Optimization of baseload electricity and hydrogen services by variable renewables for a nuclear-sized district in South Italy

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Abstract

The main critical aspects are four:

- under-estimation of the wind potentials in an orographically complex country such as Italy;
- aggregation of rooftop and ground-based solar that does not highlight the systemic advantages of ground-based solar;
- PHS....;
- unsuitability of geological storage for hydrogen in Italy and the need of an alternative for seasonal storage.

The model considers several energy pathways and related technologies for short, medium, and long-term storage. The model is implemented in the open source environment PyPSA Hörsch et al. (2018) as a linear program and solved by a commercial solver. methanation appears as a promising pathway for long-term storage, a conclusion that is increasingly found in the energy scenario literature. Analysis of the shadow prices shows that the minimum cost configuration ensures the cost-revenue balance of each sub-system in the district. Co-production of electricity and

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hydrogen is cost competitive with technology parameters forecasted for the year 2050.

Keywords:

1 Introduction

The decarbonization of the energy system requires not only a step increase in the electrification of end-use sectors such as transportation and heating, but also electro-fuels for some end-uses, and hence the need for a baseload supply of hydrogen, see e.g. Mathiesen et al. (2015); Connolly et al. (2016); Victoria et al. (2019). To this aim, we present an optimization model of a district supplying two baseload energy services with electricity and hydrogen as their carriers. We consider renewable and storage technologies with large techno-economical potentials in South Italy. The district is sized such that its services could be alternatively supplied by a nuclear reactor. By so doing, the model's results can offer a comparison for a given territory between the choice of a renewable vs nuclear-based energy district. Nuclear energy is not currently part of the Italian energy supply, but the government in 2024 expressed a willingness to evaluate this technology (add citation XX). This nuclear-sized baseload district has the further advantage of constituting an elementary building block for national scenarios. The purpose in this case would only be illustrative, since there are several limitations implied in a single-district model, as discussed in the following.

Baseload supply of energy services by renewables has been studied in (Fasihi and Breyer, 2020), and.... ...... With respect to this literature stream we want to address the following five issues that are motivated by the specific context of South Italy but that may be of general interest.

- Photovoltaic with high capacity factor as it is allowed by ground-based PV with mono-axial tracking *versus* rooftop solar.

- Prospective onshore wind with site-specific optimization.

- Conservative assumptions on short and medium-term storage technologies, and the *Pumped Hydro Storage* (PHS) as a multi-benefit option.
- Lack of low cost geological storage for hydrogen.
- Synergies with the agro-forestry sector.

(Blanco and Faaij, 2018; Wohland et al., 2021)

Wind and solar synergy is a well known leverage for reducing the supply cost of renewable-based energy systems (Breyer et al., 2022). This synergy is particularly relevant for industrial plants requiring energy supply with high capacity factors as is the case for hydrogen and in general electro-fuel production. From this steams the interest on solar and wind hybrid districts with both sources striving for high capacity factors.

Ground-based photovoltaic is often underappreciated and dismissed for its hypothesized land impacts. This hypothesis is questionable by two lines of reasoning, our analysis contribute to a third one, and the three lines are briefly mentioned in the following and explored further in this paper. First, even with massive deployment of ground-based PV the area required would not be so large to significantly interfere with other uses such as, for example, food production and natural habitat. Second, simple eco-design measures in ground-based PV may yield net benefits for other socio-environmental objectives. This multi-objective configuration of GPV traces back to the report of Macknick et al. (2013) and has been recognized as an example of green infrastructure (Commissione Europea, 2020; Semeraro et al., 2020). For example, the agricultural and ecosystem services of GPV as habitat of pollinator insects is discussed in Semeraro et al. (2018); Walston et al. (2018); Armstrong et al. (2021); Semeraro et al. (2022b), and Semeraro et al. (2022a) highlight the potential of GPV for restoring wetlands. Third, we contribute to this issue by studying the techno-economical advantage of GPV with mono-axial tracking versus rooftop solar. Our results will show that by vetoing GPV the energy system cost will increase not only because of the higher cost of rooftop solar per unit of energy *produced*. The higher capacity factor of GPV versus rooftop solar reduces the cost of energy *delivered*, since it decreases the required generation and storage capacities. This systemic view may integrate classical LCA studies where photovoltaic plants are assessed per unit of energy produced.

The techno-economical potential of onshore wind in Italy is under-estimated by methods that average wind speed over large areas. In an orographically complex country such as Italy this wide-area averaging bias is significant, and it is further compounded by assuming only one average wind turbine type and hub height, instead that optimizing for local conditions. Moreover, wind turbine technology and management has progressed in the last two decades and thus for 2050 decarbonization scenarios prospective assumptions should be included. These considerations motivate our approach of using for onshore wind prospective and locally optimized capacity factors as in Ryberg et al. (2019).

For short and medium-term storage we focus on PHS for two main reasons. First, PHS is a mature technology and further cost decreases are not expected. As our results will show, the plausible trends in solar and wind technologies are sufficient to obtain a low-cost supply of reliable energy services under this worst-case assumption on storage technologies, i.e. no breakthrough. Thus, a focus on PHS confutes that renewable-based energy systems lack techno-economical feasibility for a storage criticality. Second, closed-loop off-river PHS may have synergies with other public interests beside decarbonization, namely the minimization of extreme-weather risks under climate change such as droughts and floods. For this line of inquiry on so-called blue infrastructure in Italy see Frigerio et al. (2012); Fanelli et al. (2018). Regarding PHS techno-economical potentials, Stocks et al. (2021) locate worldwide closed-loop off-river PHS plants by the methodology of Lu et al. (2018). Simon et al. (2023) validate for the US the methodology and results of Stocks et al. (2021). For Italy Stocks et al. (2021) individuate 2347 PHS sites with a storage capacity of 64 TWh. This value is two orders of magnitude larger than what is reasonably necessary in this country. Therefore, by including PHS as a storage option we base our model on a scalable technology with potential co-benefits.

We assess the long-term storage of electricity by hydrogen in surface thank and synthetic methane in geological storage. This modeling choice is motivated in the following. Italy lacks salt caverns, the more favorable geological structures for underground storage of hydrogen, see Caglayan et al. (2020). We note that the potential for underground hydrogen storage in less favorable geological structures in Italy is not zero, see Barison et al. (2023), and this country could benefit of a European hydrogen infrastructure, see Neumann et al. (2023). Both options could lower the storage cost of hydrogen, but we prefer to err on the cautious side and we assume that hydrogen in Italy may be only stored in surface tanks. Conversely, The geological storage capacity of fossil gas in Italy is over-abundant with respect to plausible scenarios where synthetic methane is deployed as seasonal and strategic storage, see Appendix XX. Synthetic methane is usually referred to as electro-methane, and in the following is indicated by e-CH_4. The methanation process has the disadvantage of additional conversion losses with respect to the hydrogen required as input for this process. Moreover, it requires a source of non-fossil CO_2 that may be supplied by *Direct Air Capture* (DAC) with a corresponding increase in cost and primary energy. The significant advantage of e-CH_4 is its suitability for the already built storage infrastructure for fossil gas. As will be shown in the following, the optimal long-term storage option for South-Italy is e-CH_4 because of the lower cost of geological storage with respect to surface tanks.

Methanation is increasingly appraised in the energy scenario literature by a synergy with the agro-forestry sector. This synergy is usually referred to as *Power-And-Biomass-to-Gas* (P&B2G), see for example ADEME (2018); Shirizadeh and Quirion (2022); Shirizadeh et al. (2022); Shirizadeh and Quirion (2021) for France, Mortensen et al. (2020) for Denmark, and Carbone et al. (2021); Pierro et al. (2021) for Italy. We follow this approach by considering optional CO_2 feedstock flow from a biogenic source (bio-CO_2). By so doing, we can study the competitiveness of biogenic CO_2 versus DAC as an input for the methanation process. We include as well an optional source of biogenic methane to assess its competitiveness versus e-CH_4.

1.1 Outline

2 Model

The model is qualitatively described in Section 2.1, illustrated by a graph in Section 2.2, and presented as a linear program in Section 2.3. Major and minor limitations are discussed in Section 2.4.

2.1 Qualitative description

The optimization model minimizes the system cost, sum of actualized capital expenditures and operations and maintenance costs, of the technologies activated in a single-district energy system. The parameters of the technologies are estimated for the year 2050 and presented in Section 3. The model has a parametric CO_2 budget for its emissions, but in the main scenarios studied in this paper this budget is set to zero as normatively assumed for the year 2050. There are two demands of energy services with electricity and hydrogen as their carriers. The electric and hydrogen demands are constant for each time-step in the studied time horizon, i.e. are of the baseload type. The time-step is of one hour and the time horizon is a non-leap year of 8760 hours. These demands are set to 1 GW for the electricity and to 0.25 GW for the hydrogen[1]. As we will be shown in the following, when accounting for the electric input of the electrolysis process, the total power required for such a district based on nuclear would be similar to that offered by a new nuclear reactor, i.e. a generation III/III+ reactor. In this sense we deal with a nuclear-sized baseload district, even though, as will be shown, the minimum cost optimization favors renewable sources in South-Italy. Similar districts can serve as elementary building blocks for national scenarios, albeit only for illustrative purposes, given the intrinsic limitations of single-districts. For example, if Italy would require in the year 2050 XX GW of baseload electricity and XX GW of baseload hydrogen, then XX of such districts would be needed in a first approximation assessment.

[1]with respect to the lower heating value of this fuel.

The model considers the following four technologies as non-fossil primary energy sources:

- Onshore wind.
- Land based photovoltaic with mono-axial tracking.
- Photovoltaic with a fixed orientation as it usually occurs with rooftop solar.
- Nuclear fission.

Rooftop solar is further differentiated in the following two alternative cases, in the sense that only one can be activated in a scenario according to a flag parameter:

- Optimal tilt and the same solar availability as with the PV with tracking. This case yields a relatively high capacity factor, and is indicated as "solar rooftop high CF".
- Assumptions that lower the capacity factor......

The model includes as well a source of fossil gas which is constrained to zero by the CO_2 emission limit. This limit can be relaxed to draw insights on near-zero CO_2 budgets, and such analysis is carried out in Appendix XX.

The performances of the considered renewable technologies depend on their localization and ....

The direct storage of electricity is allowed by two technologies:

- Li-ion battery.
- Closed-loop off-river pumped hydro storage (PHS).

The storage lengths of these two technologies are variable to optimized.

The indirect storage of electricity is allowed by hydrogen and synthetic methane by the following technologies:

- Electrolyser.
- MethanizerXXX

- CO_2 Direct Air Capture (DAC).

Both hydrogen and synthetic methane can operate as long-term storage. The methanation process is modeled as continuous and only partially modulable. The maximum yearly capacity factor of the electrolysis is set to 90%. The capture of CO_2 by DAC requires a heat pump and thermal storage as auxiliaries for the thermal input of this process. CO_2 storage in surface tank is included to decouple the hydrogen and e-CH_4 processes. System cost minimization determines the optimal capacities of these long-term storage options and of their auxiliaries. The optimal mix between hydrogen and e-CH_4 is thus an optimized outcome and not an input parameter.

The model considers an optional CO_2 feedstock flow from a biogenic source (bio-CO_2). When bio-CO_2 is competitive, it fully or partially replaces CO_2 from DAC. In this case, the produced methane should be referred to as e-bio-CH_4 , but for simplicity we maintain the label e-CH_4. We include as well an optional source of biogenic methane to assess its competitiveness versus e-CH_4.

Because of these modeling choices, we have three possible sources for the methane that is used as an auxiliary carrier inside the energy district. Two of these sources are renewable, e-CH_4 and bio-CH_4 , and one is fossil. Methane can be used to generate electricity by an *Open Cycle Gas Turbine* (OCGT). Hydrogen, beside being supplied as final demand, can be used to generate electricity by a *Fuel Cell* (FC).

2.2 Graph representation

Fig. 1 illustrates by a graph the connections between the sub-systems of the model. The demand nodes, electricity and hydrogen, are represented as trapezoid, and derive their inputs from bus nodes depicted as rectangles. A bus node represents an energy/feedstock carrier and its associated input-output equilibrium constraint for each time step of the time horizon. The inputs of the electricity bus derive from generator nodes depicted as circles. Generator nodes produce electricity according to constraints specific of the technology. For example, the nuclear node generates electricity with a constraint on the maximum yearly capacity factor of 90%. The wind node generates electricity according to the assigned hourly availabilities. Generator nodes of primary sources do not have upstream dependencies. Conversely, generator nodes of storage technologies have specific upstream dependencies. For example, the generator node PHS depends on the state of charge of its upper basin. The OCGT node requires a methane input derived from the bus for this fuel. These dependencies are illustrated by links to bus, storage and auxiliary nodes as explained in the following. Storage nodes are depicted as cylinders, and at these nodes the hourly equilibrium considers their state of charge. Storage nodes of primary sources for fuel and feedstock do not have an input and their state of charge can be depleted during the time horizon starting from a given initial level. Storage nodes of auxiliary technologies have both input and output and their state of charge is a variable constrained to have equal values at the beginning and at the end of the time horizon. The auxiliary nodes, depicted as squares, represent processes such as methanation, electrolysis, hydrogen compression, DAC, thermal production by heat pump, and the loading phases of battery and PHS. The auxiliary nodes represents loads served by the four buses for electricity, hydrogen, methane and CO_2. As will be detailed in the Section XX, the model allows to constrain to zero some pathways in this graph in order to assess the impact of exogenous technological choices on the optimal system cost such as veto on ground-based PV, or onshore wind, or nuclear, etc. This is done by flag parameters, i.e. binary values, that in the model building phase activate or not certain energy pathways.

2.3 Linear program

The model is implemented in the framework *Python for Power System Analysis* (PyPSA) (Hörsch et al., 2018).

2.4 Limitations

A single-district energy system reliant on time-varying sources such as wind and solar has its main limitation in the absence of geographical area diversification which requires the transmission of electricity. With the hypothesis of no transmission between

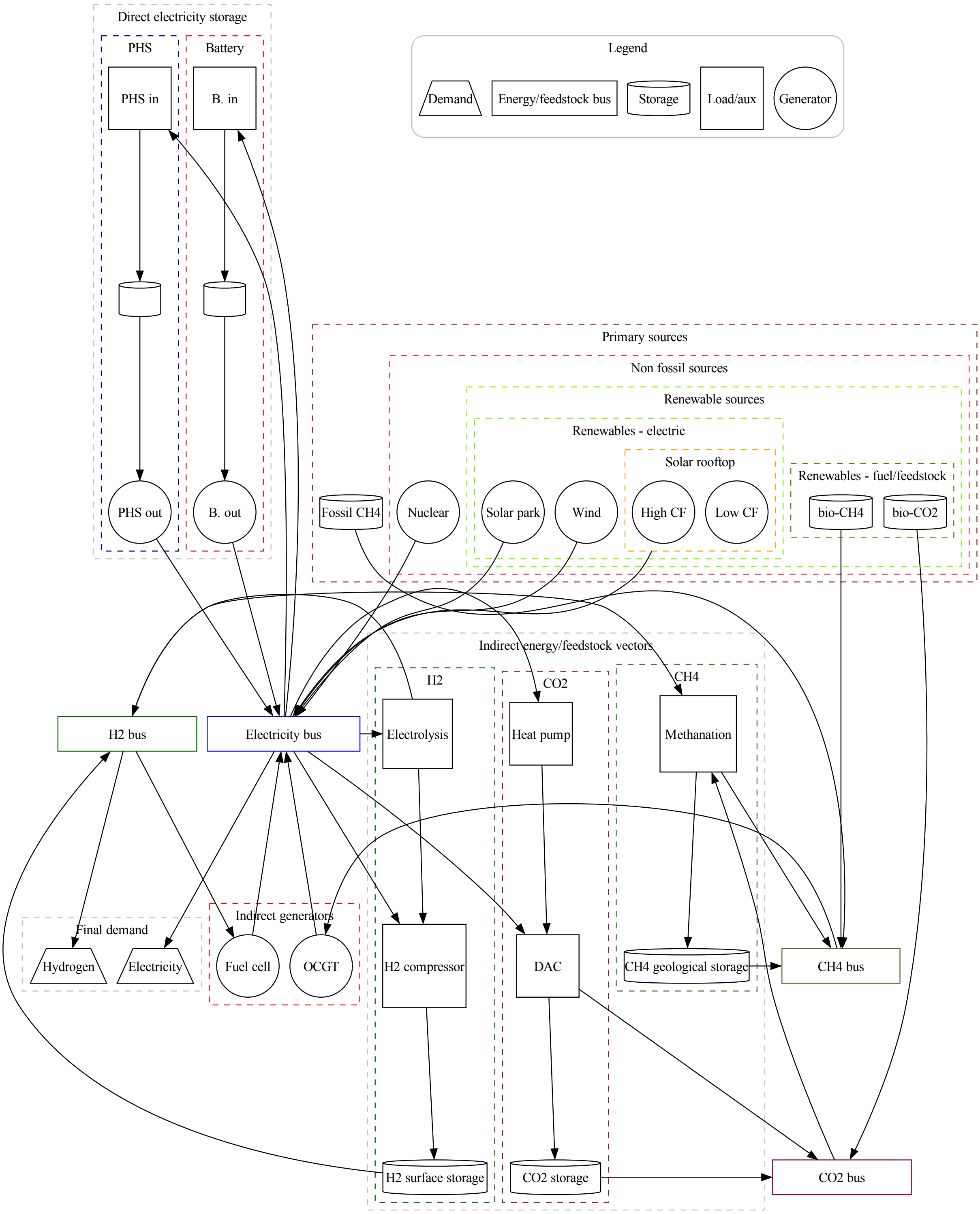

Figure 1: Graph of the sub-systems and their relationships.

areas with different temporal availabilities of wind and sun the studied energy system must be regarded as a worst-case. It is in fact well known that renewable-based scenarios over wider geographical areas yield lower system costs thanks to the increasing negative correlation between wind and solar availabilities, see e.g. Schlachtberger et al. (2017) for the cost-optimal expansion of transmission in a European-wide renewable-based electricity sector.

Having assumed a fixed demand is another worst-case assumption. Flexible demand decreases system cost in renewable energy systems. This option may considerably increase in the near-future with battery-electric vehicles, heat pumps, and inexpensive non-electric storage on the end-use side such as thermal storage. For the opportunities of massive thermal energy storage see Lund et al. (2016, 2021); Paardekooper et al. (2022), and for synergies between the electricity sector and thermal end-uses see Möller et al. (2019); Jacobson et al. (2022). These end-use options can be studied as well in a single-district setting but are better assessed at least at a regional or national scale and are out of the supply focus of this paper. In this paper we have not considered technologies that could further reduce the system cost. For example, we did not include the *Adiabatic Compressed Air Energy Storage* (A-CAES) which could replace PHS at a slightly lower system cost. According to Aghahosseini and Breyer (2018), A-CAES techno-economical potential in Italy is vast and therefore this option merits further assessments. Our rationale in excluding A-CAES is the larger uncertainty of its future cost with respect to a better assessed technology such as PHS. This choice is in line with our focus on conservative assumptions about 2050 decarbonization technologies.

Further model refinements that have not been included but that can yield plausible, albeit low, system cost reductions are:

- Combined steam-gas cycles.
- Multi-fuel turbines, e.g. gas turbines that can use both methane and hydrogen.
- Sub-networks in direct current to improve the relationships between some sources and electro-chemical storage technologies.

- Thermal sub-networks to improve synergies between endo and exo-thermal processes.

These refinements have been excluded for simplicity.

3 Data

Default techno-economical parameters in the PyPSA framework are mainly derived from the *Danish Energy Agency* (DEA) reports (DEA, 2022a,b,c). DEA is an institution that has historically led the transition from fossil to renewable energies. We have therefore decided to keep most of the default PyPSA assumptions with the following integrations.

As the representative technology for medium-term storage we have chosen PHS for the reasons discussed in Section XX. PHS is a technology insufficiently detailed in DEA datasets, as expected for the very limited potential of this technology in a country with flat orography such as Denmark. The choice of surface tank for hydrogen storage induces as well an integration with respect to standard PyPSA assumptions. Data selection for short, medium and long-term storage is discussed in Section 3.1.

Another technology insufficiently described in the DEA reports is nuclear. For nuclear we have used data from the *International Energy Agency* (IEA) report Bouckaert et al. (2021) and Lazard (2019) as detailed in Section 3.2.

We diverge from standard PyPSA data assumptions also on the hourly availabilities of wind and solar. PyPSA generate these availability profiles by the code Atlite (Hofmann et al., 2021). In order to tackle our research questions on the system advantages of ground-based solar and prospective onshore wind we need to meet the following conditions. For solar we need to differentiate between the availability profiles of state-of-the-art PV plant with mono-axial tracking and rooftop solar. For wind we want to avoid the under-estimation of its potential caused by

- wide-area integration in an orographically complex country such as Italy;

- generic wind turbine power curve instead of one optimized for specific local conditions;
- assessment limited by current technology instead of that forecasted for year 2050.

To this aim we use the open dataset Renewables.ninja[2] (Pfenninger and Staffell, 2016; Staffell and Pfenninger, 2016) oriented for wind by the results of Ryberg et al. (2019) as described in Section 3.3.

The techno-economical parameters are synthesized in Tab. 1 with their literature sources. The cost parameters of the exogenous bio-CH_4 and bio-CO_2 are 40 €/MWh$_{th}$ and 70 €/ton, respectively. All monetary values are referred to the year 2015 or years before 2022 when inflation significantly increased cost assessments.

The annuity of an investment I with an expected lifetime of y years and a discount rate r is computed as

$$I \frac{r}{1 - \frac{1}{(1+r)^y}}. \tag{1}$$

We highlight that the parameter with the largest sensitivity is the discount rate which has been set to 8% in the scenarios reported in Section ....XX...

3.1 Parameters for storage

We have derived the PHS techno-economical parameters from Guerra et al. (2021), a recent paper with a focus on future storage technologies. As a benchmark, we can compare the Guerra et al. (2021) PHS assumptions with the most recent large project in South-Italy. A PHS plant of 1 GW power and 6 GWh storage capacity has been completed in Presenzano (Caserta) in the year 1990. At current value, the investment of Presenzano plant can be estimated at circa one billion euros. With the parameters of Tab. 1 such a plant would require an investment of 1.3 bln €. In view of this we consider sufficiently conservative the use of Guerra et al. (2021) for PHS in Italy. In order to maintain coherence among storage technologies that can have overlapping

[2] https://www.renewables.ninja/

system roles, we have decided to use as well the Guerra et al. (2021) parameters for battery storage (in their paper indicated as “short term storage”).

Industrial scale storage in surface tanks is extensively reported in IEA (2019) and this is the source that we have used as well for the cost parameter of the electrolysis.

3.2 Parameters for nuclear

The International Energy Agency estimates for the year 2050 in the European Union that a nuclear reactor will have an overnight capital cost of 4500 \$/kW, an operation and management cost (OPEX) of 35 \$/MWh, a financing rate of 8%, with a resulting LCOE of 115 \$/MWh when the yearly capacity factor is 70% (Bouckaert et al., 2021). This disaggregation of the LCOE for the nuclear technology is insufficient for our model since the capacity factor itself in an outcome of the system cost minimization. Therefore, we need to differentiate the nuclear OPEX between the fixed cost components that are independent from the capacity factor (FO&M) and those that are proportional to the produced electricity (VO&M). To this purpose, we use data from the report Lazard (2019) that offers this disaggregation. The nuclear investment cost is computed as follows. Let C be the overnight capital cost, n the number of years for the building phase of the plant, and r the financing rate. We conservatively assume a linear capital expenditure during the building phase. Then the investment cost I, usually referred to as CAPEX, is:

$$I(C, n, r) = C \times \left(1 + \sum_{i=1}^{n} \frac{(1+r)^{n+1-i} - 1}{n}\right) \tag{2}$$

A building phase of 7 years and the other parameters as described above yield an investment cost of 6195 €/kW. For all these CAPEX and OPEX estimates an unitary exchange rate between euro and US dollar has been assumed. Under these hypotheses, the nuclear OPEX is 27.7 €/MWh when the CF is at its maximum value of 90%, and is 32.1 €/MWh when the CF 70%. The resulting nuclear LCOE with maximum CF is 91.1 €/MWh, and with a CF of 70% is 113.6 €/MWh. Thus the chosen parameters are coherent with Bouckaert et al. (2021). Moreover, as discussed in Appendix **??** the model results show that in 2050 with abundant and low cost wind and solar the nuclear CF can be at most 70%. If the LCOE of this technology will be economically sustainable under these conditions is debatable.

We remark that the above assumptions are relatively favorable to nuclear in our single-district comparison with variable renewables. We are assuming for nuclear a maximum capacity factor of 90% expressed as a constraint on the yearly output. This hypothesis is not realistic for a single reactor, since implicitly requires a national grid where several reactors optimally schedule their maintenance and re-fueling during the year. For a single reactor, as it would be in the case of the single district, the nuclear unavailability would not be optimally distributed during the year but concentrated in a given period, for example during one month in summer. This unavailability would be costlier to manage with respect to the constraint on the maximum yearly capacity factor that we have chosen. Our model implements a variant where the nuclear unavailability is concentrated instead than constrained by the yearly capacity factor. As expected, nuclear competitiveness worsens in this model variant and these results are omitted in this paper but are available in the online code repository XX.

Another simplification that favors nuclear with respect to renewables is the assumption of a fixed lifetime for the electrolyser. In Tab. 1 the cost parameters for the electrolysis are derived assuming a yearly capacity factor of 57%. The resulting electrolysis lifetime of 20 years is therefore a cost underestimation for a nuclear-based district where the hydrogen process CF would be at its maximum value of 90%. We comment further on this issue of green vs pink hydrogen in Section XX.

3.3 Hourly availability profiles of wind and solar

Ryberg et al. (2018, 2020) study the available areas for onshore wind in Europe according to a comprehensive set of exclusion criteria. For those available areas, Ryberg et al. (2019) define a localization procedure for individual wind turbines and an optimization method for turbine sizing under prospective technology estimated for year 2050.

The prospective technology is derived from current Vestas 4.2-136 model but at each turbine location the specific power and hub height is determined such that the multi-year LCOE is minimized. These results are relevant for our study since offer a geographical distribution of wind potential under realistic 2050 technology assumptions. For Italy, the results of Ryberg et al. (2019) are as follows. The total techno-economical potential is ~600 GW with a CF of 25%, i.e. a generation potential of 1300 TWh/a, and a subset of 153 GW yields a CF of 33%. The subset with LCOE not larger than 56 €/MWh has a cumulated capacity of 100 GW with CFs in the range 31—51% and an average value of 35%. Fig. 2 illustrates the average and marginal CFs of the cumulated capacity ordered with increasing LCOE. Fig.3 depicts the geographical distribution of the 100 GW subset with lowest LCOE aggregated at the provincial level (level 3 of the Nomenclature of Territorial Units for Statistics (NUTS)). Four fifths of this potential is located in South Italy where the best national solar resource is also available. Conservatively, we have chosen to locate the WWS district in Cosenza province, Calabria region, an area that does not offer the highest capacity factors for wind and solar in South Italy, these being Sicily for solar and Sardinia for wind. We have extracted from the online service Renewables.ninja a wind turbine availability curve located in Cosenza province for the year 2010. According to a study of the Italian electric grid operator, the meteorological year 2010 is representative of the long-term average for wind and solar in this country (TERNA-SNAM, 2022). The selected wind turbine is a Vestas 4000-150 with a hub height of 80 meters, and a CF of 33%. By so doing, we use for onshore wind a CF value representative of a 153 GW potential in Italy according to Ryberg et al. (2019). We extracted as well from the online service Renewables.ninja two solar availability profiles for the same year and location. One for the photovoltaic plant with mono-axial tracking yielding a CF of 22.7%, and the other for the rooftop photovoltaic with optimal tilt yielding a CF of 17.7%. This last curve may be regarded as a best case for PV rooftop performances and may not be representative for the average rooftop installations, not even in South Italy. It is in fact common for rooftop installations to be constrained in terms of orientation, shading, and more cumbersome

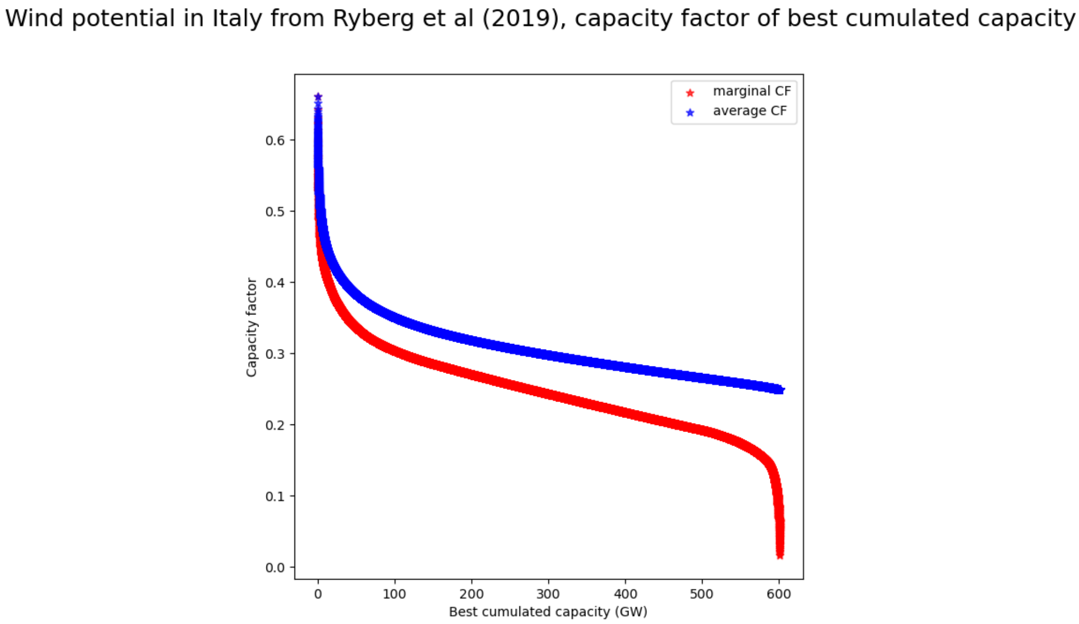

Figure 2: Onshore wind potential in Italy, average and marginal capacity factors of the cumulated capacity with increasing LCOE. Our elaboration from data of Ryberg et al. (2019).

maintenance. In fact, current PV installations in Italy are mostly rooftop and the average CF in the year 2021 has been of circa 13% (GSE, 2022). In order to assess more realistic scenarios where there is a veto to ground-based PV we have selected from the online service Renewables.ninja a solar availability curve with a CF of 13.9% by locating this plant in North Italy, province of Mantova. This curve my be regarded as more representative of the scenarios with a veto to ground-based PV. These four hourly availability profiles are illustrated in Fig. 4.

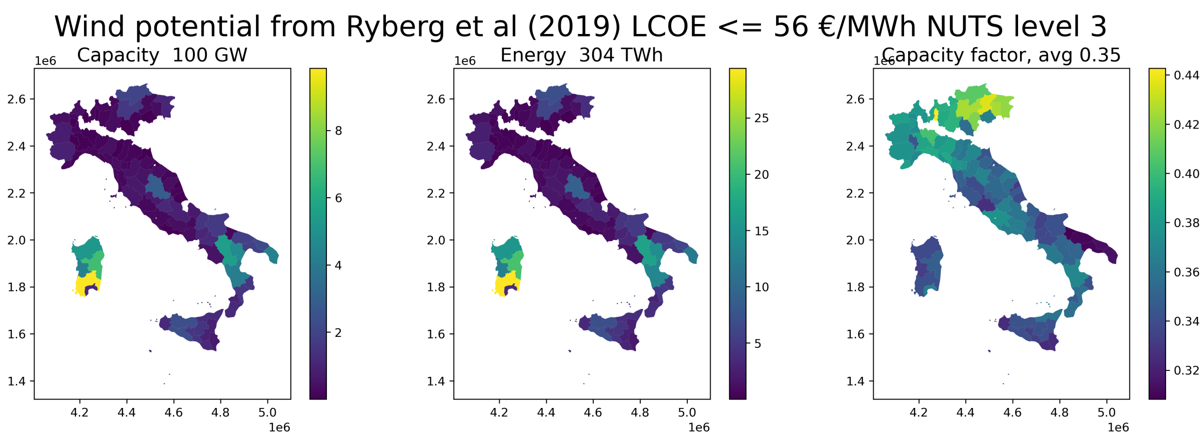

Figure 3:

Table 1: Techno-economical parameters, sources and technical notes[0]

Technology	FO&M %I/y	VO&M €/MWh	Efficiency/other	Investment (I) €/MW or MWh	Lifetime y	Source
Onshore wind	1.18	1.22	-	963070	30	DEA (2022c)
Solar utility, with tracker	2.57	0.01[1]	-	280000	40	DEA (2022c)
Solar-rooftop commercial	1.81	0.01[1]	-	374880	40	DEA (2022c)
Nuclear	1.95[2]	12.4[3]	-	6195000[4]	60	Bouckaert et al. (2021); Lazard (2019)
Open cycle gas turbine	1.8	4.5[5]	0.43	411840	25	DEA (2022c)
Li-ion battery, energy	-	-	-	115700	13	Guerra et al. (2021)
Li-ion battery, power	10.5	3.1	0.86	97800	13	Guerra et al. (2021)
Pumped hydro storage, energy	-	-	-	53100	55	Guerra et al. (2021)
Pumped hydro storage, power	0.77	1.0	0.782	1063320	55	Guerra et al. (2021)
Hydrogen storage, surface tank	4.0	-	-	2700	30	IEA (2019)[6]
Electrolysis	1.5	-	0.74	450000	20	IEA (2019)[7]
Hydrogen storage, compressor	4.0	-	0.05[8]	5903[9]	15	Stöckl et al. (2021)
Fuel cell	5.0	-	0.5	800000	10	DEA (2022c)
Methanation	3.0	-	0.78[10]	480580[11]	20	Agora Energiewende (2018)
Heat pump [12]	0.1	3.12	2.85 [13]	700000	20	DEA (2022b)
CO_2 storage tank	1.0	-	-	2528[14]	25	Lauri et al. (2014)
Direct air capture	4.95	-	(heat: 1.5, el.: 0.28)[15]	4000000[16]	20	DEA (2022a)

[0] In this table all energy values related to a fuel refer to the lower heating value (LHV).
[1] PyPSA assumption: a negligible marginal cost to avoid wasting solar energy in storage cycling.
[2] Derived from Lazard (2019) with USD-EUR parity, average cost case of 121 $/kW-y and scaled to the CAPEX of note [4].
[3] It includes fissile material, low cost case of Lazard (2019).
[4] Derived by formula 2 with overnight capital cost estimate of IEA-NetZero 2050, 4500 €/kW, interest rate 8%, and assuming 7 years construction time.
[5] It does not include fuel cost; in this model the OCGT is multi-fuel and fuel costs are accounted separately either from primary sources such as fossil or biogenic gas, or secondary sources such as electro-methane.
[6] Pag. 7 case "export terminal" and USD-EUR parity.
[7] Pag. 3 column "Long Term", USD-EUR parity; for the 20y lifetime the underling assumption is a stack lifetime of 10^5 hours and 5000/y of full load equivalent hours per year.
[8] Electricity input for compression in MWh_{el}/MWh_{H_2}.
[9] Investment per MW_{H_2} from the example in Table SI.4 of Stöckl et al. (2021), a CAPEX of 40,528 € for a compressed flow of 206 kg_{H_2}/h.
[10] Methanation efficiency wrt hydrogen, MWh_{CH_4}/MWh_{H_2}.
[11] €/MW_{CH_4}
[12] Industrial heat pump, medium temperature up to 125 °C.
[13] Coefficient of performance (COP), i.e. MWh_{th}/MWh_e.
[14] €/tCO_2.
[15] Heat efficiency 1.5 MWh/tCO_2 , electricity efficiency 0.28 MWh/tCO_2.
[16] €/tCO_2.

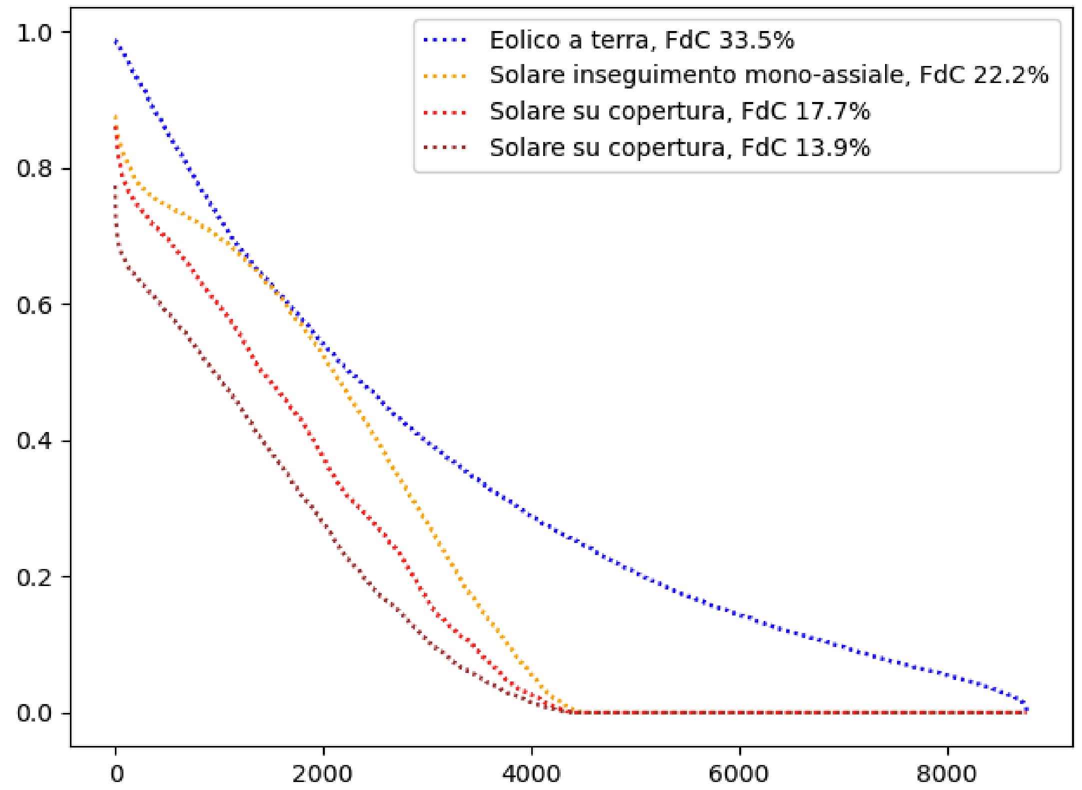

Figure 4:

4 Scenarios

We present 17 scenarios for the nuclear-sized district supplying baseload energy services in South Italy. As anticipated in Section 3, scenario results are very sensitive to the choice of the discount rate. Section 4.1 and 4.2 introduce eight scenarios each, with the difference that in the first set of scenarios the discount rate is constant among technologies and in the second set there are technology-specific discount rates. All these scenarios exclude biogenic gases which are assessed by a scenario described in Section 4.3.

4.1 Scenarios with technology-agnostic discount rate

We define eight scenarios where the discount rate is equal for all the technologies and set to 8%. In these scenarios we exclude bio-gases for reasons discussed in Section 4.3 where this constraint is lifted. We indicate as scenario A this set of assumptions. As will be detailed in Section XX, solving scenario A yields the dominance of GPV and onshore wind, and the following technologies are not activated for lack of competitiveness:

- rooftop solar;
- nuclear;
- Li-ion battery;
- fuel cell.

One of our research question is the system advantage of GPV versus rooftop solar. To assess this advantage we need to force the model to select rooftop solar. This is done in scenarios B and C where GPV is constrained to zero, and rooftop solar is allowed with high and low capacity factor, respectively. As motivated in Section 3, rooftop solar with high capacity factor refer to a best-case for this technology, unlikely to be representative of PV performances under a veto to GPV. Scenario C, solar rooftop with low capacity factor, is thus a more realistic scenario under a GPV veto. We remark that our hypotheses on rooftop solar with low capacity factor still include an optimistic bias, since we maintain the same PV cost parameter between the high and low capacity factor cases. We use this assumption in order to focus on the energy system advantage. In scenario D the only vetoed technology is onshore wind. As expected, in scenario D the dominant supply technologies becomes again GPV, and therefore to assess GPV vs rooftop solar under a veto on onshore wind we define two additional scenarios, E and F. In scenarios E and F both onshore wind and GPV are constrained to zero and solar rooftop is allowed similarly as in scenarios B and C. In scenario G all renewable sources are set to zero and thus the full decarbonization constraint leads to a 100% nuclear supply. In scenario H we constrain to zero onshore wind, GPV and nuclear. Rooftop solar is allowed with the low CF. This scenario assesses an extreme lack of social license for both nuclear and renewable technologies.

4.2 Scenarios with technology-specific discount rate

The scenarios A—H implicitly include a favorable assumption toward nuclear. Namely that the project risk among technologies is the same, and thus the technology-agnostic discount rate. The IEA report Bouckaert et al. (2021) differentiates between low project risk technologies such as onshore wind and GPV, and nuclear. This difference is relevant and realistic because of the widely recognized differences in project risk of these technologies, see e.g. Flyvbjerg (2017). We have included this enhanced realism in scenarios $\hat{A}$—$\hat{H}$ that inherit all the characteristics of the previously defined scenarios A—H but differ on the discount rate assumptions. In scenarios $\hat{A}$—$\hat{H}$ nuclear faces a discount rate of 8% and all the other technologies are assessed by a discount rate of 3.2%, as in Bouckaert et al. (2021).

4.3 Scenario with bio-gases

In the scenarios presented above the supply of biogenic gases is constrained to zero. This choice steams from the fact that scenario results vary widely on the amount of thermoelectric backup offered by OCGT. As detailed in the following section, scenarios where land-based renewables are vetoed do require a significant amount of long-term storage by synthetic methane. Allowing biogenic gases in these scenarios would yield a relevant role for these sources. These scenarios would be unlikely, since a veto to technologies with low or near-zero land impact such as onshore wind and GPV would naturally extend to the more land intensive bioenergies. Biogenic gases derived from agro-forestry residues and compatible with other socio-environmental and economic constraints would have a limited potential for the baseload supply of electricity and hydrogen, the focus of our model. In view of this, we explore the possible role of biogenic gases by a variant of the renewable scenario most parsimonious in terms of thermoelectric backup, which is scenario $\hat{A}$. We thus define a scenario $\hat{A}_{\beta}$ that inherits all characteristics of scenario $\hat{A}$ and relaxes the constraint on the zero availability of biogenic gases.

5 Results

per distinguere le tecnologie segue una mappa colori visivamente lineare come da indicazioni di Crameri et al. (2020).

Land use PV Bolinger and Bolinger (2022) updates Ong et al. (2013) ...24%... in Jacobson (2020)

Co-benifts of PV land use

PV LCA *Life-Cycle Assessment* (LCA) (Danelli and Brivio, 2021) ISO (ISO, 2006a,b) e linee guida IEA-PVPS (Raugei et al., 2021). Fthenakis and Leccisi (2021); Müller et al. (2021) e reportistica istituzionale come IEA (2022)

Un esempio classico di questi errori metodologici Ã¨ offerto dalla confutazione da parte di Zerrahn et al. (2018) delle stime di Sinn (2017) sull'accumulo per il settore elettrico tedesco.

Analysis of the shadow prices shows that the minimum cost configuration ensures the cost-revenue balance of each sub-system in the district Brown and Reichenberg (2021).

6 Conclusions

We have....

Figure 5: ....

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A – —-

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