Assessing the regional redistributive effect of renewable power production through a spot market algorithm simulator: the case of Italy

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Abstract

We develop an algorithm that simulates by iterative splitting the hourly equilibrium (price-quantity) of the Italian day-ahead market. The algorithm is employed to study the sensitivity of equilibria to changes in production from renewable units at different locations. We show that, when power markets are organised on zonal-basis with locational price signals and final buyers pay a unique price for the power bought in the day-ahead market, a larger renewable production decreases the average zonal prices, but the distribution of benefits largely depends on power plants' localisation. We analyse the impact of a larger renewable production on network congestion occurrence, zonal balance between demand and supply and zonal generation mix as well. We calculate the zonal substitution effects between renewable and non-renewable technologies, and within renewable technologies. Our analysis sheds some lights on the multiple consequences of energy transition policies and highlights the need of prioritizing over policies' objectives.

Keywords: electricity market, renewable sources, zonal merit order effect, substitution effect, congestion

1 Introduction

A strand of recent economic literature analyses the short run impact of increasing renewable production on wholesale electricity markets, notably the day-ahead, focusing on the "merit-order effect": a larger low marginal cost renewable supply is expected to reduce the average wholesale price thanks to the displacement of higher marginal cost technologies. In Europe, this effect has been acknowledged and measured in Spain (Gelabert et al., 2011), Ireland (O'Mahoney and Denny, 2011), Germany (Sensfuß et al., 2008; Wurzburg et al., 2013; Ketterer, 2014) and Italy (Clo et al., 2015). Outside Europe, similar estimations have been carried out in Australia (Cutler et al., 2011; Forrest and MacGill, 2013; Cludius et al., 2014; Csereklyei et al., 2019) and in the United States, in particular Texas, (Woo et al., 2011a), Pacific Northwest (Woo et al., 2013) and California (Woo et al., 2016). In a recent work, Bushnell and Novan (2018) present empirical evidence that the expansion of solar generation in California does not uniformly decrease the wholesale price: the change in the hourly average of the day-ahead price caused by marginally increasing daily utility-scale solar generation is indeed negative during the midday but it becomes positive during the mid-morning and early evening. The authors suggest that this result mostly depends on the abrupt fall of solar generation before the sunrise and after the sunset.

The works of Cullen (2013), Kaffine et al. (2013), Novan (2015), Callaway et al. (2017), Fell and Kaffine (2018) and Castro (2019) study, with an incremental degree of model sophistication, how the variation in the hourly level of renewable output affects fossil fuel generation and emissions level in several US power markets. Although these articles do not particularly focus on wholesale electricity prices, they highlight how renewable technologies, notably solar and wind, displace fossil fuel units with different level of efficiency. This result hinges on the heterogenous daily and seasonal production cycles of variable renewable technologies: wind units, which generate more during the nights and the winters tend to substitute the dirtiest production units, while solar units, most active during the day and the warm seasons displace mostly gas plants. The production cycle is therefore of utmost importance when estimating the substitution rate between renewable and traditional units.

Finally, another strand of empirical literature targets those power markets that are organised as two or more inter-connected sub-markets with locational pricing mechanisms (Woo et al., 2011b; Ardian et al., 2018; Figueiredo et al., 2015). In these papers, the authors quantify the impact of renewable production on the occurrence of congestion and on zonal price differences. It turns out that a larger renewable supply in usually importing zones tend to decrease the zonal price gaps but the contrary is true if the additional renewable supply is installed in already exporting zones. This literature accentuates the importance of renewable localisation in the assessment of consumers' benefits because the "merit order effect" may not occur as straightforwardly as it usually acknowledged in interconnected markets. Recently, Fell et al. (forthcoming) have studied how grid congestion negatively affects the environmental benefits of wind generation, revealing that the location channel is critical in assessing the environmental value of renewable energy.

The literature seems suggest that a correct assessment of renewables impact on electricity market functioning should take into account the generation source and its production cycle as well as the geographical localisation of the power plant. We aim at testing this claim with the help of a simulation tool called M.I.D.A.S. (Italian Day-Ahead Market Solver) developed for the Italian Power Exchange. Italy is an ideal case studies. It has reached its quota of 17% of renewables in final energy consumption in 2014 (6 years ahead of the 2020 horizon fixed in the 2009 Climate Package) thanks to a generous renewable support policy; Italy has an interconnected power market with zonal pricing; it has heterogeneous inter-zonal transmission capacities and zonal production capabilities depending on historical and geographical reasons; electricity prices have been higher than those in neighbouring countries because Italy has a generation mix strongly dependent on gas while nuclear has been phased out in 1990; last but not least, detailed hourly market data are publicly available. Other articles have been published on the Italian Power market although with very different focuses; see for instance Bigerna and Bollino (2014, 2015) on electricity demand, Bigerna et al. (2016a) on market power from congestion rent and Bigerna et al. (2016b) on how renewables affects market power in a congested network. We perform several simulations in order to study the sensitivity of the day-ahed market equilibria to changes in production from renewable power plants with a focus on wind and solar technologies.

We originally contribute to the literature in a number of ways. First, we trained M.I.D.A.S. on a four year period dataset (2015-2018) with hourly observations: the richness in data offers heterogeneity across years, zones and seasons and allows us to ensure the consistency of M.I.D.A.S. outputs. From a methodological point of view, we present an original market algorithm which, despite using a completely different optimising strategy closely mimics the original one and reproduces its equilibria in a very efficient way. Second, we isolate the market impact of different renewables, notably utility-scale wind and solar, but also smaller units bidding in the day-ahead market. Third, we analyse the zonal redistributive effect of renewables, often overlooked in the literature: this effect is generated by the fact that consumers pay for the electricity a weighted average of the zonal prices;[1] our approach allows not only to evaluate the effect of larger renewable production but also to appreciate the relevance of its localisation. Fourth, we do not limit our analysis to the price dimension (zonal and national) but we discuss the impact of a larger renewable supply on the zonal generation mix, network congestion and zonal balance between demand and supply, which are other important aspects of energy transition. We are in particular able to calculate the zonal substitution rates between renewables and non renewables technologies but also within renewables. From a policy point of view, we simulate those

[1]The article of Cludius et al. (2014) takes into account the distributional impact of the renewable target focusing on the allocation of costs and benefit across industries and residential customers.

production increases necessary to achieve the 2030 renewable targets established in the National Integrated Energy and Climate Plan;[2] we can therefore anticipate some of the consequences of national energy and climate policies.

The paper is organised as follows. Next section describes the Italian day-ahead market and its zonal configuration. Section 3 presents an overview of the data used in the analysis. Section 4 describes M.I.D.A.S. algorithm. Section 5 is dedicated to the analysis of simulations outcomes. The last section concludes by drawing some important policy implications.

2 Market overview

The Italian Power Exchange (henceforth IPEX) is managed by an independent market operator, Gestore dei Mercati Energetici (henceforth GME). The exchange of electricity is organised in a spot and a future markets. The spot market is divided in three sub-segments: the day-ahead market (henceforth MGP), the intra-day market (MI) and the balancing market (MSD). The focus of our study is the MGP which represents the main component of the IPEX and whose liquidity attained 72% in 2019 (GME, 2019). The MGP is organised in 24 hourly sessions and it operates in the form of uniform price auction. Market participants submit a quantity-price pair for each hour: all the requests are ranked according to the merit order rule, from the cheapest to the most expensive in the case of offers and vice-versa for bids. The market price is obtained at the crossing of the market supply and demand curves. The market has a zonal functioning as well. The geographic layout is depicted in Figure 1.

[2]The plan is available here.

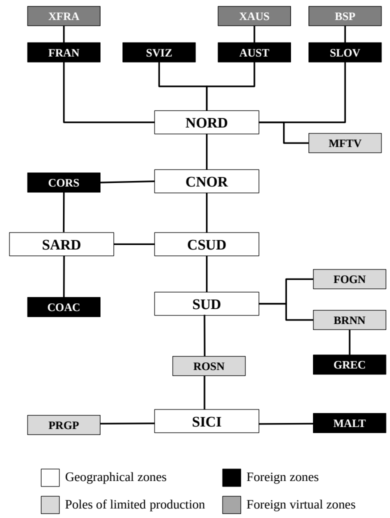


Figure 1: Italian stylised electricity network
Source: Terna

There are 22 zones, grouped into 4 types:

- National geographical zones (6 zones): NORD (North), CNOR (Centre-North), CSUD (Centre-South), SARD (Sardinia), SUD (South), SICI (Sicily)
- Poles of limited production with no withdrawal points (5 zones): MFTV (Monfalcone), FOGN (Foggia), BRNN (Brindisi), ROSN (Rossano), PRGP (Priolo)
- Foreign zones (8 zones): FRAN (France), SVIZ (Switzerland), AUST (Austria), SLOV (Slovenia), CORS (Corse), COAC (Corse), GREC (Greece), MALT (Malta)
- Foreign virtual zones in market coupling (3 zones): XFRA (France), XAUS (Austria)[3], BSP (Slovenia)

[3]The foreign virtual zones of XFRA and XAUS are in market coupling since the 25th of February of 2015.

Before the 25th of February 2015, the Italian network enjoyed tree topology; after this date a "ring" has been created between the central zones CNOR - CSUD - SARD - CORS - CNOR.[4] If the equilibrium resulting from the hourly auction respects the transmission constraints between regions a single price emerges. If, on the contrary, a constraint is saturated the geographical market is split in two: an upstream and a downstream markets. The auction is repeated on the two sub-markets, taking into account the flows between regions to the upper bound of transmission capacity, and two zonal prices result. The splitting procedure is iterated until all inter-zonal constraints are fulfilled. It is important to note that while the producers receive the zonal prices when the splitting occurs, Italian buyers pay the Unique National Price (henceforth PUN) for the power bought in the pool which is an average of national zonal prices weighted for the zonal purchases and netted of purchases from pumped-storage units and from foreign zones.[5]

Table 1 reports the statistics for the occurrence of dezoning between 2015 and 2018 with absolute and relative frequencies in the national territory. We immediately remark a constant reduction in the incidence of splitting. Comparing 2015 and 2018 we notice a considerable increase in the number of hours without congestion and the disappearance of the six zonal configuration in 2018, after a peak in 2017. The equi-

[4]The national transmission network has 25 lines for foreign interconnections: 4 with France, 12 with Switzerland, 2 with Austria, 2 with Slovenia, 2 direct current connections (a cable connection with Greece and a dual connection, called the "SACOI" interconnection, between Corsica, Italy and Sardinia), a further alternating current cable between Sardinia and Corsica, and a 220 kV submarine and overland cable connection between Italy and Malta (Source: Terna).

[5]The difference between the purchasing value and the selling value of exchanged volumes is covered with an hourly fee called fee for assignment of rights of use of transmission capacity (CCT); for injection schedules and withdrawal schedules (only if the withdrawal schedules refer to mixed points or withdrawal points belonging to neighbouring countries' Virtual Zones), this fee is equal, for each hour, to the product between: 1) the difference between the National Single Price and the Zonal Price of the Zone where the dispatching points are located; 2) the forward electricity account schedule resulting from the Day-Ahead Market (MGP).

librium with two zones remains nonetheless the most likely, followed by the unique and the three zonal one. Given the physical difficulties in connecting to the mainland, the most common two zonal grouping implies SICI being separated from the rest of the country very often with PRGP; the separation of the other island, SARD, has been significantly less frequent.[6]

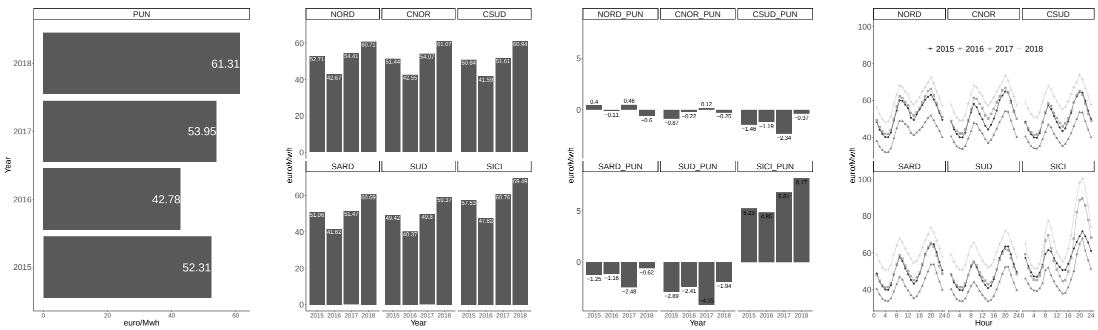
ZONES	h 2015	% 2015	h 2016	% 2016	h 2017	% 2017	h 2018	% 2018
1	978	11.16	1741	19.82	2577	29.42	3353	38.28
2	4856	55.43	4453	50.69	4113	46.95	3927	44.83
3	2319	26.47	2178	24.80	1774	20.25	1268	14.47
4	559	6.38	377	4.29	277	3.16	200	2.28
5	46	0.53	34	0.39	16	0.18	12	0.14
6	2	0.02	1	0.01	3	0.03	0	0.00
TOT	8760	100	8784	100	8760	100	8760	100

Table 1: Occurrence of congestion, 2015-2018
Source: Authors' elaboration on GME data
Note: 2016 is a leap year

The evolution of the average PUN and zonal prices between 2015 and 2018 are depicted in Figures 2a and 2b. We remark that after a fall in 2016 prices have steadily risen such that the 2018 average PUN is about 9 euro/Mwh higher compared to 2015. Looking closely at the average zonal prices at the beginning and at the end of the period, we note that NORD has experienced the smaller increase (8 euro/Mwh) as opposed to SICI (12 euro/Mwh). Figure 2d shows the differential between the zonal and the unique price over the 4 year period. We observe that NORD and CNOR prices tend to be in line with PUN. CSUD, SARD and SUD have always a negative differential, while SICI continues to have positive differentials. If we take a closer look at the hourly average prices (Figure 2d), we see that the prices have shifted downward in 2016 to come back at 2015 levels in 2017. They have again increased in 2018. The hourly pattern appears to be stable in all regions with the exception

[6] As example in 2018, SICI has been separated from the mainland in around 7% of hours alone in and 46% of the time with PRGP; SARD has been separated about 1% of hours.

of SICI. Here we remark that in 2017 prices tend to be much higher than in 2015 between 8 and 10 a.m. and after 4 p.m., while the reverse is true during the remaining hours.



(a) Average PUN

(b) Average zonal prices

(c) Av. zonal prices minus av. PUN

(d) Average hourly zonal prices

Figure 2: Evolution of prices, 2015-2018
Source: Authors' elaboration on GME data

3 Data

The training dataset for our algorithm is built on the information on hourly bids and offers on the Italian day-ahead market, publicly available on GME website. The data from 2015 to 2018 consists in more than 80 million observations; for each observation, we store 12 variables.[7] In order to perform the simulations, we merged GME and REF-E[8]databases. The latter contains information about the generation technology of a unit. The variables and their description are presented in Table 2.

[7]For the three zones in market coupling, XFRA, XAUS and BSP, the GME only provides the hourly net imported or exported quantity not the detailed list of offers and bids. These quantities will be classified in the training dataset as additional bids at price cap (for exports) and additional offers at zero (for imports)

[8]REF-E is an Italian consulting company specialised on energy markets (Website).

Variable	Description
unit_reference	power plant/withdrawal point identification number
operator	operator name
zone	the zone in which the point is located[a]
interval	the hour (0-24)
date	the date (YYYYMMDD)
purpose	a binary variable indicating if the observation is an offer (1) or a bid (0)
status	a binary variable indicating if the offer/bid has been accepted (1) or rejected (0)
sub_price	the submitted price
sub_quantity	the submitted quantity
aw_price	the awarded price
aw_quantity	the awarded quantity
bilateral	a binary variable indicating if the offer/bid comes after a bilateral transaction (1) or not (0)

Variable	Type	Name	Description
tech	Demand	Consumption	Consumption Unit
	RES	HydroM	Hydroelectric (Mixed)
		HydroRi	Hydroelectric (Run-of-river)
		HydroPo	Hydroelectric with Pond
		HydroRe	Hydroelectric with Reservoir[b]
		Wind	
		SmRES	Renewables with power $<$ 10 MVA
		Solar	
		Biomass	
		Geothermal	
		CHP	Combined heat and power[c]
	NRES	CCGT	Combined cycle gas turbine
		OCGT	Open cycle gas turbine[d]
		Coal	
		ConvSt	Conventional steam generation[e]
		Pumping	Mixed consumption/production units
	Other	Import	Foreign units
		Unknown	Unknown technology

Table 2: Variables set

[a] Each unit can place offers/bids only in the zone to which the point belongs.
[b] Hydroelectric power plants are classified according to the time needed to fill their reservoirs in a descending order of time: units with reservoirs take 400 hours or more; units with ponds take between 2 and 400 hours; run-of-river units take less than 2 hours. Mixed hydroelectric refers to a particular type of power plants called “Asta”, where the same water is exploited several times by making it passing through various hydroelectric plants placed at lower and lower altitudes where the morphology of the territory does not make it possible or convenient to have a single big jump. In the Italian Alps it is easy to find situations in which the same water has passed from 4 or 5 different hydroelectric plants before reaching the Po river.
[c] In Italy this technology is assimilated to renewables.
[d] OCGT technology includes turbogas units.
[e] To be conservative, mixed gas units are included in this category.

Table 3 reports the summary statistics for consumption and production units participating in the day-ahead market between 2015 and 2018. We remark a slight reduction in the number of suppliers all along the period not completely compensated by the rise in the number of consumption units. More than 90% of the 1561 production units participating to the market in 2018 are located in the national territory (1396 units are in the 6 geographical zones and 45 in the poles of limited production for a total of 1414 units; the remaining 147 units are located in the foreign zones). Merging GME and REF-E databases, we notice that the number of production units whose technology is unknown increases over the years, however at its peak in 2018, the production of these units represents 3.5% of the submitted quantity.[9] We can therefore ensure that our final database consistently represent Italian generation mix.

Year	**2015**		**2016**		**2017**		**2018**	
	Units	**Twh**	**Units**	**Twh**	**Units**	**Twh**	**Units**	**Twh**
Consumption	909	303	953	299	951	296	926	301
Production	1642	483	1594	484	1546	468	1561	484
known	1631	483	1564	482	1495	461	1475	467
	(99.3%)	(100%)	(98.1%)	(99.6%)	(96.7%)	(98.5%)	(94.5%)	(96.5%)
unknown	11	0	30	2	51	7	86	17
	(0.7%)	(0%)	(1.9%)	(0.4%)	(3.3%)	(1.5%)	(5.5%)	(3.5%)
Total	2551	787	2547	783	2497	763	2487	785

Table 3: Number of units and submitted quantity, 2015-2018
Source: Authors' elaboration on GME and REF-E data

The starting point for the simulations is the last year of observation, the 2018. We provide in the next sections some key figures on zonal participation and generation mix.

3.1 Geographical and technological breakdown

The share of accepted quantities by zone and type (demand/supply) is shown in Figure 3. We observe that more than half of total demand and almost half of total supply are located in NORD, while the other national regions represent between 3% and 15% of the market. SVIZ is the only foreign zone with a relevant share of accepted supply (around 8%) while COAC, MALT and CORS are importers in 2018. The poles of

[9] This figure lowers to 2.7% of the accepted quantity.

limited production (ROSN, BRNN, FOGN and PRGP, in order of importance) provide additional supply. Figures for submitted quantities are very similar.

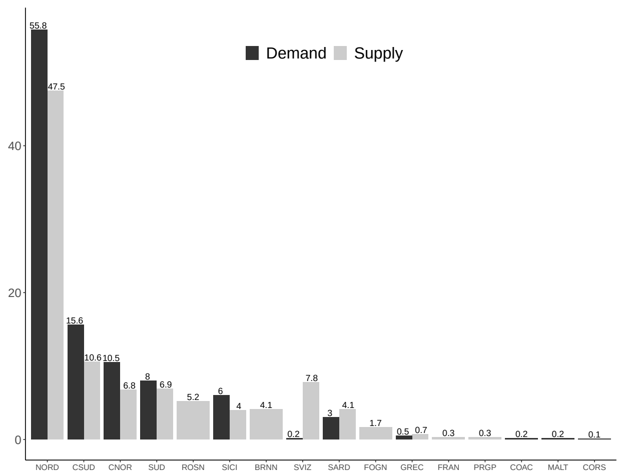
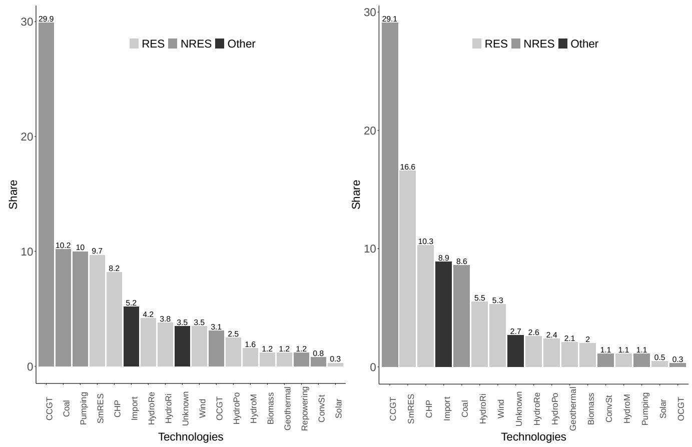


Figure 3: Share of accepted quantity by zone and type, 2018
Source: Authors' elaboration on GME data

Figures 4a and 4b present the share of submitted and accepted quantities by technology.[10] CCGT units provides about 30% of the electricity sold in the market, while Small RES are the second most important source of supply (16% of accepted quantity), followed by CHP (10%), Import and Coal (both about 9%), HydroRi and Wind (both about 5%); the other sources are marginal. The quantity provided by the unknown units represents the 2.7% of the accepted quantity. Overall, almost half of the accepted quantity comes from renewable sources, while available supply is largely represented by non renewable production.

[10]A detailed analysis of units bidding behaviours reveals that renewable power plants submit more offers compared to non renewable ones; however these offers are generally associated to smaller quantities. For our study, we decided to focus on quantities, instead of number of offers, as this variable allows a more correct comparison across technologies.

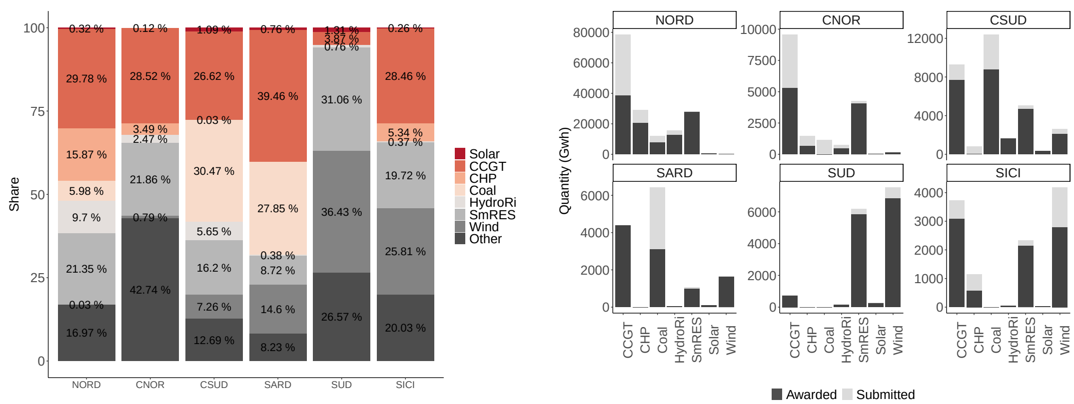


(a) Submitted quantity **(b)** Accepted quantity

Figure 4: Technological breakdown of supply, 2018
Source: Authors' elaboration on GME and REF-E data

3.2 Zonal analysis

We restrict our attention to the 6 most accepted technologies, CCGT, Small RES, CHP, Coal, HydroRi, Wind, plus Solar, and to the 6 geographical zones, NORD, CNOR, CSUD, SARD, SUD and SICI. Figure 5a shows the share of zonal accepted quantities by technology and zone. In NORD, the largest share of the electricity is provided by CCGT units, followed by SmRES, CHP and HydroRi units; Wind generation is marginal. In CNOR "Other" technologies largely contribute to the mix, thanks in particular to Geothermal production, which is concentrated in this zone. CCGT and SmRES follows; Wind production is very modest. In CSUD, Coal units provide a third of the accepted quantities, CCGT slightly less, followed by SmRES and Wind (around 16% and 7% of the accepted quantity). CCGT represents more than 40% of the accepted quantity in SARD, Coal maintains the second place, followed by Wind (about 15% of the mix). The case is striking in SUD where Wind and SmRES provide more than 60% of electricity, whereas CCGT is marginal. Finally, in SICI, CCGT, SmRES and Wind contribute with similar shares in the generation mix. Solar production is very limited in our data and it represents less than 1.5% of the accepted quantity. In percentage terms, SUD and SICI have a more decarbonised mix, SARD and CSUD heavily rely on fossil fuels (gas and coal), CNOR and NORD have an intermediate position.[11]



(a) Awarded quantities (%)

(b) Awarded and submitted quantities (Gwh)

Figure 5: Zonal generation mix, 2018
Source: Authors' elaboration on GME and REF-E data

The annual submitted and accepted quantities by technology and zone in absolute terms are shown in Figure 5b. In NORD, about 40 thousands Gwh per year are provided by CCGT, 27 thousands by SmRES, 20 thousands by CHP and about 12 thousands by HydroRi. In CNOR, GGCT units supply 5 thousand Gwh annually and SmRES around 4 thousands. Coal provides 8 thousand Gwh of electricity in CSUD. Both sources are extremely important in SARD generation mix providing about 4 thousand Gwh (CCGT) and 3 thousand Gwh (Coal) annually. In SUD, Wind and SmRES units generate between 5 and 6 thousand Gwh. In SICI, CCGT, SmRES and

[11] There are no CHP units in SARD and CSUD and no Coal units in SUD and SICI.

Wind provides between 2 and 3 thousand Gwh. The largest figures for Solar are in NORD (400 Gwh), CSUD (300 Gwh) and SUD (250 Gwh).

According to the official statistics (GSE, 2019), Wind production has reached 17.7 Twh in 2018, a figure which is pretty closed to the submitted quantity in our database, 16.135 Twh. Solar units have supplied 22.7 Twh in 2018, a quantity which is quite far from that identified in our database, 2.14 Twh. The reason may be that the 90% of solar production in Italy comes from small units which are included in the SmRES technology. The submitted quantity of these power plants has totalled 45 Twh in 2018 in our data. To overcome this limitation, we will consider Solar and SmRES supply together in the simulations.

4 M.I.D.A.S. algorithm

The algorithm which solves the Italian day-ahead market by calculating the zonal prices, the PUN, the quantities and the transits between zones for each hour is proprietary and managed by GME.[12] Theoretically, the optimisation problem consists in finding the hourly uniform price that maximises system welfare under constraints. However in practice, the Uniform Purchase Price Optimisation (UPPO) search procedure used by GME relies on heuristics: the idea behind this method is to set the uniform price at some level and repeatedly apply the UPPO search procedure to possibly find a better solution which satisfies the constraints.

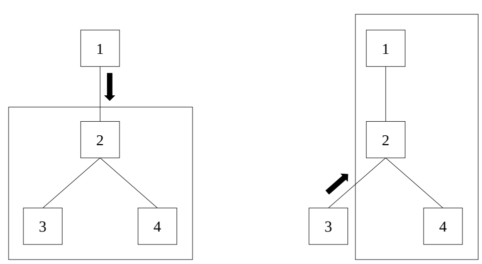
In order to study the impact of a larger renewable supply on market functioning, we have implemented an alternative algorithm to solve the market, which is called M.I.D.A.S. (Italian Day-Ahead Market Solver); M.I.D.A.S. reproduces the iterative

[12] For more details about GME algorithm see the online technical documentations and Tribbia (2015).

market splitting logic to find the hourly equilibrium. The algorithm is written in C++ and it is trained using 2015-2018 real data;[13] the output is managed in R. The input data for each date/hour pair are:

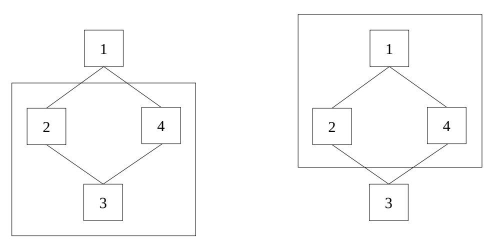
1. Hourly transmission limits across zones
2. The network scheme with links
3. Price/quantity pair for each bid/offer
4. The import/export quantity resulting from the coupling auction

We needed to introduce two random elements in our algorithm; the first is due to the different logic behind M.I.D.A.S. compared to the GME algorithm, the second depends on incomplete information concerning the real algorithm. On the first point, it should be noted that, since M.I.D.A.S. consists in an iterative splitting procedure, a starting node must be selected: the consequence of this choice is represented in a simplified setting in Figure 6.



(a) From a northern node **(b)** From a southern node

Figure 6: First random element



(a) A possible grouping **(b)** An alternative grouping

Figure 7: Second random element

In panel (a) the algorithm starts from node 1, in panel (b) from node 3. If these two nodes export power, saturating the transmission link with their closest neighbour, two

[13] More details about the algorithm are available in the Appendix.

different de-zonings emerge: in the first case the upstream market consists in node 1, while the downstream market includes the nodes 2, 3 and 4; in the second case the upstream market regroups nodes 1, 2 and 4, while the downstream market counts the node 3 alone. Since the choice of the starting node may determine the emergence of different congestion patterns and zonal groupings, this decision is submitted at random and every outer node has the same probability to be select at each round.

The second element of randomness is introduced to overcome the lack of information concerning the splitting rule used by GME in presence of a loop, notably in the centre of the Italian network (CNOR-CSUD-SARD-CORS-CNOR). The splitting rule may determine again different congestion patterns/zonal grouping as shown in Figure 7. This decision is again submitted at random.

M.I.D.A.S. can be iterated multiple times and in each run it may find a solution. In our simulations we run the algorithm 10 times, which we consider a good compromise between precision (the larger the number of iterations, the more likely the exact solution is found) and time (with 10 iterations the algorithm solves all the hourly equilibria for a whole year in about 1 minute). When multiple solutions are found, we select the one that is associated to the largest social welfare defined as:

$$W = \sum_{b \in B} p_b q_b - \sum_{o \in O} p_o q_o \qquad (1)$$

where p and q stand for prices and quantities and B and O stand for bids and offers. Only the national geographical zones are taken into account in the welfare function, as suggested in GME support documents.[14]

As a measure of performance, we report in Table 4 the statistics on the amplitude

[14] Our selection rule is not optimal since the algorithm often "finds" the real solution but does not select it on the basis of welfare. However, we were not able to define a more objective rule.

of the differences (in absolute value) between hourly zonal real and simulated prices. In our reference year (2018), M.I.D.A.S. finds the 95.39% of zonal hourly prices with an error inferior to 1 €; the 2018 mean error for hourly prices is 0.44 euro. M.I.D.AS. reproduces very closely the daily price cycle (see Figure 1 in the Appendix). If we consider the average annual prices (Table 5), the performances are very satisfying with differences of some centimes. In Table 6 we compare the frequency of real and simulated congestion occurrence in 2018, which are very closed. M.I.D.A.S tends to slightly under-estimate the occurrence of the 2 zonal configuration in favour of the 4, 5 and 6 ones.

Diff in €	% 2015	% 2016	% 2017	% 2018
< 0.01	85.509	78.081	81.016	85.210
< 0.1	87.350	81.547	84.027	88.394
< 1	91.717	90.063	92.048	95.390
< 5	95.507	95.802	96.761	98.318
< 10	97.313	97.466	98.159	99.105
< 15	98.155	98.138	98.692	99.401
< 50	99.753	99.457	99.606	99.851
< 100	99.978	99.921	99.917	99.981

Table 4: Hourly prices differences

Price	Simul	True
NORD	60.76	60.71
CNOR	61.34	61.07
CSUD	60.89	60.94
SARD	60.48	60.69
SUD	59.27	59.37
SICI	69.40	69.49
PUN	61.34	61.31

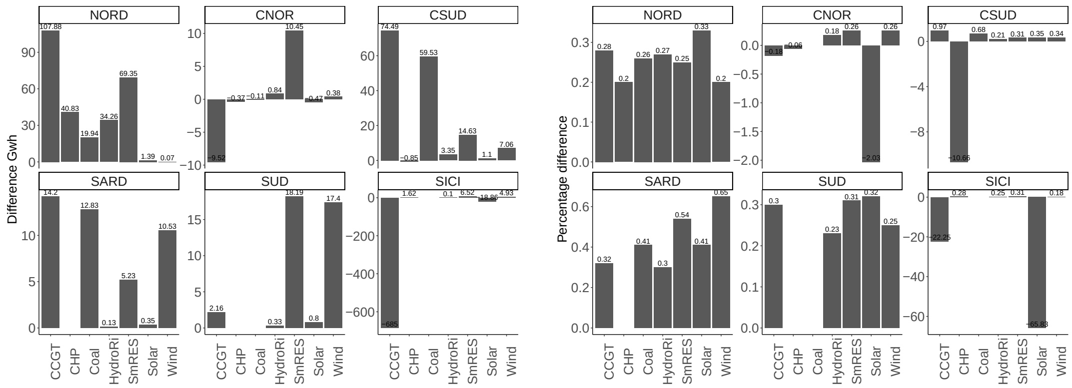
Table 5: Average prices

Zones	Simul	True
1	38.40	38.28
2	43.02	44.83
3	14.87	14.47
4	3.45	2.28
5	0.25	0.14
6	0.01	0.00

Table 6: Congestion occurrence

We report in Figures 8a and 8b the yearly difference between real and simulated awarded quantities by technology and zone in absolute and percentage terms respectively. We remark that the simulated quantity tends to be inferior to the real one in most cases with percentage differences that, overall, are negligible (between 0.2 and 1%). The 5 exceptions are CCGT and Solar in CNOR and SICI, and CHP in CSUD, where negative differences appear. In SICI the algorithm markedly over-accepts CCGT and Solar production with respect to real equilibria.[15]

[15] In Figure 8b the percentage difference for Coal in CNOR is not reported because in the real data, Coal is never accepted in this region (the denominator in our formula is zero).



(a) Absolute values (Gwh)

(b) Percentage

Figure 8: Difference between real and simulated awarded quantities, 2018

5 Simulations

We perform two sets of simulations: the first considers equal increases of renewable supply in all zones (Uniform type), while the second achieves the same national total increment by concentrating the additional production in specific zones (Heterogenous type). According to the National Integrated Energy and Climate Plan published at the beginning of 2020, Italy wants to reach a target of 73.1 Twh produced with solar power plants and 41.5 TWh with wind at the 2030 horizon, which represents an increase of 50.5 and 23.8 Twh for solar and wind production respectively. These targets are used as reference range for our simulations. Annual national submitted production in our database for the 7 considered technologies and the 6 national geographical zones is around 250 Twh: we simulate therefore a 1% (2.5 Thw), 5% (12.5 Twh), 10% (25 Twh) and 20% (50 Twh) increases in national production which may come alternatively from Wind or Solar/SmRES[16] generation. Given that increasing the supply

[16]We decide to simulate the combined effect of these technologies even if the results may overestimate the impact of Solar, given than SmRES label may include other generating technologies with small capacity.

should in principle always reduce the price regardless to the generating technology, we also provide a benchmark scenario in which the increment in production comes from CCGT power plants. The 7 considered scenarios and their abbreviations are summarised in Table 7. The impact on average prices and accepted quantities are illustrated in sections 5.1 and 5.2 (uniform and heterogenous increase respectively), the consequences on congestion and export/import balance are discussed in section 5.3.

Scenarios	Definition	Type
UG	Uniform increase in CCGT	Uniform
UW	Uniform increase in Wind	Uniform
US	Uniform increase in Solar and SmRES	Uniform
DW	Increase in Wind in SARD, SUD, SICI	Heterogenous
DDW	Increase in Wind in NORD, CNOR, CSUD	Heterogenous
DS	Increase in Solar and SmRES in SARD, SUD, SICI	Heterogenous
DDS	Increase in Solar and SmRES in NORD, CNOR, CSUD	Heterogenous

Table 7: Scenarios

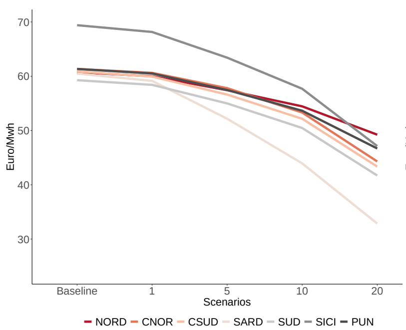
5.1 Uniform increase

In uniform simulations, the total increase in production is equally distributed in the six geographical zones; the 1% national increase corresponds to an additional 0.4 Twh of regional production, a 5% increase to 2.1 Twh, a 10% to 4.2 Twh and a 20% to 8.5 Twh. The baseline scenario is the equilibrium resulting from simulations with real submitted quantities. Figures 9a, 9b and 9c show the average price effect of these increments on zonal and unique prices when the additional production comes from Wind (UW scenario), Solar/SmRES (US scenario) and CCGT (UG scenario) units respectively.[17] We observe that the average PUN decreases more when the additional supply is provided by renewables compared to CCGT: for a 20% in-

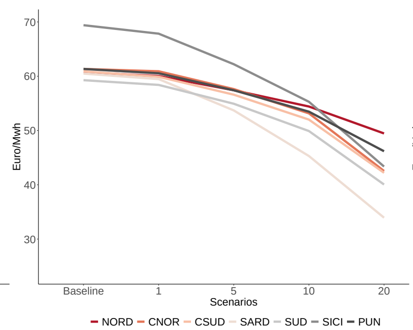
We prefer this solution given the small amount of Solar supplied in our database.

[17]Detailed results are reported in the Appendix in Tables 1 for CCGT, 2 for Wind and 3 for Solar/SmRES.

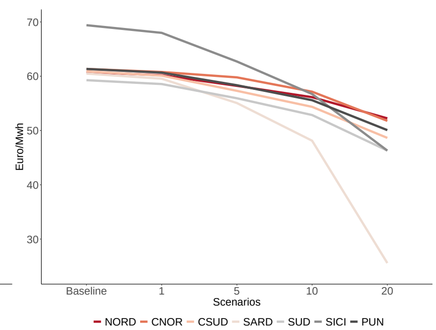
crease in production, PUN lowers to 46.69 €/Mwh with Wind and to 46.18 €/Mwh with Solar/SmRES, while it remains as high as 50.07 €/Mwh with CCGT. PUN trajectories are very similar for the two considered renewable technologies, however Solar/SmRES allow to achieve a slightly lower PUN compared to Wind for all considered percentages but the 1% increase. As far as zonal prices are concerned, we notice that SARD and SICI experience the largest price decrease, regardless to the technology. For a 20% increase in supply, CNOR, CSUD, SUD and SICI attain the lowest price with Solar/SmRES, NORD with Wind and SARD with CCGT.



(a) UW Scenario



(b) US Scenario



(c) UG Scenario

Figure 9: Uniform simulations

To disentangle the effect on prices, we have calculated for each region the additional accepted quantities in the UW and US scenarios (in Gwh and as % of additional submitted quantity), focusing on the 20% increase.[18] Overall, for the same additional submitted quantity, the total accepted supply is larger for Solar/SmRES than for Wind which can explain why in the US scenario the PUN tends to decrease slightly more compared to the UW scenario. Moreover, we observe that the incremental Wind supply in the UW scenario and the incremental SmRES and Solar supply in the US

[18] Accepted quantities and rates are reported in Table 8 in the Appendix.

scenario have higher acceptance rates in CNOR and NORD compared to the other regions.

Concerning technologies, we remark that in all simulations if the submitted quantity from a specific source is raised, the accepted quantity increase as well.[19] Although total accepted supply tends to increase, a substitution effect emerges between renewables and non renewables sources but also within renewables sources. We report in Table 8 the substitution rates, calculated as the unit variation in the regional accepted quantity by technology, following a Gwh increase of regional Wind production in the UW scenario and of Solar/SmRES in the US scenario (we consider again the 20% increase).[20]

UW							
	HydroRi	CCGT	Wind	CHP	SmRES	Coal	Solar
NORD	**-0.040**	**-0.817**		**-0.331**	**-0.149**	-0.218	**-0.003**
CNOR	-0.002	-0.179		-0.001	-0.028	0.000	-0.002
CSUD	-0.005	-0.308		-0.001	-0.078	**-0.688**	-0.002
SARD	0.000	-0.054			-0.030	-0.101	-0.001
SUD	0.000	-0.012			-0.113		**-0.003**
SICI	0.000	-0.129		-0.034	-0.048		-0.001

US							
ZONE	HydroRi	CCGT	Wind	CHP	SmRES	Coal	Solar
NORD	**-0.054**	**-0.927**	0.000	**-0.374**		-0.228	
CNOR	-0.002	-0.257	0.000	-0.001		0.000	
CSUD	-0.003	-0.354	-0.033	-0.001		**-0.642**	
SARD	-0.001	-0.043	-0.041			-0.081	
SUD	0.000	-0.015	**-0.164**				
SICI	0.000	-0.122	-0.067	-0.021			

Table 8: Substitution rates (UW and US scenarios)

Despite an evident heterogeneity across regions, the substitution between renewables and non renewables (CCGT and Coal) appears to have a larger magnitude com-

[19] Detailed zonal results are shown in the Appendix (Figures 2 to 7). The only two exceptions are Solar accepted quantity in CNOR in the US scenario (which slightly decreases from the 10% increase in supply) and CCGT in NORD in the UG scenario. An in depth analysis of price bidding behaviours of units reveals that a likely reason for these results is that a closed substitute source of supply, which has been increased in the same simulation, is less expensive: for Solar it is the case of SmRES in the same region, CNOR; for CCGT it is import of gas from CNOR.

[20] The substitution effects are calculated as $\frac{\Delta q_{in}}{\Delta q_{jn}}$ where $i =$HydroRi, CCGT, CHP, Coal, SmRES and Solar, j=Wind, $n =$NORD, CNOR, CSUD, SARD, SUD, SICI in the UW scenario and as $\frac{\Delta q_{in}}{\Delta q_{jn}}$ where $i =$HydroRi, CCGT, CHP, Coal, Wind and j=Solar+SmRES in the US scenario. It is worthy to note that this formulation does not allow to take into account possible cross-zonal effects.

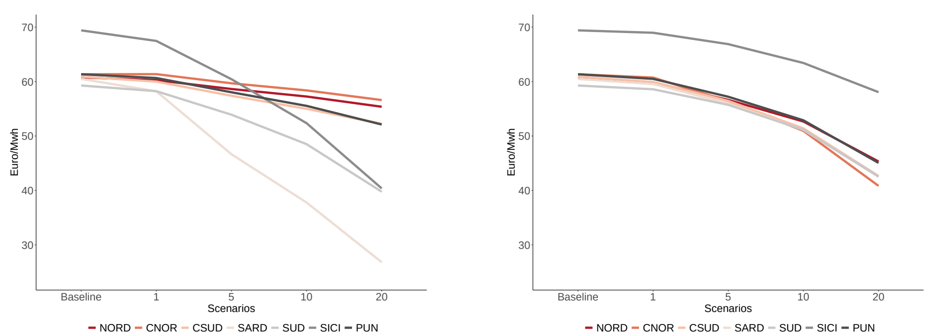
pared to the substitution within renewables; overall, within the group of renewable sources, Wind and SmRES are the more closest substitute. The largest effect for CCGT is registered in NORD: here 1 Gwh of additional Wind (Solar/SmRES) production replaces 0.8 Gwh (0.9 Gwh) of CCGT. For Coal, the substitutions are more important in CSUD, where 1 Gwh of additional Wind and Solar/SmRES production replaces about 0.6 Gwh of this polluting source. These results are totally in line with the fact that CCGT production dominates the generation mix in NORD, while the same is true for Coal in CSUD. For CHP and Hydro, the substitutions are more important in NORD, where 1 Gwh of additional Wind and Solar/SmRES production replaces about 0.3 Gwh of CHP and about 0.04-0.05 Gwh of Hydro (CHP and Hydro are the third and fourth sources of power in NORD mix). Substitutions between Wind and SmRES are more important in NORD and SUD (around -0,1 Gwh), where this source is second in the zonal generation mix; substitution effect in the whole peninsula are in the range of -0.03 to -0.1. Solar substitution effects are much smaller, between 0.001 and 0.003; the maximum is again attained in NORD and SUD. Finally, Solar/SmRES replaces Wind with rates between -0.03 and -0.1; the maximum is attained again in SUD where Wind represent the first source of power, while in NORD and CNOR these effects are null.

5.2 Heterogenous increase

In heterogenous simulations, we divide the 6 geographical zones in two groups, the Northern zones (NORD, CNOR, CSUD) and the Southern zones (SARD, SUD, SICI), and we consider the effect on market equilibria of concentrating the new renewable production in a specific group. The total increment at the national scale is the same as in previous simulations, but here, where the supply rises, the 1% national increase corresponds to an additional 0.8 Twh of regional production, a 5% increase to 4.2 Twh, a 10% to 8.4 Twh and a 20% to 16.8 Twh. The baseline scenario is always the equilibrium resulting from simulations with real submitted quantities.

5.2.1 Wind generation

Figures 10a and 10b depict the average price effect of these increments when the additional production comes from Wind and it is localised in the Southern (DW scenario) or in the Northern (DDW scenario) zones respectively.[21] We start by increasing Wind supply in the Southern zones (panel a). This choice stems from the fact that SUD and SICI have already the largest Wind production and Wind potential in SARD may be higher compared to the other regions given its favourable geographical localisation. As expected, the average zonal prices decrease more in SARD, SUD and SICI compared to the uniform case, but the other zones benefit from lower prices as well. PUN however decreases less than in the uniform case: for the maximum considered increase it remains at 52.11 €/Mwh (in the UW scenario it reached 46.69 €/Mwh).



(a) DW Scenario

(b) DDW Scenario

Figure 10: Heterogenous simulations, Wind

[21] Detailed results are reported in the Appendix in Tables 4 and 5 for DW and DDW scenarios respectively.

When the additional production is concentrated in NORD, CNOR and CSUD (panel b), these zones benefit from lower average prices than previous case and uniform case as well; the reverse is true for the zones without increment. The average zonal prices tend to converge in all regions but SICI, which maintains a spread of about 13 €/Mwh. PUN, however, decreases more than all previous simulations, attaining 45.06 €/Mwh for the 20% increase; this effect is likely due to the fact that the Northern zones have the largest demand (recall that PUN is an average weighted by zonal quantities) and that the additional renewable production has higher acceptance rates in NORD, CNOR and CSUD.[22] We can therefore say that, for the same increase in Wind production, consumers are better off when the additional supply is concentrated in NORD, CNOR and CSUD. This result is very important since it is in open contradiction both with the present reality (Wind is mostly installed in SUD and SICI) and with all considerations about potential (which would suggest to favour the island SARD for new installations). It is worthy to note that SARD registers the largest zonal merit order effect (-33.67 €/Mwh) when its local Wind supply increases by 20% in the DW scenario.

In DW scenario, Wind accepted quantities increase only in SARD, SUD and SICI, while all other accepted quantities decrease, included renewables in the same regions or not. Similarly in DDW scenario Wind accepted quantities rise only in NORD, CNOR and CSUD and all other quantities decrease.[23]

[22] We report in Table 9 in the Appendix the additional accepted quantities in the DW and DDW scenarios for the 20 % increase in production. The acceptance rates result to be substantially higher in the Northern regions although they are overall lower compared to the UW scenario (with the only exception of CSUD where the rate is slightly higher compared to the UW scenario). This result might reveal a sort of saturation effect for renewable production: as the renewable zonal submitted quantity increases, the acceptance rate decreases.

[23] A couple of exceptions are present. In the DW scenario, accepted quantities of Coal and CHP in CNOR and CHP in CSUD slightly increase; in the DDW scenario, accepted quantities of Coal rises in CNOR.

The substitution rates in these scenarios for the 20% increase in production are shown in Table 9; here we can distinguish between own regional substitution effect and cross-zonal ones.[24] Concerning the own regional effects, the results of the uniform case simulations are confirmed here, although the substitutions have smaller magnitude.[25] The largest own effect for CCGT is registered in NORD, where 1 Gwh of additional Wind production replaces 0.5 Gwh of CCGT; for Coal, the substitution is more important in CSUD, where 1 Gwh of additional Wind production replaces about 0.3 Gwh of Coal. The effects on CHP, Hydro and SmRES are more marked in NORD, where 1 Gwh of additional Wind supply replaces about 0.2 Gwh of CHP, about 0.03 Gwh of Hydro and 0.1 Gwh of SmRES.

DW								
ZONE	HydroRi	CCGT	Wind	CHP	SmRES	Coal	Solar	
NORD	**-0.005**	**-0.114**	0.000	**-0.051**	**-0.017**	-0.031	0.000	
CNOR	0.000	-0.025	0.000	0.000	-0.003	0.000	0.000	Cross effects
CSUD	-0.001	-0.037	-0.006	0.000	-0.007	**-0.089**	0.000	
SARD	-0.001	-0.075			-0.029	-0.096	-0.002	
SUD	-0.001	-0.009			-0.082		-0.003	Own effects
SICI	0.000	**-0.112**		-0.012	-0.043		-0.001	

DDW								
ZONE	HydroRi	CCGT	Wind	CHP	SmRES	Coal	Solar	
NORD	**-0.033**	**-0.540**		**-0.218**	**-0.118**	**-0.145**	-0.003	
CNOR	-0.001	-0.105		-0.001	-0.017	0.000	-0.001	Own effects
CSUD	-0.003	-0.161		0.000	-0.042	**-0.333**	-0.001	
SARD	0.000	-0.001	-0.004		-0.002	-0.007	0.000	
SUD	0.000	-0.002	**-0.027**		-0.014		0.000	Cross effects
SICI	0.000	-0.002	-0.009	-0.001	-0.003		0.000	

Table 9: Substitution rates (DW and DDW scenarios)

If we look at the cross-regional effects, we remark that Wind supply in a region

However, these quantity increases are marginal as revealed by the calculation of substitution rates (see Table 9). Detailed zonal results are shown in the Appendix in Figures from 8 to 13.

[24] The own substitution effects are calculated as $\frac{\Delta q_{in}}{\Delta q_{jn}}$ where $i =$HydroRi, CCGT, CHP, Coal, SmRES and Solar, j=Wind, $n =$SARD, SUD, SICI in the DW scenario and $n =$NORD, CNOR, CSUD in the DDW scenario. Cross-zonal substitutions are calculated as $\frac{\Delta q_{in}}{\Delta q_{js}}$, where i=HydroRi, CCGT, CHP, Coal, SmRES and Solar, $j =$Wind, $n =$NORD, CNOR, CSUD and s=SARD+SUD+SICI in the DW scenario and as $\frac{\Delta q_{in}}{\Delta q_{js}}$, where $i =$HydroRi, CCGT, CHP, Coal, SmRES and Solar, j=Wind, $n =$SARD, SUD, SICI and $s =$NORD+CNOR+CSUD in the DDW scenario.

[25] The substitution effects in the uniform case be may partly overstated since their formulation does not allow to distinguish between own and cross-regional effects. In the heterogenous case, we can make this distinction, although we consider blocks of regions instead of a region a a time, which can also give rise to some errors. A set of simulations in which the quantity varies in one region at a time should reveal their exact value but we think that the results presented here are very coherent and they provide a good approximation.

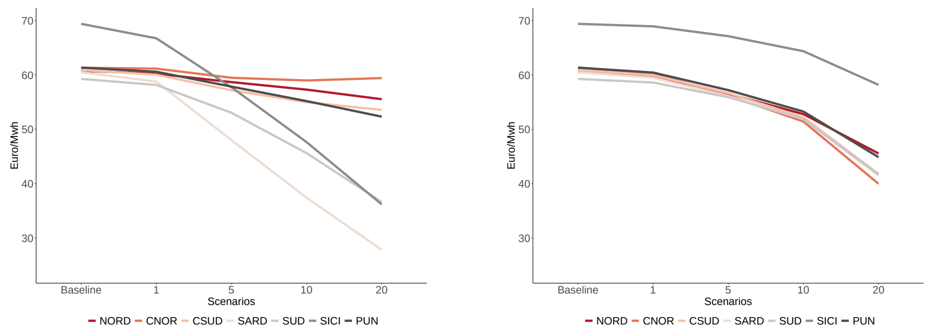
is a substitute for the same supply in another region. Wind cross-regional effects are more accentuated in the DDW scenario compared to the DW scenario; in the latter only CSUD, i.e. the contiguous geographical region shows an effect different from zero (-0.006). Increasing Wind in certain regions does have a cross-effect on the production of other sources in other regions as well. These effects are larger in the DW scenario for Hydro, CCGT, CHP and SmRES in NORD and for Coal in CSUD. In general, the magnitude of these effects confirms the intuition that Wind supply substitute other sources in other regions but the substitution rate is less strong compared to the case in which the replacement is realised within the same region. Cross-regional effects for Solar are null.

5.2.2 Solar and SmRES generation

Figures 11a and 11b show the average price effect of increasing Solar and SmRES production in the Southern zones (DS scenario) and in the Northern zone (DDS scenario) respectively.[26] In the baseline case, Solar and SmRES production is more important in the 3 Northern zones; SARD and SICI have the smallest supply from these sources. In the DS and DDS scenarios, the results are very similar to the DW and DDW scenarios. In the DS scenario, the average zonal prices decrease more in SARD, SUD and SICI compared to the uniform case and the Northern zones experience lower prices as well (although to a lesser extent compared to the US scenario). The zonal merit order effect is particularly marked in SUD (22.64 €/Mhw) and SICI (33.21 €/Mhw) for a 20% production increase. Again PUN decreases less than in the uniform case: for the maximum considered increase in production it remains at 52.33 €/Mwh (in the US scenario it reached 46.18 €/Mwh). In the DDS scenario, the

[26] Detailed results are reported in the Appendix in Tables 6 (DS scenario) and 7 (DDS scenario).

Northern zones benefit from lower average prices compared to DS and US scenarios; the reverse is true for the Southern zones. The average zonal prices tend again to converge in all regions but SICI, which maintains a spread of about 13 €/Mwh. In the DDS scenario, for a 20% increase in production, PUN decreases more than all previous simulations, attaining 44.88 €/Mwh.



(a) DS Scenario

(b) DDS Scenario

Figure 11: Heterogenous simulations, Solar and SmRES

We conclude that the best results in terms of PUN reduction are obtained in the DDS and DDW scenarios, i.e. when the additional renewable supply is concentrated in NORD, CNOR and CSUD. According to our simulations, the largest reduction in PUN for a 1% and a 20% increase in production is attained by investing on Solar and SmRES; for a 5% increase the two technologies give the same results, while for the 10% increase Wind supply seems more efficient.[27]

As expected, in the DS scenario, Solar and SmRES accepted quantities increase only in SARD, SUD and SICI; symmetrically, in DDS scenario, these quantities rise

[27] To disentangle this effect, we report in Table 10 in the Appendix the additional accepted zonal quantities in the DS and DDS scenarios for the 20% increase in production. As for Wind, the acceptance rates result to be substantially higher in the Northern regions; compared to the US scenario, the acceptance rates are here higher in the Northern regions but lower in the Southern regions (the saturation effect observed for Wind seems therefore to apply only in SARD, SUD and SICI for Solar and SmRES). These results can explain why the reduction in prices is more marketed in the DDS scenario.

in NORD, CNOR and CSUD (with the only exception of Solar in CNOR which decreases from the 10% increase as in the US scenario). All concurrent sources decrease.[28] The substitution effects in these scenarios for the 20% increase in production are shown in Table 10.[29]

DS								
ZONE	HydroRi	CCGT	Wind	CHP	SmRES	Coal	Solar	
NORD	**-0.006**	**-0.101**	0.000	**-0.046**	-0.019	-0.027	-0.001	
CNOR	0.000	-0.021	0.000	0.000	-0.003	0.000	0.000	Cross effect
CSUD	0.000	-0.041	-0.003	0.000	-0.008	**-0.084**	0.000	
SARD	-0.001	-0.059	-0.042			-0.073		
SUD	-0.001	-0.015	**-0.154**					Own effect
SICI	0.000	-0.113	-0.068	-0.018				

DDS								
ZONE	HydroRi	CCGT	Wind	CHP	SmRES	Coal	Solar	
NORD	**-0.036**	**-0.614**	0.000	**-0.243**		-0.148		
CNOR	-0.001	-0.144	0.000	-0.001		0.000		Own effect
CSUD	-0.001	-0.172	-0.015	0.000		**-0.309**		
SARD	0.000	-0.001	-0.002		-0.003	-0.006	0.000	
SUD	0.000	-0.002	**-0.017**		**-0.023**		-0.001	Cross effect
SICI	0.000	-0.002	-0.005	-0.001	-0.004		0.000	

Table 10: Substitution rates (DS and DDS scenarios)

Concerning intra-regional substitutions, the largest value for CCGT is registered in NORD, where 1 Gwh of additional Solar/SmRES production replaces 0.6 Gwh of CCGT; for Coal, the substitution is more important in CSUD, where 1 Gwh of additional Solar/SmRES production replaces about 0.3 Gwh of Coal. The effects on CHP and Hydro are more marked in NORD, where 1 Gwh of additional Solar/SmRES supply replaces about 0.2 Gwh of CHP, about 0.03 Gwh of Hydro. It is worthy to note that the results for Coal, CHP and Hydro are very similar to those obtained with Wind in the heterogenous simulations; however as far as CCGT is concerned, Solar/SmRES seems to have a greater impact at least in NORD, while the substitutions are very

[28] We observe some exceptions: in the DS scenario, CHP and Coal slightly increase in CNOR; CHP rises also in CSUD in the 20% increase; Coal in CNOR increases a little bit in the DDS scenario for a 10% increase in supply. Again, the substitution effects (see Table 10) are negligible since these quantity increases are marginal. Detailed results are shown in Figures from 14 to 19 in the Appendix.

[29] The own substitution effects are calculated as $\frac{\Delta q_{in}}{\Delta q_{jn}}$ where i =HydroRi, CCGT, CHP, Coal, Wind, j=Solar+SmRES, n =SARD, SUD, SICI in the DS scenario and n =NORD, CNOR, CSUD in the DDS scenario. Cross-zonal substitutions are calculated as $\frac{\Delta q_{in}}{\Delta q_{js}}$, where i=HydroRi, CCGT, CHP, Coal, Wind, j =Solar+SmRES, n =NORD, CNOR, CSUD and s=SARD+SUD+SICI in the DS scenario and as $\frac{\Delta q_{in}}{\Delta q_{js}}$, where i =HydroRi, CCGT, CHP, Coal, Wind, j=Solar+SmRES, n =SARD, SUD, SICI and s =NORD+CNOR+CSUD in the DDS scenario.

similar in the remaining regions. The largest impacts on Wind within the same region are registered for the Southern regions in the DS scenario, where the maximum is attained in SUD (-0.1 Gwh). These effects are null in NORD and CNOR.

We remark that inter-zonal substitutions for SmRES are always non-null (they seems therefore more significant than in the Wind case), while they are null or very limited for Solar. Again, increasing these sources does have an impact on the production of other sources in other regions. These effects are larger in the DS scenario for Hydro, CCGT and CHP in NORD, and in DDS scenario for Wind in SUD. Inter-zonal substitutions, despite being non-null, are less relevant compared to intra-zonal substitutions.

5.3 Congestion and zonal balance

With the help of M.I.D.A.S, we can study the impact of a larger supply on the occurrence of congestion as well (Table 11.). In our simulations, we observe that a unique price emerges more often in the UG scenario for all increases in supply, with the only exception of the 20% increase in which the US scenario guarantees the highest occurrence of no congestion. The two-zonal configuration is more likely in the DDW (1% and 10% increase) and and the DDS (5% and 20% increase) scenarios. The lowest occurrence of the three-zonal configurations is registered in the US scenario (followed by the DDS and the DDW scenarios). In the DDW scenario, the four and five zonal configurations are the less likely for all increases but the 20%, where the DDS scenario takes over. Finally, the six-prices equilibria arise less often in the DDW scenario for all supply increases. In the DDW (10% and 20% increase) and DDS (20% increase) scenarios, the six zonal configuration never occurs. Overall, it seems that the DDW scenario allows price converge more often.

UG					
Z	Base	1%	5%	10%	20%
1	**38.40**	**39.56**	**43.20**	**42.92**	28.30
2	43.02	42.11	37.66	34.36	33.08
3	14.87	14.57	14.43	15.49	23.35
4	3.45	3.37	4.14	5.87	10.88
5	0.25	0.37	0.49	1.25	3.89
6	0.01	0.01	0.07	0.11	0.50

UW					
Z	Base	1%	5%	10%	20%
1	38.40	38.90	36.09	33.47	29.98
2	43.02	42.52	41.46	39.20	40.28
3	14.87	14.12	16.21	19.08	20.93
4	3.45	4.01	5.12	6.63	7.16
5	0.25	0.44	0.96	1.50	1.51
6	0.01	0.01	0.16	0.13	0.14

US					
Z	Base	1%	5%	10%	20%
1	38.40	38.90	39.27	36.58	**35.33**
2	43.02	42.18	39.43	36.64	35.08
3	14.87	14.83	14.76	15.87	**18.12**
4	3.45	3.67	5.20	8.21	8.71
5	0.25	0.38	1.17	2.45	2.41
6	0.01	0.03	0.18	0.25	0.34

DW					
Z	Base	1%	5%	10%	20%
1	38.40	38.16	31.28	25.25	18.32
2	43.02	41.89	39.14	36.84	35.02
3	14.87	15.32	20.07	23.61	28.27
4	3.45	4.12	7.80	10.87	14.44
5	0.25	0.48	1.56	3.10	3.76
6	0.01	0.03	0.16	0.33	0.21

DDW					
Z	Base	1%	5%	10%	20%
1	38.40	38.93	38.52	37.03	32.87
2	**43.02**	**43.02**	44.11	**45.95**	45.59
3	14.87	14.17	13.87	14.73	19.58
4	**3.45**	**3.59**	**3.09**	**2.09**	1.86
5	**0.25**	**0.26**	**0.40**	**0.19**	0.10
6	**0.01**	**0.02**	**0.01**	**0.00**	**0.00**

DS					
Z	Base	1%	5%	10%	20%
1	38.40	38.94	35.02	31.22	27.52
2	43.02	41.77	35.12	30.43	29.36
3	14.87	14.85	18.43	22.09	28.14
4	3.45	3.98	9.42	12.57	12.29
5	0.25	0.44	1.84	3.43	2.52
6	0.01	0.01	0.17	0.24	0.17

DDS					
Z	Base	1%	5%	10%	20%
1	38.40	39.00	38.61	36.88	31.96
2	43.02	42.93	**44.20**	45.56	**47.67**
3	14.87	14.13	13.45	14.59	19.27
4	3.45	3.63	3.30	2.61	**1.05**
5	0.25	0.30	0.42	0.34	**0.05**
6	0.01	0.01	0.02	0.02	**0.00**

Table 11: Congestion occurrence

Finally, we have calculated for each scenario the ratio between zonal yearly accepted demand and supply. The NORD zone is the most balanced one, with the ratio ranging between 0.95 and 1. In UG, UW and US scenarios NORD achieves a perfect balance in the 20% increase simulations. CNOR is a net importer in the baseline scenario but it constantly reduces its import in UG, UW, US, DDW and DDS scenarios. In the DDW scenario, in particular, for a 20% increase in Wind production, the zone becomes a net exporter. In DW and DS scenarios, CNOR imports even more power compared to the baseline scenario. CSUD is a net importer too; however its demand/supply ratio worsens in all scenarios, but DDW and DDS (i.e. when Wind and Solar/SmRES production is locally augmented). SARD is a net exporter; the export increases in all simulations, but, as expected, in DDW and DDS scenarios where the demand/supply ratio slightly increases. SUD is an importer, but when experiencing an increase in local production, it becomes a net exporter (UG, DW and DS scenarios); for uniform increases in renewable supply (UW and US scenarios) the demand/supply ratio approaches 1, while when the supply increase is concentrated in other zones (DDW and DDS scenarios) the demand/supply ratio worsens. SICI is always a net importer but in the DS scenario for a 20% increase in local supply. In all scenarios the demand/supply ratio shrinks but in DDW and DDS scenarios. Detailed results are reported in Table 12.

UG					
ZONE	Base	1%	5%	10%	20%
NORD	0.95	0.95	0.96	0.98	1.00
CNOR	1.67	1.66	1.62	1.57	1.51
CSUD	1.60	1.60	1.61	1.62	1.66
SARD	0.85	0.82	0.72	0.64	0.55
SUD	1.26	1.23	1.15	1.06	0.92
SICI	1.58	1.55	1.46	1.35	1.15

UW					
ZONE	Base	1%	5%	10%	20%
NORD	0.95	0.95	0.96	0.98	1.00
CNOR	1.67	1.64	1.54	1.44	1.27
CSUD	1.60	1.60	1.61	1.61	1.65
SARD	0.85	0.82	0.75	0.69	0.62
SUD	1.26	1.24	1.17	1.11	1.03
SICI	1.58	1.56	1.47	1.39	1.28

US					
ZONE	Base	1%	5%	10%	20%
NORD	0.95	0.95	0.96	0.98	1.00
CNOR	1.67	1.65	1.56	1.47	1.35
CSUD	1.60	1.60	1.61	1.62	1.64
SARD	0.85	0.83	0.74	0.68	0.60
SUD	1.26	1.24	1.16	1.11	1.05
SICI	1.58	1.55	1.43	1.32	1.16

DW					
ZONE	Base	1%	5%	10%	20%
NORD	0.95	0.95	0.96	0.97	0.99
CNOR	1.67	1.68	1.70	1.72	1.75
CSUD	1.60	1.62	1.69	1.75	1.84
SARD	0.85	0.80	0.69	0.62	0.54
SUD	1.26	1.21	1.08	0.98	0.86
SICI	1.58	1.53	1.36	1.23	1.10

DDW					
ZONE	Base	1%	5%	10%	20%
NORD	0.95	0.95	0.96	0.97	0.99
CNOR	1.67	1.61	1.41	1.22	0.97
CSUD	1.60	1.58	1.52	1.46	1.39
SARD	0.85	0.85	0.86	0.87	0.90
SUD	1.26	1.26	1.28	1.32	1.43
SICI	1.58	1.58	1.60	1.63	1.69

DS					
ZONE	Base	1%	5%	10%	20%
NORD	0.95	0.95	0.96	0.97	0.99
CNOR	1.67	1.68	1.70	1.72	1.74
CSUD	1.60	1.63	1.72	1.78	1.86
SARD	0.85	0.80	0.68	0.61	0.51
SUD	1.26	1.21	1.08	1.01	0.95
SICI	1.58	1.51	1.30	1.14	0.99

DDS					
ZONE	Base	1%	5%	10%	20%
NORD	0.95	0.95	0.96	0.97	0.99
CNOR	1.67	1.62	1.44	1.27	1.04
CSUD	1.60	1.58	1.50	1.43	1.32
SARD	0.85	0.85	0.86	0.87	0.89
SUD	1.26	1.26	1.28	1.31	1.42
SICI	1.58	1.58	1.60	1.62	1.67

Table 12: Zonal demand/supply ratios

6 Conclusions

The reduction in wholesale electricity prices due to the "merit order" effect has been largely acknowledged as one the economic advantages of increasing power generation from renewable sources. Nevertheless, the attainment of environmental benefits through the substitution of polluting alternatives is still debated. Additionally, when the electricity markets are composed by multiple sub-markets with locational marginal pricing, other dimensions may be impacted such as the occurrence of congestion, the price difference across zones and the zonal balance between demand and supply. We have investigated this topic in detail, using Italy as case study: Italian Power market is composed by six zonal markets and the congestion has an economic value thanks to the implementation of a zonal pricing scheme. We have created an algorithm called M.I.D.A.S which reproduces the real Italian market splitting mechanism and we have studied the sensitivity of market outcomes to renewable location and production, by simulating the equilibrium prices and quantities following perturbations in the offers submitted in the Day-ahead market. We have analysed the consequences on congestion occurrence and zonal balance as well. We have used as reference for our simulations the 2030 targets for Solar and Wind production included in the National Integrated Energy and Climate Plan, approved in 2020 by the European Commission.

The results of our simulations suggest that the localisation of the additional production is a relevant variable in the assessment of renewables' benefits. If, on the one hand, we find evidence of a "zonal merit order effect" which translates in a lower average unique price paid by consumers, on the other hand, we observe that the distribution of benefits is largely heterogenous across zones. Concentrating the additional production in NORD, CNOR and CSUD, which have the largest demand, allows to obtain the best results in terms of PUN reduction, although these zones are not the ones experiencing the more important price decreases for the same amount of additional generation. If the supplementary production is located in the Northern zones, for small and large increases in renewable supply, Solar and SmRES achieve the largest reduction in PUN, while for intermediate increments, Wind seems to be more efficient.

We provided also evidence of competition between renewables and thermal sources but also within renewables sources (Solar/SmRES, Wind and Hydro). When renewable production expands, thermal generation tends to decline, but it is never crowed out; the objective of decommissioning (especially for coal) may therefore not be feasible through the substitution with renewables. The development of Solar/SmRES and Wind production comes at the expenses of Hydro production as well, although this substitution is of smaller magnitude. Interestingly, the additional Wind generation (respectively Solar/SmRES) partially replaces the existing Solar/SmRES one (respectively Wind): this effect is more marked within the same zone but it is also present when the additional production is located in another zone; renewables therefore do compete with each other. By calculating the zonal substitution effects between technologies, we highlighted the heterogenous impact that the additional renewable production can have on the zonal generation mix; these results are particularly relevant in the debate on how to decarbonise the generation mix through renewables.

As for congestion, we found that for the largest considered increase in supply, a uniform increase in Solar/SmRES production and a rise concentrated in NORD, CNOR and CSUD, favours the single and two zonal configurations respectively. Finally, we showed that the choice of localisation for the additional renewable production has a strong consequence on the zonal demand/supply ratio: in most cases, it determines the importing/exporting status of a zone, thus significantly impacting its level of independency.

Our analysis highlights how complex is the task of formulating policy recommendations when multiple objectives are to be pursued with a single instrument: a prioritisation is therefore mandatory. Up to our knowledge for instance, the reduction in the wholesale price has never been regarded as a direct goal to be achieved through the development of renewable sources; it is rather considered as a positive "side effect". If policies especially seek to attend environmental targets they should focus on the localisation that delivers the largest substitution between non pollutant and pollutant units, which might not necessarily be the one guaranteeing the lowest wholesale price. The same reasoning applies to security of supply and zonal balance which can be as well improved at the expenses of substitution and price level. In our specific case study, it is not possible to reconcile all these objectives with a single best solution. The good news is that, once the objectives are carefully prioritised, a policy offering differentiated supports according to localisation shall suffice to help driving investors' decisions.

It is worthy to note that the results presented in this paper have some limitations due to the fact that on each round we suppose that the competitors of Solar, SmRES and Wind power plants do not change their behaviours following an increase in production from these renewable sources; this assumption may be unrealistic. However, M.I.D.A.S. algorithm offers a rich analytical framework which can be expanded well beyond the simulations discussed here. We can for instance simulate the possible "strategic reaction" of displaced units, by studying the effect of perturbations in submitted prices. This would provide more credible scenarios, as the benefits of renewables in terms of lower prices may vanish if marginal units raise the prices in those hours in which renewables are less or not available. We plan in future work to use the historical data in our database to study the behaviour of non renewable producers and to use this information simulate realistic scenarios. Another interesting extensions of the present work would be to simulate the impact of changes in the transmission capacities across zones. We could also anticipate the consequences of much larger increases in renewable production than those considered here. From a more technical point of view, our future work will focus on improving M.I.D.A.S's performances, by exploring other ranking rules of the feasible solutions and by reducing the occurrence of non convergence in the algorithm.

In this paper, the analysis is limited to the benefits of expanding renewable sources; discussing the aspect of costs goes beyond our research objectives. However, we acknowledge that the same production in different zones may require a different amount of installed capacity depending of the availability of the natural resource. The investment cost in generation capacity differs for Wind, Solar and SmRES technologies, as it differs for transmission capacity, and it depends on the localisation as well. Therefore we suggest that any policy should envisage a preliminary assessment of such costs in order to compare the relative efficiency of each alternative possible solutions.

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