.m.	18 a.m.
March	Wednesday	**P Real**	39	60	47	57	39	52	38	57
		P Forecasted	39	43	0	57	0	0	0	0
		Q Real	3788	6317	6298	6436	1977	3018	2906	3221
		Q Forecasted	3788	6317	6322	6436	1989	3035	2923	3235
	Sunday	**P Real**	35	41	20	54	35	41	20	54
		P Forecasted	35	0	0	41	0	0	0	0
		Q Real	3491	4333	4510	4501	1930	2250	2301	2358
		Q Forecasted	3491	4334	4517	4501	1940	2260	2316	2359

			Sicily				Sardinia			
			3 a.m	10 a.m	12 a.m.	18 a.m.	3 a.m	10 a.m	12 a.m.	18 a.m.
March	Wednesday	**P Real**	39	52	38	57	39	60	47	57
		P Forecasted	0	0	0	0	0	0	0	0
		Q Real	1469	2273	2153	2316	793	1147	1087	1132
		Q Forecasted	1470	2280	2154	2318	793	1167	1107	1147
	Sunday	**P Real**	35	41	20	54	39	41	20	54
		P Forecasted	0	0	0	0	0	0	0	0
		Q Real	1455	1782	1791	1776	772	941	948	938
		Q Forecasted	1456	1783	1796	1781	772	941	953	938

In July we have considered having a strong impact from solar production and a low impact of wind. On average the capacity factor computed is 84% for the solar panels and 24% for the wind turbines.

As can be seen in the table, in July the prices during the dark hours do not change. The exception is Sardinia where the low electricity demand will be always covered by the new strong production. It is also noticeable that during the night the load in July is on average higher than in the other months, therefore with no production from the solar panels and low production from wind turbines, the results were expected.

During the day, on the other side, the price of electricity strongly decreases. Even in the North zone the installed solar production strongly impacts the price achieving during the day of Sunday a price of zero and contemporarily covering also the excess in demand.

In July is noticeable a second high pick in the price of electricity due to exogenous constraints. In Sicily in the Sunday studied we had a pick on the price of electricity that hit 136 and 135 €/MWh at 10 and 12 a.m. As in the case study in March, the impact of RES production foreseen has not only flattened the pick, but the new production has driven the price at 0 €/MWh covering at that price also all the demand presented in the market.

Considering all the country, out of a load of 45054 MWh at noon on a Wednesday in July the new production is estimated to be 27753 MWh.

			Prices €/MWh and Quantity MWh variability							
			North				Centre North			
			3 a.m	10 a.m	12 a.m.	18 a.m.	3 a.m	10 a.m	12 a.m.	18 a.m.
July	Wednesday	**P Real**	61	83	75	76	70	83	75	76
		P Forecasted		62	40	76	70	83	50	76
		Q Real	17308	25290	26170	26609	3253	4623	4911	4918
		Q Forecasted		25290	26170	26609	3253	4623	4911	4918
	Sunday	**P Real**	59	35	43	54	62	35	43	54
		P Forecasted		0	0	54	62	0	0	54
		Q Real	14505	14781	15637	15717	2784	2772	3009	2983
		Q Forecasted		14800	15653	15717	2784	2814	3054	2983

			Centre South				South			
			3 a.m	10 a.m	12 a.m.	18 a.m.	3 a.m	10 a.m	12 a.m.	18 a.m.
July	Wednesday	**P Real**	70	83	75	76	70	75	70	76
		P Forecasted	70	62	50	76	70	0	0	0
		Q Real	4918	6405	6988	7273	2599	3246	3337	3361
		Q Forecasted	4918	6405	6988	7273	2599	3252	3352	3386
	Sunday	**P Real**	63	35	43	54	63	35	35	32
		P Forecasted	63	35	0	54	10	0	0	0
		Q Real	4526	4431	4920	5045	2519	2420	2533	2422
		Q Forecasted	4526	4431	4928	5045	2524	2422	2550	2440

			Sicily				Sardinia			
			3 a.m	10 a.m	12 a.m.	18 a.m.	3 a.m	10 a.m	12 a.m.	18 a.m.
July	Wednesday	**P Real**	71	75	70	76	70	83	75	76
		P Forecasted	71	0	0	50	0	0	0	0
		Q Real	1886	2304	2429	2481	971	1240	1219	1170
		Q Forecasted	1886	2314	2437	2481	973	1242	1221	1172
	Sunday	**P Real**	63	136	135	32	63	35	43	54
		P Forecasted	63	0	0	0	0	0	0	0
		Q Real	1875	1807	1942	1857	967	986	1021	951
		Q Forecasted	1875	1810	1945	1861	969	988	1023	953

In November from the data available from us we estimated to have a low impact on energy production from the solar panels, due to the low intensity of solar radiation and the high probability of cloudy days. On the other side the estimated impact of wind energy it's quite high. The capacity factor that we have accounted for is 16% for solar panels, and 58% for wind turbines.

The results in the Centre and North parts of the country are therefore null, the low production of solar panels and the small quantity of wind turbines installed has a low impact on only 2 of the hours studied on the day on Wednesday in the Centre South and even in this case the impact on the price is only of four euro.

The South zone, Sicily, and Sardinia on the other side benefit from the strong investments in wind turbines. In all the hours studied the impact on the price is strong and stable, the price of electricity almost never exed 0 €/MWh. In this part of the country, the new investments are estimated in our model to meet all the demands of electricity. With the exception of a few hours in the evening, where high pick it's not compensated by any production of solar panels. We can report the example of Sunday 18 November at noon where out of an estimated production of 1375 MWh in Sardinia the reported load has been only 991 MWh.

Considering all the country, out of a load of 39969 MWh at noon on a Wednesday in November the new production is estimated to be 10689 MWh. It can be considered that while in March and July, the estimated production of the new RES can cover more than half of the total load of the Country, in November the new production will be less than a fourth at the same hour. The higher production of wind will not be enough to compensate for the strongly lower production of solar energy.

			Prices €/MWh and Quantity MWh variability							
			North				Centre North			
			3 a.m	10 a.m	12 a.m.	18 a.m.	3 a.m	10 a.m	12 a.m.	18 a.m.
November	Wednesday	P Real	52	70	66	83	52	70	66	83
		P Forecasted		70	66	83	52	70	66	83
		Q Real	14885	24595	23994	25263	2556	4429	4405	4859
		Q Forecasted		24595	23994	25263	2556	4429	4405	4859
	Sunday	P Real	53	64	64	73	53	64	64	73
		P Forecasted		64	64	73	53	64	64	73
		Q Real	12757	14947	15316	17335	2326	2779	3008	3414
		Q Forecasted		14947	15316	17335	2326	2779	3008	3414
			Centre South				South			
			3 a.m	10 a.m	12 a.m.	18 a.m.	3 a.m	10 a.m	12 a.m.	18 a.m.
November	Wednesday	P Real	52	70	66	83	52	69	58	83
		P Forecasted	52	66	62	83	0	0	0	0
		Q Real	3666	5963	5857	6884	2136	2891	2789	3598
		Q Forecasted	3666	5963	5857	6884	2154	2919	2815	3614
	Sunday	P Real	53	64	64	73	53	64	64	73
		P Forecasted	53	64	64	73	0	0	0	0
		Q Real	3531	4495	4705	5480	1943	2364	2442	2912
		Q Forecasted	3531	4495	4705	5480	1959	2384	2458	2935
			Sicily				Sardinia			
			3 a.m	10 a.m	12 a.m.	18 a.m.	3 a.m	10 a.m	12 a.m.	18 a.m.
November	Wednesday	P Real	52	69	58	94	52	70	66	83
		P Forecasted	0	0	0	2	0	0	0	0
		Q Real	1392	2023	1916	2411	764	1075	1008	1173
		Q Forecasted	1400	2033	1926	2441	769	1080	1013	1178
	Sunday	P Real	53	71	64	94	53	64	64	73
		P Forecasted	0	0	0	0	0	0	0	0
		Q Real	1426	1792	1857	2095	815	989	990	1082
		Q Forecasted	1433	1793	1857	2108	820	989	991	1087

The results achieved not only allow us to estimate the impact of the new investments by comparing the future with the past price, but the results also allow an indirect analysis. The production estimated and then added to the supply curve is for a sunny and a windy day, we have corrected it for seasonal and zonal differences, but we have also considered a higher production than the average of the period. Therefore we could as a hypothesis consider that on a cloudy and not windy day, the price of electricity will be as in the status quo. When no meaningful production from the solar panels and wind turbines will be present the load will be covered by the same plants that covered it in 2018. The implication of that is that while in 2018 the price was decently stable, excluding picks that could not be excluded also in the future, in 2030 when the new investments will be in place the variability of the prices will be strongly higher. When the sun will bright in the sky and the wind will strongly blow the price of electricity will achieve 0 €/MWh, when the sun and the wind will be absent the price will come back to 60/70/80 €/MWh.

The last important consideration that we can take from this result is related to Calabria. Due to the limitation of the research we have not been able to analyze the new zone that have been created after 2018, but we can notice that between the South zone (that comprehends Calabria) and Sicilia, the result does not differ. We can be confident that the new zone created will not have many differences from the results of the two-zone analyzed. If the infra-zonal connection will be stable and quantitatively sufficient, also the price of Calabria should not differ strongly from the zone of Sicily and especially from the zone South reported in the current thesis.

New Equilibrium with widened Zonal Exchanges Restrictions

This chapter aims to investigate the effect of removing restrictions on zonal exchanges on the new electricity sector equilibrium. In previous chapters, we calculated a potential equilibrium based on the limited zonal exchange assumption. This chapter will evaluate the consequences of changing these restrictions by determining the new equilibrium assuming exchanges between zones up to the current transit limit values.

The data used in this analysis will be consistent with that used in earlier chapters, including historical price data, production data, and other relevant information. However, in the new equilibrium, we will consider the possibility of inter-zone transfer of renewable energy sources (RES) production, therefore the new equilibrium will not only be impacted by the zonal production, but from all the new RES production.

Our methodology involves the following steps:

1. Identifying the zones where the previous equilibrium resulted in zero electricity price due to new RES production;
2. Starting from the end node of the Italian electricity grid, such as Sicily and Sardinia, we calculated the estimated excess electricity production in the zone and assumed it to be available for export, at a zero price;
3. Considering the excess electricity as exportable up to the grid limits, as shown in a table. Adding the exported electricity to the production in the importing zone. If this results in a zero price, the process is repeated to calculate the new equilibrium, excess electricity, and exportable electricity.
4. If the price of the new equilibrium was higher than zero we have not consider any export from the zone.

From	To	Transit Limit, MW[23]
Sicily	South	1200
South	Centre South	5000
Sardinia	Centre South	900
Centre South	Centre North	2800
Centre North	North	3100

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[23] The highest limits reported by Terna are considered in this analysis. Although various restrictions can be taken into account, it is deemed appropriate to examine the highest values given the planned investments to enhance the grid infrastructure.
Source: Terna, 2020. *Valori dei limiti di transito tra le zone di mercato.* Website link

The depiction of transits and their direction in the table does not represent all possible flows of electricity. In the past, electricity flow has not always been unidirectional, and sometimes flowed from north to south in Italy. However, after taking into account new investments, our analysis found that, based on our initial assumptions, regions with excess electricity supply are primarily the Islands and then Southern Italy, and this surplus gradually moves northward in all hours studied.

The impact of possible electricity transmissions on our study was mainly seen in three ways:

- In regions where there was no prior trade, new zero-priced imported electricity was added to the supply curve by combining it with the new electricity produced through investments in the region;
- In regions that were previously net importers, we could consider not only new zero-priced imported electricity but also previously imported electricity at zero price. Therefore, in the new equilibrium in these areas, renewable energy did not replace all imports, but added to them. For example, if the South region in the status quo scenario imported 1000 MWh from Sicily, in the previous computed equilibrium we first went to zero imports with the new RES production. While considering zonal trade, we could add zero-priced imports to the new production from RES. Note that if a region previously imported electricity from other countries, this quantity of electricity was also in this case replaced by the new production, and only after all imports from other countries were set to zero the new production could affect the zonal curve of supply;
- In regions that were previously net exporters, the impact of the shift from export to import due to new production was double. Firstly, the additional demand from other regions was set to zero, positively impacting the equilibrium, and then the new import was added. For example, if South was exporting 1000 MWh to Sicily in the status quo scenario, while in the new scenario Sicily could export 1000 MWh to the South, this impacted the South region by first deleting the export demand of 1000 MWh and then adding a positive production with a zero marginal price of 1000 MWh imported from Sicily.

The next table presents the new equilibriums taking into account all possible inter-zonal electricity exchanges. It can be seen that the consideration of inter-zonal electricity exchanges has a strong impact, especially in the Centre South zone, due to its connections with both Sardinia and the South. It is worth noting that the transmission limit between the South and

Centre South is significantly higher compared to the limits between other zones. The impact on the Centre North and North zones is also significant, but this effect is mitigated by the limited transmission capacity between the Centre South and Centre North, and between the Centre North and North. These two transmission lines act as a bottleneck in our analysis.

░	**lower price Eq. without exchanges**
🟩	**lower price Eq. with exchanges**
░	**lower quantity Eq. without exchanges**
🟦	**lower quantity Eq with exchanges**

			Prices €/MWh and Quantity MWh variability							
			Nord				**Centre North**			
			3 a.m	**10 a.m**	**12 a.m.**	**18 a.m.**	**3 a.m**	**10 a.m**	**12 a.m.**	**18 a.m.**
March	**Wednesday**	**P Real**	39	60	57	57	39	60	57	57
		P Forecasted	39	🟩 57	🟩 46	57	🟩 0	🟩 0	🟩 0	🟩 0
		Q Real	2803	25762	25367	24443	2803	4715	4643	4655
		Q Forecasted	2803	25762	25367	24443	🟦 2812	🟦 4797	🟦 4724	🟦 4727
	Sunday	**P Real**	35	56	140	54	35	47	47	54
		P Forecasted	35	🟩 23	░ 0	🟩 52	🟩 0	░ 0	░ 0	🟩 0
		Q Real	12686	15230	15762	15418	2330	2745	2901	2921
		Q Forecasted	12686	🟦 15321	░ 15878	15418	2330	░ 2802	░ 2963	🟦 2976

			Centre South				**South**			
			3 a.m	**10 a.m**	**12 a.m.**	**18 a.m.**	**3 a.m**	**10 a.m**	**12 a.m.**	**18 a.m.**
March	**Wednesday**	**P Real**	39	60	47	57	39	52	38	57
		P Forecasted	🟩 0	░ 0	░ 0	🟩 0	░ 0	░ 0	░ 0	░ 0
		Q Real	3788	6317	6298	6436	1977	3018	2906	3221
		Q Forecasted	🟦 3804	🟦 6340	░ 6322	🟦 6463	░ 1989	░ 3035	░ 2923	░ 3235
	Sunday	**P Real**	35	41	20	54	35	41	20	54
		P Forecasted	🟩 0	░ 0	░ 0	░ 41	░ 0	░ 0	░ 0	░ 0
		Q Real	3491	4333	4510	4501	1930	2250	2301	2358
		Q Forecasted	🟦 3493	░ 4334	░ 4517	🟦 4502	░ 1940	░ 2260	░ 2316	░ 2359

			Sicily				**Sardinia**			
			3 a.m	**10 a.m**	**12 a.m.**	**18 a.m.**	**3 a.m**	**10 a.m**	**12 a.m.**	**18 a.m.**
March	**Wednesday**	**P Real**	39	52	38	57	39	60	47	57
		P Forecasted	░ 0	░ 0	░ 0	░ 0	░ 0	░ 0	░ 0	░ 0
		Q Real	1469	2273	2153	2316	793	1147	1087	1132
		Q Forecasted	░ 1470	░ 2280	░ 2154	░ 2318	░ 793	░ 1167	░ 1107	░ 1147
	Sunday	**P Real**	35	41	20	54	39	41	20	54
		P Forecasted	░ 0	░ 0	░ 0	░ 0	░ 0	░ 0	░ 0	░ 0
		Q Real	1455	1782	1791	1776	772	941	948	938
		Q Forecasted	░ 1456	░ 1783	░ 1796	░ 1781	░ 772	░ 941	░ 953	░ 938

			Prices €/MWh and Quantity MWh variability							
			Nord				Centre North			
			3 a.m	10 a.m	12 a.m.	18 a.m.	3 a.m	10 a.m	12 a.m.	18 a.m.
July	Wednesday	P Real	61	83	75	76	70	83	75	76
		P Forecasted		50	0	76	70	0	0	61
		Q Real	17308	25290	26170	26609	3253	4623	4911	4918
		Q Forecasted		25290	26307	26609	3253	4716	4986	4918
	Sunday	P Real	59	35	43	54	62	35	43	54
		P Forecasted		0	0	54	62	0	0	0
		Q Real	14505	14781	15637	15717	2784	2772	3009	2983
		Q Forecasted		14800	15653	15717	2784	2814	3054	3049

			Centre South				South			
			3 a.m	10 a.m	12 a.m.	18 a.m.	3 a.m	10 a.m	12 a.m.	18 a.m.
July	Wednesday	P Real	70	83	75	76	70	75	70	76
		P Forecasted	70	0	0	0	70	0	0	0
		Q Real	4918	6405	6988	7273	2599	3246	3337	3361
		Q Forecasted	4918	6435	7019	7297	2599	3252	3352	3386
	Sunday	P Real	63	35	43	54	63	35	35	32
		P Forecasted	63	0	0	0	10	0	0	0
		Q Real	4526	4431	4920	5045	2519	2420	2533	2422
		Q Forecasted	4526	4438	4928	5055	2524	2422	2550	2440

			Sicily				Sardinia			
			3 a.m	10 a.m	12 a.m.	18 a.m.	3 a.m	10 a.m	12 a.m.	18 a.m.
July	Wednesday	P Real	71	75	70	76	70	83	75	76
		P Forecasted	71	0	0	50	0	0	0	0
		Q Real	1886	2304	2429	2481	971	1240	1219	1170
		Q Forecasted	1886	2314	2437	2481	973	1242	1221	1172
	Sunday	P Real	63	136	135	32	63	35	43	54
		P Forecasted	63	0	0	0	0	0	0	0
		Q Real	1875	1807	1942	1857	967	986	1021	951
		Q Forecasted	1875	1810	1945	1861	969	988	1023	953

			Prices €/MWh and Quantity MWh variability							
			Nord				Centre North			
			3 a.m	10 a.m	12 a.m.	18 a.m.	3 a.m	10 a.m	12 a.m.	18 a.m.
November	Wednesday	P Real	52	70	66	83	52	70	66	83
		P Forecasted		70	66	83	52	70	0	83
		Q Real	14885	24595	23994	25263	2556	4429	4405	4859
		Q Forecasted		24595	23994	25263	2556	4429	4515	4859
	Sunday	P Real	53	64	64	73	53	64	64	73
		P Forecasted		10	54	73	0	0	0	73
		Q Real	12757	14947	15316	17335	2326	2779	3008	3414
		Q Forecasted		15049	15316	17335	2407	2864	3097	3414

			Centre South				South			
			3 a.m	10 a.m	12 a.m.	18 a.m.	3 a.m	10 a.m	12 a.m.	18 a.m.
November	Wednesday	P Real	52	70	66	83	52	69	58	83
		P Forecasted	0	0	0	68	0	0	0	0
		Q Real	3666	5963	5857	6884	2136	2891	2789	3598
		Q Forecasted	3677	5989	5882	6884	2154	2919	2815	3614
	Sunday	P Real	53	64	64	73	53	64	64	73
		P Forecasted	0	0	0	61	0	0	0	0
		Q Real	3531	4495	4705	5480	1943	2364	2442	2912
		Q Forecasted	3547	4506	4716	5480	1959	2384	2458	2935

			Sicily				Sardinia			
			3 a.m	10 a.m	12 a.m.	18 a.m.	3 a.m	10 a.m	12 a.m.	18 a.m.
November	Wednesday	P Real	52	69	58	94	52	70	66	83
		P Forecasted	0	0	0	2	0	0	0	0
		Q Real	1392	2023	1916	2411	764	1075	1008	1173
		Q Forecasted	1400	2033	1926	2441	769	1080	1013	1178
	Sunday	P Real	53	71	64	94	53	64	64	73
		P Forecasted	0	0	0	0	0	0	0	0
		Q Real	1426	1792	1857	2095	815	989	990	1082
		Q Forecasted	1433	1793	1857	2108	820	989	991	1087

Conclusion and Policy Implications

The study aimed at evaluating the impact of new investments in the electricity sector on the price of electricity in Italy. Through an extensive analysis of the historical price data, production data and other relevant factors, we were able to estimate the future price of electricity taking into account the new investments. The results showed that the new investments in the form of solar panels and wind turbines will have a significant impact on the price of electricity in the future. This will lead to a reduction in the price of electricity, with prices potentially reaching 0 €/MWh during periods of high sun and wind. However, the study also revealed that the variability of prices will be strongly higher in 2030, with prices potentially returning to 60/70/80 €/MWh during periods of low sun and wind. This result implies that the price variability of electricity in the future will be strongly higher than it was in 2018.

The results of this study have several policy implications for the electricity sector in Italy.

First, it highlights the need to develop a comprehensive energy mix policy that takes into account the intermittency of renewable energy sources such as solar and wind. This policy should also consider the need for backup power sources to ensure a stable and reliable supply of electricity.

Second, the study highlights the need for the government to invest in infrastructure that will improve the interconnectivity of different regions, ensuring a stable and sufficient supply of electricity. This will also help in reducing the regional variability in electricity prices, promoting price stability across the country. In this context, it is important to note that the need of new investments for transmission lines is critical, especially in the south of Sicily and Sardinia where the energy produced during sunny and/or windy days will be more than the one consumed, so there will be a need for an increase in infrastructure to move the electricity to the north zone.

Third, the study highlights the need for the government to invest in research and development to improve the efficiency of renewable energy sources and to develop new storage technologies that can help to store the excess energy produced during sunny and windy days. This will help to ensure that the electricity produced during these periods is not wasted, and can be used to cover the demand during cloudy and non-windy days. New forms of storage should be considered, such as hydroelectric, battery, the intelligent use of the battery of new electric cars, or investments in hydrogen.

In conclusion, the study provides valuable insights into the impact of new investments in the electricity sector on the price of electricity in Italy and the policy implications that follow. It should be noted that the cost of the plants, new connections, technical buffers for stabilization and balancing the grid, and all other related costs were not considered in this study. However, it is important to remember that these new investments will not only aid Italy in reaching its energy production goals but also contribute to reducing its carbon footprint and transitioning towards a more sustainable energy mix. The need for new investments in transmission lines underlines the significance of incorporating a comprehensive approach when developing renewable energy projects. Policymakers must ensure that the necessary infrastructure is in place to support the growth of renewable energy and to avoid any potential bottlenecks in the energy system.

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Annex

Solar Pv				
Hours	3 a.m.	10 a.m.	12 a.m.	6p.m
CF	0%	60%	100%	20%

Months	March	July	November
CF North	70%	80%	10%
CF Centre-North	70%	80%	10%
CF Centre-South	70%	80%	10%
CF South	75%	90%	20%
CF Calabria	75%	90%	25%
CF Sicily	80%	90%	25%
CF Sardinia	70%	80%	10%

Example North Italy Final Production Factor Pv				
	3 a.m.	**10 a.m.**	**12 a.m.**	**6p.m**
March	(0.7*0)=0%	42%	70%	14%
July	0%	48%	80%	16%
November	0%	6%	10%	2%

Wind				
Hours	3 a.m.	10 a.m.	12 a.m.	6p.m
CF	100%	100%	100%	100%

Months[24]	March	July	November
CF Centre-North	52%	20%	46%
CF Centre-South	52%	26%	78%
CF South	52%	26%	78%
CF Calabria	59%	39%	72%
CF Sicily	65%	39%	85%
CF Sardinia	65%	39%	91%

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[24] The values reported here are the values from the graphs multiplied by 1.3. the reason for doing this is to consider roughly the best hours in the month studied. The percentage values shown in the graph are the monthly average, this means that it is as if the wind always blows at the same speed throughout the month. this is not realistic. To make our study more meaningful, we therefore imagined being able to analyse the hours in which the wind blows 30% more than the average in the month.

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