A MODEL-BASED ANALYSIS ON THE IMPACT OF EXPLICIT PENALTY SCHEMES IN CAPACITY MECHANISMS

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Abstract

A major aim of Capacity Remuneration Mechanisms (CRMs) is to lead the power system expansion towards the level of security of supply that the regulator considers adequate. When introducing a capacity mechanism, therefore, regulators must ensure that the resulting mix will actually provide the firmness pursued, in such a way that both the generation and the demand resources awarded with the capacity remuneration actually perform as expected when the system needs them. In order to achieve this goal, some experts stressed the importance of including performance incentives in the CRM design. However, first capacity mechanisms (implemented mainly in the American continent) did not pay enough attention to this aspect. Two decades of operation have evidenced the need for performance incentives and these instruments are, at this writing, at the centre of the regulatory discussion.

On the basis of a model analysis, this article demonstrates how the introduction of properly designed explicit penalty schemes for under-delivery can positively impact the CRM outcomes, providing resources with effective incentives to maximise their reliability, discriminating against non-firm generation units, and therefore increasing the effectiveness of the mechanism in achieving its objectives.

Keywords

Capacity Remuneration Mechanisms; security of supply; reliability option contracts; explicit penalty; long-term auction; system adequacy.

1 INTRODUCTION

Due to the presence of several market imperfections, already analysed in detail in academic literature (among others, [1], [2], [3], [4]), the vast majority of countries with a liberalised power sector have implemented or are in the process of implementing a Capacity Remuneration Mechanism (CRM). While widespread in the American continent since the very start of market implementation, CRMs are climbing regulatory agendas especially in Europe, due to, among other reasons, the impact of the regulatory-driven high penetration of intermittent renewable energy sources on the market incomes and investment decisions of other technologies ([5], [6], [7], [8])[1]. The United Kingdom has recently held the first auction of its capacity market [12], Italy is accelerating on its reliability options mechanism [13], France will soon launch a CRM based on decentralised capacity obligations [14], while Germany is currently discussing about the possibility of encompassing a market-based capacity mechanism in the Energy Transition reform [15]. Excepting the French case, all these schemes are based on centralised long-term auctions for the procurement of some kind of reliability product. The same approach is followed in many power systems in the United States and all those countries in Latin America which are still organised around market-based mechanisms, which, as stated, introduced CRMs during the last decades ([16], [17]).

CRMs provide resources with an additional and more predictable remuneration with respect to the energy market, with the objective of hedging part of the long-term risk for new entrants and fostering investments. The goal of capacity mechanisms, however, is not merely to attract investments in new "nameplate" capacity, but to foster the installation of firm generation

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[1] Despite this negative impact on investment decisions of conventional technologies, several authors also highlighted the pivotal role of renewable technologies in ensuring the security of supply in future electricity systems ([9], [10], [11]).

technologies that allow to actually enhance the security of electricity supply during real-time operation and to achieve the level of reliability established by the regulator. In exchange for an additional and predictable remuneration, resources taking part in the CRM are required to deliver the contracted contribution when the system most needs it, i.e., during scarcity conditions. However, designing the so-called reliability product that the regulator is willing to procure to actually achieve this objective has proven to be a major challenge [18].

A design element aimed at providing market agents with incentives to be available during scarcity conditions is an explicit penalty for under-delivery[2], to be applied to those generators not fulfilling the CRM commitment. Penalty schemes (also termed performance incentives) were proposed by several authors working on the design of capacity mechanisms ([19], [20], [21]). Nonetheless almost no CRM design did include effective and explicit penalties for underdelivery from the beginning. In Latin America, initial capacity payments remunerated a not-better-specified availability of generation facilities and actual performances had almost no role in the revenue flow. Long-term auctioning mechanisms later introduced corrected some of the flaws of these first schemes (see Batlle et al., 2010, for details), but did not put much emphasis on penalising underperformances either. In the capacity mechanisms implemented in the United States, a slightly stronger remuneration-performance correlation was gradually introduced. However, biases in the design of these penalties[3] hampered their

[2] The distinction between an implicit and an explicit penalty is explained in the next section, after a detailed description of the reliability option principle is provided.

[3] Examples of these biased designs were too-low penalty rates or a methodology for the identification of scarcity conditions that resulted in almost no shortage events during the year.

effectiveness. This absence of properly-designed penalties has often resulted in costly CRMs that were not able to guarantee the level of reliability they were supposed to pursue[4].

However, the situation is swiftly changing. At this writing, penalties and, more generally, performance incentives in CRMs are at the core of the regulatory debate. As largely discussed in recent US Federal Energy Regulatory Commission's dockets ([23] [24]), ISO New England and PJM, two among the most relevant regional power systems in the United States, are reforming their capacity mechanisms following the so-called "pay-for-performance" principle. On the other side of the Atlantic, a specific working group established by the European Commission is focusing on the design of appropriate obligations and penalties [25], and CRMs implemented or under design in Member States already consider stringent penalty schemes. Nevertheless, many questions about performance incentives still need to be answered. How do they affect the generation mix installed in the system? Which is their impact on reliability, measured in terms of non-served energy? How do performance incentives, such as explicit penalties, affect the total cost of electricity supply? Is the higher cost in the capacity market offset (and outbalanced) by a reduction in the expenses related to non-served energy and energy market?

Despite the growing number of reports on this subject issued by relevant institutions working on the implementation of CRMs, no formal analysis of the problem is available in academic literature. The objective of this article is to fill this gap and to stress the ability of the explicit penalty in discriminating against non-firm energy units, providing existing plants with stronger incentives to improve their reliability and eventually leading to the entrance of new

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[4] An analysis of international experience exceeds the scope of this article. However, examples of these regulatory issues were found, for example, in Colombia during the dry year that affected the country in 2009/2010 [22], or in PJM during the "polar vortex" event occurred in 2014 [23].

and more reliable generation plants. The research is developed on the basis of a simulation model that analyses and highlights the effect of the penalty scheme on the merit order of a CRM auction. This discussion benefits from and extends the seminal work of Vázquez et al. (2002) [19], who provided the theoretical basis of one specific kind of capacity mechanism, the reliability option contracts, which strongly inspired mechanisms implemented in different systems[5]. The mechanism, described in detail in the following section, is based on the centralised procurement of call options, which oblige the seller to return any positive difference between the spot price and a strike price, associated to a physical delivery, subject to an additional penalisation for underperformance. Vázquez et al. (2002) [19] also proposed a theoretical framework for the bid calculation to be expected from market agents in the auction. This article draws on such framework to provide a detailed discussion on the role of the explicit penalty through: (i) a theoretical analysis of the problem, focusing on the bids building methodology, and (ii) a two-stage model that simulates the auction itself and allows analysing case studies to confirm the outcomes of the theoretical analysis.

The paper is organised as follows. Section 2 describes the methodology used to face the problem. In the first subsection, the reliability option contracts mechanism is presented, together with the bid calculation methodology originally proposed. In the second subsection, the model used to simulate the auction mechanism is introduced and the theoretical analysis of the problem is developed. After that, section 3 presents the outcomes of the simulation and provides an interpretation of the results. Finally, section 4 draws conclusions and identifies potential policy implications.

[5] The reliability option contracts mechanism is at the base of the capacity mechanisms implemented in Colombia (Firm Energy Obligations) and New England (Forward Capacity Market), and of the CRM currently under design in Italy [13].

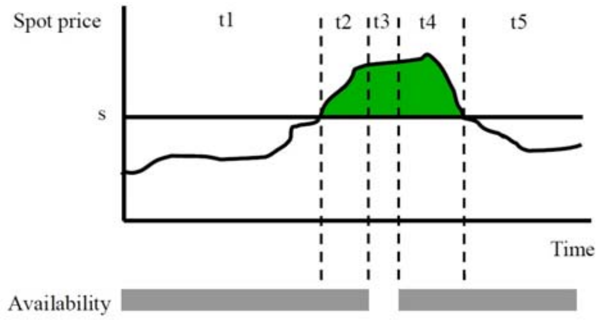
2 MATERIAL AND METHODS

Prior to delving into the description of the methodology, it is worth starting with a caveat: the whole discussion is based on a centralised capacity auction for the so-called reliability option contracts, as originally defined by [19] a mechanism that is introduced just below. However, most of the results of the analysis presented in this article are valid also for other quantity-based CRM designs, procuring different reliability products or using alternative critical period indicators, i.e., the periods of time when CRM-resources have to actually deliver.

2.1 Reliability option contracts

The reliability option contract, consists of a combination of a financial call option with a high strike price to be backed by physical resources and an explicit penalty for non-delivery. It entitles the buyer of the option to receive from the seller any positive difference between the short-term market price p and the contract strike price s for each MW purchased under the contract. In exchange for that, the seller receives a premium fee F. From the generator point of view, selling an option means that it will receive an amount of money F in exchange for limiting to s the price it will obtain from selling its energy, therefore renouncing to the opportunity of selling at short-term prices higher than s. The generator is exchanging an uncertain income, associated to the part of the spot price above the strike price s, for the fixed payment F. The option stabilises a fraction of the generator's income, therefore reducing its risk.

The mechanism also clearly identifies the scarcity conditions of the system as the periods of time when the short-term market price p exceeds the strike price s. In order to strengthen the incentive for the generator to be available at this time, an explicit obligation associated to the physical delivery of the committed capacity is encompassed in the mechanism. Whenever p is higher than s and the unit is unable to honour its obligation to produce, the generator has to pay, apart from the implicit penalty $(p-s)$ representing the basic fulfilment of a plain vanilla financial call option, an additional penalty, denoted as pen. This explicit penalty is meant to discourage those bids that are not backed by reliable generation capacity. The overall functioning of the reliability option contracts mechanism was represented in [19] through Figure 1, which analyses the contract payoff for all possible combinations of spot price, strike price and generator's availability.



Time period		$t1$	$t2$	$t3$	$t4$	$t5$
Demand pays ($/kWh)		p	$p-(p-s) = s$	s	s	p
Generator receives ($/kWh)	without option	p	p	-	p	p
	with option	p	$p-(p-s) = s$	$-(p-s)-pen$	s	p

Figure 1. Payoff of the reliability option contract.

Commonly this mechanism is associated to centralised long-term auctions. The regulator (in most cases with the support of the System Operator) needs to determine the total amount of reliability option contracts to be purchased in order to guarantee the system adequacy in the future, as well as the strike price, the penalty, the lag period (i.e., the range of time that runs between contract signature and delivery) and the duration of the commitment. The bids in these auctions are the premium fees (the so-called capacity remuneration) required to enter into the reliability option contract.

This capacity mechanism presents several advantages from the regulatory point of view, if compared with alternative designs. In a fully-functional electricity market, using the market price as the critical period indicator allows to efficiently and transparently identify scarcity conditions [18].

The difference between implicit and explicit penalties

Now that the functioning of the reliability option mechanism has been recalled and before proceeding with the analysis, it is essential to clarify the difference between implicit and explicit penalties. An implicit penalty requires an underperforming agent to purchase in the electricity market the reliability product it is not able to provide at a certain time, in order to provide its entire expected contribution, even if not through its own assets. An explicit penalty can then be added to the implicit one, in the form of an extra charge for non-compliance. In this case, the underperforming resource is directly "fined" for its missing contribution.

Some experts and most of generation companies argued in the past that the implicit penalty was a sufficient incentive to proper performance [25], but this is not correct, since it reflects a misinterpretation of the opportunity-cost concept: for a generating unit, having to pay a settlement based on a high market price during scarcity conditions has the same value (cost) of missing the opportunity to be paid such a high price. An agent with an obligation subject to an implicit penalty and an agent without that obligation face exactly the same incentive to produce. While the explicit penalty provides resources with a direct performance incentive, the implicit penalty only constitutes a financial settlement.

In order to clarify this issue, imagine a system with reliability option contracts in place. The strike price of the reliability contracts is 100 \$/MWh and the current spot price is 800 \$/MWh. An agent holding a reliability option and delivering its contribution obtains 800 \$/MWh from the market but has to return 800 − 100 = 700 \$/MWh to the system operator, with a net profit of 100 \$/MWh (variable costs are neglected). If the same agent is not able to fulfil its commitment, it will be asked to pay anyway the implicit penalty equal to 700 \$/MWh, with a net loss of 700 \$/MWh. The difference between delivering and not delivering represents a net loss of 800 \$/MWh. However, an agent not holding a reliability option contract, gains 800 $/MWh if it produces or 0 $/MWh if it does not produce. The difference between delivering and not delivering is always a net loss of 800 $/MWh (Table i).

Table i. Market settlements of agents with and without a reliability option contract when producing or not producing. Spot price 800 $/MWh, strike price 100 $/MWh.

	Producing	NOT Producing	Difference
Agent WITH reliability option contract	100 $/MWh	-700 $/MWh	-800 $/MWh
Agent WITHOUT reliability option contract	800 $/MWh	0 $/MWh	-800 $/MWh

Therefore, no further incentive is provided by the implicit penalty[6]. This example shows how only a properly-defined explicit penalty scheme can foster the agents to fulfil their obligations and ensure the reliability of the system.

2.2 Bid calculation in the theory

As mentioned above, the bid in the auction reflects the required premium fee of the option contract. Since the option caps the future hourly remuneration of the generating unit selling the contract to the strike price s (this obviously does not mean that the spot price cannot exceed this value, since not all available resources have necessarily been committed in the auction), the bid will be defined with the objective of at least recovering, through the fee, this loss of income, plus the expected charge to be paid in case of underperformance. Each agent

[6] Actually, the problem is even more complex. In the cash accounting of power companies, the two net losses presented in the example are perceived in a very different way, since not earning a certain revenue is not the same as having to pay out the same amount. Therefore, also an implicit penalty could, in some cases, provide a weak performance incentive. However this effect is not comparable with the strong signal provided by a proper explicit penalty, thus it is not analysed further.

is expected to calculate the offer according to its forecasts on the short-term market price and on its expected availability during scarcity conditions. As discussed right next, the approach depends on whether the plant is an existing generation facility (whose investment costs are considered as sunk) or a new investment.

Bid calculation for existing facilities

As just mentioned, for existing generation facilities, investment costs do not play any role in the offer, so in this case the bid calculation can be represented by the following formula [19]:

$$F_i = \int_{p>s} \left(1-\lambda_i\right)\cdot\left(p-s\right)dt + \int_{p>s} \lambda_i \cdot \left(p-s+pen\right)dt \tag{1}$$

In this equation, λ_i represents the probability of generator i not being able to produce the capacity committed in the option contract during scarcity conditions. In order to clarify and gain insights on the previous expression, it will be considered that each time the spot price exceeds the strike price, it reaches the price cap[7]. The expression can then be expressed as:

$$F_i = \left(p_{cap} - s\right)\int_{p>s} dt + pen\int_{p>s} \lambda_i dt \tag{2}$$

According to this last formulation, the bid from risk-neutral agents can be divided into two terms. The first term represents the expected option value for a risk neutral agent, i.e., the

[7] Price caps (or offer caps) are in place in the vast majority of short-term power markets. They are used to set the price when the generation is not sufficient to cover the load, because in these conditions the inability of a large part of the demand to properly reflect their utility value in their bid does not allow to clear the market. Their application is often justified by regulators as necessary to tackle market power issues, but they are commonly used to simply avoid electricity prices that regulators and governments consider unacceptable to be passed through to consumers. Even if economic theory demonstrates that price caps negatively affect market efficiency, these instruments are so widely used that a realistic analysis has to take them into account.

remuneration that the generator is losing from the spot market because of signing the option contract, while the second term represents the expected penalty. With this formulation, it is also possible to observe how the option value depends on the expected number of hours with scarcity conditions $(p > s)$, while the penalty depends on the integral of λ_i. This factor is of special interest for the analysis outlined in this paper. It represents the expected number of hours in which the scarcity conditions are concurrent with the unavailability of the generation facilities of the agent, due for example to the forced outage of a generating unit or to fuel supply constraints. Furthermore, it must be underlined that the expected option value is the same for all the agents, whereas the expected penalty is different for each agent (the same penalty value is applied to different unavailability factors).

Bid calculation for new investments

In the case of a potential new generating unit, which can still decide whether to invest or not, an additional term must be included in the bid calculation, besides the expected option value and penalty. For the investment to be attractive, the agent needs to recover the total fixed and variable costs. If the spot price is not sufficient to recover the investment, the agent will be eager to seize this required income in the reliability market, i.e., in the auction. Such additional term can therefore be expressed as any positive difference between the required annual income and the expected short-term market remuneration.

2.3 Model structure

Vázquez et al. (2002) [19] developed a stylised case example in order to simulate possible auction results. The approach followed was based on some simplified heuristic assumptions (for example, generators, at the moment of calculating their bid based on the expected future dispatch, perceive the number of hours of scarcity as proportional to their own availability).

Although some relevant insights could be obtained with such modelling approach, many relevant correlations were lost.

The objective of this study is to refine the modelling approach by allowing the agents to forecast more realistically the parameters required for properly calculating the bid in the long-term auction. The problem is represented through a two-stage model that replicates the tender itself based on the results of a simulated future short-term market. The latter is represented by means of a deterministic Unit Commitment (UC, used to reproduce a day-ahead market with perfect competition), including explicit consideration of hourly availability through Monte Carlo simulation[8]. In this paper a direct-search approach is applied. First, all potentially feasible generation mixes are identified and the short-term market is simulated for each one of them. Then, bids are calculated based on the result of the short-term market and long-term auctions are cleared. Finally, the mix resulting from the auction is compared to the initial mix used to simulate the short-term market for validation. Once all feasible solutions are determined, the model selects the one that minimises the price in the auction. This methodology, graphically represented in Figure 2, is carefully described in the sections that follow.

[8] For other modelling approaches on capacity mechanisms or, more in general, investment strategies, the reader can refer to [26], [27], [28], and [29] among others. For demand response modelling in capacity market programmes under penalty schemes, see [30].

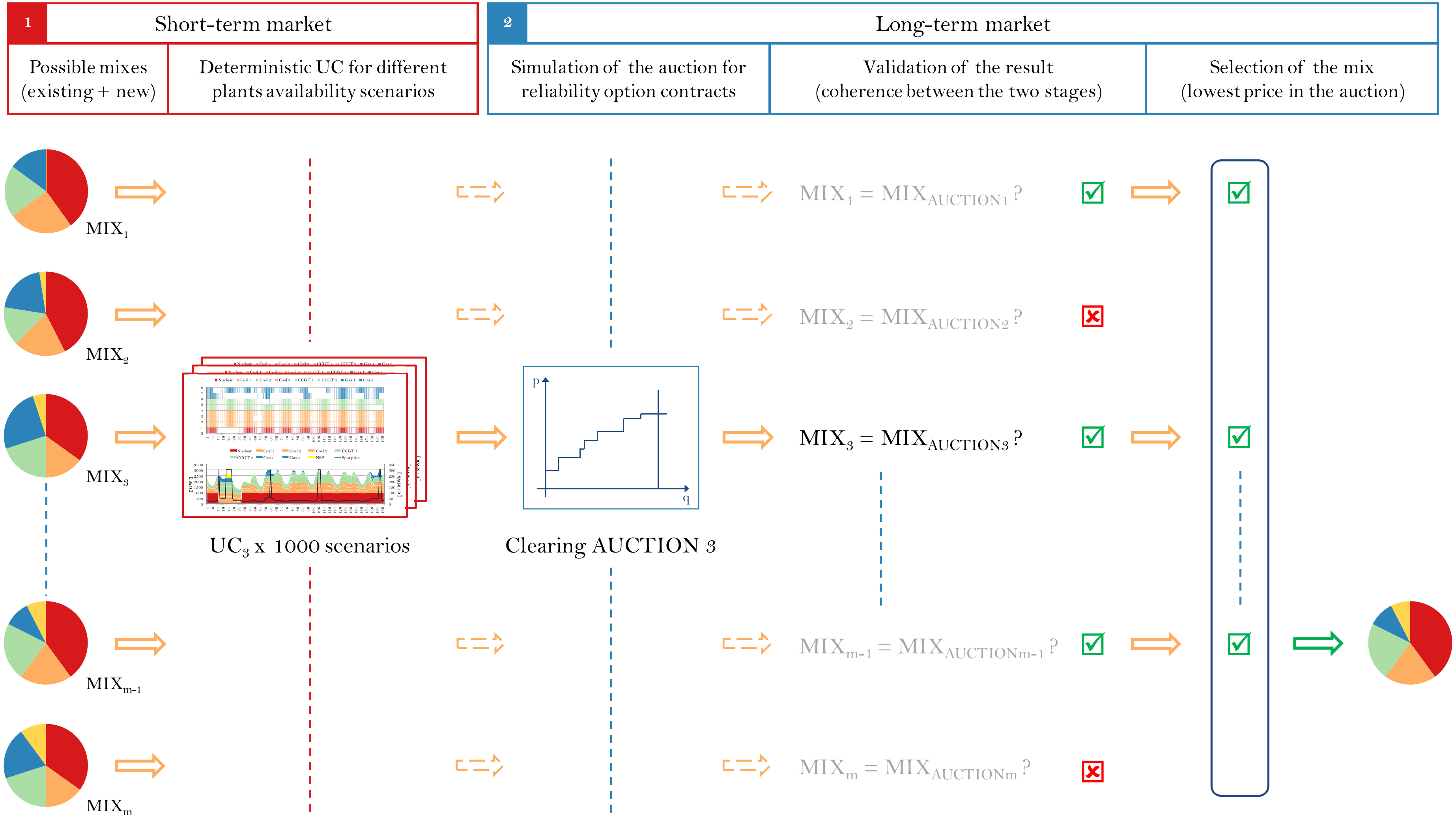


Figure 2. Schematic representation of the two-stage model used to simulate the auction process.

First stage: the short-term market considering unavailabilities

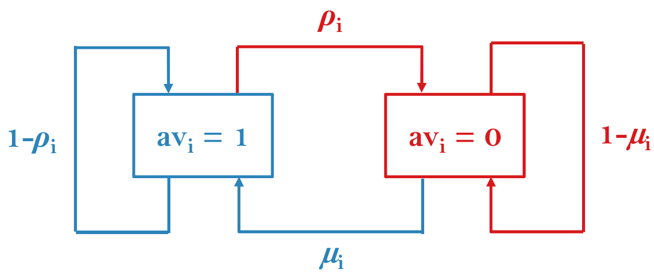
The model is based on a reference generation mix composed only by thermal plants. The selection of the technologies to be included in the mix was guided by the goal pursued through the model. The objective of this research is not to predict actual results for a specific system, but rather to show the impact of a parameter, the explicit penalty for underperformance, on the outcomes of a capacity mechanism. Therefore, the generation mix considered in the case studies is realistic, but as simple as possible, in order not to mix too many effects together and not to "dilute" results[9]. 80 existing thermal generation units (20 nuclear units, 30 coal units, 25 CCGT units, and five fuel oil units) are considered, to whom 15 potential new CCGTs are added. Different combination of existing and new plants are explored and, depending on the number of new units considered to be installed, different initial mixes are created.

For each one of these potential generation mixes, a deterministic unit commitment is run for a time period of one year. The UC is used to reproduce a day-ahead market with perfect competition, whose spot price is calculated as the marginal cost of the system, as in the Security Constrained Economic Dispatch (SCED) models used in many power systems in the United States [31]. Besides the spot price, non-linear side payments with daily settlements are considered for those units which do not recover their start-up, no-load, or shut-down costs. Furthermore, a 3 000-€/MWh price cap is applied, as in the EUPHEMIA algorithm

[9] For this reason, hydropower and renewable technologies are not considered as part of the reference generation mix. Nonetheless, similar results as those presented in section 3 would apply to these plants, depending on the EFOR they are assigned. The same model could be used to see, e.g., how a photovoltaic power plant is less affected by the explicit penalty if it is coupled to a storage system.

used to clear the European regional day-ahead market, see [32]. For the detailed model formulation, as well as for data used, see the Appendix.

On the other hand, a proper representation of generation availability is of utmost importance for the purposes of this study. The hourly representation of plants availability allows to analyse the contribution of each generator to the reliability of the system during scarcity conditions. This is achieved through a random availability matrix, which defines for each plant i and for each period t, i.e., each hour for which the unit commitment problem is solved, whether the unit is available or not (i.e., $av_{i,t}$ can be either 0 or 1). This random availability matrix is created through a two-state Markov chain, which simulates the transition from the availability to the unavailability state and vice versa through predefined probabilities. The schematisation of the process is presented in Figure 3, in which ρ_i represents the probability of failure of unit i, while μ_i represents the probability of recovery from failure of unit i.



$$\rho_i = 1/\mathrm{MTBF}_i \qquad \mu_i = 1/\mathrm{MTR}_i$$

$$EFOR_i = \mathrm{MTR}_i/(\mathrm{MTBF}_i + \mathrm{MTR}_i)$$

Figure 3. Two-state Markov chain used for the creation of the availability matrix.

The two probabilities involved in the process are calculated from the combination of three parameters: the Equivalent Forced Outage Rate (EFOR) of thermal units, which represents the percentage of hours of unit failure and can be used as a proxy of the probability of the unit not being able to produce; the Mean Time Between Failures (MTBF), which represents the expected elapsed time between successive failures of a thermal unit; and the Mean Time to Recovery (MTR), which represents the expected time required to repair the thermal unit. For the sake of simplicity, the MTR has been considered to be the same for all the units. Therefore, it is the EFOR, and consequently the MTBF, the parameter which is used to reflect the diverse reliability level of each generation plant. In the case study (presented in the following section), new CCGT units are considered to have lower EFOR rates than existing plants, reflecting the higher expected reliability of new facilities.

Once ρ_i and μ_i probabilities have been calculated for each plant, the availability matrix can be created, through a random number generator. In order to get comparable results for different case studies and input parameters, the random numbers are maintained constant through the use of the same random seed. Furthermore, the utilisation of Monte Carlo techniques requires to solve the UC problem for several scenarios, applying different availability matrixes, so as to have a statistically relevant sample. In this model, 1 000 scenarios, 1-year long, have been used for each generation mix.

In order to illustrate the impact of generation availability on the solution of the unit commitment, a sample week has been selected and the UC problem was solved for a simplified system with only eight generation units (for graphical purposes). The results are presented in Figure 4 and Figure 5. As it can be observed in the charts, the consideration of unavailability through the matrix causes plants to "fall" in the resulting unit commitment, causing the start-up of more expensive plants and, in the cases in which the available generation is not sufficient to cover the demand, the occurrence of non-served energy and the consequent activation of the price cap (as described in the appendix, demand is assumed to be inelastic). As it can be seen in the availability matrix, units' failures have different durations (but the average duration is equal to the Mean Time to Recovery).

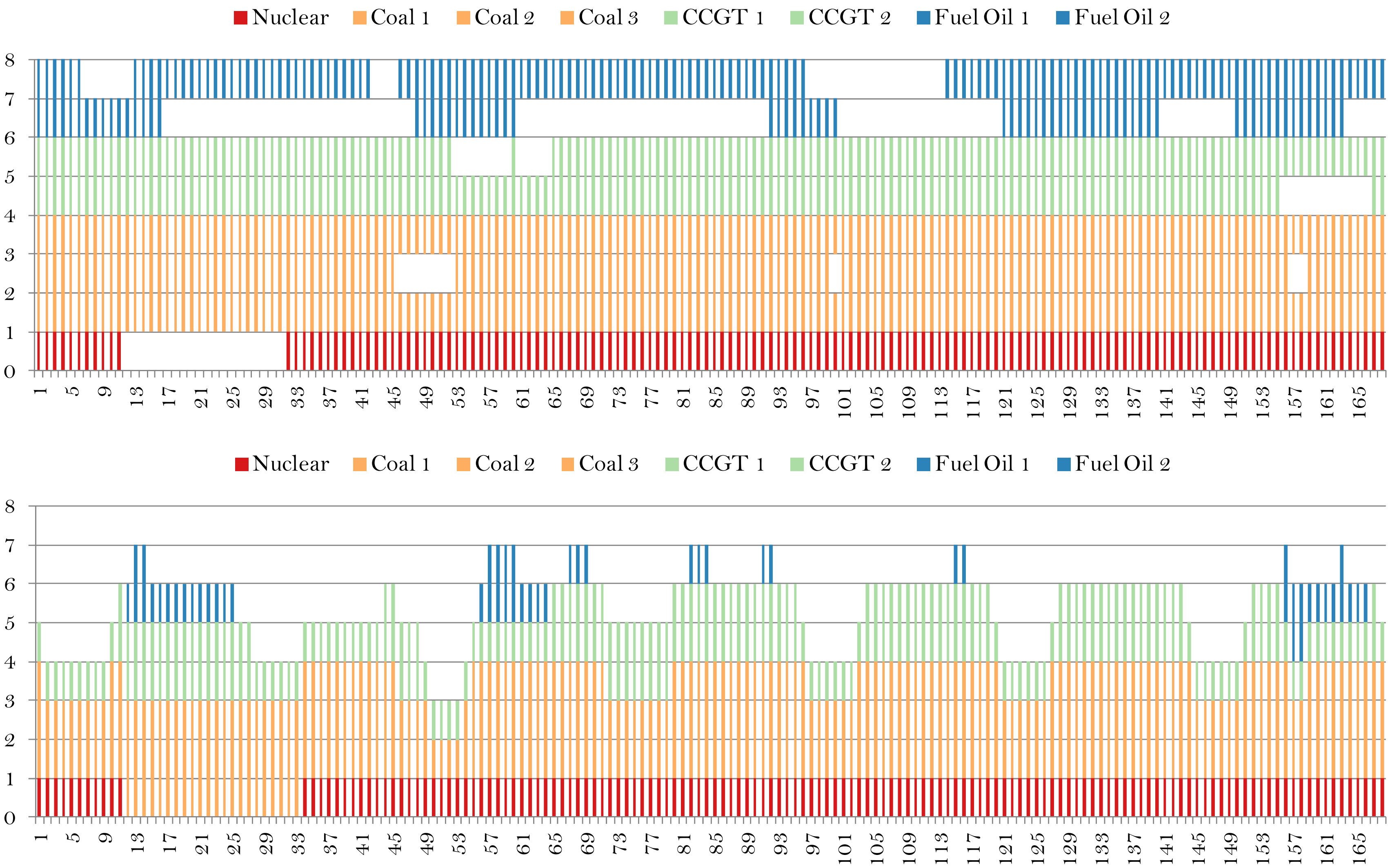


Figure 4. Availability matrix (above) and resulting commitment variables (below) for one week and one scenario.

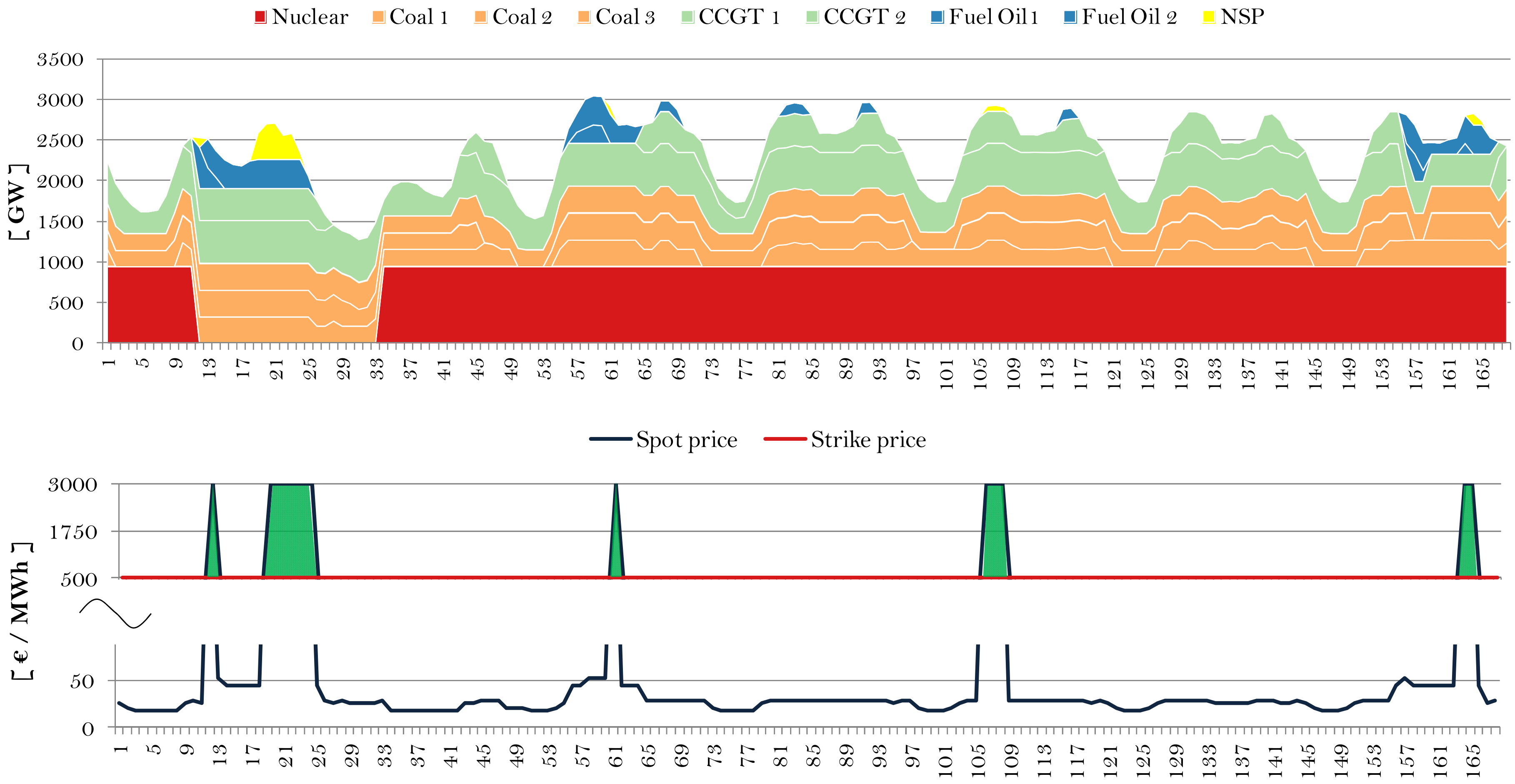


Figure 5. Production variables for the UC problem (above) and comparison between the resulting spot and the strike price (below).

In Figure 5, the spot price resulting from the unavailability consideration is compared to the strike price[10] of the option contracts. This exercise allows to identify the scarcity conditions of the system. It is easy to observe the equivalence between Figure 5, obtained from the modified unit commitment, and Figure 1, which was shown when presenting the payoff of reliability option contracts. The results from the model allow not only to identify scarcity conditions, but also to assess the performance of each generation unit in those conditions. This provides all the information required for the calculation of the expected bids in the auction.

Second stage: the long-term market

The outcomes of the first stage are used to feed the auction simulation. The economic performance of each generator is analysed for each scenario and the bid is calculated considering the economic impact of signing a reliability option contract (the bid calculation methodology used in the model is explained in detail in the next subsection 3.4). An average bid is then calculated for each unit by averaging the results of the 1 000 scenarios, and the auction is cleared for a predefined demand value. These operations are carried out for each one of the generation mixes initially considered.

Once the simulated auction is cleared, it is possible to check how many new power plants are selected and installed based on the auction result, and therefore, to define the resulting generation mix. In fact, in this model new entrants will invest only if they are cleared in the

[10] In order to avoid the interference of the capacity mechanism with the short-term market, in [19] the strike price was suggested to be set at least 25% above the variable costs of the most expensive generator expected to produce in the market. The strike price for the model has been selected complying with this rule and it has been set to 500 €/MWh. This implies that when the strike price is exceeded, the spot price automatically reaches the price cap active in the short-term market.

auction and have access to the CRM remuneration. However, this creates the need for a validation of the result. If the generation mix resulting from the auction is different from the mix used to simulate the short-term market through the unit commitment, then the two stages of the model are not coherent and that solution must be rejected. Otherwise, the two stages are coherent and the solution is maintained (green checks in Figure 2). This operation results in several feasible solutions, representing all possible generation mixes.

The final solution, which represents the generation mix resulting from the auction for a certain set of input parameters, is selected as the feasible solution that has the lowest clearing price in the tender.

2.4 Bid calculation in the model

Bid for existing generators

The premium fee required by each unit, i.e., the bid it would present with perfect information, can be obtained by processing the results of the short-term market simulation. This requires the introduction of new parameters, which are presented hereunder.

- $cuna_i$ is the counter of unavailability of generator i and represents the number of hours during the year in which the unit has been unavailable.
- $csca$ is the counter of scarcity conditions in the system and represents the number of hours during the year in which the spot price exceeds the strike price and reaches the price cap.
- $cund_i$ is the counter of under-delivery of generator i and represents the number of hours during the year in which the unavailability of the unit is concurrent with the occurrence of scarcity conditions in the system.
- $lrem_i$ is the lost remuneration of generator i and represents the summation along the year of the income that the agent is returning to the buyer of the option contract when it

is producing electricity during scarcity conditions, because in those hours its remuneration is capped to the strike price s.

- $ipen_i$ is the implicit penalty of generator i and represents the summation along the year of the difference $p-s$ that the agent has to return to the buyer of the option for each MW considered in the contract when scarcity conditions occur and the unit is not producing.
- $epen_i$ is the explicit penalty of generator i and represents the summation along the year of the explicit penalty that the agent has to pay to the buyer of the option because of under-delivery during scarcity conditions.
- $capa_i$ is the maximum capacity that generator i can bid in the auction and is equal to its nameplate capacity (no constraints on tradable quantities are considered).
- bid_i is the bid of generator i in the auction and represents the premium fee that the agent requires in order to enter into the option contract.

For the sake of simplicity, it will be considered that all the units are willing to take part in the auction with their entire capacity, for which they will present one single price bid. With these assumptions, the parameter bid_i can be calculated as the sum of the loss of income $(lrem_i)$ plus the implicit $(ipen_i)$ and explicit $(epen_i)$ penalty that the generator incurs because of signing the reliability option contract, divided by the capacity that it can bid in the auction $(capa_i)$. Note that these new parameters represent yearly values, this is why the integral does not appear in the following equations. The expression can be written as:

$$bid_i = \frac{lrem_i + ipen_i}{capa_i} + \frac{epen_i}{capa_i} \tag{3}$$

With this formulation, it is possible to observe once again two terms, one representing the option value and the other representing the penalty. The bid calculation formula can be expressed as:

$$bid_i = \frac{capa_i \cdot \left(p_{cap} - s\right) \cdot \left(csca - cund_i\right) + capa_i \cdot \left(p_{cap} - s\right) \cdot cund_i}{capa_i} + \frac{capa_i \cdot pen \cdot cund_i}{capa_i} \tag{4}$$

$$bid_i = \left(p_{cap} - s\right) \cdot csca + pen \cdot cund_i \tag{5}$$

The second equation, obtained by simplifying the first one, is exactly equivalent to equation (2), resulting from the theoretical analysis. Again, the option value is the same for all the agents, while the penalty varies according to the parameter $cund_i$, which is different for each generator (and which is equivalent to the integral of the λ_i term in the original equation).

Bid for new entrants

In the case of new entrants, the same considerations expressed in the previous section apply. Since the new entrant can still decide whether to invest or not, an additional term must be included in the bid calculation, representing any positive difference between the required annual income and the expected short-term market remuneration. With the formulation proposed in this section, this can be obtained through the introduction of further parameters.

- $icos_n$ is the annualised investment cost of generator *n* and represents the required annual income.
- $ocos_n$ is the operation cost of generator *n* along the year simulated.
- $mrev_n$ is the short-term market revenue of generator *n* and represents the summation along the year of the incomes from the spot market.

- bid_n is the bid of generator *n* in the auction and represents the premium fee that the new entrant requires in order to invest and to enter into the option contract.

The bid_n parameter can therefore be calculated as for existing generators, with the addition of the new parameters.

$$bid_n = Max\left(0; \frac{icos_n + ocos_n - mrev_n}{capa_n}\right) + \left(p_{cap} - s\right) \cdot csca + pen \cdot cund_n \tag{6}$$

Therefore, the formulation for new entrants has three terms. Besides the option value (the same for all existing generators and new entrants) and the penalty (different for each generator, depending on the $cund_n$), the first term is related to the annualised investment costs and it depends on the technology considered and on its incomes in the market.

Theoretical discussion on the dependence of the bid on the penalty

The next section presents the impact of the explicit penalty on the merit order of the auction and on electricity supply costs based on the outcomes of the model. In order to understand such impact, this subsection clarifies the dependence of bids on the explicit penalty. In the previous subsections, the formula for the calculation of the bid from existing unit was expressed as follows.

$$bid_i = \left(p_{cap} - s\right) \cdot csca + pen \cdot cund_i \tag{7}$$

In order to highlight the dependence of the bid_i on the pen value, the previous expression can be rewritten as:

$$bid_i = A + pen \cdot B_i \tag{8}$$

Therefore, the bid from existing units is composed of a term that does not depend on the explicit penalty (the option value), which can be considered as a constant for all the existing plants (A), and a term where the pen value is multiplied by the $cund_i$ factor (B_i), which is different for each resource. As mentioned in the previous subsection, the $cund_i$ factor measures the expected unavailability of each unit during scarcity conditions and it depends basically on the EFOR.

However, this is no longer true in the case of new entrants bidding in the auction. In fact, their bids consider an additional term, as introduced in the methodology and repeated here.

$$bid_n = Max\left(0; \frac{icos_n + ocos_n - mrev_n}{capa_n}\right) + \left(p_{cap} - s\right) \cdot csca + pen \cdot cund_n \quad (9)$$

Once again, the previous expression can be rewritten as:

$$bid_n = C_n + pen \cdot D_n \quad (10)$$

The same two terms as in the case of existing generators can be identified. However, in the case of new entrants, also the constant term that does not depend on the explicit penalty is different for each new entrant. It can be assumed that the C_n factors are greater than A, because of the investment term to be added to the option value in the bids from new entrants, and that the D_n factors are usually lower than the B_i factors, because new facilities are commonly more reliable than existing ones.

Offers from existing generators and new entrants are represented in a *bid-pen* chart in Figure 6 for a simplified example with three generators. The evolution of the unitary bids (€/MW) from existing generators as the penalty increases is represented by a family of straight lines leaving from the same intercept (the option value) and having different slopes. Bids from new entrants leave from a higher intercept, due to the internalisation of their investment costs, but have lower slopes, reflecting their higher reliability. Lines representing the evolution of unitary (€/MW) bids from existing units never cross among them, but they do cross the bid from the new entrant. This means that a change in the explicit penalty does affect the merit order causing the displacement of existing units by new entrants. This can be observed in the right part of Figure 6.

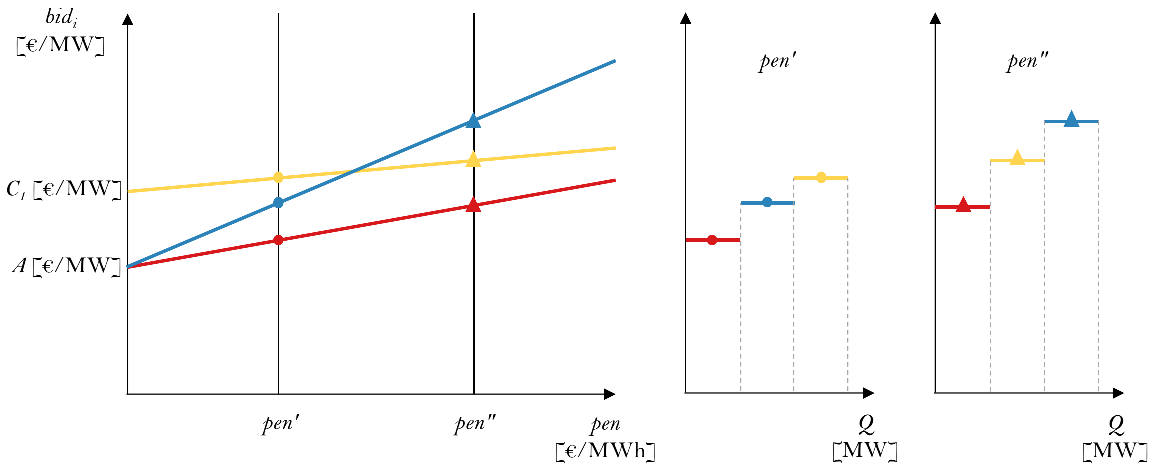


Figure 6. *bid-pen* chart with two exiting generators and a new entrant and the impact on the merit order.

3 RESULTS AND DISCUSSION: THE IMPACT OF THE EXPLICIT PENALTY

After the detailed explanation of the functioning of the model, this section presents the outcomes of the case study. Results are divided in two subsections. In the first one, the impact of the explicit penalty on the merit order of the auction is analysed. In the second one, the attention is focused on how the explicit penalty affects the total cost of electricity supply for final consumers.

3.1 The impact on the auction merit order

As mentioned in the methodology, the model allows to find the generation mix (thus, the number of new entrants joining the system) that results in the lower auction clearing price for a certain set of input parameters. However, instead of providing results in terms of single sets of inputs, in this section the attention is focused directly on the parameter under study in this article, i.e., the explicit penalty. For different values of the explicit penalty, the model selects a different generation mix (even if the impact of investment lumpiness is observed) due to the dependence that this parameter has on auction bids, as showed in the previous section. The first result that can be obtained is a reproduction of Figure 6 with real data produced by the model for the case study. Figure 7 shows the results of a simulation with a generation mix composed by 80 existing units plus nine new CCGT plants.

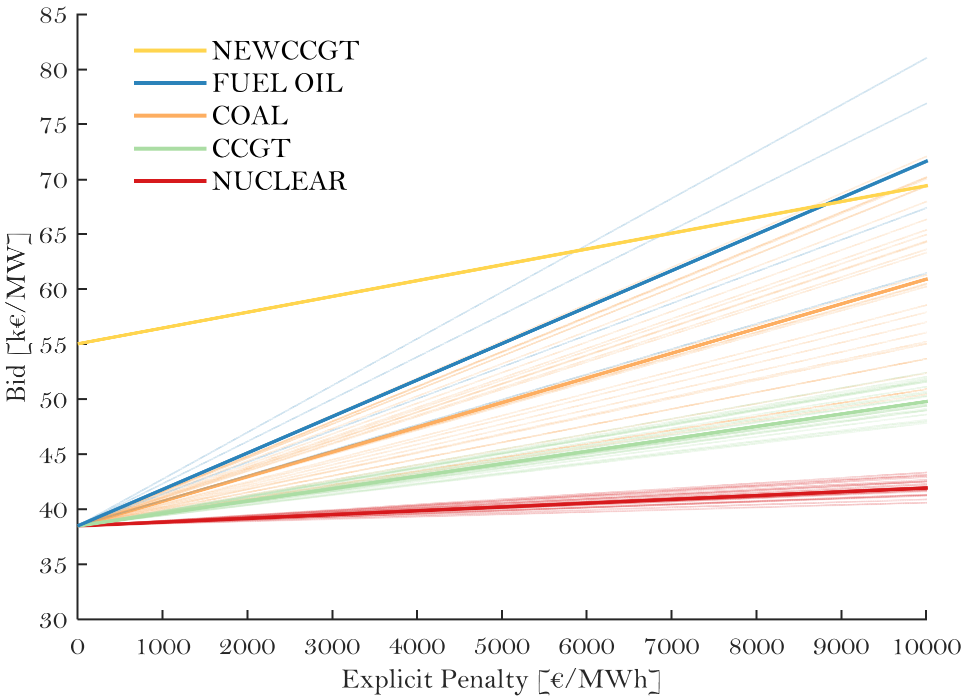


Figure 7. *bid-pen* chart for a system with 80 existing units and 9 new CCGT plants.

As mentioned in the theoretical discussion, bids from existing units are represented by a family of straight lines leaving from the same intercept (the option value) and having different slopes (the counter of under-delivery, B_i in the picture). Each technology is represented with a different colour. Since each plant may have a different EFOR within a range defined for each technology, dark lines represent the unit with the median EFOR for the specific technology and light lines the rest of the units. If only existing plants are considered, an increase in the explicit penalty can widen or narrow the gap between different bids, but it cannot affect the merit order, because the straight lines do not cross. The merit order is completely defined by the slope of the lines, i.e., by the counter of under-delivery.

On the other hand, bids from new entrants are represented as a single line (since they are all the same technology, i.e., CCGT, the same investment costs and the same EFORs are considered), leaving from a higher intercept, but having a lower slope, which crosses the family of straight lines representing existing units. Since the lines cross, in this case a change in the explicit penalty does affect the merit order, causing the displacement of existing units by new entrants.

The chart in Figure 7 represents a specific initial generation mix (in this case, the one considering nine new units), which is used to run the unit commitment. Similar charts can be drawn for different initial mixes, considering a different number of new CCGT plants. By applying the coherency checks described in section 2 (Figure 2), it is possible to aggregate all this information to obtain the chart in Figure 8, which represents the generation mix cleared in the auction for increasing values of the explicit penalty for underperformance.

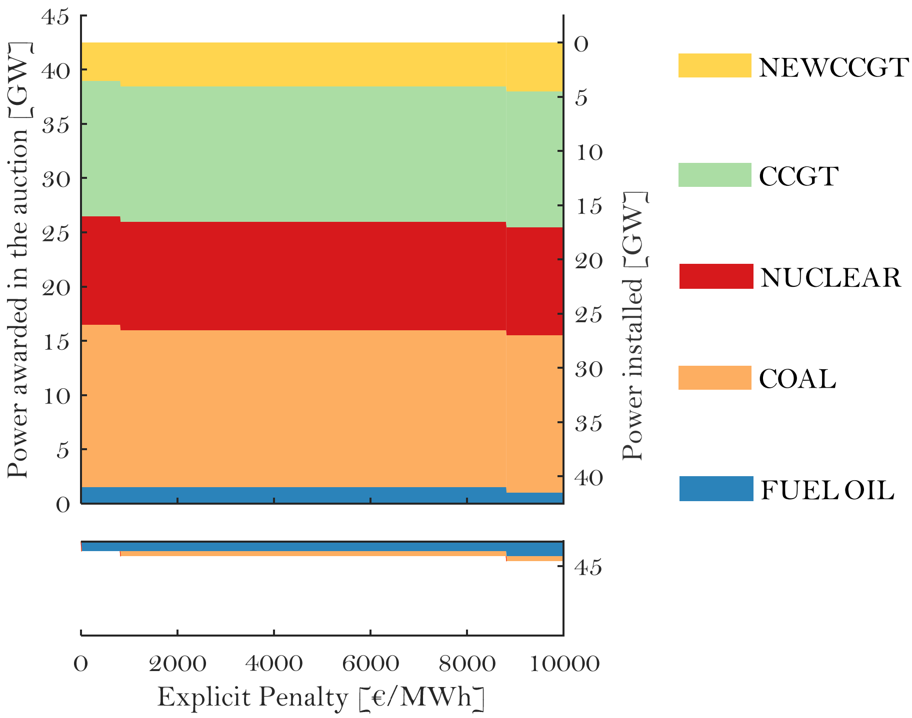


Figure 8. Evolution of the auction merit order and resulting mix for different values of explicit penalty.

The positive y-axis shows the merit order of the auction and which plants are cleared in. The negative y-axis shows existing plants which have been displaced by new entrants with lower bids. Those plants are not cleared in the auction, but they are considered to keep on being part of the system. Thus, on the right side of the y-axis, the total installed capacity, including both new and existing units, is shown.

The effect of the explicit penalty can be clearly observed. Without an explicit penalty, only those new plants needed to cover the demand in the auction (which represents the expected growth in electricity demand with respect to the current one) are cleared in and all existing units are granted reliability contracts. However, as the explicit penalty is increased, new units start displacing existing plants in the merit order. The higher the penalty, the higher the number of new and more reliable units that enter the system and the higher the number of non-firm existing generation plants that are displaced. This is due to the fact that, as shown in Figure 7, the economic impact on the bid caused by higher penalties is more severe for those less-reliable units with higher EFOR rates.

3.2 The impact on the total supply costs

The previous subsection showed the effect of the explicit penalty on the merit order of the auction and how it fosters the entrance of new and more reliable units. However, this intervention can affect in different ways the market income of the existing generation mix, the cost that end consumers have to pay for their electricity supply and, in general, the net social welfare. This subsection analyses the variation in capacity-market and energy-market costs (as well as the evolution of non-served energy) for different values of explicit penalty. The objective is to assess the impact of the explicit penalty on the cash flows of power sector agents and on the overall cost of electricity supply.

First of all, the application of higher penalties decreases non-served energy. The entry of new units, obtained through the introduction of the explicit penalty, results in a higher reliability of the system, which can be measured through the number of hours with scarcity conditions (Figure 9). In this chart, the effect of the lumpiness of investments is evident. Each time a new CCGT plant is cleared in the auction (when the penalty value becomes high enough to allow it to displace an existing unit) the number of scarcity hours is significantly reduced. This is due to the combined effect of having a more reliable plant in the system, and of an increased reserve margin (the displaced existing unit is considered to remain in the system, as explained in the methodology).

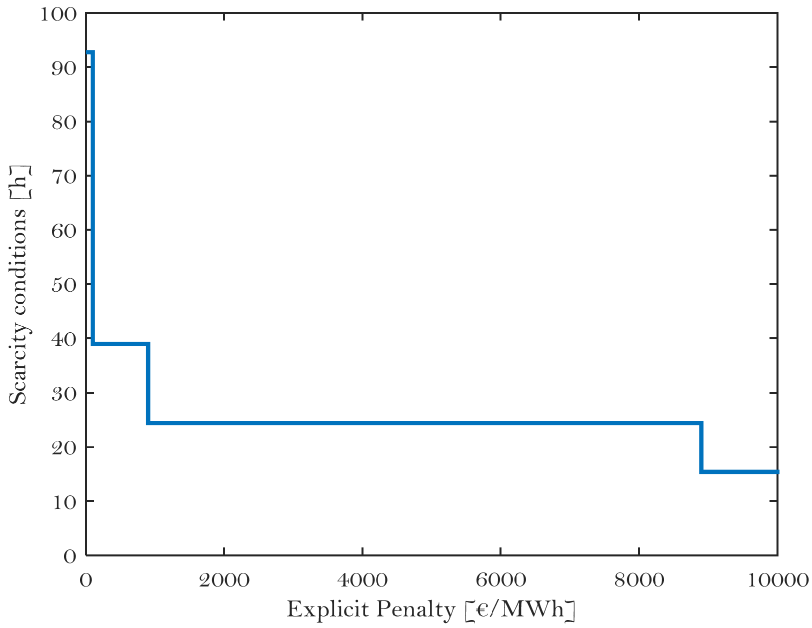


Figure 9. Evolution of the number of hours with scarcity conditions for different values of explicit penalty.

Beyond this straightforward "physical" impact on the system reliability, the level of the explicit penalty also alters the economic flows among market agents. Figure 10 provides a graphical comparison of the capacity-market and the energy-market costs (including the value of non-served energy) as the explicit penalty increases. Two different penalty values are considered, a low-penalty (1 000 €/MWh) and a high-penalty scenario (10 000 €/MWh).

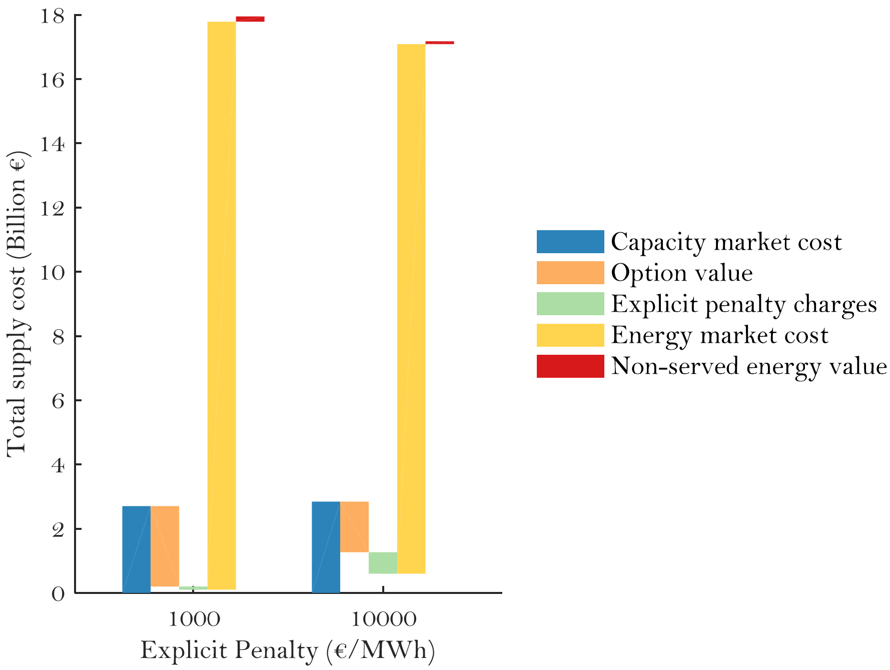


Figure 10. Overall cost of electricity supply for two different values of the explicit penalty.

The introduction of higher penalties increases the clearing price in the auction (as shown in Figure 7) and, therefore, the overall cost of the capacity mechanism (which is eventually paid by end-users), as a higher clearing price is received also by those existing units selected in the auction. This has been identified by some stakeholders as a windfall profit [33]. This effect can be observed in Figure 10, where the cost of the capacity market increases as the penalty value grows from 1 000 to 10 000 €/MWh. However, in order to understand this increase, the reader must remember the functioning of reliability option contracts. Part of the premium paid to generation resources is recovered during scarcity conditions, when agents under the CRM have to return the difference between the spot and the strike price, i.e., the option value. It can be observed that the option value declines when the penalty is increased. This is due to the entry of new plants that improve the reliability, decrease the number of scarcity events, and therefore decrease the total rent to be returned by resources during shortages.

Another part of the premium paid in the auction is also finally compensated to the system through the explicit penalty charges paid by underperforming reliability providers. This part obviously increases for higher penalties. In fact, even if fewer scarcity conditions occur due to the improved reliability, the growth of the penalty value counterweights and overcomes this effect.

Subtracting from the capacity-market cost both the option value and the explicit penalty charges, it is possible to obtain the "net" cost of introducing the capacity mechanism, which represents the remuneration distributed among power resources taking part in the CRM. When the penalty value is increased, new units are cleared in the auction, through bids that internalise part of the investment cost of these facilities, thus resulting in a higher net cost of the capacity mechanism. In this case, it is true that a very reliable existing unit is receiving a higher remuneration from the capacity market in the high-penalty scenario by selling the same product as in the low-penalty scenario.

Nevertheless, the analysis must encompass also an assessment of the energy market cost. Also the latter is affected by an increase in the penalty value. In fact, when new and more reliable plants enter the system because of higher penalties in the capacity market, these units displace old and more expensive generation plants also in the energy market. This reduces the short-term market price, decreasing the energy-market remuneration for all agents, existing and new, resulting in a lower energy-market cost. This effect is reflected in Figure 10. Obviously also the non-served energy value diminishes with higher penalties, due to the enhanced reliability of the system. Summing up all these components, it can be observed how the overall cost of electricity supply can decrease when the explicit penalty increases. This demonstrates that the supposed windfall profits obtained in the capacity market can be overcome by the lower remuneration in the energy market.

These outcomes, even if by means of rough numbers, provide regulators with an important recommendation. The introduction of a capacity mechanism always represents an intervention in the electricity market. Some agents benefit from this intervention, while some others are impaired by it and this is unavoidable. However, positive results are still achievable if the intervention could eventually result in an increment of the social welfare.

As a final remark, the x-axis in all the charts presented in this section considers penalty values from 0 to 10 000 €/MWh and the effect of the penalty is more evident for higher values, in the order of thousands of €/MWh. These "fines" could be perceived as quite high if compared with prices commonly recorded in most electricity markets. However, they are in the same order of magnitude of the explicit penalties which are planned to be introduced in some capacity mechanisms in United States, which are leading the discussion on this topic. ISO New England is introducing a penalty rate which will grow up to 5 455 $/MWh [24], while PJM proposed to apply a charge which has been estimated to be around 3 625 $/MWh [34].

4 CONCLUSIONS AND POLICY IMPLICATIONS

In the last decade, the implementation of capacity mechanisms has "climbed" the regulatory agendas in several countries with a liberalised electricity market. In Europe, after many years of firm opposition to their introduction, a general rethink is swiftly taking place. At the same time, those countries which from the very beginning opted for the implementation of capacity mechanisms, especially in the United States and Latin America, keep on looking for measures to fine-tune their schemes. Particularly in the United States, many regulators have recently emphasised the importance of penalty schemes for under-delivery (also called performance incentives), which provide a strong signal for the resources contracted in the capacity mechanism to be actually available during scarcity conditions in the system. This is leading to reforms inspired by the "pay-for-performance" concept.

Besides this short-term signal, incentivising the availability during real-time operation, penalty schemes in capacity mechanisms also provide resources with a long-term signal. Since less reliable units are more likely to fail in providing their contribution during scarcity conditions, they are more exposed to an explicit penalty and this is reflected in their bid. The explicit penalty, in case existing generators and new entrants compete in the same auction, can alter the merit order of the tender, causing the exit of non-firm energy blocks and the entrance of new and more reliable generation plants.

This article presented a model that studies the impact of the explicit penalty on the generation mix resulting from the implementation of a capacity mechanism. As explained in section 2, the two-stage model is based on the simulation of an auction for reliability option contracts, in which bids are calculated according to the results of a short-term market, represented through a unit commitment considering the unavailability of generation units. Results from the model, presented in section 3, confirm the expected effect of the explicit penalty and allow to draw some relevant conclusions, summarised hereunder.

- New entrants include in their bid an estimation of the part of the required annual income that they do not manage to recover in the short-term market. Therefore, without an explicit penalty, new units will present higher bids than existing plants and they will be cleared only to cover the expected demand growth.
- However, new units are expected to be more reliable than existing ones and to provide a higher contribution to the reliability of the system if they are cleared in the auction. Therefore they represent a better asset for the regulator to achieve the reliability target it sets. The explicit penalty can be used to amplify this signal. Less-firm generation plants are more exposed to higher penalties and this is reflected in their bids. This results in the displacement of non-firm energy blocks by new and more reliable generation units.
- Improvements in reliability can be observed through the number of hours with scarcity conditions in the system. When a new unit is cleared in the auction because the penalty value is high enough to allow it to displace an existing plant, the number of hours with scarcity conditions is reduced.

- Higher penalty values may result in an increase of the net cost of the capacity market (obtained by subtracting the option value and the penalty charges from the capacity-market cost). However, this increase can be counterweighted and overcome by the decrease in the energy-market cost (new units reduce short-term market prices) and in the non-served energy value.

- The penalty value for which the above-mentioned effects are more evident is quite high if compared with electricity market prices normally observed, but it is in line with the penalties being proposed and implemented in capacity mechanisms in the United States.

The main policy implication that can be extracted from this article is that capacity mechanisms must consider a penalisation scheme if they aim at attracting investment in new and more reliable resources. This represents a lesson worth learning for European regulators, especially in the current framework of widespread introduction of capacity remuneration mechanisms.

APPENDIX: DETAILED MODEL FORMULATION

This appendix includes the detailed formulation of the unit commitment model used to simulate the outcome of the short-term market. For the scope of this analysis, the UC problem has been simplified and some constraints, not relevant for the product considered in the auction, have been removed. Moreover, the demand is supposed to be totally inelastic.

In order to accurately model the functioning of a "real-size" system with 80 generation units during a whole year while, at the same time, keeping the computational time within acceptable levels, the UC problem is based on a clustered formulation proposed, for example, in [35].

As regards the representation of units' availability, prior to the execution of each scenario, a different availability matrix is generated using a string of random numbers and the probabilities ρ and μ, as described in Section 2.3.

Unit commitment formulation

Indexes and sets

$g \in G$	Generating technologies
$t \in T$	Hourly periods

Parameters

C_g^{LV}	Linear variable cost of a unit of technology g [$/MWh]
C_g^{NL}	No-load cost of a unit of technology g [$/h]
C^{NSE}	Non-served energy price [$/MWh]
C_g^{SD}	Shut-down cost of technology g [$]
C_g^{SU}	Start-up cost of a unit of technology g [$]
D_t	Load demand in hour t [MWh]
$\overline{P}_g$	Maximum power output of a unit of technology g [MW]
$\underline{P}_g$	Minimum power output of a unit of technology g [MW]
N_g	Number of units installed of technology g

$AV_{g,t}$	Number of units of technology g available in hour t

Variables

nse_t	Non-served energy in hour t [MWh]
$p_{g,t}$	Power output at hour t of all technology g units above the minimum output $\underline{P}_g$ [MW]
$u_{g,t}$	Number of units of technology g committed at hour t
$v_{g,t}$	Number of units of technology g starting-up at hour t
$w_{g,t}$	Number of units of technology g shutting-down at hour t

Formulation

$$\min \sum_{t \in T} \left[\sum_{g \in G} \left[C_g^{NL} u_{g,t} + C_g^{LV} \left(\underline{P}_g u_{g,t} + p_{g,t} \right) + C_g^{SU} v_{g,t} + C_g^{SD} w_{g,t} \right] + C^{NSE} nse_t \right] \tag{A.1}$$

$$s.t. \quad \sum_{g \in G} \left[\underline{P}_g u_{g,t} + p_{g,t} \right] = D_t - nse_t \qquad \forall t \in T \tag{A.2}$$

$$u_{g,t} - u_{g,t-1} = v_{g,t} - w_{g,t} \qquad \forall g \in G, \forall t \in T \tag{A.3}$$

$$p_{g,t} \le \left(\overline{P}_g - \underline{P}_g \right) u_{g,t} \qquad \forall g \in G, \forall t \in T \tag{A.4}$$

$$u_{g,t} \le AV_{g,t} \qquad \forall g \in G, \forall t \in T \tag{A.5}$$

$$0 \le u_{g,t}, v_{g,t}, w_{g,t} \le N_g, \quad u_{g,t}, v_{g,t}, w_{g,t} \in \mathbb{Z} \qquad \forall g \in G, \forall t \in T \tag{A.6}$$

$$p_{g,t}, nse_t \ge 0, \quad p_{g,t}, nse_t \in \mathbb{R} \qquad \forall g \in G, \forall t \in T \tag{A.7}$$

Input data

This subsection provides the data used for the case study presented in section 3, in terms of cost items and technical parameters of each technology (other data, as the price cap or the strike price, are already specified in the body of the article). The objective of this research is not to predict actual results for a specific system, but rather to show the impact of a parameter, the explicit penalty for underperformance, on the outcomes of a capacity mechanism. Some data have been approximated (as the installed capacity of generation units), but they keep on reflecting realistic values. Table ii provides the data used for the case study, with the acronyms presented in the formulation.

Table ii. Input data for the case study.

	Nuclear	Coal	CCGT	Fuel oil	New CCGT
No. of units	20	30	25	5	15
$\overline{P}_g$ [MW]	500	500	500	500	500
$\underline{P}_g$ [MW]	500	300	200	200	200
C_g^{LV} [$/MWh]	6.50	37.25	60.75	189.50	59.00
C_g^{NL} [$/MWh]	-	525	3 150	6 750	3 150
C_g^{SD} [$]	-	4.5	7	1.5	7
C_g^{SU} [$]	-	45	70	15	70
$\overline{EFOR}_{tech}$ [p.u.]	0.01	0.05	0.04	0.10	0.02
$\underline{EFOR}_{tech}$ [p.u.]	0.02	0.15	0.06	0.20	0.02
AIC_{tech} [k$/MW]	-	-	-	-	120

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