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The role of offshore wind power in Italy in 2050 according to highRES model

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Abstract

This master thesis uses the model highRES, an high spatial and temporal resolution power system model, to analyze the role of offshore wind power for the Italian electricity system in 2050. Three different scenarios projected by the International Energy Agency (IEA) are simulated: Stated Policies scenario, which represents the possible development in case the present situation stays, Announced Pledges scenario, which considers the case according to the Paris Agreement are respected, i.e. keeping global temperature rise below 2 °C, and the Net Zero Emissions by 2050, that represents the best case in terms of global emissions. These scenarios are analyzed considering a demand equal to the present and with an increase of 30%.

Results show a combination of different technologies: solar, wind onshore, wind offshore, nuclear, natural gas and RoR hydroelectricity for the power production and hydro reservoir and batteries for the storage system. The technology preferred by the model is found to be solar, but the lower the cost becomes, the more wind offshore contributes to the system. At the same time nuclear and wind onshore are completely ignored by the model. Results also include import and export data, which are found to give a small contribution to the total system, and storage usage, necessary for an high level of renewable in an electricity generation infrastructure, and curtailment data, that is the reduction of the power output necessary to adapt to the demand. Curtailment, like storage, represents a characteristic practice of renewable energy.

Model outputs are then compared with the real situation and with the PNIEC (Piano Nazionale Integrato per l'Energia e per il Clima) projections. This comparison shows a discrepancy between results and projections, but this has to be traced back to the own nature of highRES, i.e. a linear optimization model. In particular power production relies too much on one technology and import and export have a too little impact.

Considerations to improve the study are also presented and the main point is adjusting the model to represent just one country, in this case Italy. This represents the future use of highRES, in fact it has already been done for UK and a project for Norway is in progress.

Introduction

Greenhouse gas emissions are leading to global climate change, making necessary for all countries making plans to counteract and limit its effect and decreasing emissions in all sectors. Energy production represents one of the most polluting sector, thus meaning that it is important to go on with the transition to a new power system based on renewable energy technologies.

This final project aims to understand what could be the future of renewable energy and in particular offshore wind power in the Italian electricity production system in 2050. In order to reach this result, an optimization model called highRES is used.

HighRES builds the entire European electricity system in terms of GW of installed technology reducing the emission by 80% with respect to the whole energy system model [15], taking into account the hourly demand required by the EU.

Using several sets of inputs for the model allows to analyze a variety of possible projections and making sensitivity analysis. I simulated three different scenarios described by the IEA and then I compared the obtained results with the actual plan that the country has for the ecological transition.

The following thesis presents a literature review in section 1, in which the state of the art is described along. It follows section 2 in which the model used and the sensitivity analysis are explained. section 3 discusses results from the different simulations considering the power production in section 3.1, the import and export in section 3.2 and the storage production in section 3.3, and discuss them especially comparing them with the reality. Finally, in the section 3.5 there is a summary of the whole project and some possible further use of the highRES model.

1 Chapter 1: Literature review

1.1 Plans to counteract climate change

The need to counteract the climate change led 194 countries (considering EU as a country) to sign the Paris agreement in 2015 [12]. This contract aims to keep the temperature rise below 2 °C with respect to pre-industrial levels, to increase the ability to adapt to the impact of climate change, to encourage climate resilience and low greenhouse gas emissions development and make it economically feasible. The decarbonisation of the power sector is fundamental to achieve the above target.

Therefore, in order to achieve the Paris Agreement goals, the European Union adopted its own strategy by signing the European Green Deal. Through the European Green Deal, the EU commits to be the first continent to reach Net Zero Emission by 2050, while reducing the 55 % of emission with respect to 1990 before 2030 following a strategy called "Fit for 55"[4].

Each country in the EU has its own national plan to fulfill the European target. The Italian government, in particular, approved a document called "Piano Nazionale Integrato per l'Energia e il Clima" (PNIEC), which contemplates to reach 30% of gross final energy consumption produced by renewable energy by 2030, other than improving energy efficiency, thus reducing energy consumption by 43% and decreasing emissions [10].

1.2 Offshore wind turbines technology

Offshore wind power consists in the generation of electricity through wind farms at sea. Although initially it was not economically competitive with respect to onshore wind power, in the last few years it became more and more competitive also considering its advantages with respect to onshore wind power, in fact this technology has an higher capacity factor meaning that the same plant located offshore would produce more than in land and also it is commonly more accepted by the public opinion because this kind of wind turbines have less impact on people and landscape. Nowadays, offshore wind power is used the most in China and in Northern Europe.

The Mediterranean Sea is considered to account for 20% of the 2030 projected total offshore wind potential [1]. The PNIEC mentioned in section 1.1 set the goal of 300 MW of installed offshore wind power by 2025 and the triple by 2030 [6], although, at the moment, there is just one offshore wind power plant, located in Taranto coast, composed by 10 turbines for a total installed power of 30 MW.

Until now, this technology was stopped by the water depth, which implies an higher investment because fixed bottom turbines cannot be used, thus making floating wind turbines almost the only possible choice.

Figure 1: Ongoing wind offshore plant projects

It has been estimated that the Italian coast has the potential for 6 GW bottom fixed turbines and 183 GW floating turbines [2].

There are also ongoing project for the Sicilian Channel, a floating wind turbines power plant of 25 turbines of 10 MW each, for the Sardinia coast, 42 turbines of 12 MW each, and near Rimini coast, 59 fixed bottom structures of 5.6 MW each [6].

1.3 HighRES model

HighRES is a powerful high spatial and temporal resolution power system optimisation model that predicts the electricity generation mix in each zone. Regardless the fact that it is a recent model, it has already been used for several research project, which are described in paper. It can be noticed that the following papers descriptions uses the UK version of highRES. This has to be reported to two main factors, that is the existence of other models, referred to UK, together with highRES can be used, for example UKTM, and the greater level of accuracy that the model can give if it is built on one single country, in fact while the European version divides all Europe in 31 zones, the UK version divides Great Britain into 20 zones.

The research presented in [20] describes the results of an highRES version modified to include just Great Britain, i.e. UK is divided into 20 zones which are used in the model and of course all input change consistently. HighRES is soft-linked with the UKTM model. They analyzed two scenarios, with 50% of VRE and with 80% of VRE, using ten different weather years to understand how it effects the total production.

In the paper [14], researchers studies three different scenario based on the wind energy capacity potentials according to the influence of public sensitivity of visual impact. This reference explains that public opinion in VRE field represents an important factor because surveys conducted all over Europe showed that potential can be reduced by 50% or even more. Results report that the more public sensitivity increases, the more investments go from onshore wind to offshore wind and solar, in particular the worst case shows a reduction of 89% in wind onshore, thus leading also to higher costs.

The reference [11] investigates the future of floating offshore wind turbines for Great Britain in 2050. It explores the effect of different total share of VRE, floating offshore costs and the impact of waves on operation and it finds the cost crossover point at which floating turbines contributes to the optimal system, the technologies and their locations replaced by floating turbines along with the other change of the total system necessary to increase floating offshore wind turbine, i.e. storage and dispatchable generation (meaning generating power plant that are programmed according to the electricity demand). Results tell that as floating wind cost is reduced, its capacity increases and the capacity of other renewable sources decreases, especially mid depth offshore wind. The deployed capacity of floating wind reaches parity with mid depth wind when costs are just under 5% higher. According to the model floating wind can complement bottom-mounted offshore wind by providing an aggregate increase in spatial diversification, so they suggest to incentivize developers to build in system-optimal locations.

HighRES has been used also to evaluate if building new nuclear power plat is necessary for the UK's net-zero emissions energy system in [13]. They made a sensitivity analysis on future UK power system designs considering four key dimensions: nuclear capital costs; technology availability; interconnection expansion; and weather conditions, all these sum up in four different scenarios. They conclude that new nuclear capacity is cost-effective just if ambitious cost and construction times are assumed, competing technologies are unavailable and interconnection expansion is not possible.

The reference [16] develops an energy-land-water nexus modelling framework and uses highRES to perform a scenario analysis that aims of understanding the planning and operational implications of real-world constraints on Great Britain's power system in 2050. It explains how these limitations can cause important changes in system design both in terms of the spatial pattern of where generators are located and the capacity mix of the system. In this project research highRES was used together with other models, i.e. UKTM, which represents the whole British energy system under a given decarbonisation objective designing the optimal low carbon transition from 2010 to 2050, and Foreseer, which is an energy-land-water nexus tool that calculates emissions and other measures of stress in response to user-defined scenarios. They analyzed three different scenarios considering high, medium and low restriction, thus meaning different land, water availability, then they did simulations analyzing system cost and design impacts of all the combinations of the already mentioned constraints but considering at least 80% of VRE in electricity system.

2 Chapter 2: Methodology

2.1 Optimization modelling for climate change

The optimization modelling is an approach to solve complex problems in an efficient way through mathematical techniques and algorithms used to represent a real-world situation.

Its target is maximizing or minimizing the objective function taking into account also limits and constraints related to the study case. The optimization model reaches its aim changing certain decision variables specific to the problem.

It is particularly useful when there are limited resources and multiple variables to consider for making effective decisions.

It is important to remember, when analyzing the optimization model results, that its limits should be taken into account. In fact, linear optimization models tend to prefer one solution over another if the first one is even just slightly better, but in reality this is not possible.

Optimization modelling is used also to help understanding how to bear climate change and for decision making regarding investment in renewable energies. They generally take as input availability of different technologies, costs, CO_2 emissions and energy policies to satisfy energy demand being less polluting as possible. Example of this kind of models are highRES and Calliope.

2.2 highRES model

HighRES model [15] is a spatial and temporal resolution system model implemented in GAMS and solved through the solver CPLEX. It is an high-resolution electricity system model that considers infrastructure planning and operational decisions to identify the most cost-effective strategies to cope with growing shares of intermittent renewables. Its objective is to minimise power system investment and operational costs to meet hourly demand, subject to a number of unit and system constraints. It runs for one snapshot year and optimises the dispatch and locational investments into power plants, storage and transmission grid extension.

The highRES model works with grid aggregated to zones, in this case there are 31 zones for each country in Europe.

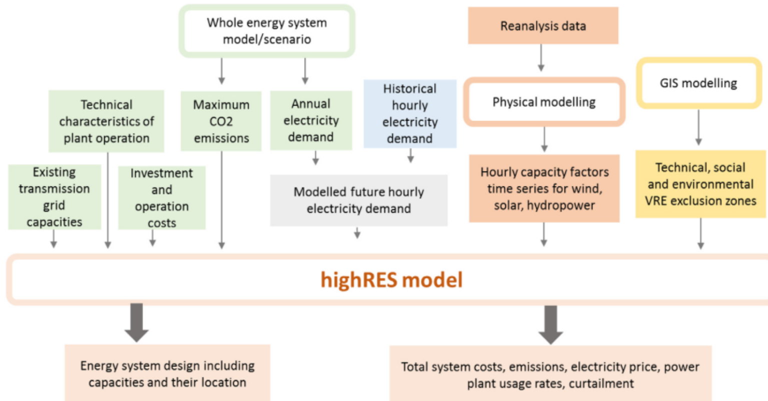


Figure 2: The HighRES modelling framework reported in [15]

The above figure sums up the whole model functioning, in fact from the input side it shows that the model takes directly the technical characteristics of plant operation, which are the technical factors referred to technologies, the investment and operation costs data and the existing transmission grid capacities. Furthermore, from the whole energy system model/scenario the maximum CO_2 emissions are computed and also the annual electricity demand is derived, which together with the historical hourly electricity demand is used to model the future hourly electricity demand. The GIS modelling results in technical, social and environmental VRE exclusion zones. The ERA-5 realanysis data give the hourly capacity factors time series for wind, solar and hydropower. HighRES take all these inputs and returns as output the energy system design which include capacities installed and their location and the total system costs, emissions, electricity price, power plant usage rates and curtailment data.

The objective function and the balancing equation are the most important equations that govern the model and they are defined by

$$
\begin{aligned}
Min \sum_{z,g^n,h} (var^{nvre\_gen}_{z,h,g^n} \cdot g\_varom_{g^n}) + \sum_{z,g^v,h} (var^{vre\_gen}_{z,h,g^v} \cdot g\_varom_{g^v}) + \\
+ \sum_{z,s,h} (v^{s\_gen}_{z,s,h} \cdot s\_varom_s) + \sum_{g^n} (var^{nvre\_cap}_{g^n} \cdot g\_capex_{g^n}) + \\
+ \sum_{g^v} (var^{vre\_cap}_{g^v} \cdot g\_capex_{g^v}) + \sum_{z^1,z^2} (var^{t\_cap}_{z^1,z^2} \cdot t\_dist_{z^1,z^2} \cdot t\_capex) + \\
+ \sum_{s} (v^{s\_cap}_s \cdot s\_gen\_capex_s + v^{s\_cap}_s \cdot s\_gen\_to\_cap_s \cdot s\_cap\_capex_s) + \\
+ \sum_{z,h} (v^{p\_gen}_{z,h} \cdot penalty) \quad (1)
\end{aligned}
$$

and

$$d_{z,h} = \sum_{g^n}(var^{nvre\_gen}_{z,h,g^n} + \sum_{g^v}(var^{vre\_gen}_{z,h,g^v} - \sum_{g^v}(var^{curtail}_{z,h,g^v}) - \sum_{z^2}(var^{t\text{-}flow}_{z^2,h,z^1})+$$
$$+ \sum_{z^2}(var^{t\text{-}flow}_{z^1,h,z^2} * (1 - (t\_dist_{z^1,z^2} \cdot t\_loss))) - \sum_{s}(var^{s\text{-}store}_{z,h,s})+$$
$$+ \sum_{s}(var^{s\text{-}gen}_{z,h,s}), \quad (2)$$

where z stands for zones, g for generator, h for hours, g^n for non variable renewable generator, g^v for variable renewable generator, t for transmission links, s for storage, $var^{nvre\_gen}_{z,h,g^n}$ for non VRE generation by zone, hour and technology, g_varom_g for variable operation and maintenance costs per generator, including fuel costs, $var^{vre\_gen}_{z,h,g^v}$ for VRE generation by zone, hour and technology, $v^{s\text{-}gen}_{z,s,h}$ for electricity generated from storage by hour, technology and zone, s_varom_s for variable operation and maintenance costs for storage, $var^{nvre\_cap}_{g^n}$ for non VRE capacity by technology, g_capex_g for annuitizied capital costs per generator, $var^{vre\_cap}_{g^v}$ for VRE capacity for technology, $var^{t\text{-}cap}_{z^1,z^2}$ for capacity of zone to zone transmission links, t_capex for annuitized capital cost oh high voltage transmission, $v^{s\text{-}cap}_{s}$ for capacity of storage generator deployed nationally, $s\_gen\_capex_s$ for annuitized capital cost for the storage generator, $s\_gen\_to\_cap_s$ for sizing of storage generator in relation to the storage system, $s\_cap\_capex_s$) for annuitized capital cost for the storage system, $v^{p\text{-}gen}_{z,h}$ for penalty generation, $d_{z,h}$ for demand per zone and hour, $var^{curtail}_{z,h,g^v}$ for power curtailed by zone, hour and VRE technology, $var^{t\text{-}flow}_{z^2,h,z^1}$ for flow of electricity from zone to zone by hour, $t\_dist_{z^1,z^2}$ for transmission line distance between zones, t_loss for transmission losses, $var^{s\text{-}store}_{z,h,s}$ for electricity into storage by hour, technology and zone, $var^{s\text{-}gen}_{z,h,s}$ for electricity generated from storage by hour, technology and store [21].

The objected function reported in eq. (1) aims to minimize the sum of variable and fixed costs. The variable costs are composed of non vre costs, vre costs and storage costs, while capital costs are composed of non VRE, VRE, transmission and storage capital costs plus the cost of penalty. The penalty generation makes sure that the model solves even in case the balancing equation is not met.

The balancing eq. (2) ensures that the demand is equal to supply in each hour and zone.The demand must be equal to the generation from renewable and non renewable minus the curtailment, minus the electricity exported plus electricity imported into the zone reduced by losses which depend on the distances, minus electricity which is stored plus electricity generated from storage plus penalty generation.

2.2.1 Technologies used

The technologies considered by the model are divided into three categories: Renewable (VRE), non renewable (NVRE) and storage. For VRE the emission factor is considered equal to 0.00 g CO_2/kWh.

It follows a description of all technologies considered in the model, starting from the VRE, then the NVRE and finally the storage methods.

All technologies are characterized by an emission factor, which for all VRE have is equal to 0.00 g CO_2/kWh.

The VRE have a capacity to area factor, which represents the capacity in MW that can be installed in 1.00 km^2.

The NVRE and the hydropower methods present an availability factor, which represents the ratio between the amount of time during which the plant is able to produce electricity and the total amount of time.

Solar

Solar power is the conversion from sunlight into electricity through photovoltaic cells also called solar cells. A solar cell is an electronic device which spreads the photovoltaic effect to convert the energy of light directly into electricity, because it is a device that varies its electrical characteristics, i.e. current, voltage and resistance, when it is exposed to light. Solar cells linked together make a photovoltaic model. Solar has a capacity to area factor of 40.00 MW/km^2.

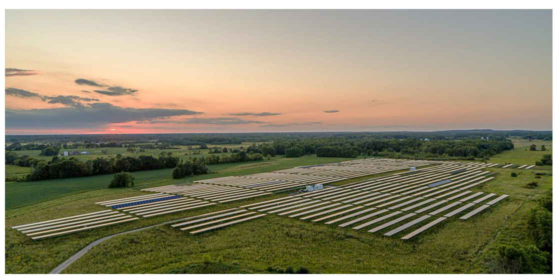


Figure 3: Solar Power plant

Wind onshore

Wind power means the use of wind energy to generate electricity. Wind turbines use blades to collect the wind's kinetic energy. The blades are connected to a drive shaft, so the wind makes the blades turn which make the drive shaft to turn an electric generator, which produces electricity. Wind onshore has a capacity to area factor of 3.00 MW/km^2.

Figure 4: Wind onshore power plant

Wind offshore

Wind power offshore works with the same principle of onshore, but in the sea. Several kind of turbines exist: fixed-foundation for shallow water or floating wind turbines for deeper water. Wind offshore has a capacity to area factor of 5.00 MW/km^2.

Figure 5: Wind offshore power plant

Run of River hydroelectricity

This is a type of hydroelectric generation plant, considered suitable where streams of river can sustain a minimum flow. Typically, in hydropower plants, water flows through a pipe, then pushes against and turns blades in a turbine that spin to power a generator that will produce electricity. In RoR, the force of the river's current applies pressure on a turbine. The availability factor is considered equal to 0.98 and the capacity to area is 1.00 MW/km^2.

Figure 6: Run-of-river hydropower plant

After having described the VRE, here are reported the NVRE technologies considered by the model. Since highRES aims to minimize the emissions, the technologies chosen are the least polluting, so even if coal, for example, is still used as a power source nowadays, it hypothesis that it won't be a source anymore in the future.

Nuclear

Nuclear power uses nuclear reactions, in particular nuclear fission of uranium and plutonium, to produce electricity. This fission reaction releases heat, which is used to produce steam which goes into a turbine generator to generate electricity. Nuclear is considered to have an emission factor of 0.00 g CO_2/kWh in the model. Nuclear has an availability factor of 0.91.

Figure 7: Nuclear power plant

Natural Gas

Natural Gas power plant generate electricity by burning natural gas as their fuel. In the model two kind of power plants are considered: a "simple cycle gas turbine", also known as open cycle gas turbine (OCGT), and a combined cycle gas turbine (CCGT).

The first one is a plant cheap to build and it is usually run just for a few hours a day because of its small efficiency, so it is considered a peaking power plant. This kind of power plant has an emission factor of 0.53 g CO_2/kWh.

The second one is composed by a gas turbine followed by a heat recovery steam generator and a steam turbine. Its efficiency is higher with respect to the OCGT. This kind of power plant has an emission factor of 0.04 g CO_2/kWh.

They both have an availability factor of 0.90.

Figure 8: Natural gas power plant

Considering the non continuity of renewable technology, storage will represent an important part of electricity system in the future. In highRES two different type of storage are taken into account.

Hydropower reservoir

This type of hydroelectric energy storage. It stores energy in form of gravitational potential energy of water. The stored water is released through turbines to produce electric power.

Figure 9: Hydroelectric reservoir plant

VRFB4

The model takes into account also the batteries option through the VRFB4, that is the vanadium redox flow battery. It uses vanadium ions as charge carries. With respect to other type of batteries VRF presents several advantages and they will have a big role in the future energy transition.

Figure 10: Vanadium Redox Flow Batteries

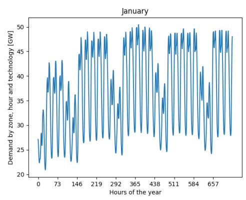
2.3 Base model results

Taking into account just the results for Italy, according to the base model, i.e. the model how it is presented in the paper [15], the most used VRE technology is Solar, supported by hydro-power, but also Natural gas and Nuclear. The demand is also satisfied through imported energy from neighborhood countries and the use of batteries. The excess of production, instead, is curtailed or exported.

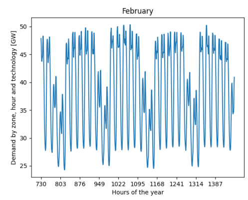
The demand, which will be considered standard in all simulations described in this thesis document, is reported in fig. 11. Its trend is pretty much constant over the year, in fact it is evident that the demand is higher during week days while it clearly decreases during weekends. At the same time demand is lower during holidays, for example Christmas between December and January, Easter in March or summer holidays in August. In order to obtain these graphs the model uses data collected in 2013.

To understand if this data are still reasonable and that they are not outdated, I should point out that the electricity request for Italy in 2021 was 319.90 billions of kWh [18], while in the model it is 316.03 billions kWh, thus leading to say that they are still comparable.

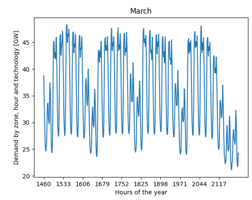
According to the technical report published by the European Commission "Trends to 2050" [3], the electricity demand in Europe will increase by 30% in 2050 with respect to 2013. So I decided to run the model also considering the new scaled demand, which clearly presents the same trend as the one showed in fig. 11, but increased by 30%. This increment means for Italy a total production in one year of 410.84 billions of kWh.



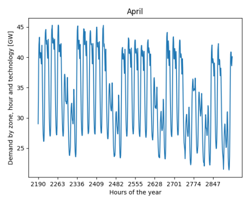
(a) Demand in January



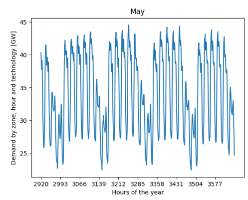
(b) Demand in February



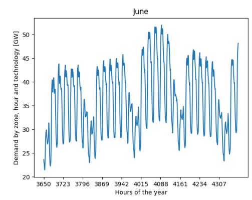
(c) Demand in March



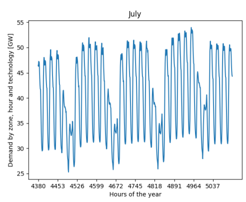
(d) Demand in April



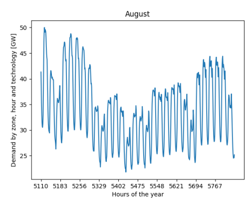
(e) Demand in May



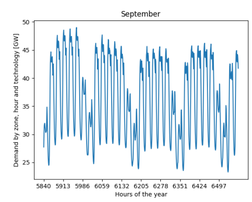
(f) Demand in June



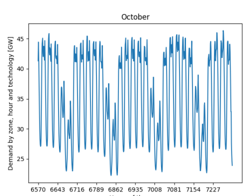
(g) Demand in July



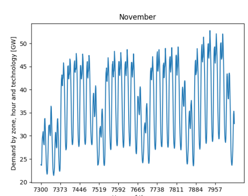
(h) Demand in August



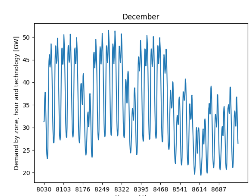
(i) Demand in September



(j) Demand in October

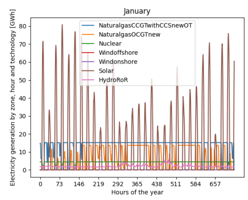


(k) Demand in November

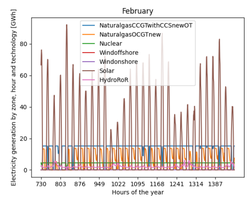


(l) Demand in December

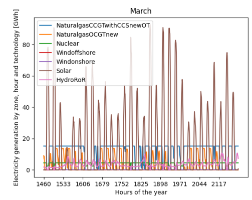
Figure 11: Demand month by month for the whole year



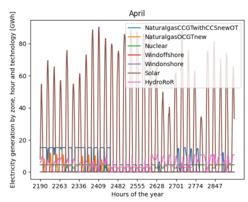
(a) Power production in January



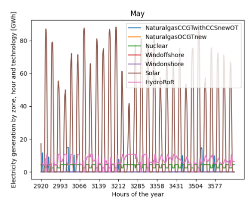
(b) Power production February



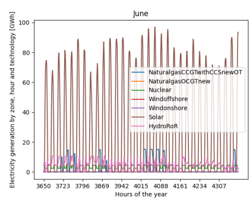
(c) Power production March



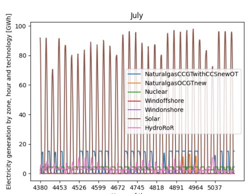
(d) Power production in April



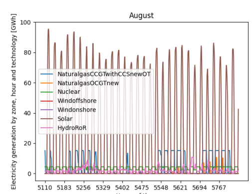
(e) Power production in May



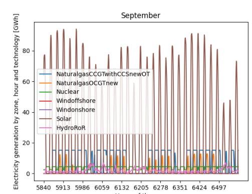
(f) Power production in June



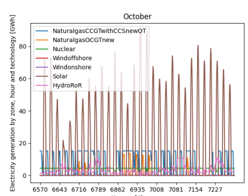
(g) Power production in July



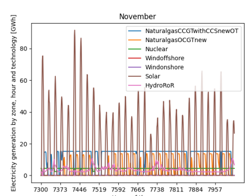
(h) Power production in August



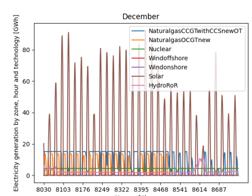
(i) Power production September



(j) Power production October



(k) Power production November



(l) Power production December

Figure 12: Power production month by month for the whole year

The graphs in fig. 12 show the energy production from all technology for all months according to the base model.

As already mentioned, the model as it is proposes a scenario where solar is the most spread technology and it is helped by Natural gas power plant, nuclear and hydropower, while it suggests that it is not convenient investing in wind power both onshore or offshore.

Having analyzed the model and made several trials to become more familiar with it, the most important consideration that I took from studying the model is that an hypothetical scenario in which a great part of the energy production is due to wind offshore is possible, thus meaning that according to the model there is a significant potential in the Italian coast.

Along with what said before, I understood that the parameters which influence the most the energy production are the capital costs and the fixed operation and maintenance one. In the model the capital cost is considered to be annualized according to the formula

$$Annuity = \frac{Cap \cdot i}{1-(1+i)^{-y}} + Fix, \tag{3}$$

where Cap stands for the capital costs, Fix represents the fixed operation & maintenance costs, y is the lifetime and i is used for the interest rate of 4%. For wind offshore turbines the lifetime y is considered to be 30 years. The constraints that limit each technology in the model are: area, capacity per area, capital cost, fixed operation and maintenance cost and variable O&M cost. The available area was computed using GIS modelling, while the other factors are taken from literature or from other model as described in the highRES paper.

2.4 Scenarios analyzed

So I decided to analyze three different scenario presented in the technical model by IEA "Global energy and climate model" [9]. The scenarios presented are the following: Stated Policies Scenario, Announced Pledges Scenario and Net Zero Emission by 2050 Scenario.

2.4.1 Stated Policies Scenario

The Stated Policies scenario reflects current policy settings based on a sector-by-sector and country by country assessment of the specific policies that are in place, as well as those that have been announced by governments around the world. The aim of this scenario is providing a benchmark to assess the potential achievements (and limitations) of recent developments in energy and climate policy. It does not take for granted that governments will reach all announced goals and it is not designed to achieve a particular outcome.

In this scenario using the eq. (3) an annualized capex of 86.74 e/kW is computed along with a fixed O&M cost of 87.6 e/kW.

2.4.2 Announced Pledges Scenario

A scenario which assumes that all climate commitments made by governments around the world, including Nationally Determined Contributions (NDCs) and longer-term net zero targets, as well as targets for access to electricity and clean cooking, will be met in full and on time. The aim is to show how close do current pledges get the world towards the target of limiting global warming to 1.5 °C, it highlights the "ambition gap" that needs to be closed to achieve the goals agreed at Paris in 2015. It also shows the gap between current targets and achieving universal energy access.

In this scenario using the eq. (3) an annuitized capex of 76.34 e/kW is computed along with a fixed O&M cost of 43.8 e/kW.

2.4.3 Net Zero Emission by 2050

A scenario which sets out a pathway for the global energy sector to achieve net zero CO2 emissions by 2050. It does not rely on emissions reductions from outside the energy sector to achieve its goals. Universal access to electricity and clean cooking are achieved by 2030. The aim is to show what is needed across the main sectors by various actors, and by when, for the world to achieve net zero energy related and industrial process CO2 emissions by 2050 while meeting other energy-related sustainable development goals such as universal energy access. This scenario is consistent with limiting the global temperature rise to 1.5 °C.

In this scenario using the eq. (3) an annualized capex of 71.71 e/kW is computed along with a fixed O&M cost of 43.8 e/kW.

3 Chapter 3: Results and Discussion

In this chapter the results of the simulations run are discussed. These chosen simulations are the result of the model understanding and studying, which required at least other 15 simulations to identify the key factors in this study case, i.e. in which condition the usage of wind offshore is convenient.

As mentioned in the previous chapters, it was found that the bottle neck for the spread of the wind offshore technology is represented by the cost, both fixed and variable. The International Energy Agency produced different scenarios based on three levels of conscious and effort for bearing the climate change and so data taken from this report were used to run highRES.

The simulations run led to different combinations of installed technologies, reported in table 1, table 2, table 3 for standard demand and in table 4, table 5 and table 6 for increased demand. It can be noticed that in the above mentioned tables the power installed is reported for the following technologies: Natural Gas CCGT, Natural Gas OPGT, Solar and Wind offshore.

Hydropower is considered in these tables to have a fixed power installed of 17 GW is taken as an input, this includes both hydropower Run Of River and hydropower Reservoir. This choice derived from the fact that hydropower plants are hypothized to last for decades and the possible further spread of this technology mostly regards the efficiency improvement and not other installations, at least in a short term. The data 17 GW used has to be compared to the actual installed hydropower which is 18.94 GW and it is considered almost the maximum possible [8] for the Italian case.

Wind onshore and Nuclear have an insignificant value, i.e. an order of magnitude of $10^{-}7$, reported as 0.00 in the following tables. This is due to the fact that highRES does not consider them convenient in the mixture of technologies proposed.

Technology	Power installed	
Natural Gas CCGT	5.79	GW
Natural Gas OCGT	16.74	GW
Solar	169.17	GW
Wind offshore	17.32	GW
Hydropower	17.00	GW
Wind onshore	0.00	GW
Nuclear	0.00	GW

Table 1: Technologies installed for NZE with standard demand

Technology	Power installed	
Natural Gas CCGT	7.60	GW
Natural Gas OCGT	16.03	GW
Solar	173.18	GW
Wind offshore	13.71	GW
Hydropower	17.00	GW
Wind onshore	0.00	GW
Nuclear	0.00	GW

Table 2: Technologies installed for AP with standard demand

Technology	Power installed	
Natural Gas CCGT	18,77	GW
Natural Gas OCGT	10.84	GW
Solar	192.45	GW
Wind offshore	0.00	GW
Hydropower	17.00	GW
Wind onshore	0.00	GW
Nuclear	0.00	GW

Table 3: Technologies installed for SP with standard demand

Observing the data in table 1, table 2 and table 3 it is evident that in all scenarios Solar is the most used source of power.

In particular, in the Stated Policies one, reported in table 9, solar reaches its maximum extension because is found to be the only renewable energy in which investing is worth it. Solar is supported by Natural Gas OCGT and Natural Gas CCGT. With respect to the other cases the gigawatts of Natural Gas CCGT installed are higher than OCGT. This anomaly derives from the fact that Natural Gas OCGT is a peaking power plant, thus is kind of necessary when the amount of renewables in the system increases, but to actually produce electricity in more stable way Natural Gas CCGT is preferred.

In the Announced Pledges Scenario wind offshore pops up with 13.71 GW installed. At the same time the amount of solar decreases and also the distributions between OCGT and CCGT changes to support the new system.

For the Net Zero Emissions case the mixture is quite similar to the AP one, especially the trend, but wind offshore becomes the second technology for GW installed.

Technology	Power installed	
Natural Gas CCGT	9.46	GW
Natural Gas OCGT	16.50	GW
Solar	236.14	GW
Wind offshore	29.35	GW
Hydropower	17.00	GW
Wind onshore	0.00	GW
Nuclear	0.00	GW

Table 4: Technologies installed for NZE with increased demand

Technology	Power installed	
Natural Gas CCGT	11.12	GW
Natural Gas OCGT	15.67	GW
Solar	240.06	GW
Wind offshore	24.99	GW
Hydropower	17.00	GW
Wind onshore	0.00	GW
Nuclear	0.00	GW

Table 5: Technologies installed for AP with increased demand

Technology	Power installed	
Natural Gas CCGT	26.95	GW
Natural Gas OCGT	11.95	GW
Solar	244.64	GW
Wind offshore	0.00	GW
Hydropower	17.00	GW
Wind onshore	0.00	GW
Nuclear	0.00	GW

Table 6: Technologies installed for SP with increased demand

In table 6, table 5 and table 4 results for increased demand are sum up. The distribution between different solutions follows the same concept of results for standard demand, but at the same time it is interesting to notice the potential of the renewable, in fact Solar reaches 244.64 GW and wind offshore almost 30 GW.

3.1 Power generation

The graphs shown in fig. 13, fig. 14 and fig. 15 and fig. 18, fig. 17 and fig. 16 represent the outputs for the three scenarios described in section 2.2.

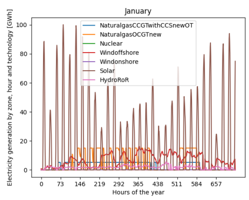
In particular they show the exact power production given by the different mixture of technologies described in the above paragraph. These figures report the power production from each technology in each hour of the year. They are divided into monthly graph to be more readable.

As expected production from offshore wind power increases from SP to NZE, as the power installed increases. For what concerns the simulations run for the increased demand, the trend stays the same but to fulfill the demand, the model decides to invest more in both solar and wind offshore and consequently Natural Gas OPGT is more used than CCGT.

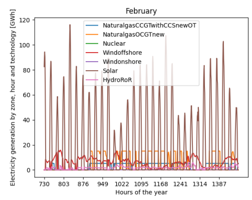
About wind onshore, the model does not consider it feasible for Italy, although nowadays there are 12 GW installed and this amount should be doubled by 2030 [7]. This result has to be reported to the fact that highRES is a linear optimization model so if one option is even slightly better than a similar one, it prefers the first one. In real life, there are much more variables to include in the problem like public opinion or bureaucracy time, thus leading to do other specific consideration regarding this technology.

About solar, the results reach almost 245 GW installed for the Stated Policies scenario for increased demand. Nowadays, there are 21 GW already installed and according to the PNIEC 50 GW more will be installed by 2030 totalling in around 70 GW [17]. This output has to be interpreted considering the great potential that this technology has, but it does not look realistic.

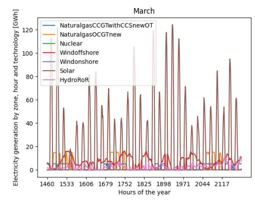
To sum up, it is clear that for the model the main technology would be solar but helped through wind offshore, hydropower and natural gas power plants. Nuclear is not shut off, but the model decided that it is not convenient in any case, as for wind onshore.



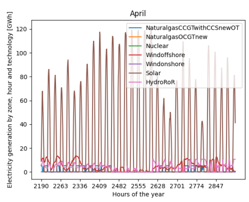
(a) Power generation in January



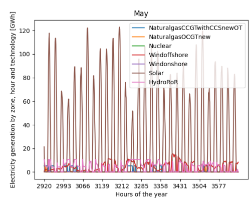
(b) Power generation February



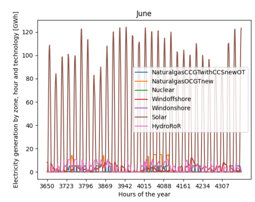
(c) Power generation March



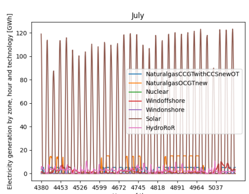
(d) Power generation in April



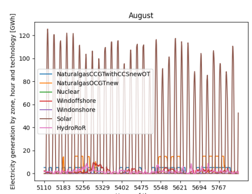
(e) Power generation in May



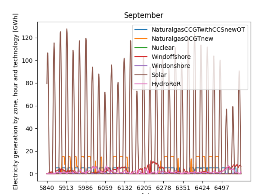
(f) Power generation in June



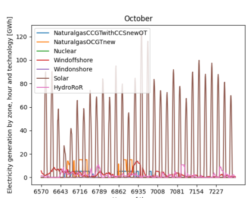
(g) Power generation in July



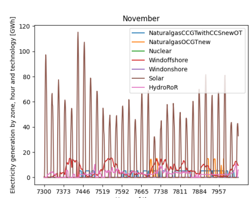
(h) Power generation in August



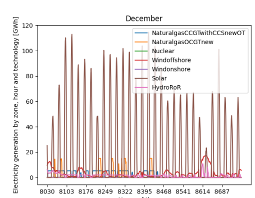
(i) Power generation September



(j) Power generation October

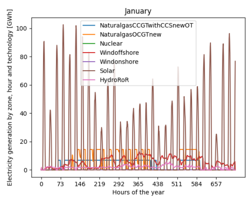


(k) Power generation November

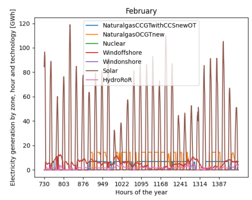


(l) Power generation December

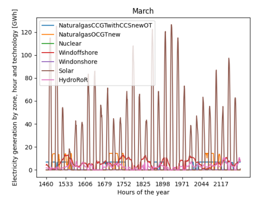
Figure 13: Power production month by month for the Net Zero Emission by 2050 scenario



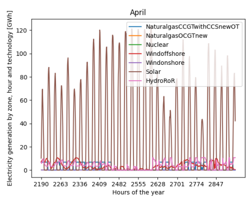
(a) Power generation January



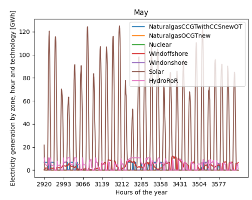
(b) Power generation February



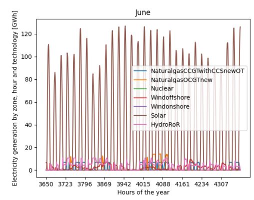
(c) Power generation March



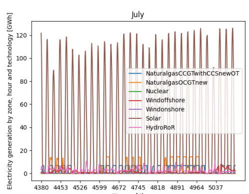
(d) Power generation in April



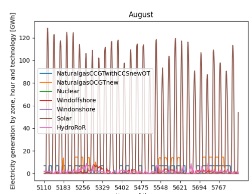
(e) Power generation in May



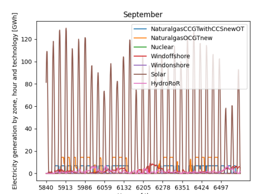
(f) Power generation in June



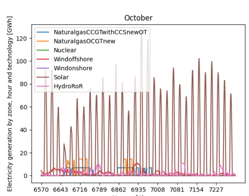
(g) Power generation in July



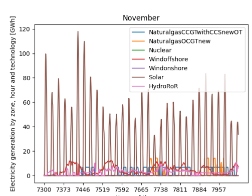
(h) Power generation August



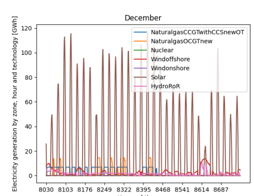
(i) Power generation September



(j) Power generation October

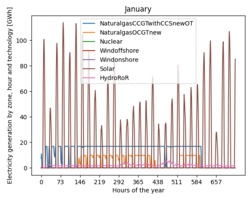


(k) Power generation November

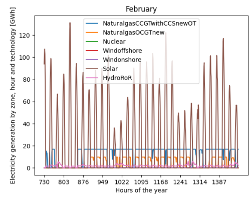


(l) Power generation December

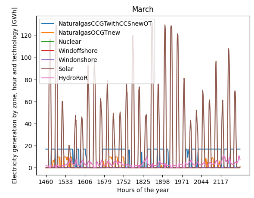
Figure 14: Power production month by month for the Announced Pledges Scenario



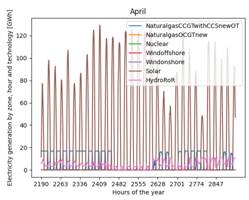
(a) Power generation in January



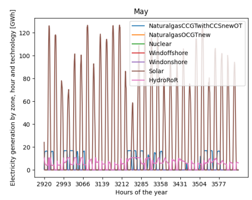
(b) Power generation February



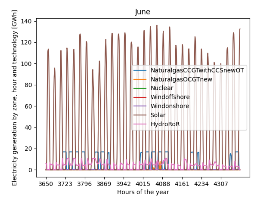
(c) Power generation March



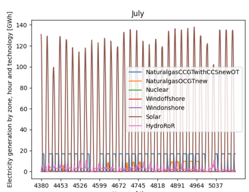
(d) Power generation April



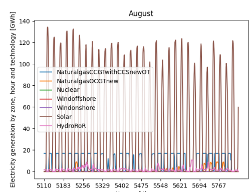
(e) Power generation May



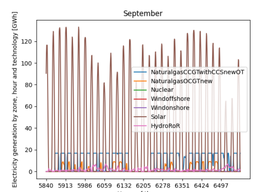
(f) Power generation June



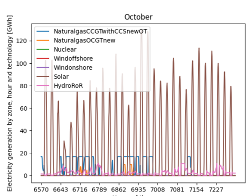
(g) Power generation July



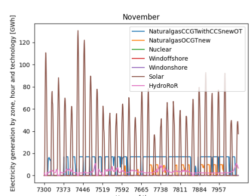
(h) Power generation August



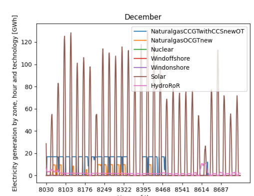
(i) Power generation September



(j) Power generation October

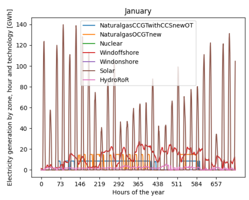


(k) Power generation November

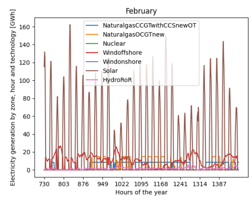


(l) Power generation December

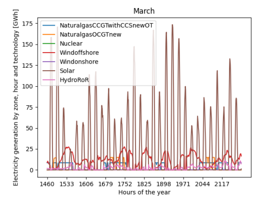
Figure 15: Power production month by month for the Stated Policies Scenario



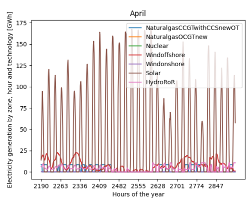
(a) Power generation in January



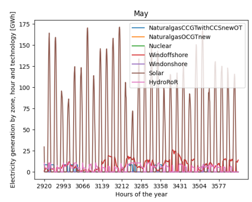
(b) Power generation February



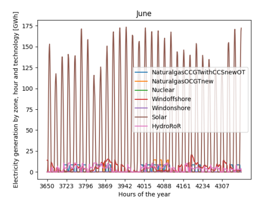
(c) Power generation March



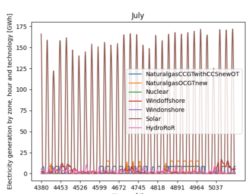
(d) Power generation in April



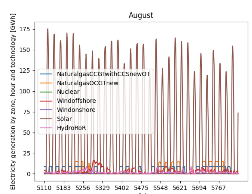
(e) Power generation in May



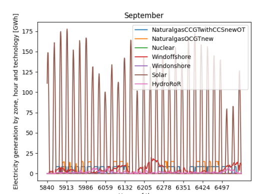
(f) Power generation in June



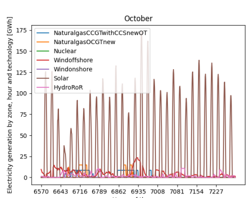
(g) Power generation in July



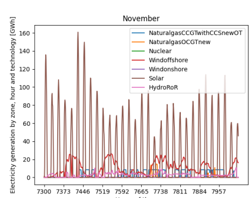
(h) Power generation in August



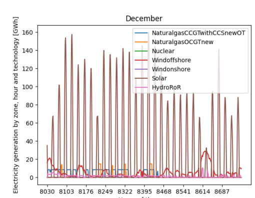
(i) Power generation September



(j) Power generation October

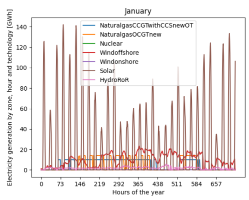


(k) Power generation November

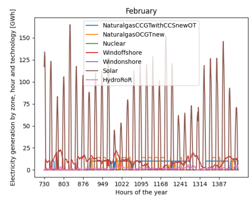


(l) Power generation December

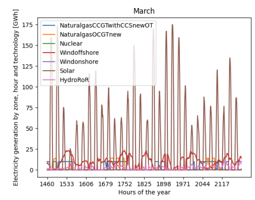
Figure 16: Power production month by month for the Net Zero Emission by 2050 scenario for increased demand



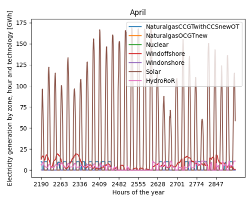
(a) Power generation January



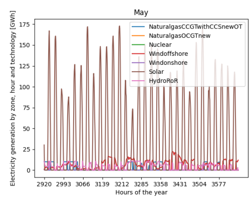
(b) Power generation February



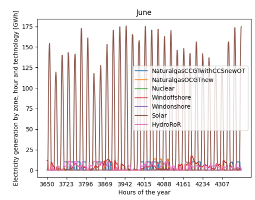
(c) Power generation March



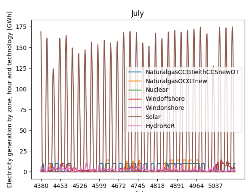
(d) Power generation in April



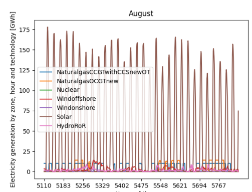
(e) Power generation in May



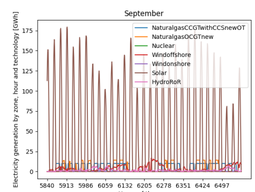
(f) Power generation in June



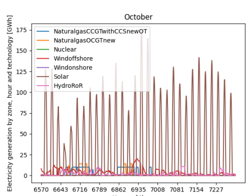
(g) Power generation in July



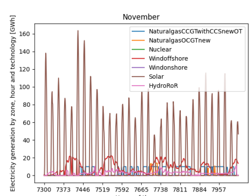
(h) Power generation August



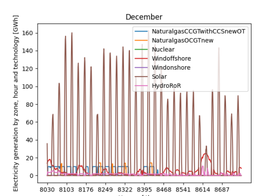
(i) Power generation September



(j) Power generation October

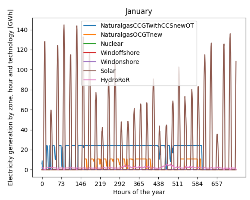


(k) Power generation November

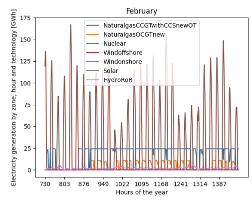


(l) Power generation December

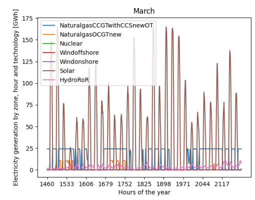
Figure 17: Power production month by month for the Announced Pledges Scenario for increased demand



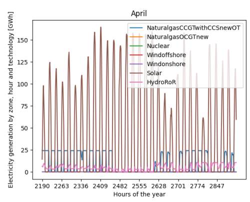
(a) Power generation in January



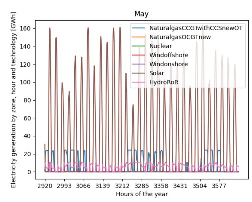
(b) Power generation February



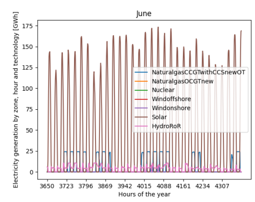
(c) Power generation March



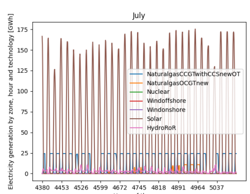
(d) Power generation April



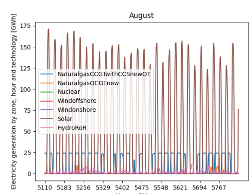
(e) Power generation May



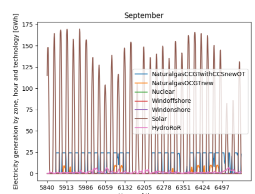
(f) Power generation June



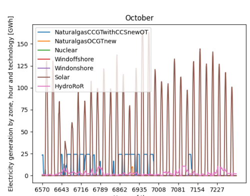
(g) Power generation July



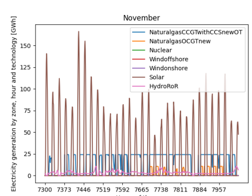
(h) Power generation August



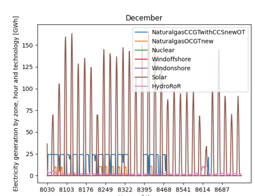
(i) Power generation September



(j) Power generation October



(k) Power generation November



(l) Power generation December

Figure 18: Power production month by month for the Stated Policies Scenario for increased demand

Observing the graphs it can be noticed that Natural Gas CCGT is used as a constant base, higher in the Stated Policies scenario with around 20 GWh. For what concerns the Natural Gas OCGT instead, it is turned on when needed, that is during the night when the main technology, i.e. solar, does not produce energy.

Comparing these results with PNIEC target described in section 2, the model decides to install 29.35 GW of Offshore turbines in the NZE scenario for increased demand contributing to the 14 % of the total energy production.

The following table 7,table 8 and table 9 show the same production represented in the above graphs, but month by month considering also the percentage of each technology. In particular in all scenario Solar power represents at least the 70% of the total production, while offshore wind reaches the 8% in AP and the 14% in the NZE scenario for increased demand. The total amount of energy produced is greater than the demand, meaning that power is both curtailed and exported and storage is not really used.

	NaturalgasCCGT	NaturalgasOPGT	Windonshore	Windoffshore	Solar	HydroRoR	Total	
January	2136.35	3084.04	0.00	5095,44	11811.88	1279.67	22.13	TWh
February	2417.25	3174.11	0.00	4549.25	14963.12	1233.00	25.10	TWh
March	1643.65	1448.00	0.00	5126.42	15369.23	1793.02	23.59	TWh
April	1368.26	5.78	0.00	3355.80	21798.36	2831.17	26.53	TWh
May	675.72	23.42	0.00	3258.52	21652.25	3162.17	25.61	TWh
June	1294.36	716.22	0.00	2067.56	26355.86	2712.53	30.43	TWh
July	1991.58	2034.31	0.00	1372.76	26743.17	1892.05	32.14	TWh
August	2058.38	2077.07	0,00	1354.50	25016,86	1323.33	30,51	TWh
September	2174.07	2894.47	0,00	1923,69	22825,24	1213.00	29,82	TWh
October	895.54	976.30	0,00	1909,33	16092,06	1342.27	19,87	TWh
November	1553.31	515.05	0,00	4265.72	12524.41	2071.95	18.86	TWh
December	1346.54	719.41	0.00	2274.63	14503.50	1059.55	18.84	TWh
	0.06	0.06	0.00	0.12	0.757	0.072	303.43	TWh

Table 7: All power generation Net Zero Emission Scenario with standard demand

	NaturalgasCCGT	NaturalgasOPGT	Windonshore	Windoffshore	Solar	HydroRoR	Total	
January	2819.60	3054.57	0.00	4030.89	12092.27	1362.08	22.00	TWh
February	3239.56	3091.08	0.00	3599.05	15318.31	1247.27	25.25	TWh
March	2244.88	1430.15	0.00	4064.90	15729.87	1976.57	23.47	TWh
April	1826.91	0.00	0.00	2678.10	22290.91	2872.37	26.80	TWh
May	992.41	2.48	0.00	7.14	22161.13	3302.78	23.16	TWh
June	1649.93	568.75	0.00	1638.58	26970.65	2791.04	30.83	TWh
July	2561.57	1853.49	0.00	1082.97	27375.99	1908.16	32.87	TWh
August	2706.07	1903.07	0.00	1071.06	25594.51	1323.61	31.27	TWh
September	2825.46	2735.84	0.00	1523.84	23363.33	1215.37	30.45	TWh
October	1241.31	846.89	0.00	1506.61	16473.22	1354.61	20.07	TWh
November	2111.60	603.53	0.00	3390.62	12821.71	2118.47	18.93	TWh
December	1781.72	687.89	0.00	1796.53	14847.77	1126.91	19.11	TWh
	0.085	0.055	0.00	0.088	0.773	0.074	304.209	TWh

Table 8: All power generation Announced Pledges Scenario with standard demand

	NaturalgasCCGT	NaturalgasOPGT	Windonshore	Windoffshore	Solar	HydroRoR	Total	
January	8996.27	2384.83	0.00	0,00	13437.35	1482.88	24.82	TWh
February	9312.99	2492.63	0.00	0.00	17021.29	1452.23	28.83	TWh
March	7176.97	935.35	0.00	0.00	17339.13	2452.07	25.45	TWh
April	5010.63	0.51	0.00	0.00	24369.36	3487.56	29.38	TWh
May	2762.86	6.73	0.00	0.00	24420.71	4079.46	27.19	TWh
June	3344.16	31.40	0.00	0.00	29552.38	3021.42	32.93	TWh
July	6476.31	777.14	0.00	0.00	30259.93	2047.54	37.51	TWh
August	6022.74	415.50	0.00	0.00	27895.10	1334.86	34.33	TWh
September	674.34	1031.27	0.00	0.00	25773.47	1254.69	27.48	TWh
October	3654.80	208.96	0.00	0.00	18270.83	1808.64	22.13	TWh
November	8110.60	1071.71	0.00	0.00	14247.52	2454.14	23.43	TWh
December	5239.74	831.85	0.00	0.00	16497.22	1495.46	22.57	TWh
	0.20	0.03	0.00	0.00	0.77	0.08	336.05	TWh

Table 9: All power generation Stated Policies Scenario with standard demand

	NaturalgasCCGT	NaturalgasOPGT	Windoffshore	Windonshore	Solar	HydroRoR	Total	
January	3392.65	2652.79	8567.34	0.00	16488.48	1251.58	32.35	TWh
February	3858.21	2447.78	7641.40	0.00	20887.36	1193.53	36.03	TWh
March	2509.14	948.44	8510.61	0.00	21456.46	1770.84	35.19	TWh
April	1950.90	0.00	5648.56	0.00	30417.13	2808.55	40.82	TWh
May	1071.41	0.00	5418.09	0.00	30226.52	3114.58	39.83	TWh
June	2060.38	423.01	3432.32	0.00	36780.80	2746.20	45.44	TWh
July	3196.98	1514.57	2301.33	0.00	37332.92	1868.51	46.21	TWh
August	3232.16	1687.45	2263.17	0.00	34926.35	1303.56	43.41	TWh
September	3485.94	1977.64	3195.23	0.00	31863.19	1185.04	41.71	TWh
October	1417.14	691.75	3109.78	0.00	22463.16	1309.05	28.99	TWh
November	2232.65	213.23	7091.57	0.00	17483.12	2025.84	29.05	TWh
December	2118.47	483.29	3828.95	0.00	20245.76	999.82	27.68	TWh
	0.07	0.03	0.14	0.00	0.72	0.05	446722.67	

Table 10: All power generation NZE for increased demand

	NaturalgasCCGT	NaturalgasOPGT	Windoffshore	Windonshore	Solar	HydroRoR	Total	
January	4034.03	2616.55	7304.72	0.00	16762.27	1277.84	32.00	TWh
February	4602.24	2422.45	6509.23	0.00	21234.19	1221.41	35.99	TWh
March	3025.04	988.84	7285.34	0.00	21802.40	1798.07	34.90	TWh
April	2407.15	0.00	4810.74	0,00	30871.69	2817.00	40.91	TWh
May	1437.69	0.00	4643.95	0.00	30719.53	3187.41	39.99	TWh
June	2347.54	359.38	2922.68	0.00	37368.46	2763.87	45.76	TWh
July	3782.81	1391.43	1954.25	0.00	37949.19	1868.63	46.95	TWh
August	3867.02	1537.89	1923.63	0.00	35463.62	1314.45	44.11	TWh
September	4046.14	1842.62	2720.82	0.00	32385.85	1188.09	42.18	TWh
October	1685.87	662.89	2612,04	0.00	22834.80	1340.45	29.14	TWh
November	2900.91	253.11	6035.11	0.00	17773.42	2049.06	29.01	TWh
December	2470.83	480.48	3243.08	0.00	20581.94	1041.55	27.82	TWh
	0.08	0.03	0.12	0.00	0.73	0.05	448.74	TWh

Table 11: All power generation Announced Pledges Scenario for increased demand

	NaturalgasCCGTwithCCSnewOT	NaturalgasOCGTnew	Windoffshore	Windonshore	Solar	HydroRoR	Total	
January	12648.80	2478.67	0.00	0.00	17081.55	1496.63	33.71	TWh
February	13343.11	2507.76	0.00	0.00	21637.61	1463.57	38.95	TWh
March	10230.69	751.93	0.00	0.00	22022.50	2460.77	35.47	TWh
April	6848.51	0.00	0.00	0.00	30897.06	3502.32	41.25	TWh
May	3763.20	0.00	0.00	0.00	30997.10	4188.60	38.95	TWh
June	4519.06	0.00	0.00	0.00	37505.10	3036.88	45.06	TWh
July	8868.32	540.90	0.00	0.00	38458.25	2022.22	49.89	TWh
August	7841.03	178.71	0.00	0.00	35370.15	1336.34	44.73	TWh
September	9184.04	617.84	0.00	0.00	32750.43	1259.59	43.10	TWh
October	4928.38	59.79	0.00	0.00	23226.37	1846.00	30.06	TWh
November	11086.19	817.06	0.00	0.00	18111.61	2463.93	32.48	TWh
December	7310.09	694.09	0.00	0.00	20972.23	1506.03	30.48	TWh
	0.22	0.02	0.00	0.00	0.71	0.06	464.83	TWh

Table 12: All power generation Stated Policies Scenario for increased demand

The graphs show that a system with power production from renewable of 85% for SP, 93.5% for AP, 94.9% for NZE.

3.2 Import and Export

The highRES model not only consider power production for each country, but also the presence and the possible increase of transmission lines between countries and consequently the possibility of import and export.

For what concerns import and export data, an high voltage transmission network is considered, in particular HVAC of 400 kV over the ground and HVDC sub sea. Furthermore, the hypothesis is that each country can buy or sell power from or to its neighbour countries. For Italy in particular Austria, Switzerland, France, Greece, Malta and Slovenia are considered.

Comparing import and export data results with realistic data, in 2021 the exported amount of power was 42.8 TWh, while 46.60 TWh were imported from France, Switzerland, Austria, Slovenia, Greece, Malta and Montenegro [18].

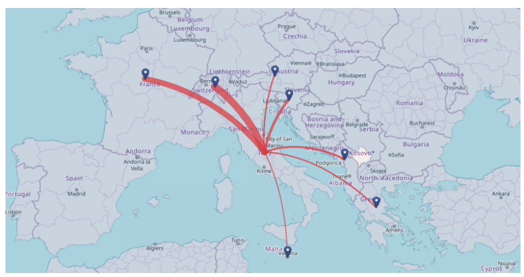


Figure 19: Import and export countries. Source: Eurostat

Considering the countries above mentioned, it can be noticed that the model does not include Montenegro, which, according to the document "Dati statistici sull'energia elettrica in Italia 2021" [18] produced by Terna, amounts for 3.36 TWh in import and 3.80 TWh in export. This number is not negligible so it has to be taken into account when analyzing the results.

According to the model the total amount of import data for the NZE scenario with increased demand, reported country by country and month by month in table 16, goes up to 121.36 GWh, which is a lot lower than data reported in the most recent years. Same goes for the AP scenario, whose data are reported in table 14, for which the total amount of import energy is 85.30 GWh, and SP scenario, which results in 94.32 GWh and its output are visible in table 15.

As already said, these data are much lower than realistic ones and this could explain why so much solar power is installed. In other words, the model is saying that producing power on your own would be more convenient than importing it from neighbour countries and that selling energy is not worth it. Clearly, in real world import and export agreements are not just a matter of economical convenience, but they are also related to international relationship so it is not so simple shutting them just down. In particular, they are regulated by laws, regulations and organizations like the ARERA (Autorità di Regolazione per Energia Reti e Ambienti) which defines the operation of the electricity markets, the GME (Gestore dei Mercati Energetici) which organizes the buying and selling process also among international exchanges, at an higher level also the European Energy Market which sets rules and agreement for European member states and bilateral agreements which cover aspects such as the quantity of energy, prices, delivery methods, duration, responsabilities, dispute resolution and regulatory and tax considerations. The bilateral agreement more than other factor may or may not become public through official publication.

A possible improvement of the highRES model could be including a minimum quantity of energy imported and exported based on historical data or bilateral agreement if accessible.

Anyhow what can be extrapolated from the results is that the country could potentially be self-sufficient, but expanding grid connections in order to improve efficiency and increase exchanging is already planned [19].

	AT	CH	FR	GR	MT	SI	
January	1791.09	744.00	644.78	0.00	12.17	386.46	MWh
February	2541.67	797.96	548.07	0.00	10.52	611.69	MWh
March	2749.26	1005.58	804.43	0.00	13.10	603.81	MWh
April	4774.55	1838.85	1610.44	0.00	22.99	888.71	MWh
May	4843.01	1574.90	1284.65	0.00	10.43	1083.27	MWh
June	5763.87	2029.21	1957.59	0.00	36.17	1254.91	MWh
July	5304.08	1774.19	1527.58	0.00	76.32	875.24	MWh
August	5530.72	2090.69	1976.14	0.00	50.63	1049.21	MWh
September	4737.49	1703.51	1348.88	0.00	38.16	967.50	MWh
October	2811.38	479.75	183.61	0.00	55.52	833.28	MWh
November	1778.45	332.13	267.34	0.00	46.16	527.19	MWh
December	1710.18	800.07	827.68	0.00	48.89	591.01	MWh
	44.34	15.17	12.98	0.00	0.42	9.67	GWh

Table 13: Export data for Net Zero Case Scenario with standard demand

	AT	CH	FR	GR	MT	SI	
January	1834.85	771.31	665.30	0.00	12.04	395.11	MWh
February	2633.98	877.43	610.51	0.00	10.21	597.27	MWh
March	2708.62	1105.77	844.75	0.00	12.91	588.72	MWh
April	4766.16	1926.50	1640.18	0.00	22.68	885.41	MWh
May	4873.12	1702.36	1374.72	0,00	10.32	1102.22	MWh
June	5841.25	2161.42	2097.19	0.00	35.94	1264.45	MWh
July	5413.92	1914.03	1643.15	0.00	75.92	883.18	MWh
August	5596.79	2238.97	2134.31	0.00	50.48	1060.87	MWh
September	4877.11	1829.98	1461.63	0.00	37.76	995.69	MWh
October	2884.65	520.20	231.31	0.00	55.04	844.91	MWh
November	1812.00	325.97	261.63	0.00	45.90	533.53	MWh
December	1795.44	813.92	915.88	0.00	48.87	621.34	MWh
	45.04	16.19	13.88	0.00	0.42	9.77	GWh

Table 14: Export data for Announced Pledges Scenario with standard demand

	AT	CH	FR	GR	MT	SI	
January	2281.96	821.16	676.14	0.00	10.92	322.76	MWh
February	3461.14	1154.46	760.31	0.00	9.74	476.06	MWh
March	2948.23	1319.58	1005.72	0.00	9.90	357.59	MWh
April	5949.49	2258.14	1570.89	0.00	21.65	488.42	MWh
May	5625.73	1774.02	1385.79	0.00	9.16	661.20	MWh
June	6960.15	2465.85	2015.85	0.00	35.50	861.54	MWh
July	6555.04	2510.56	1802.13	0.00	76.32	703.34	MWh
August	6596.95	2554.29	1977.64	0.00	48.70	792.01	MWh
September	5755.01	2104.60	1390.22	0.00	39.80	731.35	MWh
October	2943.80	790.83	334.63	0.00	55.61	655.60	MWh
November	1936.32	483.24	544.44	0.00	45.95	402.28	MWh
December	2219.76	899.87	1081.58	0.00	50.13	545,74	MWh
	53.23	19.14	14.54	0.00	0.41	7.00	GWh

Table 15: Export data for Stated policies Scenario with standard demand

From the above tables it can be noticed that the main export country is Austria, followed by Switzerland, France and Slovenia.

At the same time Greece is excluded and Malta is almost negligible.

Reading this tables it is also evident that exporting data increase during the summer period, because the electrical system proposed is mainly based on Solar and because of that during summer months the energy produced increases.

	AT	CH	FR	GR	MT	SI	
January	2857.70	1291.73	894.12	0.00	19.60	653.44	MWh
February	3912.18	1331.75	772.77	0.00	20.81	890.18	MWh
March	4271.10	1582.94	1204.81	0.00	23.89	921.88	MWh
April	7107.52	2753.17	2243.16	0.00	37.77	1368.44	MWh
May	7068.06	2355.77	1864.99	0.00	18.46	1606.41	MWh
June	8327.02	3014.25	2632.16	0.00	66.76	1841.86	MWh
July	7581.78	2599.55	2062.82	0.00	132.55	1343.21	MWh
August	7937.24	3110.05	2611.20	0.00	88.02	1522.18	MWh
September	6812.17	2577.21	1863.38	0.00	69.33	1369.28	MWh
October	4097.54	890.86	330.09	0.00	96.19	1199.07	MWh
November	2830.32	544.79	376.63	0.00	72.59	871.48	MWh
December	2764.58	1097.77	1262.14	0.00	81.94	936.29	MWh
	65.57	23.15	18.12	0.00	0.73	14.52	GWh

Table 16: Export data for Net Zero Case Scenario with increased demand

	AT	CH	FR	GR	MT	SI	
January	2814.22	1302.03	908.55	0.00	19.49	666.20	MWh
February	3914.96	1424.43	794.39	0.00	19.80	880.80	MWh
March	4206.58	1583.90	1205.91	0.00	23.51	924.38	MWh
April	7022.40	2801.37	2228.15	0.00	38.07	1371.10	MWh
May	7044.75	2428.82	1899.52	0.00	18.27	1624.66	MWh
June	8317.43	3129.23	2613.61	0.00	67.04	1900.56	MWh
July	7624.38	2688.31	2095.34	0.00	133.53	1415.52	MWh
August	7953.77	3214.92	2685.33	0.00	87.19	1613.56	MWh
September	6880.82	2627.23	1916.25	0.00	69.34	1413.46	MWh
October	4094.11	933.43	347.47	0.00	95.94	1233.87	MWh
November	2803.95	531.50	382.94	0.00	72.48	876.23	MWh
December	2728.86	1138.77	1239.82	0.00	82.02	950.38	MWh

Table 17: Export data for Announced Pledges Scenario with increased demand

	AT	CH	FR	GR	MT	SI	
January	2818.45	849.64	904.71	0.00	17.88	309.69	MWh
February	4325.74	1212.99	1008.22	0.00	17.78	462.97	MWh
March	3468.08	1341.19	1465.78	0.00	21.33	293.29	MWh
April	7205.96	2230.36	2186.42	0.00	40.41	421.20	MWh
May	6752.52	1829.34	1793.32	0.00	20.43	565.09	MWh
June	8423.75	2486.58	2694.26	0.00	72.16	784.50	MWh
July	7890.75	2466.74	2405.90	0.00	138.49	596.32	MWh
August	8131.30	2609.28	2725.51	0.00	89.32	744.40	MWh
September	7111.69	2102.76	1946.95	0.00	75.30	662.82	MWh
October	3562.90	722.15	438.83	0.00	97.58	602.61	MWh
November	2215.09	400.28	623.10	0.00	73.62	358.64	MWh
December	2548.53	901.08	1325.31	0.00	81.95	517.03	MWh
	64.45	19.15	19.52	0.00	0.75	6.32	GWh

Table 18: Export data for Stated policies Scenario with increased demand

For what concerns import data, results for all the scenarios are reported in table 19, table 20 and table 21 for standard demand and table 24, table 23 and table 22 for increased demand.

The total amount per year for all cases is lower than 1.00 TWh.

As evident, they are lower than realistic data and the same considerations done for import data are valid.

	AT	CH	FR	GR	MT	SI	
January	3793.52	1040.35	2493.74	0.00	396.33	654.11	MWh
February	2566.64	996.27	2812.97	0.00	371.76	492.66	MWh
March	3599.29	693.90	1805.52	0.00	310.82	627.72	MWh
April	1955.55	765.07	2358.65	0.00	269.31	532.51	MWh
May	1843.83	885.82	2507.51	0.00	307.07	379.00	MWh
June	1869.87	1059.35	2262.68	0.00	165.22	271.35	MWh
July	2201.28	1017.41	2653.54	0.00	15.85	586.94	MWh
August	2538.98	688.73	1126.49	0.00	64.92	484.16	MWh
September	2218.87	797.59	2052.10	0.00	128.64	388.24	MWh
October	3620.36	2343.58	4022.09	0.00	55.90	281.77	MWh
November	3700.54	1736.02	4185.81	0.00	213.05	571.04	MWh
December	4613.77	2059.23	3610.80	0.00	147.80	592.29	MWh
	34522.53	14083.33	31891.89	0.00	2446.67	5861.79	MWh
	34.52	14.08	31.89	0.00	2.45	5.87	GWh

Table 19: Import data for Net Zero Case Scenario with standard demand

	AT	CH	FR	GR	MT	SI	
January	3699.63	1196.53	267.77	0.00	395.92	628.38	MWh
February	2500.98	1004.73	2987.64	0.00	373.10	459.00	MWh
March	3592.88	735.51	1848.51	0.00	313.55	592.31	MWh
April	1832.21	702.30	2466.62	0.00	269.81	476.65	MWh
May	1869.7	865.27	2567.07	0.00	309.58	344.36	MWh
June	1723.85	1048.87	2368.41	0.00	166.89	245.39	MWh
July	1961.41	886.13	2733.28	0.00	15.47	539.81	MWh
August	2334.73	649.67	1062.63	0.00	64.47	434.79	MWh
September	2039.22	777.74	2087.10	0.00	129.06	357.20	MWh
October	3428.24	2368.57	4248.78	0.00	59.09	234.70	MWh
November	3490.33	1760.34	4364.13	0.00	214.53	511.69	MWh
December	4357.52	2046.49	3836.62	0.00	147.78	550.05	MWh
	32830.70	14042.15	33242.56	0.00	2459.25	5374.33	MWh
	32.83	14.04	33.24	0.00	2.46	5.37	GWh

Table 20: Import data for Announced Pledges Scenario with standard demand

	AT	CH	FR	GR	MT	SI	
January	3535.92	848.17	1203.48	0.00	414.19	68.72	MWh
February	2217.82	490.43	1577.35	0,00	407.13	38.90	MWh
March	3089.29	620.61	953.76	0.00	342.07	101.99	MWh
April	1658.93	502.00	1085.70	0.00	291.69	64.99	MWh
May	1964.90	571.10	1514.05	0.00	326.62	44.05	MWh
June	1940.08	740.36	1456.83	0.00	167.46	13.02	MWh
July	1514.93	210.48	1260.63	0.00	13.88	30.96	MWh
August	1615.89	231.53	564.03	0.00	58.92	3.73	MWh
September	1503.85	390.41	1236.85	0.00	132.87	7.87	MWh
October	3601.48	1658.13	2910.52	0.00	61.06	8.50	MWh
November	2788.67	619.54	2063.28	0.00	234.80	44.60	MWh
December	3762.84	1597.31	2292.98	0.00	155.64	29.19	MWh
	29194.60	8480.07	18119.46	0.00	2606.33	456.52	MWh
	29.19	8.48	18.12	0.00	2.61	0.46	GWh

Table 21: Import data for Stated Policies Scenario with standard demand

From the tables above it can be read that the main import country is Austria, followed by France, Switzerland and Malta. In this case, differently from what happened for import data, Slovenia is almost negligible, but Greece is still excluded.

At the opposite of what happens for export, import increases during winter time because the energy produced by solar panels decreases and at the same time decreases during spring and summer.

	AT	CH	FR	GR	MT	SI	
January	4382.33	1468.90	3146.27	0.00	344.18	733.08	MWh
February	3023.42	1386.27	3557.62	0.00	320.55	566.07	MWh
March	4248.13	840.26	2358.41	0.00	264.54	636.52	MWh
April	2152.47	912.74	2931.74	0.00	234.36	468.24	MWh
May	2203.39	973.33	3095.59	0,00	256.99	368.14	MWh
June	1949.87	1258.14	3142.81	0,00	140.77	275.29	MWh
July	2642.77	1385.22	3320.24	0,00	6.64	630.56	MWh
August	2943.55	918.38	1543.88	0.00	48.28	504.62	MWh
September	3109.78	1067.01	2688.31	0.00	100.45	457.40	MWh
October	4429.14	3211.76	5163.67	0.00	40.98	253.42	MWh
November	4437.08	2266.57	5148.08	0.00	182.83	597.12	MWh
December	5510.96	2726.19	4629.33	0.00	125.35	627.27	MWh
	41.03	18.41	40.73	0.00	2.07	6.12	GWh

Table 22: Import data for Net Zero Case Scenario with increased demand

	AT	CH	FR	GR	MT	SI	
January	4592.17	1555.41	3247.69	0.00	344.66	799.50	MWh
February	3052.11	1405.18	3664.74	0.00	321.23	580.68	MWh
March	4331.28	919.35	2442.61	0.00	265.89	695.32	MWh
April	2164.01	919.25	2823.34	0.00	234.78	480.18	MWh
May	2161.35	1000.23	3116.46	0.00	263.79	370.50	MWh
June	1903.88	1256.21	3075.39	0,00	140.82	278.21	MWh
July	2422.24	1211.70	3297.70	0,00	7.24	607.79	MWh
August	2769.42	871.69	1388.88	0.00	47.15	505.49	MWh
September	2961.68	1043.58	2639.18	0.00	101.84	467.25	MWh
October	4368.26	3234.51	5172.34	0.00	40.72	269.19	MWh
November	4347.76	2284.89	5246.40	0.00	182.63	590.32	MWh
December	5349.15	2714.44	4685.85	0.00	125.27	646.44	MWh
	65.57	23.15	18.12	0.00	0.73	14.52	GWh

Table 23: Import data for Announced Pledges Scenario with increased demand

	AT	CH	FR	GR	MT	SI	
January	4822.93	988.92	1642.95	0.00	365.69	141.89	MWh
February	3007.29	587.81	2016.28	0.00	356.67	87.70	MWh
March	4248.46	592.05	1361.92	0.00	301.80	226.41	MWh
April	2427.45	609.72	1418.84	0.00	260.65	175.67	MWh
May	2961.53	727.94	2015.13	0.00	295.97	158.90	MWh
June	2847.47	839.09	1879.80	0.00	149.34	73,19	MWh
July	2178.80	331.84	1301.99	0.00	9.31	101.63	MWh
August	2562.31	327.19	672.61	0.00	46.25	60.88	MWh
September	2431.89	486.74	1510.10	0.00	108.18	69.91	MWh
October	5155.36	1977.68	3802.64	0.00	47.40	52.37	MWh
November	3982.03	759.87	2844.93	0.00	204.08	156.82	MWh
December	5188.67	1751.27	3023.87	0.00	143.28	84.91	MWh
	41,81	9.98	23.49	0.00	2.29	1.39	GWh

Table 24: Import data for Stated Policies Scenario with increased demand

3.3 Storage usage

In an electricity system that maximized the amount of renewable energy is almost taken for granted the presence of a storage system to compensate the typical intermittency of green technology. In fact, highRES includes also storage usage together with the power production and the import and export data.

Nowadays common method for storage are lithium-ion batteries, which have an high efficiency and a long lifespan, but if used in large application can represent a serious safety problem, pumped hydro storage and Compressed Air Energy Storage. At the other hand, for the future, possible technologies could be the vanadium flow batteries, which are taken into account mainly for large scale grid application because of their safety advantages, solid-state batteries, which could represent the evolution of lithium batteries, hydrogen storage, advanced thermal storage, gravitational energy storage, superconducting magnetic energy storage.

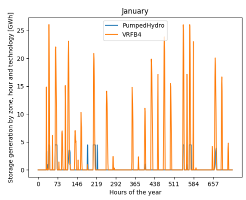
HighRES includes as storage method pumped hydro and vanadium batteries. This choice is due to the fact that its aim is building a huge system and as said before vanadium batteries represents the technology to invest in that field.

Looking at the results, it is evident that storage usage contributes consistently to the electricity system, in particular the VRFB4 technology takes the lead and in terms of production can be compared to the other technologies and even more because it represents the second source of power after solar.

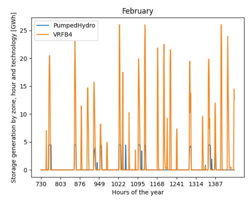
As said, this kind of technology is considered pretty much new and with a great potential. It is necessary, together with the pumped hydro, in order to stabilize the whole system and so in order to solve the intermittency and discontinuity problem of the renewable energy.

It is common knowledge that more and more installations will be present, linked with new wind and solar power plants. According to the Italian government, a part of European funds given for the Piano Nazionale di Ripresa e Resilienza (PNRR) will be used to produce 11 GWh from storage by 2024 [5].

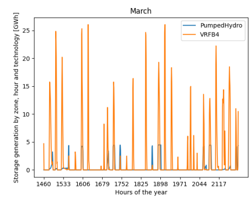
From the graph below, in particular the ones related to the Stated Policies scenario reported in fig. 22 and in fig. 25, it can be noticed that storage usage is strictly related to the Solar usage, because it is the technology that most of all have the intermittency, that is day night cycle. In fact in the Stated Policies scenario, the one in which Solar is used the most also storage is more used.



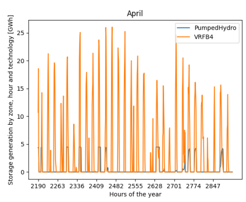
(a) Storage generation in January



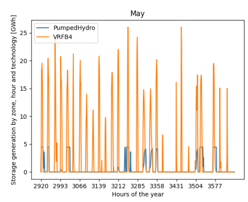
(b) Storage generation February



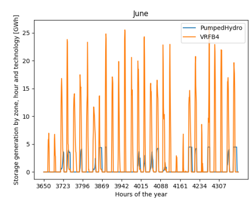
(c) Storage generation March



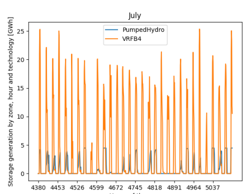
(d) Storage generation in April



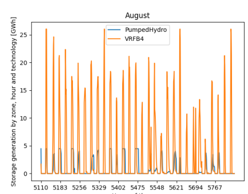
(e) Storage generation in May



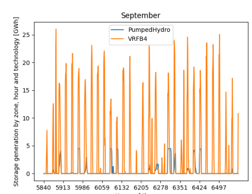
(f) Storage generation in June



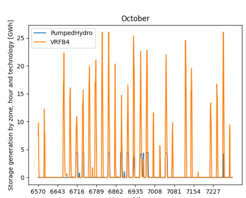
(g) Storage generation in July



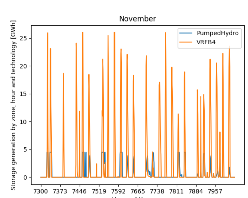
(h) Storage generation in August



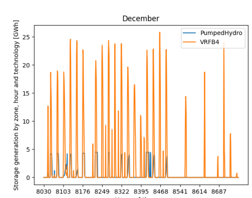
(i) Storage generation September



(j) Storage generation October

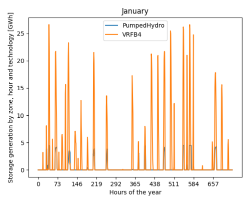


(k) Storage generation November

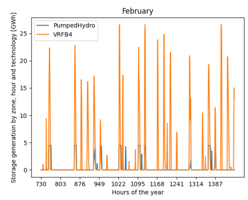


(l) Storage generation December

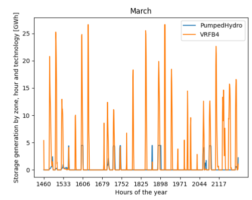
Figure 20: Storage production month by month for the Net Zero Emission by 2050 scenario



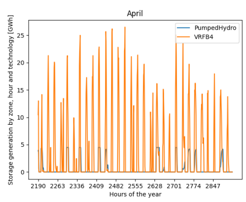
(a) Storage generation January



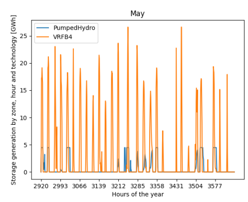
(b) Storage generation February



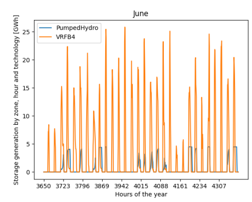
(c) Storage generation March



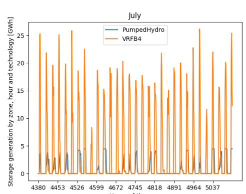
(d) Storage generation in April



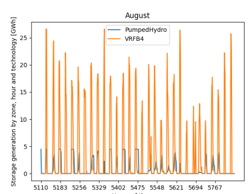
(e) Storage generation in May



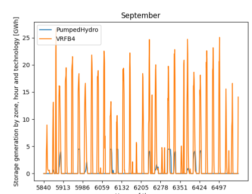
(f) Storage generation in June



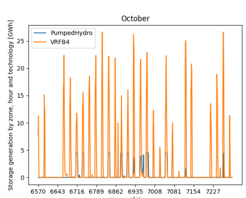
(g) Storage generation in July



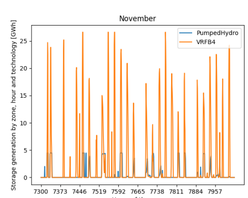
(h) Storage generation August



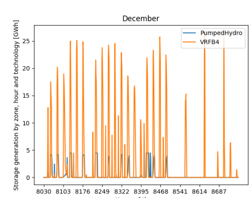
(i) Storage generation September



(j) Storage generation October

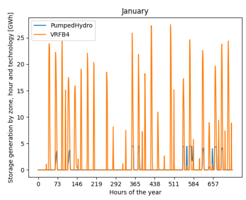


(k) Storage generation November

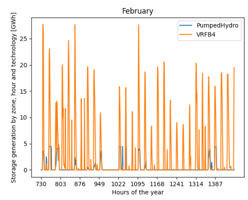


(l) Storage generation December

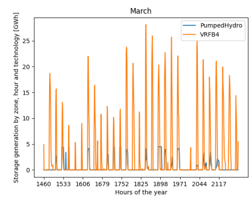
Figure 21: Storage production month by month for the Announced Pledges Scenario



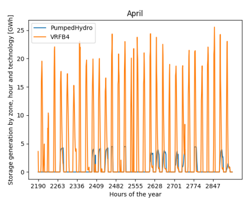
(a) Storage generation in January



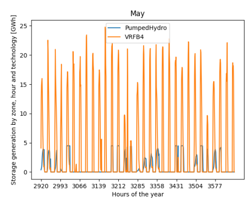
(b) Storage generation February



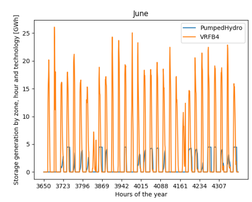
(c) Storage generation March



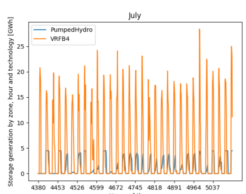
(d) Storage generation April



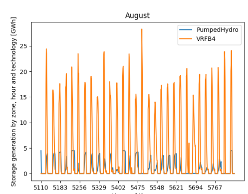
(e) Storage generation May



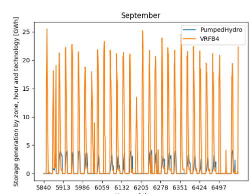
(f) Storage generation June



(g) Storage generation July



(h) Storage generation August



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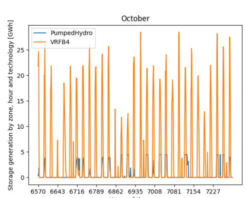
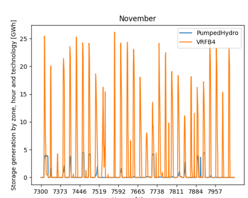
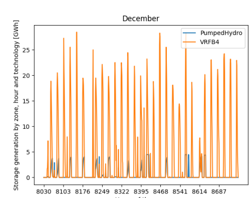


(j) Storage generation October

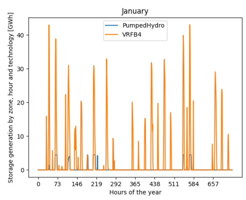


(k) Storage generation November

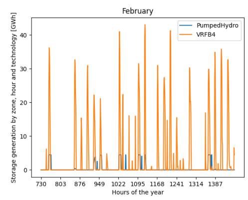


(l) Storage generation December

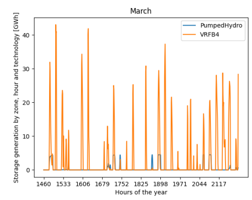
Figure 22: Storage production month by month for the Stated Policies Scenario



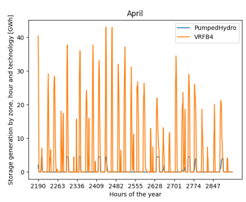
(a) Storage generation in January



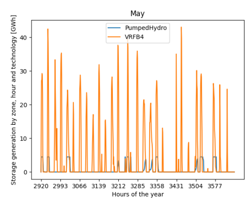
(b) Storage generation February



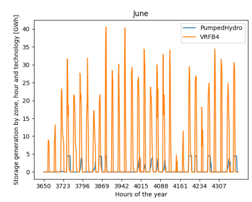
(c) Storage generation March



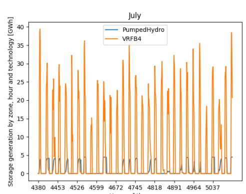
(d) Storage generation in April



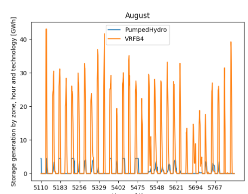
(e) Storage generation in May



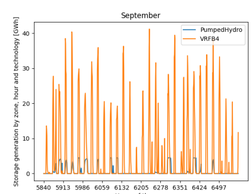
(f) Storage generation in June



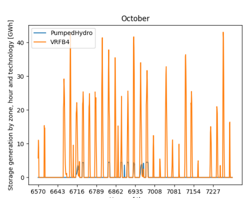
(g) Storage generation in July



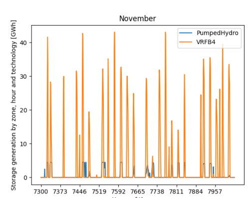
(h) Storage generation in August



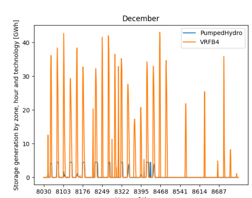
(i) Storage generation September



(j) Storage generation October

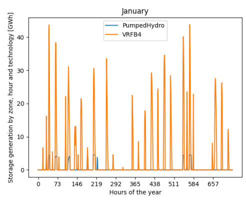


(k) Storage generation November

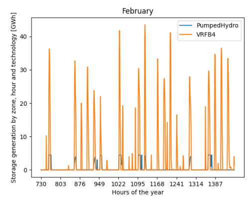


(l) Storage generation December

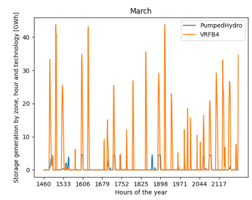
Figure 23: Storage production month by month for the Net Zero Emission by 2050 scenario for increased demand



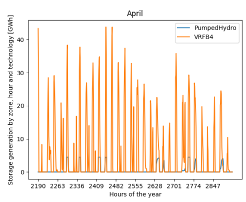
(a) Storage generation January



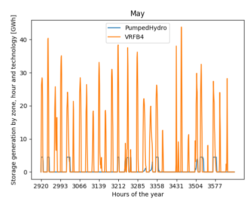
(b) Storage generation February



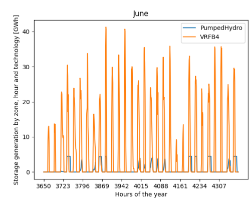
(c) Storage generation March



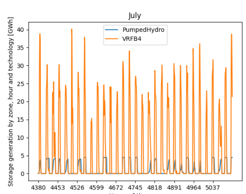
(d) Storage generation in April



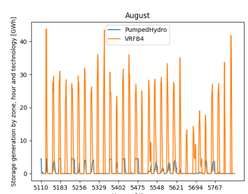
(e) Storage generation in May



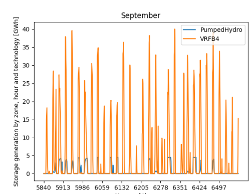
(f) Storage generation in June



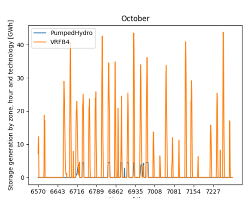
(g) Storage generation in July



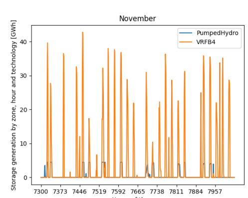
(h) Storage generation August



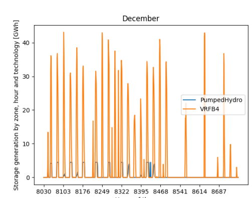
(i) Storage generation September



(j) Storage generation October

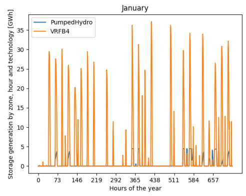


(k) Storage generation November

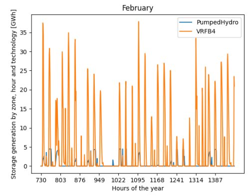


(l) Storage generation December

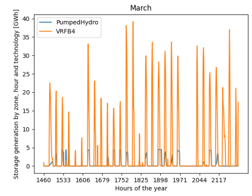
Figure 24: Storage production month by month for the Announced Pledges Scenario for increased demand



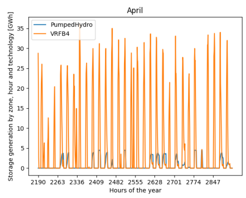
(a) Storage generation in January



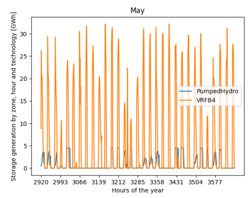
(b) Storage generation February



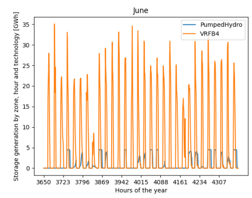
(c) Storage generation March



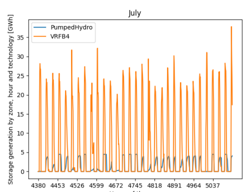
(d) Storage generation April



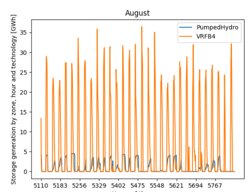
(e) Storage generation May



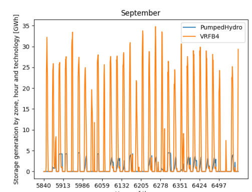
(f) Storage generation June



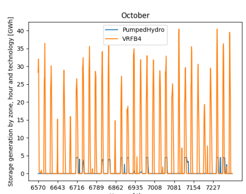
(g) Storage generation July



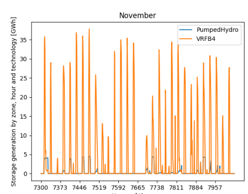
(h) Storage generation August



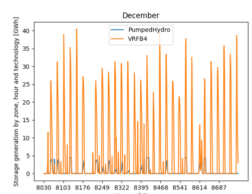
(i) Storage generation September



(j) Storage generation October



(k) Storage generation November



(l) Storage generation December

Figure 25: Storage production month by month for the Stated Policies Scenario for increased demand

3.4 Costs

The model gives as output the total electricity system dispatch cost, meaning the total cost of the system per megawatt hour. This cost actually represents the main result of the model because is the data to be minimized in the objective function reported in eq. (1). This data is referred to the whole European system and not to single countries.

As showed in the fig. 26, costs decrease going from Stated Policies to Net Zero Emissions scenario, because the model decides to use the technology that, at the same time, has a good potential and became cheaper.

An increase of 30% in demand generates and increase in cost of 32.59% for Stated Policies scenario, 32.93% for the Announced Pledges and 32.97% for Net Zero emissions.

For what concerns differences between scenarios considering separately stable demand and rise in demand, there is a decrease of 15.29% from SP to AP and of 16.89% from SP to NZE for the first one, while for the second case there is a decrease of 15.07% from SP to AP and of 16.66% from SP to NZE. At the same time moving from AP to NZE ends up in just a slight difference in total costs, specifically 1.90% for the stable demand and 1.87% for the increased one.

Anyway this trend shows that a projected lowering of the fixed and O&M costs of the offshore wind technology can lead to a cheaper prediction, thanks to the great capacity potential that this resource has in the whole continent.

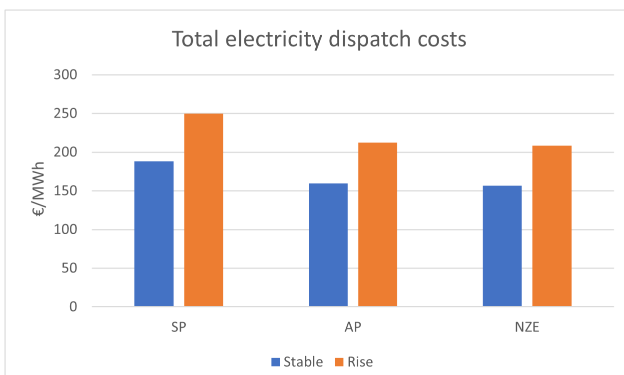


Figure 26: Total electricity system dispatch cost for all scenarios and in case of stable and increased demand

3.5 Further improvements

HighRES represents a powerful model to help making decisions through the ecological transition and mainly because of that can be updated and improved.

For sure modifying the model making it just for Italy, like it has already been done for UK and will be for Norway [15], would be the best way to have more realistic results and a more specific distribution in the territory. The zones could be modified to represent the 20 Italian regions, thus an analysis about their potentials, GIS modelling and data about transmission line between them should be researched. At the end data for each region should be obtained.

Furthermore, other technologies could be added like tide energy or geothermal energy for the energy production.

For what concerns import and export new data like minimum energy to be sell or buy between countries based on historical data or bilateral agreement if public.

Conclusion

The highRES model along with others similar can contribute in a meaningful way to the plans for the power transition in the next decades, especially to help understanding the potential of each technology in a specific zone.

After a sensitivity analysis of highRES, the main factors that produces effect on results were found to be the fixed and the variable cost of the technologies. Because of that three different scenarios produced by the International Energy Agency were analyzed: Stated Policies, Announced Pledges and Net Zero Emissions, which represent three degrees of awareness and effort to bear climate change. These three scenarios were simulated for both the present demand and for the projected one, which is the present one amplified by the 30%.

The model produces results about technology installed, power production, import and export data and storage usage.

The Stated Policies scenario presented a situation where the electricity system is based upon Solar, helped with Natural Gas CCGT to guarantee a fixed production.

The Announced Pledges scenario introduced in the mixture wind offshore and the equilibrium between Natural Gas OCGT and Natural Gas CCGT change.

The Net Zero Emissions scenario, as AP, presents both solar and wind offshore in the solution, increasing the quote of wind offshore in the mixture.

In all scenarios a fixed installed Run of the River hydropower contributes to the energy production.

It is important to notice that when the demand increases the distribution of installed power does not change coherently, but wind offshore increases by around 80% in Announced Pledges and Net Zero Emissions.

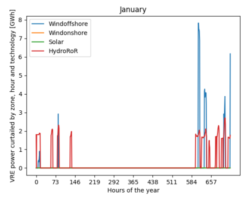
In all three cases the other possible sources of power, i.e. wind onshore and nuclear, are excluded meaning that they are not convenient. The interesting fact is that wind offshore and wind offshore in the NZE scenario have practically the same cost, but evidently the model decides to invest just in offshore because of its greater potential.

In these results import and export data do not contribute in a meaningful way to the whole system, causing discrepancies with the reality. Anyhow, it can be noticed that, being the system mainly based on Solar, import is more consistent during autumn and winter and export increases during spring and summer. The problem with this fact is represented by the fact that the European Energy Market is regulated by laws, organizations and Bilateral Agreement, not just the actual energy need.

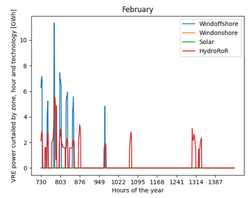
On the other hand storage is strongly present, in particular the vanadium batteries, represented through the VRFB4. This choice is explained considering that all scenarios outputs as solution an energy system mainly based on Solar, which clearly has an inner intermittency between night and day.

In order to obtain better and more meaningful results, highRES could be modified to present just Italy with its own zones or also including other technology and limits in the import and export section.

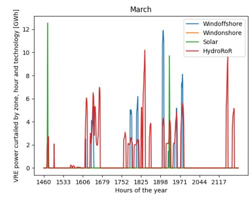
A Curtailment



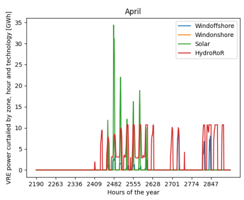
(a) Curtailment in January



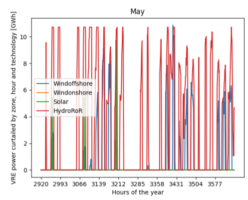
(b) Curtailment February



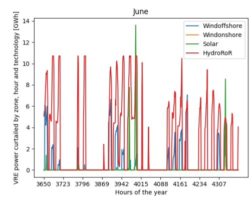
(c) Curtailment March



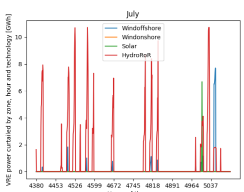
(d) Curtailment in April



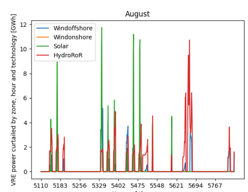
(e) Curtailment in May



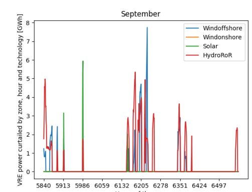
(f) Curtailment in June



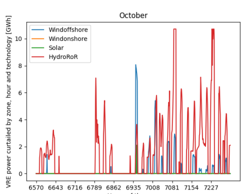
(g) Curtailment in July



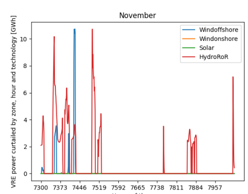
(h) Curtailment in August



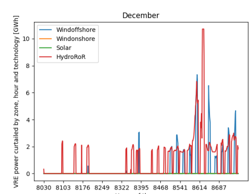
(i) Curtailment September



(j) Curtailment October

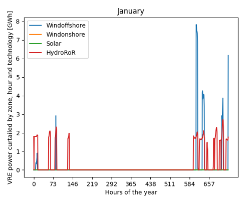


(k) Curtailment November

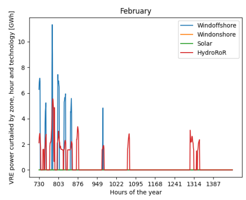


(l) Curtailment December

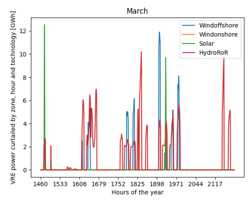
Figure 27: Curtailment month by month for the Net Zero Emission by 2050 scenario



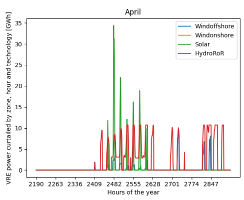
(a) Curtailment January



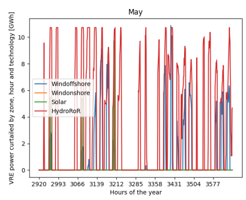
(b) Curtailment February



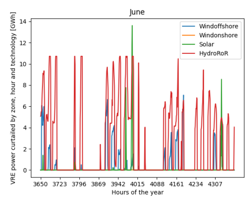
(c) Curtailment March



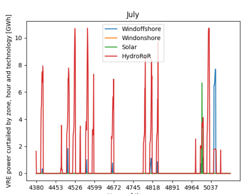
(d) Curtailment in April



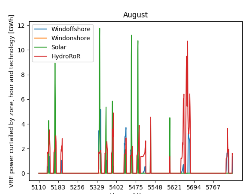
(e) Curtailment in May



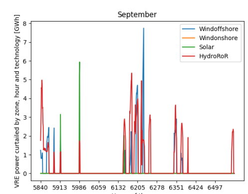
(f) Curtailment in June



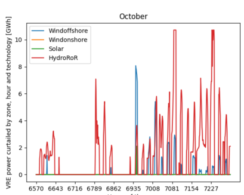
(g) Curtailment in July



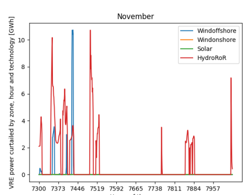
(h) Curtailment August



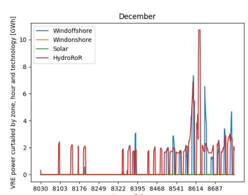
(i) Curtailment September



(j) Curtailment October

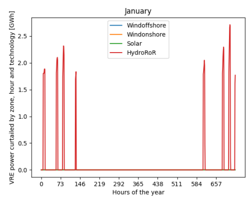


(k) Curtailment November

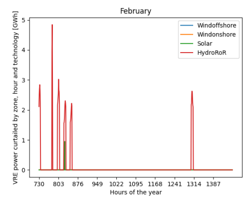


(l) Curtailment December

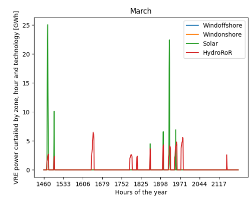
Figure 28: Curtailment month by month for the Announced Pledges Scenario



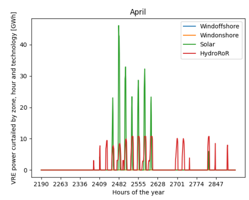
(a) Curtailment in January



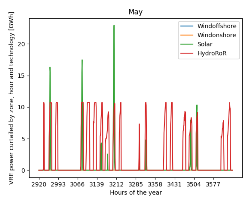
(b) Curtailment February



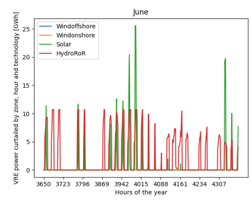
(c) Storage generation March



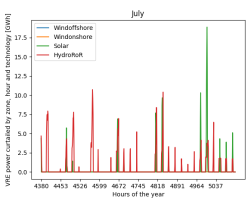
(d) Curtailment April



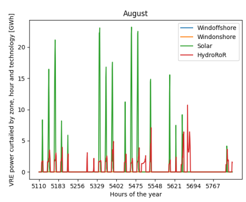
(e) Curtailment May



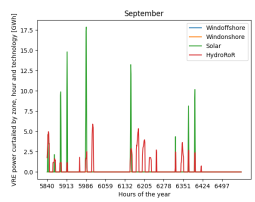
(f) Curtailment June



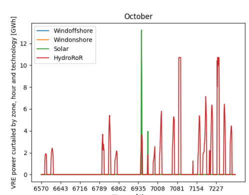
(g) Curtailment July



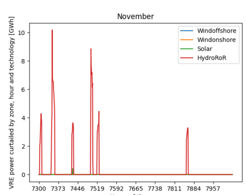
(h) Curtailment August



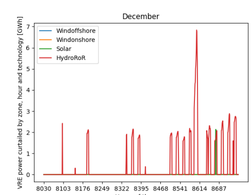
(i) Curtailment September



(j) Curtailment October

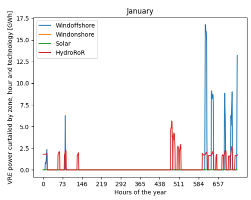


(k) Curtailment November

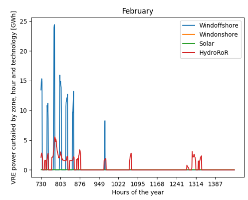


(l) Curtailment December

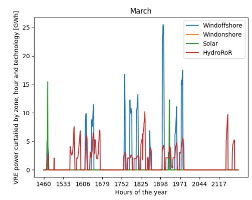
Figure 29: Curtailment month by month for the Stated Policies Scenario



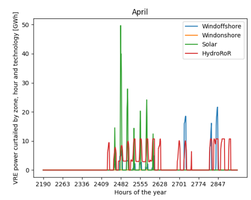
(a) Curtailment in January



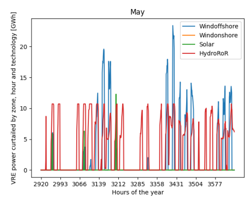
(b) Curtailment February



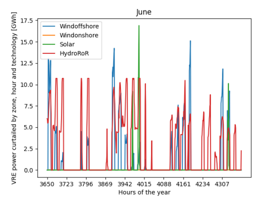
(c) Curtailment March



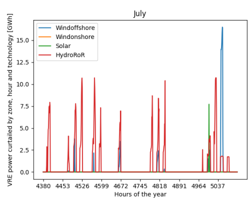
(d) Curtailment in April



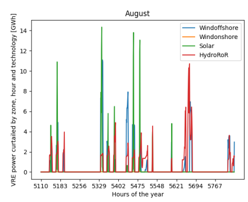
(e) Curtailment in May



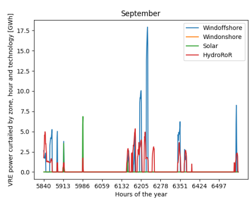
(f) Curtailment in June



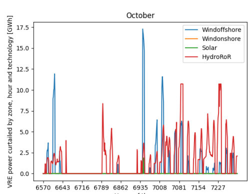
(g) Curtailment in July



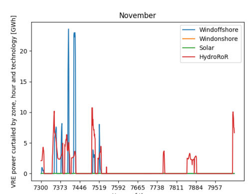
(h) Curtailment in August



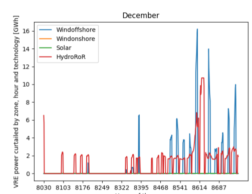
(i) Curtailment September



(j) Curtailment October

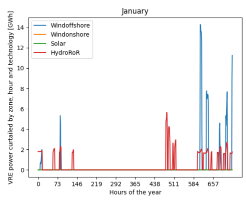


(k) Curtailment November

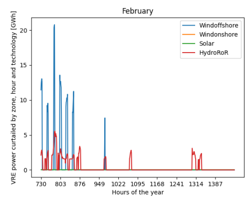


(l) Curtailment December

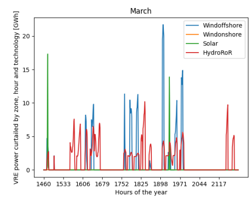
Figure 30: Curtailment month by month for the Net Zero Emission by 2050 scenario for increased demand



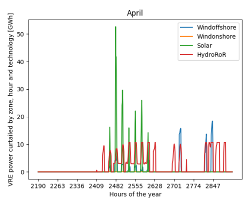
(a) Curtailment January



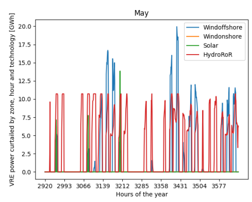
(b) Curtailment February



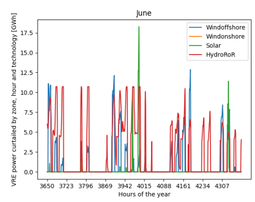
(c) Curtailment March



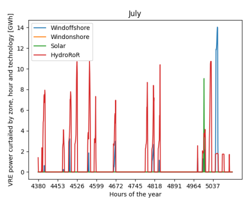
(d) Curtailment in April



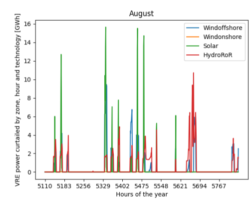
(e) Curtailment in May



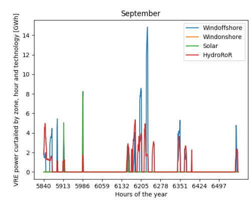
(f) Curtailment in June



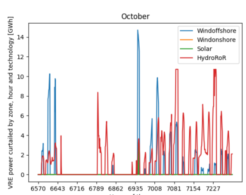
(g) Curtailment in July



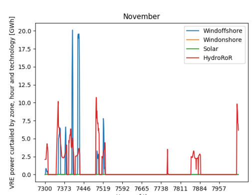
(h) Curtailment August



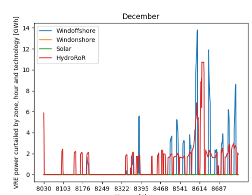
(i) Curtailment September



(j) Curtailment October

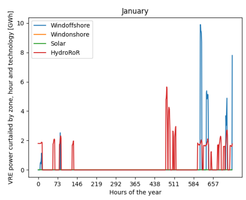


(k) Curtailment November

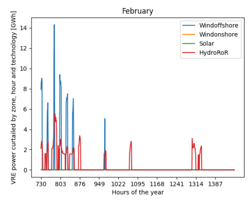


(l) Curtailment December

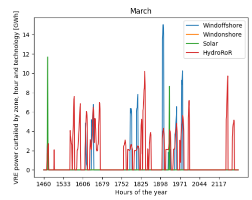
Figure 31: Curtailment month by month for the Announced Pledges Scenario for increased demand



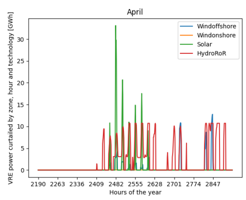
(a) Curtailment in January



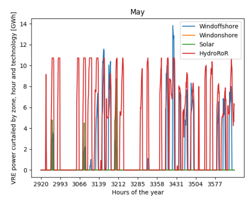
(b) Curtailment February



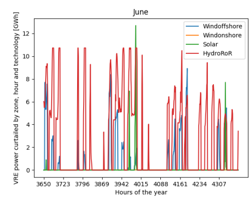
(c) Curtailment March



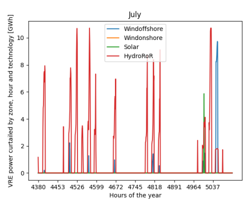
(d) Curtailment April



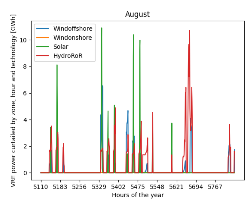
(e) Curtailment May



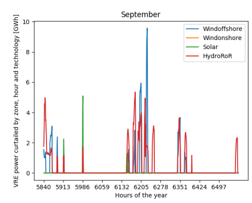
(f) Curtailment June



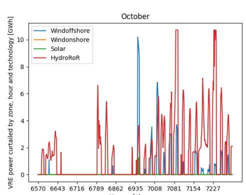
(g) Curtailment July



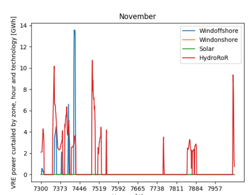
(h) Curtailment August



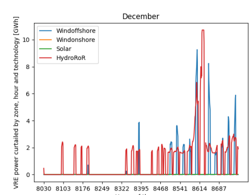
(i) Curtailment September



(j) Curtailment October



(k) Curtailment November



(l) Curtailment December

Figure 32: Curtailment month by month for the Stated Policies Scenario for increased demand

B Main code

```
******************************************
* highres main script
******************************************

* $ontext
option profile=1
* $offtext
option limrow=0, limcol=0, solprint=OFF
option decimals = 4
$offlisting
$ONMULTI
$ONEPS
$offdigit

* Switches:

* log = text file to store details about model run time, optimality or not, etc.
* gdx2sql (ON/OFF) = whether to convert output GDX to sqlite database -> easier to
read into Python
* storage (ON/OFF) = should storage be included in the model run
* hydrores (ON/OFF) = should reservoir hydro be incliuded in the model run
* UC (ON/OFF) = unit committment switch
* water (ON/OFF) = model technologies with a water footprint (currently disabled)
* sensitivity (ON/OFF) = whether a sensitivity file is available
* GWatts (YES/NO) = model is run in GW (YES) or MW (NO)

* sense_run = sensitivity file identifier
* esys_scen = energy system scenario (sets the carbon budget and demands to be used)
* psys_scen = power system scenario (sets which technologies are available)
* RPS = renewable portfolio standard
* vre_restrict = VRE land use deployment scenario name
* model_yr = which year in the future are we modelling
* weather_yr = which weather year do we use
* dem_yr = which demand year do we use

* fx_trans_2015 (YES/NO) = fix transmission network to 2015 (for GB model)
* fx_natcap (YES/NO) = fix total national capacities ->  let highRES decide where to
place them
* pen_gen (ON/OFF) = run with option for model to spill some load

* outname = output name of GDX file


$setglobal log ""
```

```
$setglobal gdx2sql "ON"

$setglobal storage "ON"
$setglobal hydrores "OFF"
$setglobal UC "OFF"
$setglobal water "OFF"
$setglobal sensitivity "OFF"

$setglobal GWatts "YES"

$setglobal sense_run "s2"
$setglobal esys_scen "NewPl_min80"
$setglobal psys_scen "NewPl_min80"
$setglobal RPS "optimal"
$setglobal vre_restrict "dev"
$setglobal model_yr "2050"
$setglobal weather_yr "2013"
$setglobal dem_yr "2013"
$setglobal fx_trans_2015 "NO"
$setglobal fx_natcap "NO"
$set pen_gen "OFF"

$setglobal outname "hR_dev"


**************************************************

* rescale from MW to GW for better numerics (allegedly)

scalar MWtoGW;

$ifThen "%GWatts%" == YES

MWtoGW=1E3;

$else

MWtoGW=1;

$endif

$INCLUDE highres_data_input.gms

$IF "%storage%" == ON $INCLUDE highres_storage_setup.gms
$IF "%sensitivity%" == ON $INCLUDE sensitivity_%sense_run%.dd
```

```
* if no RPS set just do an optimal run

$IF "%RPS%" == "optimal" $GOTO optimal1

scalar
RPS
/%RPS%/
;
RPS=RPS/100.

$label optimal1


* CO2 emissions price - can be set by user

scalar
emis_price
/0/
;


demand(z,h)=demand(z,h)/MWtoGW;
gen_cap2area(vre)=gen_cap2area(vre)/MWtoGW;
trans_links_cap(z,z_alias,trans)=trans_links_cap(z,z_alias,trans)/MWtoGW;
gen_unitsize(non_vre)=gen_unitsize(non_vre)/MWtoGW;
gen_maxramp(non_vre)=gen_maxramp(non_vre)/MWtoGW;

*store_e_unitcapex(s)=store_e_unitcapex(s)/MWtoGW;



* Existing VRE capacity aggregated to zones

exist_vre_cap_r(vre,z,r) = 0.0;

gen_exist_pcap_z(z,vre,"FX")=sum(r,exist_vre_cap_r(vre,z,r));

* Existing zonal capacity aggregated to national

parameter gen_exist_cap(g);
gen_exist_cap(g)=sum((z,lt),gen_exist_pcap_z(z,g,lt));

* Limit which regions a given VRE tech can be built in
* based on buildable area in that region. Stops offshore solar
* and onshore offshore wind.
```

```
set vre_lim(vre,z,r);
vre_lim(vre,z,r)=((area(vre,z,r)+exist_vre_cap_r(vre,z,r))>0.);

* Non VRE cap lim to dynamic set, stops Nuclear being built in certain countries
(e.g. Austria)

set gen_lim(z,g);
gen_lim(z,non_vre)=((sum(lt,gen_lim_pcap_z(z,non_vre,lt))+sum(lt,gen_exist_pcap_z
(z,non_vre,lt)))>0.);
gen_lim(z,vre)=(sum(r,(area(vre,z,r)+exist_vre_cap_r(vre,z,r)))>0.);


sets
gen_lin(non_vre)
ramp_on(z,non_vre)
mingen_on(z,non_vre)
ramp_and_mingen(z,non_vre)
;


$ifThen "%UC%" == ON

set gen_uc_lin(non_vre);
set gen_uc_int(non_vre);
set gen_quick(non_vre);

gen_uc_lin("NaturalgasOCGTnew")=YES;
*gen_uc_lin("Nuclear")=YES;
*gen_uc_lin("NaturalgasCCGTwithCCSnewOT")=YES;

*gen_uc_int(non_vre)=NO;

gen_quick("NaturalgasOCGTnew")=YES;

gen_uc_int("Nuclear")=YES;
gen_uc_int("NaturalgasCCGTwithCCSnewOT")=YES;

gen_lin(non_vre)=(not gen_uc_lin(non_vre) and not gen_uc_int(non_vre));

$else

gen_lin(non_vre)=YES;
gen_mingen("NaturalgasOCGTnew")=0.0;
gen_mingen("NaturalgasCCGTwithCCSnewOT")=0.0;

$endIf
```

```
* Sets to ensure ramp/mingen constraints are only created where relevant

ramp_on(z,non_vre)=((gen_maxramp(non_vre)*60./gen_unitsize(non_vre)) < 1.0 and
gen_lim(z,non_vre) and gen_lin(non_vre) and gen_unitsize(non_vre) > 0.);

mingen_on(z,non_vre)=(gen_mingen(non_vre) > 0. and
gen_lim(z,non_vre) and gen_lin(non_vre));

ramp_and_mingen(z,non_vre) = (ramp_on(z,non_vre) or mingen_on(z,non_vre));

* Buildable area per cell from km2 to MW power capacity

area(vre,z,r)=area(vre,z,r)$(vre_lim(vre,z,r))*gen_cap2area(vre);

* To be conservative, existing capacity is removed from new capacity limit

area(vre,z,r)=area(vre,z,r)-exist_vre_cap_r(vre,z,r);
area(vre,z,r)$(area(vre,z,r)<0.) = 0.  ;

* Fuel, varom and emission costs for non VRE gens;

*gen_varom(non_vre)=round(gen_fuelcost(non_vre)+gen_emisfac(non_vre)*emis_price+
gen_varom(non_vre),4);

gen_varom(non_vre)=gen_fuelcost(non_vre)+gen_emisfac(non_vre)*emis_price+
gen_varom(non_vre);

* Total capex = capex + fom;

gen_capex(g)=gen_capex(g)+gen_fom(g);

* Penalty generation setup

scalar
pgen /0./;

* Solar marginal - small value necessary to avoid transmission system issue

gen_varom("Solar")=0.001;

* Rescale parameters for runs that are greater or less than one year

if (card(h) < 8760 or card(h) > 8784,
co2_budget=round(co2_budget*(card(h)/8760.),8);
gen_capex(g)=round(gen_capex(g)*(card(h)/8760.),8);
```

```
gen_fom(g)=round(gen_fom(g)*(card(h)/8760.),8);
trans_capex(trans)=round(trans_capex(trans)*(card(h)/8760.),8);

store_fom(s)=round(store_fom(s)*(card(h)/8760.),8);
store_p_capex(s)=round(store_p_capex(s)*(card(h)/8760.),8);
store_e_capex(s)=round(store_e_capex(s)*(card(h)/8760.),8);
*store_e_unitcapex(s)=round(store_e_unitcapex(s)*(card(h)/8760.),8););

Variables
costs                                     total electricty system dispatch costs

Positive variables
var_new_pcap(g)                           new generation capacity at national level
var_new_pcap_z(z,g)                       new generation capacity at zonal level
var_exist_pcap(g)                         existing generation capacity at national level
var_exist_pcap_z(z,g)                     existing generation capacity at zonal level
var_tot_pcap(g)                           total generation capacity at national level
var_tot_pcap_z(z,g)                       total generation capacity at zonal level
var_gen(h,z,g)                            generation by hour and technology
var_new_vre_pcap_r(z,vre,r)               new VRE capacity at grid cell level by tech-
nology and zone
var_exist_vre_pcap_r(z,vre,r)             existing VRE capacity at grid cell level by
technology and zone
var_vre_gen_r(h,z,vre,r)                  VRE generation at grid cell level by hour zone
and technology
var_vre_curtail(h,z,vre,r)                VRE power curtailed
*var_non_vre_curtail(z,h,non_vre)
var_trans_flow(h,z,z_alias,trans)         Flow of electricity from node to node by hour
                                          (MW)
var_trans_pcap(z,z_alias,trans)           Capacity of node to node transmission links
                                          (MW)

var_pgen(h,z)                             Penalty generation

;

*** Transmission set up ***

* Sets up bidirectionality of links

trans_links(z_alias,z,trans)$(trans_links(z,z_alias,trans))=
trans_links(z,z_alias,trans);

trans_links_cap(z_alias,z,trans)$(trans_links_cap(z,z_alias,trans) > 0.)=
trans_links_cap(z,z_alias,trans);
```

```
trans_links_dist(z,z_alias,trans)=trans_links_dist(z,z_alias,trans)/100.;

* Bidirectionality of link distances for import flow reduction -> both monodir and
bidir needed, monodir for capex

parameter trans_links_dist_bidir(z,z_alias,trans);

trans_links_dist_bidir(z,z_alias,trans)=trans_links_dist(z,z_alias,trans);
trans_links_dist_bidir(z_alias,z,trans)$(trans_links_dist(z,z_alias,trans) > 0.)=
trans_links_dist(z,z_alias,trans);

* currenlty no exisiting transmission capacities in the European version but can be
implemented
*set to fix transmission line capacities to current levels and not making investments

$IF "%fx_trans_2015%" == "YES" var_trans_pcap.FX(z,z_alias,trans) =
trans_links_cap(z,z_alias,trans);

*******************************

var_exist_pcap_z.UP(z,g)$(gen_exist_pcap_z(z,g,"UP")) = gen_exist_pcap_z(z,g,"UP");
*var_exist_pcap_z.L(z,g)$(gen_exist_pcap_z(z,g,"UP")) = gen_exist_pcap_z(z,g,"UP");

var_exist_pcap_z.LO(z,g)$(gen_exist_pcap_z(z,g,"LO")) = gen_exist_pcap_z(z,g,"LO");
var_exist_pcap_z.FX(z,g)$(gen_exist_pcap_z(z,g,"FX")) = gen_exist_pcap_z(z,g,"FX");

var_exist_pcap_z.UP(z,g)$(not (sum(lt,gen_exist_pcap_z(z,g,lt)) > 0.)) = 0.0;


var_tot_pcap_z.UP(z,g)$(gen_lim_pcap_z(z,g,'UP'))=gen_lim_pcap_z(z,g,'UP');
var_tot_pcap_z.LO(z,g)$(gen_lim_pcap_z(z,g,'LO'))=gen_lim_pcap_z(z,g,'LO');
var_tot_pcap_z.FX(z,g)$(gen_lim_pcap_z(z,g,'FX'))=gen_lim_pcap_z(z,g,'FX');


*var_vre_pcap_r.LO(z,vre,r)$(exist_vre_cap_r(vre,z,r))=exist_vre_cap_r(vre,z,r);

$IF "%fx_natcap%" == YES var_new_pcap.FX(g)$(gen_fx_natcap(g))=gen_fx_natcap(g);

$IF "%UC%" == ON $INCLUDE highres_uc_setup.gms

$IF "%hydrores%" == ON $INCLUDE highres_hydro.gms


Equations
eq_obj
eq_elc_balance
```

```
eq_new_pcap
eq_exist_pcap
eq_tot_pcap
eq_tot_pcap_z

eq_gen_max
eq_gen_min
eq_ramp_up
eq_ramp_down
*eq_curtail_max_non_vre

eq_new_vre_pcap_z
eq_exist_vre_pcap_z
eq_gen_vre
eq_gen_vre_r

eq_area_max

eq_trans_flow
eq_trans_bidirect


eq_co2_budget

*eq_cap_margin

;

*****************************************
* OBJECTIVE FUNCTION

eq_obj .. costs =E=

* gen costs
sum((h,gen_lim(z,g)),var_gen(h,z,g)*gen_varom(g))

* startup costs
$IF "%UC%" == OFF $GOTO nouc1

+sum((h,z,non_vre)$(gen_uc_int(non_vre) and gen_lim(z,non_vre)),
var_up_units(h,z,non_vre)*gen_startupcost(non_vre))
+sum((h,z,non_vre)$(gen_uc_lin(non_vre) and gen_lim(z,non_vre)),
var_up_units_lin(h,z,non_vre)*gen_startupcost(non_vre))

*+sum((h,z,s)$(s_lim(z,s) and h2(s)),var_up_store_units(h,z,s)*0.01)
```

```
$label nouc1

*+sum((trans_links(z,z_alias),h),var_trans_flow(z,h,z_alias,trans)*
trans_varom(trans))

* fixed costs
* gen_capex includes gen_fom

+sum(g,var_new_pcap(g)*gen_capex(g))

+sum(g,var_exist_pcap(g)*gen_fom(g))

* transmission costs

+sum(trans_links(z,z_alias,trans),var_trans_pcap(z,z_alias,trans)*
trans_links_dist(z,z_alias,trans)*trans_capex(trans))

* storage costs

$ifThen "%storage%" == ON

+sum((h,s_lim(z,s)),var_store_gen(h,z,s)*store_varom(s))

+sum(s,var_exist_store_pcap(s)*store_fom(s))

+sum(s,var_new_store_pcap(s)*store_p_capex(s)+var_new_store_ecap(s)*store_e_capex(s))

*+sum(s$(h2(s)),var_new_store_pcap(s)*store_p_capex(s)+store_e_unitcapex(s)*
var_store_tot_n_units(s))

$endIf

$IF "%pen_gen%" == ON +sum((h,z),var_pgen(h,z)*pgen)

;
******************************************


******************************************
* SUPPLY-DEMAND BALANCE EQUATION (hourly)

eq_elc_balance(h,z) ..

* Generation
sum(gen_lim(z,g),var_gen(h,z,g))
```

```
* NonVRE Curtailment due to ramp rates
*-sum(non_vre,var_non_vre_curtail(z,h,non_vre))

* Transmission, import-export
-sum(trans_links(z,z_alias,trans),var_trans_flow(h,z_alias,z,trans))
+sum(trans_links(z,z_alias,trans),var_trans_flow(h,z,z_alias,trans)*
(1-(trans_links_dist_bidir(z,z_alias,trans)*trans_loss(trans))))

$ifThen "%storage%" == ON

* Storage, generated-stored
-sum(s_lim(z,s),var_store(h,z,s))
+sum(s_lim(z,s),var_store_gen(h,z,s))

$endIf

$IF "%pen_gen%" == ON +var_pgen(h,z)

=G= demand(z,h);

******************************************

*** Capacity balance ***

eq_new_pcap (g) .. sum(gen_lim(z,g),var_new_pcap_z(z,g)) =E= var_new_pcap(g);

eq_exist_pcap(g) .. sum(gen_lim(z,g),var_exist_pcap_z(z,g)) =E= var_exist_pcap(g);

eq_tot_pcap_z(z,g) .. var_new_pcap_z(z,g) + var_exist_pcap_z(z,g) =E=
var_tot_pcap_z(z,g);

eq_tot_pcap(g) .. sum(z,var_tot_pcap_z(z,g)) =E= var_tot_pcap(g);

*********************
*** VRE equations ***
*********************

* VRE generation is input data x capacity in each region

eq_gen_vre_r(h,vre_lim(vre,z,r)) .. var_vre_gen_r(h,z,vre,r) =E= vre_gen(h,vre,r)*
(var_new_vre_pcap_r(z,vre,r)+var_exist_vre_pcap_r(z,vre,r))-var_vre_curtail(h,z,vre,r);

* VRE gen at regional level aggregated to zonal level

eq_gen_vre(h,z,vre) .. var_gen(h,z,vre) =E= sum(vre_lim(vre,z,r),
```

```
var_vre_gen_r(h,z,vre,r));

* VRE capacity across all regions in a zone must be equal to capacity in that zone

eq_new_vre_pcap_z(z,vre) .. sum(vre_lim(vre,z,r),var_new_vre_pcap_r(z,vre,r)) =E=
var_new_pcap_z(z,vre);

eq_exist_vre_pcap_z(z,vre) .. sum(vre_lim(vre,z,r),var_exist_vre_pcap_r(z,vre,r)) =E=
var_exist_pcap_z(z,vre);

* VRE capacity in each region must be less than or equal to buildable MW as governed
by buildable area for each technology in that region

eq_area_max(vre_lim(vre,z,r)) .. var_new_vre_pcap_r(z,vre,r) =L= area(vre,z,r);

*************************
*** NON VRE equations ***
*************************

* Maximum generation of Non VRE

eq_gen_max(gen_lim(z,non_vre),h)$(gen_lin(non_vre)) .. var_tot_pcap_z(z,non_vre)*
gen_af(non_vre) =G= var_gen(h,z,non_vre) ;

* Minimum generation of Non VRE

eq_gen_min(mingen_on(z,non_vre),h)$(gen_lin(non_vre)) .. var_gen(h,z,non_vre) =G=
var_tot_pcap_z(z,non_vre)*gen_mingen(non_vre);

* Ramp equations applied to Non VRE generation, characterised as fraction of total
installed capacity per hour

eq_ramp_up(h,ramp_on(z,non_vre))$(gen_lin(non_vre)) .. var_gen(h,z,non_vre) =L=
var_gen(h-1,z,non_vre)+(gen_maxramp(non_vre)*60./gen_unitsize(non_vre))*
var_tot_pcap_z(z,non_vre) ;

eq_ramp_down(h,ramp_on(z,non_vre))$(gen_lin(non_vre)) .. var_gen(h,z,non_vre) =G=
var_gen(h-1,z,non_vre)-(gen_maxramp(non_vre)*60./gen_unitsize(non_vre))*
var_tot_pcap_z(z,non_vre) ;

* Non VRE curtailment due to ramping/min generation

*eq_curtail_max_non_vre(ramp_and_mingen(z,non_vre),h)..
var_non_vre_curtail(z,h,non_vre)= L= var_non_vre_gen(z,h,non_vre);

******************************
```

```
*** Transmission equations ***
******************************

* Transmitted electricity each hour must not exceed transmission capacity

eq_trans_flow(h,trans_links(z,z_alias,trans)) .. var_trans_flow(h,z,z_alias,trans) =L=
var_trans_pcap(z,z_alias,trans);

* Bidirectionality equation is needed when investments into new links are made

eq_trans_bidirect(trans_links(z,z_alias,trans)) ..  var_trans_pcap(z,z_alias,trans) =E=
var_trans_pcap(z_alias,z,trans);

***********************
*** Misc. equations ***
***********************

* Emissions limit

*when doing mutliple-year runs, hr2yr_map(yr,h) maps between hours and years, a certain
hour is summed up to be in that particular year to make sure the budget is summed up
correctly; to be found in the _temporal.dd file
eq_co2_budget(yr) .. sum((h,z,non_vre)$(hr2yr_map(yr,h)),var_gen(h,z,non_vre)*
gen_emisfac(non_vre)) =L= co2_budget*1E6/MWtoGW ;

scalar dem_tot;
dem_tot=sum((z,h),demand(z,h));

* Capacity Margin

*scalar dem_max;
*dem_max=smax(h,sum(z,demand(z,h)));

*eq_cap_margin .. sum(non_vre,var_tot_pcap(non_vre)*gen_peakaf(non_vre))+
sum(vre,var_tot_pcap(vre)*gen_peakaf(vre)) =G= dem_max*1.1 ;

*eq_max_cap(z,g) .. var_cap_z(z,g)+sum(vre_lim(vre,z,r),exist_vre_cap_r(z,vre,r))+
gen_exist_pcap_z(z,non_vre) =L= max_cap(z,g)

* Equation for minimum renewable share of generation in annual supply, set based on
restricting non VRE generation

set flexgen(non_vre) / NaturalgasOCGTnew / ;

$IF "%RPS%" == "optimal" $GOTO optimal
Equations eq_max_non_vre;
```

```
eq_max_non_vre .. sum((h,z,non_vre)$(gen_lim(z,non_vre) and not flexgen(non_vre)),
var_gen(h,z,non_vre)) =L= dem_tot*(1-RPS);
$label optimal

Model Dispatch /all/;

* don't usually use crossover but can be used to ensure
* a simplex optimal solution is found

Option LP = CPLEX;
Option MIP = CPLEX;

$onecho > cplex.opt
cutpass=-1
solvefinal=0
epgap=0.01

solutiontype=2

ppriind=1
dpriind=5

lpmethod=4
threads=4

heurfreq=5

startalg=4
subalg=4

parallelmode=-1

tilim=720000

barepcomp=1E-7

mipdisplay=5

names no
scaind=0
epmrk=0.9999


clonelog=1

$offecho
```

```
Dispatch.OptFile = 1;

*numericalemphasis=1
*dpriind=5

$ontext

writelp="C:\science\highRES\development\highres.lp"

epopt=1E-4
eprhs=1E-4
var_n_units.prior(z,non_vre) = 1;
var_up_units.prior(z,h,non_vre)=100;
var_down_units.prior(z,h,non_vre)=100;
var_com_units.prior(z,h,non_vre)=100;
Dispatch.prioropt=1;
$offtext

*writelp="C:\science\highRES\work\highres.lp"

* 2003 flexgen+store baralg=2, scaind=1 optimal
* barepcomp=1E-8
* ppriind=1

*execute_loadpoint "hR_dev";

$ifThen "%UC%" == ON Solve Dispatch minimizing costs using MIP;

$else

Solve Dispatch minimizing costs using LP;

$endIf


parameter trans_f(h,z,z_alias,trans);
trans_f(h,z,z_alias,trans)=var_trans_flow.l(h,z_alias,z,trans)$
(var_trans_flow.l(h,z,z_alias,trans)>1.0);
*display trans_f;

parameter max_bidir_trans;
max_bidir_trans=smax((h,z,z_alias,trans),trans_f(h,z,z_alias,trans));
*display maxtrans;

*parameter pgen_tot;
*pgen_tot=sum((z,h),var_non_vre_gen.l(z,h,"pgen"));
```

```
$IF "%log%" == "" $GOTO nolog
scalar now,year,month,day,hour,minute;
now=jnow;
year=gyear(now);
month=gmonth(now);
day=gday(now);
hour=ghour(now);
minute=gminute(now);

file fname /"%log%"/;
put fname;
fname.ap=1;
put "%outname%"",",day:0:0"/"month:0:0"/"year:0:0" "hour:0:0":"minute:0:0",
"Dispatch.modelStat:1:0","Dispatch.resUsd:0;
$LABEL nolog

* write result parameters

$INCLUDE highres_results.gms

* dump data to GDX

execute_unload "%outname%"

* convert GDX to SQLite

$IF "%gdx2sql%" == ON execute "gdx2sqlite -i %outname%.gdx -o %outname%.db -fast"
```

C Other equations

In this section a further mathematical description of the model is presented.

VRE equations

The generation curtailed per zone and hour $var^{curtail}_{z,h,g^v}$ has to be less or equal to the generation from VRE technologies var^{gen}_{z,h,g^v}

$$var^{curtail}_{z,h,g^v} \leq var^{gen}_{z,h,g^v}. \tag{4}$$

Generation from VRE itself has to be equal to the installed capacity $var^{vre\_cap\_z}_{z,g^v}$ multiplied by the capacity factor $vre\_gen_{g^v,z,h}$

$$var^{gen}_{z,h,g^v} = var^{vre\_cap\_z}_{z,g^v} \cdot vre\_gen_{g^v,z,h}. \tag{5}$$

The summation of the VRE capacity across all the zones must be equal to the total installed capacity $var^{vre\_cap}_{g^v}$

$$\sum_z var^{vre\_cap\_z}_{z,g_v} = var^{vre\_cap}_{g^v}. \tag{6}$$

At the same time the VRE capacity in each zone need to be less than or equal to the maximum feasible capacity $capacity_{g^v,z}$

$$var^{vre\_cap\_z}_{z,g^v} \leq capacity_{g^v,z}. \tag{7}$$

Non VRE equations

Non VRE capacity across all zones $var^{nvre\_cap}_{g^n}$ has to be equal to the total non VRE capacity $var^{nvre\_cap\_z}_{g^n}$

$$var^{nvre\_cap}_{g^n} = \sum_z var^{nvre\_cap\_z}_{z,g^n}. \tag{8}$$

The capacity of non VRE $var^{nvre\_cap\_z}_{z,g^n}$ times the availability factor af_{g_n} has to be greater than or equal to the generation from NVRE $var^{nvre\_gen}_{z,h,g^n}$

$$var^{nvre\_cap\_z}_{z,g^n} \cdot af_{g_n} \geq var^{nvre\_gen}_{z,h,g^n}. \tag{9}$$

The generation from NVRE has to be also greater than or equal to the capacity times the minimum generation of the technology $mingen^n_g$

$$var^{nvre\_gen}_{z,h,g_n} \geq var^{nvre\_cap\_z}_{z,g^n} \cdot mingen^n_g. \tag{10}$$

It follows the ramp up equation that is needed to ensure that a power plant does not ramp up more than it is technically feasible. Generation from NVRE in an hour $var^{nvre\_gen}_{z,h,g^n}$ must be less than or equal to the generation in previous hour $var^{nvre\_gen}_{z,h-1,g^n}$ plus the maximum ramp $maxramp^n_g$ times the capacity $var^{nvre\_cap\_z}_{z,g^n}$

$$var^{nvre\_gen}_{z,h,g^n} \leq var^{nvre\_gen}_{z,h-1,g^n} + maxramp^n_g \cdot var^{nvre\_cap\_z}_{z,g^n}. \quad (11)$$

Same concept goes for the ramp down equation. The generation from NVRE in an hour needs to be greater or equal to the generation in the previous hour minus the maximum ramp times the capacity

$$var^{nvre\_gen}_{z,h,g^n} \geq var^{nvre\_gen}_{z,h-1,g^n} - maxramp^n_g \cdot var^{nvre\_cap\_z}_{z,g^n}. \quad (12)$$

Transmission system equations

The transmitted electricity $var^{t\_flow}_{z^1,h,z^2}$ between two zones has to be less than or equal to the transmission capacity between that two zones $var^{t\_cap}_{z^1,z^2}$

$$var^{t\_flow}_{z^1,h,z^2} \leq var^{t\_cap}_{z^1,z^2}. \quad (13)$$

Trasmission capacity between two zones must be equal bidirectionally

$$var^{t\_cap}_{z^1,z^2} = var^{t\_cap}_{z^2,z^1}. \quad (14)$$

Storage equations

The amount of electricity stored in an hour $var^{s\_level}_{z,h,s}$ must be equal to the storage level in the previous hour reduced by self-discharge $var^{s\_level}_{z,h-1,s} \cdot (1 - loss_{h_s})$ plus electricity stored reduced by storage losses $var^{s\_store}_{z,h,s} \cdot (1 - loss_s)$ minus electricity generated from the storage reduced bu storage losses $\frac{var^{s\_gen}_{z,h,s}}{(1-loss_s)}$

$$var^{s\_level}_{z,h,s} = var^{s\_level}_{z,h-1,s} \cdot (1 - loss_{h_s}) + var^{s\_store}_{z,h,s} \cdot (1 - loss_s) - \frac{var^{s\_gen}_{z,h,s}}{(1 - loss_s)}. \quad (15)$$

The storage level $var^{s\_level}_{z,h,s}$ needs to be less than or equal to the capacity of the generator times the ratio between the capacity of the storage generator and the capacity of the storage system $var^{s\_cap\_z}_{z,s} \cdot s\_gen\_to\_cap_s$

$$var^{s\_level}_{z,h,s} \leq var^{s\_cap\_z}_{z,s} \cdot s\_gen\_to\_cap_s. \quad (16)$$

The electricity generated from storage $var^{s\_gen}_{z,h,s}$ must be less than or equal to the storage generator capacity $var^{s\_cap\_z}_{z,s}$ times the availability factor af_s

$$var^{s\_gen}_{z,h,s} \leq var^{s\_cap\_z}_{z,s} \cdot af_s. \quad (17)$$

The electricity which goes into the storage $var^{s\_gen}_{z,h,s}$ must be less than or equal to the capacity of the storage generator times the availability factor

$$var^{s\_gen}_{z,h,s} \leq var^{s\_cap\_z}_{z,s} \cdot af_s. \quad (18)$$

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