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THE ITALIAN ELECTRICITY PRICES IN YEAR 2025: AN AGENT-BASED SIMULATION

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The Italian Electricity Prices in year 2025: an Agent-Based Simulation

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Abstract

In this paper, we build a realistic large-scale agent-based model of the Italian day-ahead-electricity market based on a genetic algorithm and validated over several weeks of 2010, on the basis of exact historical data about supply, demand and network characteristics. A statistical analysis confirms that the simulator well replicates the observed prices. A future scenario for the year 2025 is then simulated, which takes into account market's evolution and energy vectors' price dynamics. The future electricity prices are contrasted with the ones that might arise considering also the possible (yet unlikely) construction of new nuclear power (NP) plants. It is shown that future prices will be higher than the actual ones. NP production can reduce the prices and their volatility, but the size of the impact depends on the pattern of the expected demand load, and can be negligible.

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1. Introduction

The definition of the electricity price dynamics is a challenging task: several parameters have to be identified, such as energy vectors prices' path, demand evolution, the structure of the physical constraints and the market settings; moreover, the interactions of players that compete in the markets has to be considered too. The problem is made complex by the agent's interactions, which depend on the physical and regulatory structure of the environment in which they act. Electricity markets are complex systems and have to be modelled and evaluated accordingly. In the literature, it has been proposed to evaluate complex system through agent-based simulations, which are able to provide a rich understanding of the dynamics of player interaction as well as viable forecasts of future dynamics. In particular, realistic large-scale/nationwide agent-based models have already been proposed in the literature, for instance,[1] for the U.S., EMCAS (Conzelmann et al., 2005), MAIS (Sueyoshi and Tadiparthi, 2008), AMES (Sun and Tesfatsion, 2007); for Australia, NEMSIM (Chand et al., 2008); moreover, the agent based methodology has been applied to the NETA of England and Wales (Bunn and Oliveira, 2001) and to the German EPEX Spot prices (Sensfuss and Genoese, 2006). However, these models often lack a statistical validation, thus reducing the reliability of the what-if simulation. On the contrary, the agent-based approach coupled with a statistical analysis that validates it can provide a better forecast of the evolution of a complex system's dynamics, such as the Italian wholesale (day ahead) electricity market. This is the aim of our work. In order to accurately replicate the pattern of observed price realised in the Italian power exchange (IPEX) an agent-based simulation is constructed, based on a genetic algorithm, tailored so as to include each active power plant in the Italian grid and in which agents are allowed to make complex bidding strategies across plants and zones. The model is validated taking into account real data and contrasting the outcome of the simulation with the effective (observed) price time series, for a sufficiently long time span. It is shown that the model provides a better fitting than a purely cost-based one, which neglects the interactive dimension of agents' behaviour. Then, a plausible scenario for the evolution of the power supply in Italy is described. The year 2025 is taken as a reference future year; it has been chosen sufficiently away from the

[1] The agent-based literature on electricity markets is quite vast. For an extensive survey on the topic see Guerci et al., 2010.

simulation period in order to make realistic assumptions about new investments in power plants that will replaced the existing ones which will be dismissed. More precisely, a future scenario is described based on a forecast of investments and energy vectors that is widely used by operators active in the Italian market. Such a scenario, elaborated together with REF (a leading Italian research company specialized in energy markets) and discussed and validated with market operators and institutional entities, takes into account: *i*) the existing plans to dismiss power plants, renovate power plants or invest in new power plants, as have been disclosed by existing operators; *ii*) a plausible evolution of the market share of the operators; *iii*) the planned investment in the grid by the Transmission System Operator (TSO); *iv*) the introduction of new power capacity due to renewable sources considering the EU targets; *v*) the introduction of the best flexible thermal technology that is actually being developed, which is also needed for system balancing; *vi*) the forecasted evolution of energy vector costs and energy demands.

Market operators' interactions are introduced through the agent based simulator, validated with the existing data, and future energy prices are forecasted in different times of the day and period of the year.

A second future scenario is also considered, which assumes the existence of new Nuclear Power plants. Indeed, in Italy, there used to be four[2] NP plants connected to the electrical grid, producing more than 4% of that nation's total electricity in 1986. They were closed after a 1987 referendum following the Chernobyl disaster in that same year. In 2009, the Italian government launched a plan (law 23/7/09 n. 99 and ff.) to build at least four new NP plants in the near future. As a consequence of the new trend, ENEL, the major electricity producer in Italy, signed a memorandum of understanding with the French EDF aimed at adopting third-generation European pressurised reactor (EPR) technology for the new plants.[3] Several other energy producers in Italy expressed their interest in NP production. However, the government

[2] In Italy, there were four NP plants connected to the electrical grid (name, connection year, net power in MW, type): Caorso, 1978; 860, BWR; E. Fermi, 1965; 260; PWR; Garigliano, 1964; 150; BWR; Latina, 1963, 153, Magnox. The fifth one, in Montalto di Castro, was almost completed, but has since been phased out. It was recently converted into a conventional power station. Of the four existing plants, only Caorso was closed while it was active. The other three were at the end of their lifecycle or already in disuse. For a summary of the Italian NP phase-out, see Casale R. (2009).

[3] Memorandum of the understanding between ENEL and EDF, signed February, 24, 2009. See www.enel.it/ewcm/salastampa/comunicati/1600316-1_PDF-1.pdf.

plan, which did not have a general consensus across operators, consumers, environmental associations and local authorities, was lately halted by a referendum that took place just few weeks after the Fukushima Dai-ichi Nuclear accident in Japan (although its date had been fixed well in advanced). It is not clear at present if NP plants will return to the Italian electrical system. However, taking into account the increase in hydrocarbons' costs, the security of supply concerns and the environmental pressures related to global warming, it is well possible (even though perhaps not quite probable) that NP production will be reconsidered and that NP plants will make their way back into the Italian electricity system. This is therefore a scenario that is worth while evaluating, even if it is not possible at present to assess its effective likelihood. Notice that, given the long delays in prior large Italian investment projects, taking into account the strong opposition to NP by political parties, local communities, consumers and environmental associations and on the basis of the long time-to-market of similar projects like the Olkiluoto plant in Finland, it is quite implausible that NP plants will be active in Italy before year 2025, if they will ever be; this further justifies the choice of the reference year for the forecast exercise.

We believe that our model can be of interest for at least three different streams of literature: a) it offers a detailed one-to-one agent-based reconstruction of an economic environment which is an original attempt, seldom performed in the agent-based literature; b) from an electricity systems study perspectives, it provides a reliable analysis of a large complex market such as the Italian one, based on realistic assumptions and statistically validated; c) from an energy policy perspectives, it forecast the future Italian electricity prices contrasting a plausible scenario without Nuclear Power plants with a possible, yet more unlikely, one which includes Nuclear Power production.

The paper is structured as follows: In Section 2, we describe the actual structure of the Italian day-ahead market. In Section 3, the agent-based simulation methodology is introduced and explained. In section 4, the data and the statistical validation are presented and the results of the simulation of the actual market are commented. In Section 5, we describe the structure of the prospective scenario for the year 2025, first without NP plants and then introducing NP plants into it. The simulation assumptions of the electricity prices without and with NP plants are introduced in section 6. The results of the simulations for the different scenarios are presented in section 7. Conclusions and references follow in Section 8.

2. The model of the Italian day-ahead market

2.1. The Italian day-ahead market

Power generators' bids at the Italian wholesale day-ahead market (DAM) of the IPEX (Italian Power EXchange) consist of[4] $\hat{Q}_i$ and $\hat{P}_i$, the quantity that will be produced and the minimum price that will be accepted for that quantity for each hour of the subsequent day. We assume that each unit of power generation has lower, $\underline{Q}_i$, and upper, $\overline{Q}_i$, production limits that define a feasible production interval for its hourly real-power production level: $\underline{Q}_i \le \hat{Q}_i \le \overline{Q}_i$ (MW). Generator cost curves, for Hydrocarbon-fired Thermal (HT) power plants, are usually not smooth. One commonly used approximation is to represent generator total variable costs (i.e. costs of operation) as quadratic functions (Shahidehpour et al., 2002). The cost function of the i^{th} thermal power generator is:

$$TC_i = (FP_l + \mathrm{ETS} \cdot x_l) \cdot (a_i Q^2_i + b_i Q_i + c_i), \qquad (1)$$

where both FP_l and x_l (Euro/GJ) are fuel-specific parameters: the price of the fuel l used by the i^{th} generator and the conversion value to determine the amount of CO2 generated by the combustion of a unit of fuel l ([GJ]). ETS is the price of carbon permits in the European Emission Trading System. Coefficients a_i (GJ/MW^{2}h), b_i (GJ/MWh) and c_i (GJ/h) are assumed to be constants, but vary across power plants with different technologies and efficiency levels. They represent technology-specific efficiency parameters that define the relationship between the energy input and

[4] The bidding format of supply functions allows a maximum of four couples of prices and quantities offered. However, a simple statistical analysis performed on historical data shows that almost 75% of the offers are composed of a single point bid.

output. The constant term $(FP_l + \text{ETS} \cdot x_l) \cdot c_i$ corresponds to the no-load cost, the quasi-fixed costs that generators bear if they continue to run at almost zero output. However, these costs vanish if energy is not supplied.

We assume, as is common in the literature for HT power plants (Stoft, 2002), that plants' amortisation is being repaid by marginal rent that is assigned to producer *g,* once the energy price is set by the system. The marginal costs MC_i for the i^{th} thermal generator can be easily derived from the cost function TC_i:

$$MC_i = (FP_l + \text{ETS} \cdot x_l) \cdot (a_i Q_i + b_i) \qquad (2)$$

Demand is assumed to be rigid. After receiving all generators' bids, the market operator, Gestore del Mercato Elettrico (GME) in Italy, clears the market by performing a total welfare maximisation, subject to the equality constraints posed by the zonal energy balance (Kirchhoff's laws) and inequality constraints, i.e., the maximum and minimum capacity of each power plant and inter-zonal transmission limits. This is generally denoted as the DC optimal power flow - DCOPF. The welfare maximisation, given inelastic demands, corresponds to the total production costs minimisation problem providing the locational marginal price (LMP). The LMP is the shadow price of the active power balance equations constraint (Kirchhoff's law) in each zone (Kirschen and Strbac, 2004). In the Italian market, an LMP is set for each zone, namely a subset of the transmission network that groups local unconstrained connections. Moreover, an average national price (Prezzo Unico Nazionale - PUN) is also calculated as the average of zonal prices, weighted on the basis of the zonal load. Zones are defined and updated by the TSO (Terna, in the case of Italy) based on the evolution and the structure of the transmission power-flow constraints. The transmission network model considered in this paper reproduces exactly the zonal market structure and the relative maximum transmission capacities between neighbouring zones of the Italian grid model, as defined by Terna S.p.A. for the reference period.[5]

[5] See Terna website: http://www.terna.it/default/Home/SISTEMA_ELETTRICO/mercato_elettrico/

In our work, we take into account real demand, including that traded on forward markets, which is effectively dispatched. Supply from imports (corresponding, in general, to power generated abroad by cheap technologies, such as hydro or nuclear power, coming mainly from France and Switzerland), hydropower (including pumped-storage facilities) and other renewables is modelled as must-run production at zero-price. Bilateral contracts are modelled on the supply side as quantities at zero-price. The system marginal price is given in each zone by the LMP of the marginal thermal technology. For HT plants, the profit per hour R_i for the i^{th} generator belonging to zone k is obtained as follows:

$$R_i = ZP_k \cdot Q_i^* - TC_i\, Q_i^* \tag{3}$$

where Q_i^* is the equilibrium quantity generated by each power plant. It is the quantity that solves the TSO's cost minimisation problem, given the constraints and the quantity offered by each plant. ZP_k is the set of LMP prices calculated by the TSO for each zone $k \in \{1, 2, ..., K\}$.

3. The agent-based simulation methodology

3.1. The agent-based model

The constructed model replicates the rules and adopts the exact historical information of the DAM. Demand is assumed to be price-inelastic and equals the historical load profile for the observation period. The supply side of the market is composed of generation companies (GenCos) submitting bids for each of their power plants and gaining an overall profit, which corresponds to the sum of the profits displayed in Equation 3 for each plant they own. Agents/GenCos simultaneously submit 24 bids, one for each hourly session of the wholesale market. Each hourly market is assumed to be independent. Plants are grouped by five major technologies: coal-fired (CF), oil-

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fired (OF), combined cycle (CC), combined heat and power (CHP) and turbo-gas (TG). Each g^{th} GenCo, g = (1, 2, .., G), owns $M^g_{z,f}$ thermal power plants in zone z with technology f. We collect the $M^g_{z,f}$ power plants of GenCo g in zone z and of technology f in a representative generating unit $r = (z, f)$, and we assume that GenCo g adopts a common strategy for them. By doing so, we reduce the size of the strategy space. Let us denote N^g_r as the number of representative generating units of GenCo g in all zones and for all technologies. For every r and every hour h, each GenCo g bids to the DAM $M^g_{z,f}$ pairs of values $\left(\hat{P}^g_{r,1}, \hat{Q}^g_{r,1}\right), \ldots, \left(\hat{P}^g_{r,M^g_{z,f}}, \hat{Q}^g_{r,M^g_{z,f}}\right)$. $\hat{P}^g_{r,i} = a^g_r \cdot MC^g_{r,i}$ ([Euro/MWh]) corresponds to a limit price, where $a^g_r \in A^g_r$ denotes the common mark-up value adopted for all power plants belonging to the representative power unit r and $MC^g_{r,i}$ is the marginal cost of the i^{th} power plant belonging to the r^{th} representative power plant owned by GenCo g. GenCos are assumed to bid the maximum capacity for each power plant $\hat{Q}^g_{r,i} = \overline{Q}^g_{r,i}$ [MW]. Let A^g denote the action space of GenCo g. It equals the Cartesian product of the action space of each representative unit it owns: $A^g = \times_r A^g_r$, where A^g_r denotes the action space of the representative generating unit. Actions are mark-up levels. In the computational experiments, we assume A^g_r = {1.00, 1.04, 1.08, …, 5.00}, corresponding to a mark-up increase value of 4% and a maximum mark-up value of 500%, with respect to the marginal cost, for a total of 100 actions.

3.2. The agent-based genetic algorithm[6]

The strategy space of a given GenCos can be huge. In order to make the problem computationally tractable, a learning procedure based on a standard genetic evolutionary process has been employed. Each GenCo repeatedly interact with the other companies at the end of each run $\rho \in 1, \ldots, R$, that is, they all submit bids to the DAM according to their current beliefs on opponents' strategies. At the beginning of run ρ, GenCos need to study the current market situation in order to identify a better reply to the opponents, to be played at the end of run ρ. In order to explore its strategy

[6] For further references, see Guerci e Sapio (2011).

space in search of a better strategy, the g^{th} GenCo need to repeatedly solve the market for different private strategies, kept fixed the strategies of its opponents at run $\rho-1$. This procedure is adopted in order to enable each GenCo to learn foregone profits by exploring the profitability of fictive actions. A standard genetic algorithm is adopted, in order to keep a large population of candidate strategies and to improve at the same time their fitness/performance in the market. We define a population of size *Po* of strategies, which will evolve throughout the K_ρ generations belonging to run ρ. The number of generations per run varies with the run ρ. The idea is to favour exploration in initial rounds (small values for K_ρ) and then to exploit the gained experience (large values for K_ρ), expressed in the final population of candidates by the relative frequency of occurrences of each candidate solution F_{m_g}. Then, at the end of each run ρ, each GenCo bids to the market by selecting one strategy belonging to its current population of candidates. The selection is done according to a probabilistic choice model in order to favour the most represented strategy in the population, i.e., the one that has best responded to the evolutionary pressure by ensuring the highest fitness. The functional form of the probabilistic choice model which has been considered is the logit:

$$\pi_{m_g}^{\rho} = \frac{e^{F_{m_g}/\lambda}}{\sum_{m_g}^{M_g} e^{F_{m_g}/\lambda}} \tag{4}$$

where $\pi_{m_g}^{\rho}$ expresses the probability of selecting action m_g at run ρ. Summarizing, the algorithm can be seen as an "approximate" best reply at each run because of three aspects. First of all, at each run the population of candidate solutions represents only a subset of all actions. Secondly, even if the number of generations progressively increases it is limited and does not guarantee convergence to the optimal action for the current population. Lastly, we adopt a probabilistic choice model to select at the end of each run, the action being played by each GenCo. Model's parameters have been calibrated in such a way that during the final run all the GenCos select their optimal action given the final population of strategies. In particular, there are four parameters that have to be determined in order to run the experiment: ρ, K_ρ, *Po,* λ. In this paper we have adopted the following assumption: $\rho = 50$, $K_\rho = \{3,..., 25\}$, $Po = 300$, $\lambda = 2$. Finally, it is worth mentioning that we have adopted for all simulations the common procedure to include in the initial population of candidate actions the no mark-up case, that is, the bid at marginal cost. Furthermore, we have imposed that the first action being played by all agents at run $\rho = 0$ is the marginal cost for each power-plants.

4. Data, calibration and results for the year 2010.

4.1. The data used for the simulation.

One of the aims of the paper is to propose a highly realistic computational model of a liberalized electricity market, which is able to perform analyses of scenarios. In order to measure the performance level of the simulator, we adopt a goodness of fit criterion over a sufficiently long PUN time series observed in the Italian market. In particular, we validate the adopted methodology and modelling assumptions by choosing to simulate the hourly PUN of an entire week, for three different weeks of the year, that corresponds to different yearly load profiles, namely high-, mid- and low-demand periods. The most recent yearly data available for our work refer to 2010. We consider a week in July, a month that usually displays a peak in demand, the last week of September, when demand is at a medium level, when it is coupled with non-extreme weather conditions, and a mid-week of April, that historically corresponds to the second lowest bottom in demand. The lowest bottom is in August, however this has not been considered, because of the holiday period coupled with high temperatures, which would make the figures quite unrepresentative of the Italian electricity market.[7]

The chosen data refer to the 15th week of 2010 (from the 12th of April to the 18th), the 28th week (from the 12th of July to the 18th) and the 39th week (from the 27th of September to the 3rd of October), for a total of 504 hourly observations. Table 1 reports the fuel prices used for the simulations, both for the years 2010 and 2025.

[7] It is worth noting that huge computing resources are required to run the simulations in reasonable time. The most demanding task is the largely repeated solution of the DCOPF routine, because of the best-reply analysis performed at each iteration by each GenCo on a huge action space. Adopting a 12 cores PC (2 processors with 6 cores) and 24GB of RAM, it takes almost a day to run the 24 hour-market simulation per each scenario.

	COAL	DIESEL	NTURAL GAS	OIL	ETS
	€/Gcal	€/Gcal	€/Gcal	€/Gcal	€/tCO2
Weekly Avg. April 2010	10,94	54,44	35,21	40,15	14,04
Week Avg. July 2010	12,91	52,84	36,59	39,19	14.03
Week Avg. September 2010	13,81	54,81	37,50	39,78	15,5
July 2025	13,41	57,25	36,90	38,20	32,10
October 2025	13,39	57,12	36,81	38,08	32,10

Table 1: Fuel (€/GJ) and ETS ((€/tCO2) prices used in the computational experiments. Year 2010 (average weekly price) and 2025 (daily price).

At the date chosen for our simulation experiment, the chosen set of HT power plants consisted of 223 generating units grouped according to five technologies: CF, OF, CC, CHP and TG. These power plants were independently or jointly owned by 19 different GenCos. If a plant is jointly owned, it was attributed to the GenCo holding the largest share. The GenCos are: A2A, AA_API, AceaElectrabel, AE EW, AES, ATEL, EDIPOWER, EDISON, EGL, Elettrogorizia, ENEL Produzione, ENIPOWER, EnPlus, Eon, ERG, Iride, SET, SORGENIA and TIRRENO Power. For each hour of each considered day, we have determined exactly from real GME data which power-plants of the considered database effectively bid. Hourly subsets of the 223 HT power-plants have been adopted to simulate independently each hourly market. Summarizing, both the supply and demand sides of the market have been simulated exactly in terms of both aggregate and individual values. Furthermore, the exact values of hourly transmission limit constraints have been considered in the simulations, as provided by GME.

4.2. Simulation results for 2010.

For each scenario, 10 computational experiments were carried out independently. Averages were computed to estimate market outcomes. Over time, the profit-seeking agents learn what bidding prices to submit to the IPEX, using the algorithm described in the previous section. The simulated scenario is contrasted with the effective PUN observed for each hour of the observation period. Figures 1, 2 and 3 display the observed and simulated PUNs for the three weeks in 2010. They also show the cost-based prices, i.e., the prices obtained from a hypothetical scenario in which firms do not add any mark-up to their marginal costs. Moreover, hourly market demands are plotted in the figures as well. Table 2 reports the summary statistics. Data refer to each single week of the period and to the overall sample of 504 observations. They are grouped by the day, and peak hours (from 8am to 8pm Mon-Fri) and off-peak hours are differentiated.[8] For each group, the table reports the mean observed and simulated price (Euro/MWh), the correlation coefficient between the former and the latter and the root mean square error between the historical and simulated prices, both in terms of their absolute value (Euro/MWh) and in terms of the percentage of the observed price.

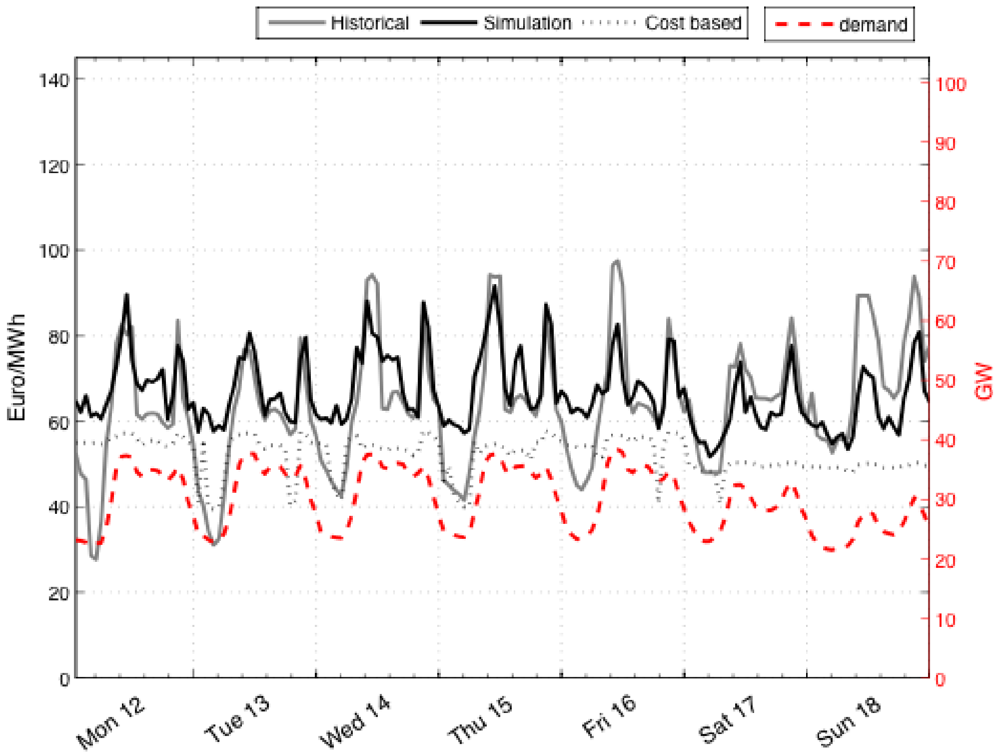

Figure 1: real (gray line), estimated (black line) and cost-based (dotted line) prices - left axis; market demand (dashed line) - right axis; for the 15th week of 2010 (April)

[8] The full data of the hourly simulations can be downloaded from the following repository: http://www.decon.unipd.it/personale/curri/fontini/Data.html

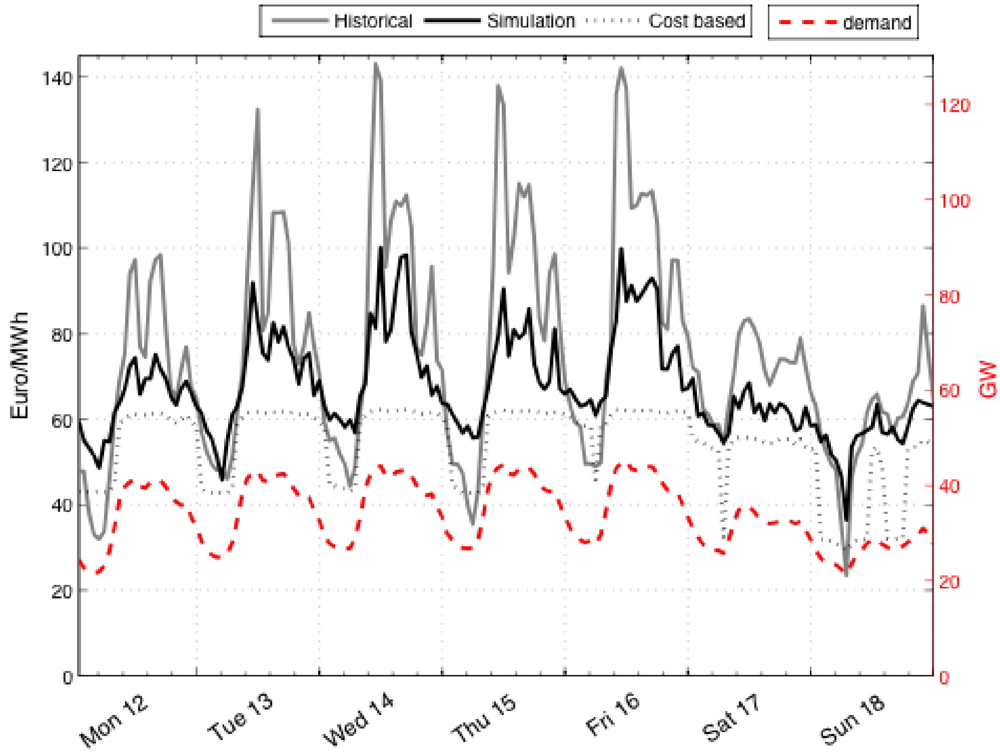

Figure 2: real (gray line), estimated (black line) and cost-based (dotted line) prices - left axis; market demand (dashed line) - right axis; for the 28th week of 2010 (July)

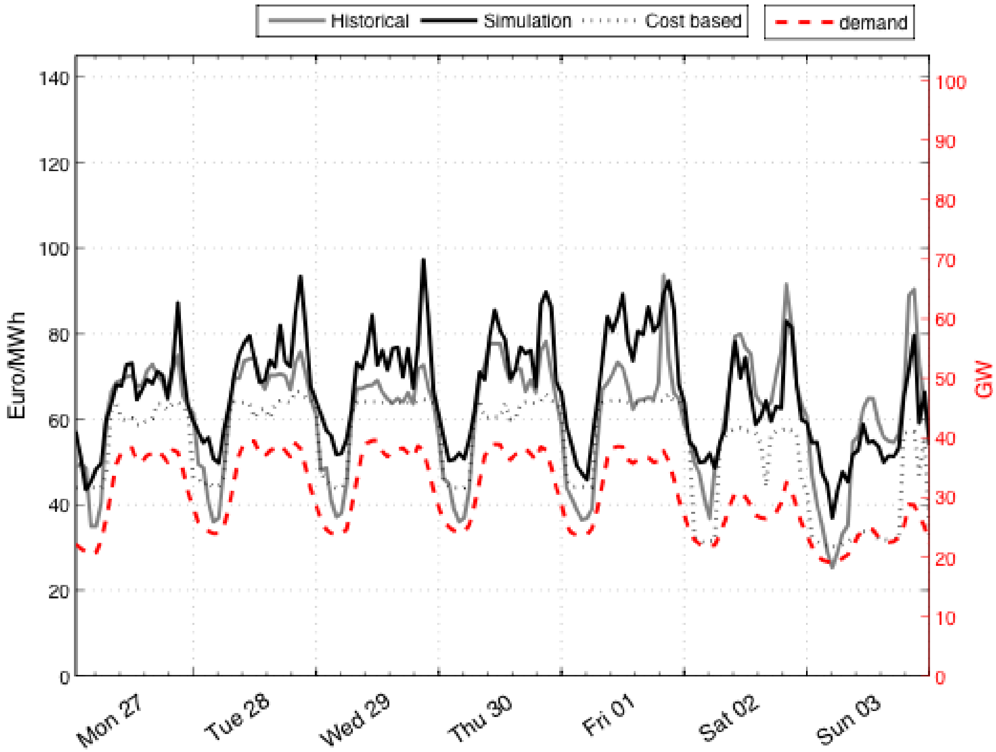

Figure 3: real (gray line), estimated (black line) and cost-based (dotted line) prices - left axis; market demand (dashed line) - right axis; for the 39th week of 2010 (September-October)

		April		July		Sept-Oct		Overall	
		Historical	Simulation	Historical	Simulation	Historical	Simulation	Historical	Simulation
Mean price	all hours	63,77	66,68	75,51	67,23	60,99	66,04	66,76	66,65
Correlation coeff.			0,72		0,90		0,83		0,78
RMSE (€/MWh)			10,67		17,49		9,24		12,97
RMSE (% of hist. Price)			16,74%		23,16%		15,15%		19,44%
Mean price	peak hours	69,08	70,79	96,54	77,44	69,58	75,18	78,40	74,47
Correlation coeff.			0,78		0,83		0,42		0,70
RMSE (€/MWh)			7,47		24,38		8,16		15,46
RMSE (% of hist. Price)			10,82%		25,25%		11,72%		19,72%
Mean price	off peak hours	60,42	64,09	62,24	60,79	55,57	60,28	59,41	61,72
Correlation coeff.			0,65		0,80		0,81		0,72
RMSE (€/MWh)			12,27		11,12		9,86		11,13
RMSE (% of hist. Price)			20,31%		17,86%		17,74%		18,73%

Table 2. Summary statistics for the 2010 simulations and comparison between real and simulated prices.

We can see that there is a satisfactory fit with the historical data. The simulated patterns of the PUN follow the observed ones quite well, both in terms of trends and absolute values. This is confirmed by the statistics of the simulation. The overall correlation coefficient equals 0,78. All estimates show correlations higher than 72%, except for the September-October week peak hours estimates and April's off peak hours estimates. There is also a solid fit in terms of the PUN's absolute values. The overall root mean square error equals 13 Euro/MWh; it is higher during peak hours (when the average price is higher) and lower during off-peak hours. The week for which the estimate performs worse is in July, in particular for the peak hours, for which the root mean square error is about 25% of the average observed prices. All other simulated prices perform much better, in particular those for the peak hours during the other two weeks, for which the root mean square error is not higher than 12% of the observed prices. The behaviour of peak hours for the week in July might be due to some strategic behaviour that has influenced the market price. In particular, we notice that it is coupled with the highest demand. Having fixed the number of plants, this reduces the market competition. There might have been some (implicit) collusive strategy that cannot be replicated by the simulator. By observing the shape of the simulated and historical PUN curves, we can see that there is also a discrepancy for the off-peak hours, due to higher simulated prices for the off-peak hours of working days, in particular for those in April. A plausible explanation for such a behaviour has emerged during conversation with market operators. We consider in our simulator a normal set up for HT plants. However, because of the economic crisis and the consequent fall in consumption levels the huge investments in mid-merit HT plants are highly affected. In order to guarantee a certain number of hours of production and not to incur in high shut-down and start-up costs, GenCos alter the set up of HT plants, mostly in night hours, forcing them to produce at a reduced quantity and lower marginal cost. This is confirmed by the analysis of bids submitted to the market,[9] showing that in night hours, bids are lower than plants' marginal costs at normal set-up. Such an effect is not negligible but cannot be captured by our simulator.

[9] Power plants bids are made available by GME with a one week delay at the following website: http://www.mercatoelettrico.org/En/Esiti/MGP/EsitiMGP.aspx

Nevertheless, we stress that there is a good fit between the simulation and the observed data. It performs much better than a purely cost-based one. This shows that the simulation is able to reproduce most of the behaviours of agents in the market.

5. The 2025 scenario

5.1. The forecasted scenario.

The 2025 scenario depicts the future structure of electricity supply and demand.[10] It starts by evaluating the Italian economic growth, which is expected to return to its (low) long run level. This determines the recovery of the electricity demand growth after the present economic crisis. However, the composition of demand will be changed by the reduction of residential demand, due to improved energy efficiency, and the increase in the service sector demand, coupled with the increase in private transportation and heating needs. By 2025, the electricity demand is expected to be equal to 421.1 TWh. The future hourly composition of the market thermal load, i.e., the net demand for self-production, renewables, imports and pumped-storage hydroelectric, will be different from the current one. On one hand, there is expected to be a rise in production from renewables, fostered by European and national programs for the development of sustainable energy. As a result, it is expected that 30% of electricity consumption needs will be filled by renewables in the year 2025, of which 40% will be hydroelectric, 17% wind power and 23% PV. On the other hand, there will probably be a reduction in imports, due to a reduction in base load electricity production in Germany and Switzerland, following their NP phase-out, which will be replaced by some other more-expensive forms of energy. Moreover, the reduction in residential demand is coupled with an enhanced domestic efficiency due to improved two-sided real-time metering that increases off-peak demand. As a result, the hourly profile of the market thermal load is expected to assume a more uniform shape compared to that of 2010, with reduced differences between night-time and peak

[10] The scenario has been developed by REF, a leading consultancy company in Italy and discussed with operators and public bodies. For more details, please contact REF at the following email address: vcanazza@ref-online.it

hours. The hourly profile for the market thermal load for the simulation period is displayed in Figures 4 and 5 (right axis).

The structure of supply is expected to evolve also. On one hand, older power plants are expected to be switched off on the basis of their age or repowered according to plans brought to the market by operators. This, however, will not change the actual power supply structure very much until 2020, given that the Italian power plants are quite new on average. 60% entered into production after 2000. 35% entered after 2005. A new large ultra-super critical coal-fired plant (about 2 GW at Porto Tolle) is expected to be operating by 2021, together with other CC units. After 2020, the estimated need for new installed capacity rises in order to maintain the adequacy of supply. The reserve margin is expected to fall far below the targeted level of adequacy (23%), because of the dismissal of old plants and the increasing relevance of renewables. This implies that there will be an increasing need for new, flexible capacity in order to balance the system. The price signals on the DAM and the ancillary service market would induce new investment in the best flexible technology, which, at present, we expect to be the full-flexible combined cycles gas turbines with a top efficiency factor of 61%. The long-run scenario doesn't consider the introduction of any new mechanism[11] that would guarantee capacity adequacy. Thus, the system will gradually become inadequate to cover the overall demand, and boom-bust investment cycles will occur. Such a dynamic is related to strong overcapacity and low margins for market participants during the boom phase, and capacity shortage and elevated margins during the bust cycles. For our simulation, this implies that, by the year 2025, there will be newly installed fully-flexible combined cycles gas turbines (we will identify these as "new CCGT", using the acronym NC) that will have a capacity of 14 GW. A caveat must be placed about the ownership of NC and the market share of operators. Indeed, it is expected that actual market share will not change too much, on the basis of the divested investment plans of existing operators, until 2020. In that year, ENEL is expected to be the biggest operator, holding a 35% market share, measured in terms of capacity installed. By 2025, however, when new investments in NC will have been introduced into the market, such a new capacity will almost equal the market share of ENEL (31% ENEL, 30% NC). Clearly,

[11] The Italian Energy Authority (AEEG) has proposed a mechanism (Capacity Market) that is expected to contribute to the long-term adequacy goal. It should begin by 2017. However, its effective implementation is still unclear at present.

attributing such a new capacity to a single owner implies abruptly changing the market structure of Italian electricity production from a market characterized by a leader and several smaller followers to an almost pure duopoly. The other operators' market shares will be dramatically reduced by 2025. This is highly implausible. The new capacity will have to be planned, financed and constructed by companies. It is likely that existing operators, being already active in the Italian market, will exploit, at least partially, their pre-emption advantages when investing in the new NC. In order to provide a plausible description of market evolution, we assume that the flow of investment to new capacity will be partially distributed across active operators and partially attributed to potential entrants. More precisely, it will be uniformly distributed[12] across the 28 existing GenCos in 2020. There will also be 12 newcomers that will provide an additional 6600 MW of capacity to the market. In the case of NP production scenario, these new plants will be displaced by the NP investments, as explained below.

New transmission and interconnection lines are expected to be completed according to the Terna Strategic Plan (Terna, 2011), which has planned the investment aimed at eliminating zonal congestion. Accordingly, zonal prices will become uniform across zones by 2015.

Energy vectors' prices[13] are expected to continue to covariate with Brent. The latter is expected to reduce slowly from a 110\$/bbl spike and converge with the long-run limit set at 77\$/bbl. As a consequence, oil prices in 2025 will equal 89\$/bbl. The dollar/euro exchange rate is expected to oscillate around 1.42\$ by year 2025, and the price differential across energy vectors is assumed to replicate the actual one. The NG price is linked to oil prices through a standard indexing formula. Finally, the ETS cost is assumed to reach 28 euro/tonCO2.

5.2. The new Italian NP plants.

[12] The uniform distribution is chosen so as not to exogenously alter the market share of existing operators. It corresponds to the application of the probabilistic principle of "insufficient reason", which claims that an equal probabilistic treatment is appropriate for similar cases, when there is no information supporting different conjectures.

[13] All prices are expressed in real 2010 terms.

At present, several aspects of the possible NP re-introduction in Italy are unclear. The number and characteristics of the new NP plants have not been defined,[14] nor have their locations been revealed. Italy's major utility, ENEL, has established a partnership with EDF to build and operate four 1650 MWe reactors based on EPR technology, which is currently being implemented in Flamanville, France. Even if other utilities (such as E-On) are interested in taking on leading roles in nuclear build projects, ENEL's plan seems to be the most developed (i.e., it is the plan that is most likely to be undertaken), at least in terms of the data that has been disclosed so far.

The location of the four plants is still unknown; however, it is likely that these will be uniformly distributed across the major zones, the North, Centre-North, Centre-South and South, for the following reasons: *i*) such a distribution would minimise the impact on the transmission network and reduce transmission losses; this would be coherent with the Terna Strategic Plan aimed at eliminating zonal congestion by 2015; *ii*) a uniform distribution might reduce the opposition of local communities, which may be exacerbated by the concentration of NP plants in particular regions; *iii*) it roughly corresponds to the distribution of former NP sites, which shows the distribution of the proper sites in terms of geographical and geological characteristics to host NP plants.

We assume that the increased capacity based on NP installation will reduce the need for investments in NC in the NP scenarios, given that NP power is a must-run base load. This implies that NC capacity is lowered to 7.4 GW under the two NP scenarios, and the additional 6.6 GW are replaced by NP capacity. There is one important point regarding the ownership of the NP plants. The memorandum of understanding that ENEL signed with EDF states that the NP plants will be operated by a joint ENEL-EDF company that will be open to other producers, but the majority of shares will be retained by ENEL. It is agreed that ENEL will have priority over electricity production and usage. At present, it is unclear what share of NP plants will be divested to other market operators and how the electricity produced will be sold in the market. For example, it is unknown whether it will be sold through forward contracts or spot contracts. However, it seems plausible to assume that the NP plants' market operation will be managed by ENEL and that it will be regulated in the spot market.

[14] According to the proponents of the government plan, its aim was to introduce up to 25% NP into the fuel mix in Italy by 2030. Note, however, that this is just a tentative figure (see: ANSA, 2010).

Different assumptions would simply result in a lower share of NP electricity owned by ENEL. Results would change accordingly.

6. The simulation of PUN in 2025 without and with NP plants

6.1 The agent-based simulation of 2025 without NP

We assume that market rules will remain unchanged. Therefore, we repeat the simulation exercise described in Section 3 for 2025 without NP plants. This is called the NO-NP Scenario. We simulate the price for four days, a working day and an off-peak day during the same weeks of the year as in the previous simulation. We chose not to replicate the analysis for the entire week, because the forecast of hourly loads does not change significantly across consecutive days, except when these switch from working days to weekend ones. The price is simulated for the 24 hours of a Wednesday and a Saturday of the 28th and 39th week of 2025, specifically for the 9th and 12th of July and the 1st and 4th of October. On these days, there will be 40 active agents in the market.

6.2 Introducing NP plants

The simulation of prices in year 2025 for the representative days chosen is repeated, with the introduction of NP plants. The methodology introduced in Section 3.1 is updated, assuming that four EPR reactors will be active in the NP scenario. The following equation describes the cost function of an NP plant:

$$TC_{NP}(Q_{NP}) = dQ_{NP}\,, \tag{5}$$

where d is the (constant) NP marginal cost that depends, inter alia, on the technology adopted, the uranium cost, the enrichment process costs and the operation and maintenance (O&M) expenses, including waste cycle management. Q_{NP} is the energy supplied to the market by the NP plant. The marginal cost of NP has been set at 10 Euros/MWh.[15]

In the NP scenario a single agent that owns the NP plants is added to the other 28 agents that represent HT power plants, replacing the 12 NC producers that were active under the NO-NP scenario. We assume that NP plants will not be operated strategically, while all other agents can strategically bid on the HT technologies. The NP producer always bids at the NP marginal cost, i.e., its bid is (d, $4 \cdot Q_{NP}$). Bids are always accepted and constitute the base load of energy production, which is consistent with the observed behaviour of other markets with active NP plants. Such an assumption allows us not to specify the NP plants' profit function, which is not needed since we do not intend to evaluate ex ante the optimality of the decision to invest in NP but rather measuring ex post the impact of such a decision on energy prices.

7. The Italian wholesale electricity price by 2025

We report the simulation results for the chosen days in 2025 in Figures 4 and 5. The figures display the hourly prices in the two scenarios (left axis) and the market demand (right axis), for the Wednesday (left panel) and Saturday (right panel) in July (Figure 4) and October (Figure 5). Table 3 describes the summary statistics for the chosen days, distinguishing between peak and off-peak hours.

[15] This is the average NP marginal cost in the literature (Du and Pearson (2009), MIT (2009), OECD and IEA NEA (2010)), updated to take into account the appraisal of the Euro/Dollar exchange rate. In any case, for the purposes of our simulation, the exact cost is not relevant, because NP is a must-run technology that is always a baseload for the electricity production.

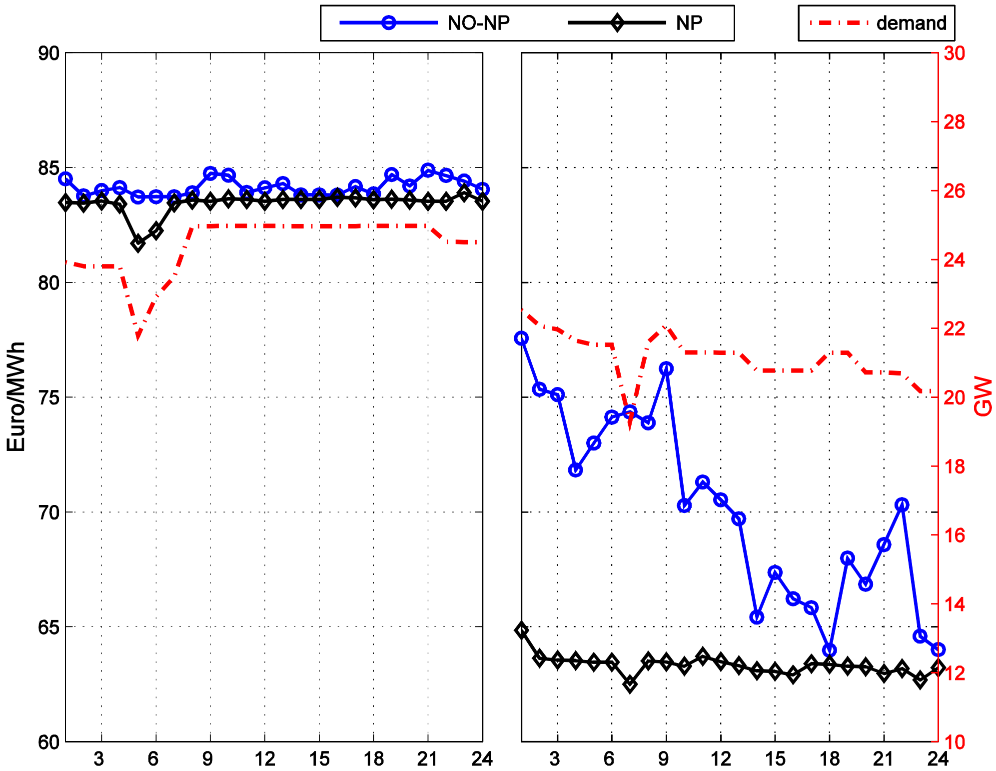

Figure 4: simulated prices for the NO-NP scenario (blue circle-marked line) and NP scenario (black diamond-marked line) -left axis; market demand (dashed line) - right axis; Wednesday the 4th (left panel) and Saturday the 9th (right panel) of July 2025.

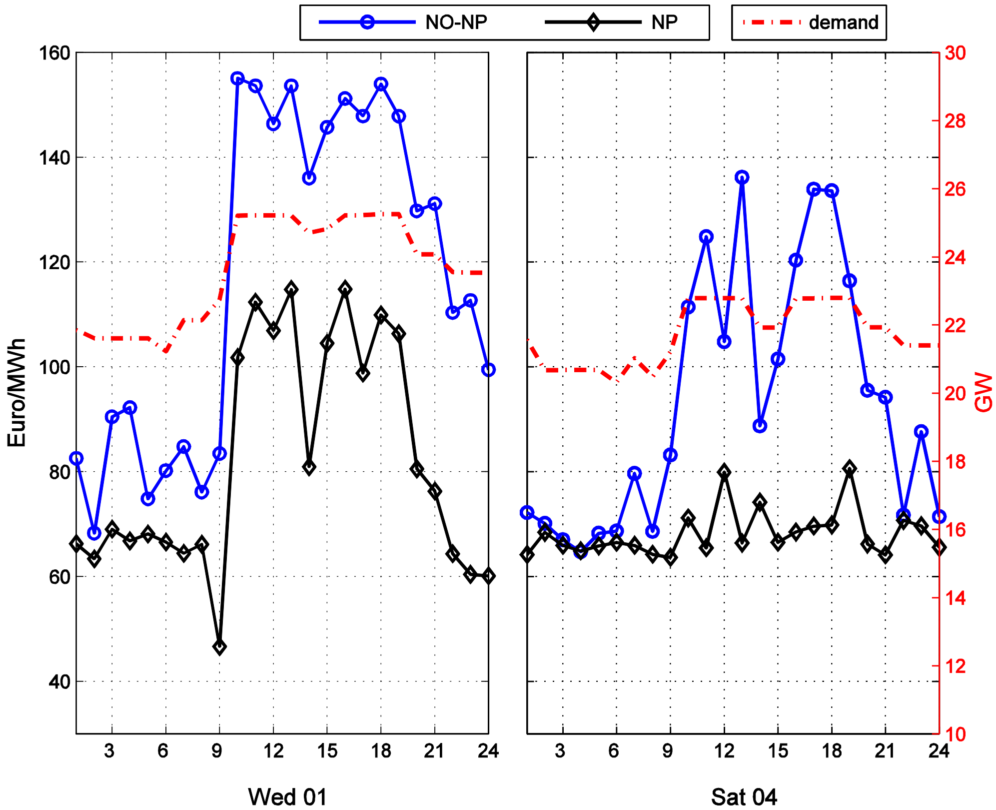

Figure 5: simulated prices for the NO-NP scenario (blue circle-marked line), NP scenario (black diamond-marked line) -left axis; market demand (dashed line) - right axis; Wednesday 01 (left panel) and Saturday 04 (right panel) of October 2025

		July (09 and 12)		October (01 and 04)	
		NO-NP	NP	NO-NP	NP
Mean price	all hours	77,16	73,39	105,05	75,18
St. Dev.		7,63	10,17	30,43	16,98
Mean price	peak hours	84,15	83,60	136,96	95,74
St. Dev.		0,35	0,05	26,45	21,02
Mean price	off peak hours	74,57	69,60	93,19	67,54
St. Dev.		7,40	9,39	22,35	4,56

Table 3 Simulated prices for the NO-NP scenario and NP scenario; summary statistics

The plotted time series show quite different behaviours between the two periods of the year. The simulation for the days in July shows a rather stable pattern for the hourly demand, completely flat for the peak hours. This is coupled with an almost uniform shape for the peak-hours' prices in the NO-NP time series, which becomes slightly more volatile during the off-peak ones. The October demand is higher and more volatile across all hours. The simulated electricity prices are higher and more volatile too. In particular, notice that they spike up to almost 160 Euro/MWh in the peak hours. Comparing the NO-NP prices with the simulated ones for the year 2010, we can see that on average we should expect higher future prices, particularly for the October week. Indeed, the increase in prices is due to a rise in peak hours one for the October simulation and a (lower) increase for the off peak ones. The average rise of peak hours' prices in July 2025 is just 8.6%, while the October prices almost double (82% rise). We can observe also a 15% increase in off peak prices in July and a 54% rise in October.

Contrasting the NO-NP scenario with the NP one, we can see that the NP price time series is lower and less volatile, for both periods of the year and time of the day. This can be observed by comparing the NO-NP time series with the NP ones. When prices are low, as it is in July, the reduction is extremely small: 0.6% in peak hours and 6.6% in off-peak hours. The reduction is higher when prices are high, as is for the October simulations: 30% in peak hours and 27.5% in off-peak hours. In October, the introduction of NP also reduces the volatility, while it slightly increases it in July, remaining extremely low, though. We can summarize the findings by pointing out that the impact of NP on electricity prices corresponds to what one expects, namely that the higher the price, the more NP reduces prices and stabilizes the market. However, its relevance in terms of price reduction is highly different, depending on the hour of the day and the size of the demand load. Moreover, for some peak-hours simulation, it can even be negligible.

8. Conclusions

In the paper a realistic agent-based model was created that replicates the Italian market, with its structural supply and transmission conditions. The computational results show that the model is able to simulate the real Italian day-ahead market performances better than a perfect competition cost-based model. In the proposed framework, agents are able to achieve higher prices by learning their optimal bidding strategies, thus pushing prices above the marginal costs. Sellers take into account their total costs of production, including no-load costs, and generate a pricing behaviour that follows the pattern of the historical one quite well. The few observed price discrepancies might be due to some characteristics of the simulation assumptions, as previously discussed. In particular, we highlight that no collusion among agents is allowed in the model. Moreover, only simple bids are assumed, while in reality, 25% of bids are complex, such as multiple prices and quantities, thus hockey-stick strategies that might arise are not considered in the simulation. One further source of discrepancy comes out from a specific modelling assumptions related to the historical characteristic of the market scenarios learned by the adaptive agents. In order to simulate electricity prices for hour *x* of day *y*, agents learn on a scenario which is based on the exact historical information about the hour *x* of day *y*. However, because of the actual intrinsic uncertainty about the one day ahead forecast and the seasonal behaviour of several market factors, it is well possible that the fit would improve if agents learned on the scenario of hour *x* of the day *y-7* or on other combinations of past scenarios. The misalignment between the expected demand and supply and the real one is a potential source of mismatch among bidding strategies in the current model. A detailed study on the optimal assumptions on past expectations that would determines the best fit goes beyond the aim of this paper; however, it is certainly an intriguing research issue that will be addressed in future works.

In the paper, the simulation model is first compared to the observed prices. Then, it is projected in the future, introducing a plausible market scenario based on conjectures discussed and validated with real market operators. In such a scenario, prices are simulated. It is shown that future prices will be on average higher than actual (simulated) ones. The rise will be more relevant during periods of high expected load.

A further scenario with Nuclear Power plants is also considered. The simulations show that NP production will reduce prices and their volatility. The effect, however, is different across times of the day, being high in periods of high prices, but quite negligible when prices are lower.

An important caveat must be mentioned when interpreting the results of our simulation. Indeed, the results depend on the foreseen market structure. Even if we have made great efforts to describe and incorporate a realistic description of the market in 2025 into our simulator, we are well aware that our scenario depends on several assumptions that need not necessarily be realised in the future. Different scenarios will imply different prices. Our simulation is intended as a tool to evaluate, in a realistic context, the future electricity prices under different assumptions for power production, but should not be intended as a precise projection of future electricity prices. Moreover, in our work, we have not taken into account the choice to reintroduce NP itself. Rather, we have performed a what-if type of study, without evaluating the optimality of NP investments from the point of view of the investor or from a social welfare perspective. In order to do so, a clear estimate of NP investment costs is needed, which is not available at present. Moreover, we have solely considered marginal costs, without taking into account replacement costs, risks and environmental externalities. If we were to take into account all the consequences of NP production and the entire set of costs, the possible impact on total welfare of NP reintroduction might not be positive. This point is worth investigating in further analyses.

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