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REGULATORS IN LIBERALISED ELECTRICITY SYSTEMS:
GENERATION ADEQUACY AND INDICATIVE PLANNING.
JUSTIFICATION, AVAILABLE MECHANISMS, AND A
SIMULATION STUDY ON SOME CONCRETE POLICIES

Álvaro López-Peña, Efraim Centeno and Julián Barquín

EUROPEAN UNIVERSITY INSTITUTE, FLORENCE
ROBERT SCHUMAN CENTRE FOR ADVANCED STUDIES
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*Long term issues to be addressed by regulators in liberalised electricity systems:
generation adequacy and indicative planning. Justification, available mechanisms,
and a simulation study on some concrete policies*

ÁLVARO LÓPEZ-PEÑA, EFRAIM CENTENO AND JULIÁN BARQUÍN

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For further information

Loyola de Palacio Energy Policy Chair
Email contact: yannick.perez@eui.eu
Robert Schuman Centre for Advanced Studies
European University Institute
Via delle Fontanelle, 19
I-50016 San Domenico di Fiesole (FI)
Fax: +39055 4685755

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Abstract

For ensuring electricity security of supply in the long run, liberalised electric systems' regulators have to worry, not only about the presence of enough installed capacity, but also about the generation mix. Hence, indicative planning must be taken into account as well, for limiting dependence upon non-indigenous fuels, for instance. This can, simultaneously, help in meeting growing environmental constraints: renewables promotion is a clear example. There exist several mechanisms for addressing the adequacy problem (having enough megawatts) and for promoting renewables (having the good megawatts).

In this study, a brief review of these mechanisms is done, and some are chosen for assessing their efficacy and efficiency over a system similar to the Spanish one, concretely capacity payments and capacity markets for the first problem and renewable energy premiums for the second. A simulation study is performed, which confirms the better characteristics of capacity markets in stabilising reserve margins, but whose effects may be damaged by an inadequate renewables promotion policy.

Keywords

System-dynamics, generation capacity investment analysis, feed-in-premiums, capacity mechanisms

1. Introduction*

“Energy security of supply” is not a clearly defined concept, and the measures and policies that would have to be put in place to strengthen energy security are a source of confronted interests among the agents involved (governments, policy makers, companies, consumers, for instance). Anyhow, some consensus on the best ways to enhance security of supply is being reached, primary energy sources’ diversification being one of them.

Focusing on electricity, in liberalised systems, where power transmission and distribution are still regulated, security of supply is importantly affected by the generation business, where the changes of deregulation have been more pronounced (Pérez-Arriaga, 2001). And the generation activity, if viewed from the long term perspective, is strongly related with primary energy sources’ diversification.

Consequently, governments or regulators concerned about long-term security of supply may be interested in looking into the future and strategically influencing the private companies’ decisions regarding generation expansion. They may want to influence these decisions from a double perspective. Firstly to address the adequacy problem, as presented in (Batlle and Pérez-Arriaga, 2008), i.e. having enough installed capacity to cover estimated demand with a fair reliability level. And secondly to deal with the strategic problem, that is, influencing the generation mix for diversifying primary energy sources (constraining gas dependency, promoting local fuels or renewables, or supporting nuclear generation may be some examples). This second perspective is the one treated by indicative planning.

The aim of this study is to assess the efficacy and efficiency of some of the mechanisms that are being considered worldwide for influencing companies’ investment decisions in electricity generation assets in liberalised electricity systems. This will be done from the above-mentioned double perspective:

- For having enough installed capacity in the system. “Having enough megawatts”.
- For having a generation mix that fulfils strategic restrictions and materialises indicative planning. “Having the good megawatts”.

The paper is organised as follows: after this introduction, the second section gives an overview of the available policy instruments and the third one justifies the chosen ones. The fourth includes a brief description of the model used to simulate the electricity sector under study, and how these policies are considered in it. In section five, the numerical case that has been studied and the obtained results are described. In the final section conclusions are drawn and policy implications are identified.

2. State of the Art

2.1 Security of electricity supply: generation reliability

As mentioned, in liberalised power sectors, security of electricity supply to the final consumers depends importantly on generation reliability. Following (Batlle and Pérez-Arriaga, 2008), generation reliability concerns three dimensions, with three different time horizons: security (meaning the readiness of the existing generation to respond to the load in the short-term), firmness (generators being available when needed, resulting from a correct operational scheduling in the mid-term) and

* The author thanks Endesa S.A., who partially supported this work, as well as IIT’s colleagues who provided many helpful comments. All remaining errors are the author’s responsibility.

adequacy (sufficient installed generation capacity, a long-term issue). It is agreed that security issues are efficaciously addressed by system operators using operating reserves markets. But there is no consensus about the best ways to deal with firmness and adequacy issues, which are as well strongly linked: long-term measures are not isolated from mid-term effects. For a revision on the “firmness” problem, see {Batlle, 2008 #12}.

This study will focus on the adequacy issue (i.e. the presence of enough installed capacity in the system), and its relation with the regulator’s strategic policies seeking primary energy sources diversification (for ensuring electricity security of supply in the long term). For a general perspective of the adequacy problem, see (Vázquez et al., 2003), (Joskow, 2008) and (de Vries, 2007).

2.2 The adequacy problem: how many megawatts are needed?

Under traditionally regulated electricity sectors, all the investments in new generation facilities are decided by the government or the regulator. Hence, the materialisation of its strategic policies is immediate, and all the costs and benefits are finally born by the consumers or the tax payers.

In liberalised electricity markets, on the contrary, it is up to the private companies to make the decision of investing in a new generator, whose investment costs should be recovered selling the energy in the market. In fact, if the market is perfectly competitive, there are no economies of scale in generation, demand responds to prices and there is an optimal generation mix (Pérez-Arriaga, 2001), all generators will recover all their variable and fixed costs, with an acceptable rate of return on investment, as proved in (Olsina et al., 2006).

The above-mentioned optimal generation mix implies that, during a number of hours a year, there will be non-served demand, because the cost of serving this load is higher than the value given to it by consumers. Thus, the overall costs of the whole system are minimal. If the generators’ failure probability is taken into account, this optimal value of total installed capacity has to overpass the peak load, as can be seen in (Cazalet et al., 1978). Thus, a positive reserve margin in the system may be desired by the regulator under real circumstances. If this is achieved, peaking generators may not fully recover their total costs with an adequate rate of return only by selling their energy into the market. Hence an extra income is needed to make profitable the entrance of additional peaking units and therefore reach a positive reserve margin. In conclusion, some regulatory intervention is needed in reality to maintain a positive reserve margin in the system, increasing the total generation capacity over the theoretical values obtained with an optimal mix analysis.

Besides, this optimal mix viewpoint is somehow static; it represents an ideal equilibrium, an equilibrium that is hardly reached in a capital-intensive industry such as the electric power sector, where investment cycles tend to occur (de Vries, 2008). Applying basic microeconomic theory to spot electricity markets, demand growth will make electricity prices raise and this will provide an efficient signal for new generators to enter the system, as can be seen in (Pérez-Arriaga and Meseguer, 1997). But this is not what occurs in real electricity markets: the observed installed capacity of peaking technologies is lower than the theoretically expected one. The non-storability of electric power has sometimes been mentioned as a cause of the non satisfaction of microeconomic principles in real electricity markets. But this physical characteristic was explicitly taken into account in the above-referenced study (Pérez-Arriaga and Meseguer, 1997). Hence, this is not the real reason.

Even if all units under an optimal generation mix (and this includes peaking generators) would recover their costs with a fair rate of return on invested capital, the presence of price caps (what limits generators’ incomes), as well as investors’ risk aversion, seem to be the main causes of not enough presence of peaking units in real systems (Vázquez et al., 2003). The risk aversion of investors is mainly due to price volatility and regulatory uncertainty (Joskow, 2008). Concerning price volatility, even if peaking generators would statistically recover their investment costs, it would imply a higher

cost of capital for them. But following this reference, this is not the real reason. The main cause of risk aversion and therefore lack of investment is regulatory risk, not price volatility.

As said in (Vázquez et al., 2003), this risk aversion of investors could theoretically be solved by consumers, signing long term contracts with generators. But in real markets consumers are not behaving this way: they are not experiencing real prices (due to tariffs or price caps) and they do not feel the fear of high prices, because they think that “the regulator will not let rationing happen”. Consumers are not, therefore, mature enough to sign these long-term contracts that would solve the problem of the investors’ risk aversion. A deeper review on the causes why a long-term market has not developed naturally can be seen in (de Vries, 2007).

The most orthodox solution would be eliminating tariffs and price caps, and letting the consumers experience real spot prices (Vázquez et al., 2003). When rationing happens, high prices would make them learn and they would start signing long-term contracts with generators. But no government seems to be willing to accept the political risk of this learning period, especially after the 2001 experiences in California.

The presence of a positive reserve margin in the system has other advantages: it makes the abuse of dominant positions more difficult, abuse that at the same time makes it harder to rely on prices as an indicator of scarcity (de Vries, 2007).

In conclusion, some regulatory intervention is needed to promote the entry of enough generators in the system in order have a positive reserve margin, what is highly desirable in real markets. In other words, some kind of specific regulation must be put in place to have the desired amount of megawatts in the system.

2.3 The strategic problem: which megawatts are needed?

In order to ensure long-term security of electricity supply, the regulator may want to promote some technologies for the generation mix, such as local fuel fired ones, renewables, or nuclear; or it may as well want to constrain dependency on a particular imported fuel, such as gas.

Then, in the above-mentioned adequacy problem, it does not suffice to promote, with a concrete policy, the entrance of a number of megawatts into the system. Specific technologies may be required (e.g. wind megawatts or local coal megawatts).

For instance, as shown in (CNE, 2008), in the Spanish electricity sector the most installed technology in the last years has been combined cycle gas turbines. This increases dependency upon gas, a non-indigenous fuel, which can jeopardise security of supply in the long run. Thus, the Spanish regulator may be interested in constraining the gas share in the generation mix: in the adequacy problem it may not be interested in any megawatts, but only in non gas-fired megawatts. In (Centeno et al., 2008), an assessment on the efficacy and effectiveness of some possible measures to limit gas-share in a market like the Spanish one is performed, and it is concluded that some of them may prevent enough capacity from being installed, i.e. they can worsen the adequacy problem.

2.4 The Regulator’s complete problem: how to obtain those megawatts?

The complete problem that the regulator must address is a combination of the two presented above: obtaining enough megawatts, but megawatts of the technology he wants to promote from a strategic viewpoint.

2.4.1 Addressing the adequacy problem:

For obtaining enough megawatts, a number of mechanisms have so far been proposed in the literature and are nowadays being used or considered by policy makers worldwide: the so-called *capacity mechanisms*. A good review of them can be seen in (Pérez-Arriaga, 2001) or (de Vries, 2007). Following these references, the main mechanisms, all of them with their advantages and drawbacks, are:

- Leaving it to the market, i.e. no intervention on the energy-only market
- Capacity payments
- Strategic reserves
- Capacity auctions
- Capacity markets
- Reliability options

The “leave it to the market” approach is the most orthodox and would work well in a mature market where demand responds to high prices by signing long term contracts but, as already said, the learning period may be too politically-harmful.

Capacity payments have a theoretically-sound justification (establishes the compensations for generators in the case of a price cap) and are effective, but are not easy to implement in a thorough way without introducing distortions in the market.

Strategic reserves (peaking units-purchase) and capacity auctions may also be effective, but are highly interventionist measures and may as well introduce important distortions in the electricity markets.

Capacity markets seem to constitute a better method because it is market-based, but may be hard to implement in a system with hydro-generation (due to the difficulty of calculating the firm capacity a hydro power plant provides to the system).

Reliability options overcome much of the drawbacks of the other methods but have, as well, some problems: they do not promote an active demand respond to high prices, and can be subject to market-power abuses. For a detailed description of this mechanism, see (Vázquez et al., 2002).

2.4.2 Addressing the strategic problem:

For obtaining the good megawatts, two main strategies can be followed: constraining the *bad*, or promoting the *good* megawatts.

To constrain the share of a certain technology in the generation mix, some alternatives as limiting building permits or production-taxation can be considered, as done in (Centeno et al., 2008). This may have a negative impact upon reserve margin. Therefore, as concluded in this study, in some cases it may be more suitable to support alternative technologies.

For promoting a determined technology, different strategies can be followed. They can be classified in price-based (aiming at making them more profitable for investors, for instance through extra-incomes as feed-in tariffs or premiums over energy market price, or by means of tax-exemption), or quantity-based (obligating consumers to buy a certain amount of energy from this generators, for instance).

3. Policies Chosen for Study

The aim of this paper is to assess the efficacy and efficiency of some of the possible policies the regulator may adopt for making the generation mix evolve in the desired direction while maintaining an acceptable level of total installed capacity. For doing so, he may combine some capacity mechanisms (to obtain *enough* megawatts) with some technologies promotion or limitation methods (for having the *good* megawatts).

Among the above-reviewed capacity mechanisms, two of them will be analysed: a fully price-based one (*capacity payments*) and a quantity-based one (*capacity market*). The *leave it to the market* approach, given the political cost it may imply, is not considered as a plausible policy and, thus, it will not be studied. *Capacity auctions* and *strategic reserves*, as they are highly interventionist mechanisms, will not be assessed either. Analyzing *reliability options* would imply a thorough modelling of each technology's firmness, what is a very complex problem, as shown in (Batlle et al., 2007). For that reason, reliability options are out of the scope of this paper (their study could be very interesting for future research).

Among the mix evolutions the regulator may pursue from the strategic viewpoint, in the energy policy debate forums there are three main concerns: energy security (ensuring security of energy supply), climate change (curving greenhouse emissions) and energy prices (keeping them in acceptable levels for not damaging industries' competitiveness).

There is a strong debate about nuclear power production: it does not produce greenhouse emissions, and its fuel is distributed more widely and in more politically-stable countries. Hence, it may be a plausible solution for two of the mentioned regulators' concerns. But it may be an expensive source of energy (if the complete life-cycle costs are considered, including financing) and entails other serious problems as security, waste management or the possible uses of nuclear technology for non-peaceful objectives. Entering in this hot debate, where very different positions are found within Europe (Nuttall, 2008), is out of the scope of this paper.

Some new technologies are as well being developed. One of them is Carbon Capture and Sequestration, which may make it possible to generate power from coal with much lower emissions. Given the abundance of coal in countries that are great energy consumers such as the United States or China (BP, 2008), this technology may be able to address energy security and climate change at the same time. But it remains in an early stage of the learning curve, thus it may increase energy prices. Some figures can be seen in (IPCC, 2005) and (McKinsey&Co., 2008). For that reason, it will not be considered for this study either.

Anyway, in energy policy debate forums, especially in Europe and more recently in the United States, there seems to be a high level of consensus about the positive effects of promoting renewable energies for achieving the above-mentioned policy objectives. Clear proofs of this are the European Union's 2020 objectives. Renewables are autochthonous (increasing energy security), mostly clean (the whole life-cycle must be considered), great advances in their learning curves have been achieved (thus they start to be competitive, especially under high oil and/or carbon prices), and in addition they can help in achieving other political objectives such as boosting related industries. Therefore, in this paper we will consider renewables as the *good* megawatts.

Among the main renewable promotion systems, the most effective has been the *feed-in-tariff* system: paying the energy produced with renewables at a previously fixed price. This has been the method adopted in Denmark, Germany and Spain, for instance, with great success in promoting them: (Ragwitz et al., 2007), (EC, 2007). The main reason for this success is the low risk it implies for investors, making project financing cheaper. But its main drawback is that it removes the price signal for renewable producers, what may lead to inefficient operation of these generation assets. For these reasons, this system is considered appropriate for systems where there is a small renewables penetration and where it wants to be strongly incentivized.

Another renewable promotion mechanism is the *feed-in-premiums* system. It consists on a fixed premium that is perceived by renewables in addition to the electricity price. The price signal is perceived by the producers, thus their efficient production is indeed incentivized. But it entails greater risk for investors. This method is appropriate for systems with a higher renewables penetration where an efficient operation becomes more important, which is the case in a system like the one studied in this paper (similar to the Spanish).

The third main system is the *tradable green certificates* system, where a complementary market for renewable energy is created. Renewable producers perceive both the electricity price and the green certificate price. This is the most efficient system, but it involves the higher risks for investors, and is therefore appropriate for mature markets with high renewable penetration and stable technologies.

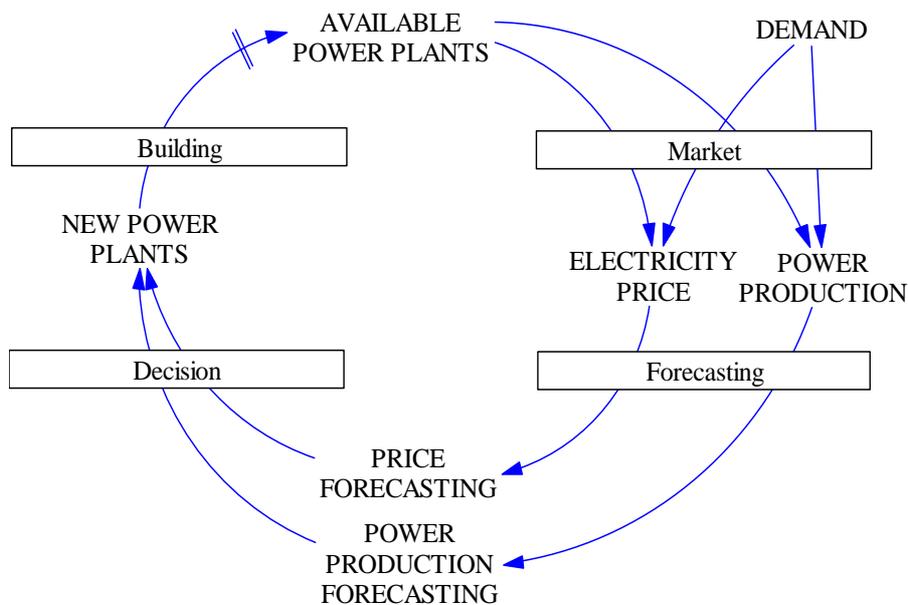
In conclusion, the policies chosen for study in this paper are capacity payments and capacity markets, combined with different scenarios of feed-in-premiums for renewables.

4. Methodology Description

In order to assess the impacts of the studied policies over a hypothetical liberalised electric system, its long-term evolution is simulated through a model based on System Dynamics (Sterman, 2000). The model represents the investment-decision process taking into account some of the main aspects that, in liberalised systems, affect these decisions: imperfect competition, forward contracting influence over the generators' bidding strategies in the energy market, or the companies' differentiation when evaluating new investments. It is based on a system similar to the Spanish one: a mainly thermal system, where no new investments in hydro power plants are considered, i.e. capacity-limited rather than energy-limited. A fully detailed description of the complete model can be found in (Sánchez, 2009).

4.1. Model Overview

Fig. 1 Model overall structure



The agents' investment-decision process is modelled as a feedback loop divided in four main blocks, as shown in Fig. 1. Beginning with demand and available power plants, a representation of the market determines electricity prices and every plant's power productions. The second block represents the

price and plant outputs forecasting process that every agent performs for a determinate time horizon. These results are used -third step- to compute the number of new plants that each agent decides to build, taking into account the capacity mechanism that is being studied (capacity payments or capacity market), and considering each technology's characteristics and each company's own profitability criteria. Finally, in the fourth block, the building process is represented by time delays that correspond to permit obtaining and plant construction itself. In the model, simulation is done sequentially with a one-year resolution, while prices and productions are calculated with a higher resolution: for each load level.

The *Market*, *Forecasting* and *Building* blocks are briefly explained in the following three sections. The *Decision* block, as it contains the capacity mechanism modelling and the renewables promotion system, will be described in greater detail after that.

4.2 Market

Starting from demand and available power plants, this block determines electricity prices and power outputs for every plant. Electricity prices and productions are the main investment signal in liberalised frameworks, and many of these markets are subject to imperfect competition. Thus, for better modelling the main investment driver, a detailed representation of the oligopoly has been done in this *Market* block.

4.2.1 Spot Market

The spot electricity price is calculated through a strategic production costing model, extending the one in (Batlle and Barquín, 2005) in order to deal with forward contracting. It represents the bid function of the generators as their marginal cost function plus a mark-up term, which represents market power exercise. Therefore, the bid function B of each company i for each load level is:

$$B_i(q_i) = C'_i(q_i) + \theta_i \cdot [q_i - F_i] \quad (1)$$

Where C'_i is the marginal cost function of the company, q_i its production, F_i its forward sales and θ_i is a strategic parameter reflecting the conjectured price response, as in (Centeno et al., 2007). The mark-up -the second term in equation (1)-, is the product of the ability to exercise market power (the strategic parameter θ_i) and the incentive to exercise it (the uncontracted production $q_i - F_i$). When a company can not control the market price, the slope of its residual demand function will be zero, as well as the above-mentioned strategic parameter. Thus, the ability to exercise market power, and therefore the mark-up term, will be null.

More concretely, the conjectured price response is defined as (being p the spot price):

$$\theta_i = \left\| \frac{\partial p}{\partial q_i} \right\| \quad (2)$$

A basic assumption is normally made here: that this conjectured price response can be deduced from the market evolution in the past, because it is nothing but the first derivative of the residual demand curve. This hypothesis is valid if it is assumed that the market structure and the agents' costs do not change significantly with time, what is valid in the short and medium-term. However, in the long term, this is not the case. If an accurate description of the main investment signals (prices and productions) wants to be performed, this parameter has to be estimated while the simulation advances over the studied years, in order to capture market evolution in the long term. In this model, an endogenous method for calculating this strategic parameter, while the simulation runs and the market structure

changes, has been developed. It is based on *Supply Function Equilibria* concepts. A brief description can be found in (Sánchez et al., 2007b) and, for a more thorough one, see (Sánchez, 2009).

4.2.2 Forward Market

Forward-contracted quantities (F_i in equation (1)) are decided by generation companies taking into account the conditions in the market and the electric system.

In this model, the forward market representation is based on the ideas in (Allaz and Villa, 1993). They modelled the forward market as a two-stage equilibrium from which the optimal quantities to be contracted in the forward market by the agents can be obtained. Their main assumptions were: symmetric duopoly, constant marginal costs for each company, Cournot competition in the spot, risk-neutral agents and a forward market where contracts traded call for delivery during the next spot market. Allaz & Vila's paper concluded that, even in the absence of risk aversion, forward-contracting has a pro-competitive effect: each agent has the incentive to contract forward but, if both of them do so, they end worse-off because less market power is exercised and prices fall. It can be seen as a kind of prisoner's dilemma. This started a wide discussion about the pro- or anti-competitive effects of forward markets. One of the main objections is, for example, the same applicable to the prisoner's dilemma: the agent's learning process when these forward and spot markets are repeated periodically (as they are in reality): (Liski and Montero, 2006) and (Amaya et al., 2006). Another objection is the high results-sensitivity to the assumptions considered: (Green, 1999) found a case where the agent's do not have the incentive to contract forward. Anyhow, the main conclusion in (Allaz and Villa, 1993), i.e. the pro-competitive effects of forward contracting, will be accepted in this paper.

In this model's representation, Allaz and Vila's modelling has been extended to consider asymmetric duopoly, conjectural variations competition in the spot market, risk aversion of the agents and linear marginal costs. The complete equations can be found in (Sánchez et al., 2007b). Introducing this equations in the model, contracted quantities that call for delivery in the next spot market are calculated for each step of the simulation, that is, for each year.

To sum up, in the *Market* block a forward market is firstly simulated and then a spot market is calculated taking into account, in the agents' strategies, the quantities that they have contracted in that previous forward market as well as an endogenously-calculated strategic parameter.

4.3 Forecasting

In order to compute, each year, the profitability of the new investments that are being evaluated, companies have to forecast the prices of electricity in the following years, as well as the estimated productions of the generation assets under evaluation. For doing so, the actual generation mix in the system will be considered, and a reasonable hypothesis for the long term will be used: optimal generation portfolio and perfect competition. For a given year in the future (in this case, 40 years after the current one, which may overpass the study horizon), an estimated price-duration curve is calculated supposing this optimal mix in the system and marginal cost bidding. By softly approximating the current year's price-duration curve to the one obtained for that future year, all the price-duration curves for every future year can be obtained. Once we have the price-duration curves for all years, the productions of a new group are calculated by supposing that it is going to be bidden by its marginal costs. A complete description of this methodology can be found in (Sánchez et al., 2007a) and in (Sánchez, 2009).

4.4 Building

The Building block of the overall scheme is composed by two delays: the first one represents the construction permits obtaining process and the second one the construction itself (different delays for each technology).

4.5 Decision

As it has been said, this paper's main contribution is studying the influences of different capacity mechanisms (capacity payments and capacity markets) and renewable support schemes over the investment process in new generation assets. Among the four blocks in which the model is divided, the *Decision* one, where agents decide on the new investments to be done, is the one the most affected by the regulatory instruments under study. Thus, a deeper description of this block will be done here for a better understanding of the dynamics under study.

Some System-Dynamics models have represented investment decisions in a global and aggregated way, without differentiating them among companies, for instance the ones in (Kadoya et al., 2005), (Olsina et al., 2006), (Botterud et al., 2002) or (Vogstad, 2005). Some others do differentiate among companies but using as decision criteria, apart from the expected profitability, exogenous strategic parameters. (Ford, 2001), (Bunn and Larsen, 1994) or (Gary and Larsen, 2000) are some examples.

For better representing the investment-decision process in oligopolistic markets, this model considers investment decisions' disaggregation among companies, based on financial and strategic criteria, as will be explained later.

Each agent' decision is based on the expected profitability of the new possible power plants, measured as the Net Present Value (NPV) of the free cash flows the agent perceives from this investment.

As this profitability calculation is used to decide which technology to invest in, and each technology's power plants have different typical sizes, this profitability calculation must be normalised to the installed capacity. Thus, the NPV will be calculated for a single installed megawatt of each technology, and will be expressed, for instance, in €/MW. For doing this, a key hypothesis must be made: electricity prices are not influenced by the new entrance of a single power plant in the system, whichever its size is. This is equivalent to supposing a linear relation between the NPV and the installed capacity (for small amounts of capacity). This allows us to compare in constant terms, without worrying about the typical size of each technology's plants. This hypothesis is considered to be valid in large systems where a single plant's capacity is small compared to the total installed capacity.

In order to take into account companies' differentiation when evaluating new investments, an endogenously-calculated discount rate is used by each company to calculate its NPV. Thus, the above-mentioned decisions' disaggregation based on financial criteria is modelled.

Once all companies have calculated the profitability of an installed megawatt of every technology, they choose the technology they are willing to invest on. Investing, in the same year, on several technologies would imply some kind of risk management and portfolio analysis from the companies, which has not been modelled. Thus, in each year, every company invests only in its most profitable technology.

Once all companies have chosen the technology to invest in, they compute the size of the investment they are willing to make. This is done considering the previously-mentioned strategic criteria, i.e. the observed profitability and a maximum quantity they are willing to invest.

Thus, the *Decision* module can be seen as composed by three main steps: endogenous discount rate computation, profitability calculation and new investment decision-making. The first two steps are

common for both capacity mechanisms under study, and will be explained in the next two sections. The decision-making step is different under the *capacity payment* and the *capacity market* schemes, so separated sections will explain each of them.

4.5.1 Endogenous discount rate computation

This model calculates the different agents' discount rates using a method based on credit risk theory. The basic idea underlying this method is that, when a company does a new investment, it needs to issue new debt for totally financing it. This hard hypothesis (new investments financed just by debt) is made for not having to consider, when evaluating the cost of capital of the company, the equity term, which would complicate the analysis (by having to model the stock market, for instance).

The cost of the new debt issued can be seen as the minimum required rate of return for the new investment, and thus, it should be the discount rate used for the NPV calculation. The cost of new debt depends on the risk that the creditor perceives on the company failing the credit: a perfect example of this is the current financial crisis, where creditors' risk aversion has grown significantly, and with it, the cost of debt. Companies *default* when they can not (or choose not to) meet their financial obligations. This default probability is the credit risk perceived by the creditor, and can be calculated by three different types of models (structural, reduced-form and statistical), as seen in (Duffie and Singleton, 2003).

The approach chosen here is based on one of the structural models: the Black-Scholes-Merton (BSM) Debt Pricing Model, which is described in (Black and Scholes, 1973) and (Merton, 1974). In this model, a company does not give back its debt if its assets value goes below the value of its debt. Hence the default probability is the probability of the assets' value being below the debt value. In our model, both of these values are computed at each step, that is, for every year. Hence, for each year, once having them, by using the BSM Debt Pricing Model, the default probability and the value for the discount rate of each company is obtained. This is done for big companies, where the investment cost of a new power plant is small compared to the total value of its debt. For small companies, an exogenous discount rate is used.

A complete description of this approach can be found in (Sánchez et al., 2008) and (Sánchez, 2009).

4.5.2 Profitability calculation

Once the discount rate for each company in each year is obtained, it is used to compute the profitability of a new installed megawatt of all technologies, by means of its NPV. This NPV per installed megawatt (€/MW) is obtained by discounting to the present year all the free cash flows that megawatt would produce, i.e. incomes minus costs.

The incomes term is composed by market incomes (calculated with the price and production forecasts performed in the *Forecasting* block: the evaluated megawatt produces all the hours when its marginal cost is below the market price), capacity mechanism incomes and regulated subsidies (if the technology under consideration is, for example, a renewable one).

The costs term is composed by variable costs (only when the studied megawatt is producing), investment cost (the new megawatt is supposed to be completely paid the year it enters the market) and a fixed yearly cost (input data per technology).

In addition, renewables may have a support scheme. As said before, the one that will be studied is the feed-in-premiums system (these premiums are perceived in addition to the market price). In this model, when calculating the profitability of renewable technologies, the agents take as well into account this regulated subsidy perceived per energy produced (per MWh) and calculate their market incomes adding it to the market price. Its value is exogenously introduced.

4.5.3 Investment decisions with Capacity Payments

The first modelled capacity mechanism is the *capacity payments* scheme. As already said, it is a price-based capacity mechanism, i.e. the investment signal the generators receive is a payment for their installed capacity that complements their market incomes making the investment more profitable (it has the concise effect of reducing fixed costs).

Under this modelling, each agent will only invest in the most profitable technology each year. This is a reasonable hypothesis because, due to the capital-intensity of investments, agents will try, each year, to maximise their profits, therefore investing just in the most profitable technology in that year (even if this implies a possibly myopic strategy that may lead to an inefficient generation portfolio in the long term under the risk analysis perspective).

The number of permits (one per megawatt) he will ask for depends on the expected profitability, i.e. the greater the NPV obtained for a megawatt of that technology, the bigger the investment the agent is willing to make. But a maximum amount of asked permits is considered, which aims at modelling financial constraints or auto-imposed restrictions in order to maintain prices high enough or to limit the risk in case of massive capacity entry. In this modelling, for big companies this represents the maximum of money the agent spends per year, calculated as a percentage of the total assets value (5% is being actually used) and transformed to MWs through the technology's investment cost. For small agents (independent power producers, IPPs), who normally tend to have more aggressive strategies, this limitation is calculated as the 5% of the peak demand.

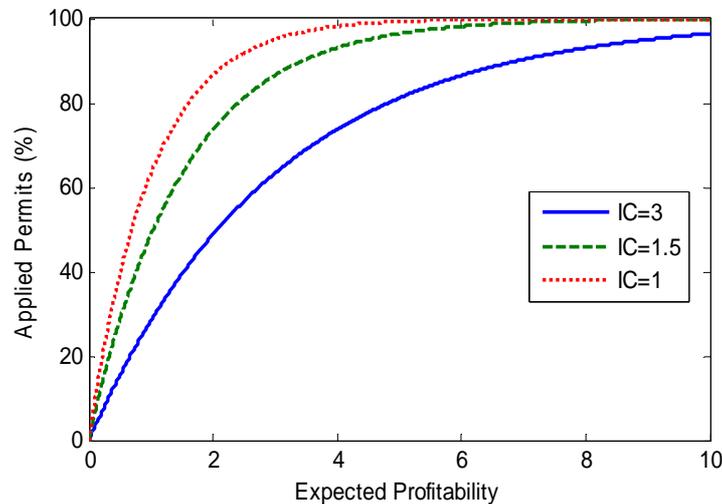
The relation between asked permits and expected profitability can be really complex in reality. In our model it is represented using an empirical growing curve that saturates at the maximum established limit. The saturation speed is inversely proportional to the investment cost: as the investment cost grows, the saturation is slower, i.e. for the same profitability, if the investment cost grows, the agent will ask for fewer permits. This is modelled with the following relation:

$$AP_{tgi} = MAP_{tgi} \cdot \left(1 - e^{-\frac{NPV_{tgi}}{IC_{tgi}}}\right) \quad (3)$$

Being i the agents, g the technologies and t the years. AP_{tgi} stands for the applied permits, MAP_{tgi} for the maximum applied permits, NPV_{tgi} is the profitability (measured as the Net Present Value) and IC_{tgi} is the investment cost.

This relation is shown graphically in Fig. 2, where the number of asked permits (as the percentage of the maximum limit) is related to the expected profitability, considering three technologies with high, medium and low investment costs. It is important to point out that, in this simulation stage, these permits are continuous, i.e. they are a continuous number of megawatts, not a multiple of a plant's size.

Fig. 2 Applied permits (% of the maximum) versus expected profitability, for three technologies with different investment costs. Expected profitability and investment costs expressed in the same units, M€MW, for instance



Once a company has asked for the permits, there is a first delay, modelling the administrative process of granting them. When the permits are obtained, these are divided by the size of a typical plant of that technology, in order to obtain the number of new plants whose building starts in that moment.

Finally, this building process is modelled as a new delay, and after that, the new plants enter in the generation portfolio of the agent, closing the loop shown in Fig. 1.

4.5.4 Investment decisions with Capacity Market

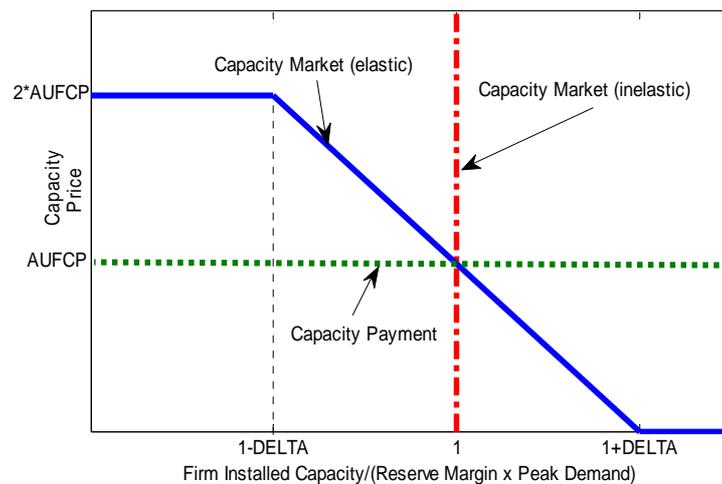
Whereas the previously-described capacity mechanism was based on prices, *capacity markets* are based on quantities: the regulator sets a level for extra reserves (reserve margin) and all consumers and load serving entities must forward contract with generators an amount of firm capacity that equals their expected peak demand plus the reserve margin set by the regulator.

As said in (Cramton and Stoft, 2005), initial designs of capacity markets were far from being efficient, mainly because of two reasons. The first reason was the big incentives large suppliers had for exercising market power, due to the excessively short terms of the markets (the moment of demanding the energy generated from contracted capacity was too soon after the market date, what made it very difficult for new entrants to sell the new capacity they were considering to build) and to the inelasticity of the demand curve. The second reason was that capacity was rewarded based on its availability over non-maintenance hours, but not based on how much it really contributed to the system reliability (it should, instead, be rewarded based on its availability over scarcity hours).

The Capacity Market modelling implemented for this paper is based on the ideas in (Hobbs et al., 2005) where a hybrid capacity market is proposed, i.e. it is not fully quantity-based, and so it overcomes the first difficulty. For overcoming the second, some penalties (in case of not being available in scarcity times) should be fixed. The main difficulty for it is establishing a sound mechanism for determining scarcity times. Reliability options (Vázquez et al., 2002), although not being exactly a capacity market with a penalisation, are a similar approach, which establishes high market prices as the scarcity indicator.

For a better understanding, Fig. 3, will be used. In it, the horizontal axis represents the per-unit relation between firm installed capacity and desired firm installed capacity (that equals peak demand times reserve margin), and vertical axis represents capacity price (€/MW, for instance). A fully quantity-based capacity market can be represented as an inelastic demand curve (the vertical line), whereas a fully price-based mechanism (capacity payments) is a horizontal line. The capacity market proposed in (Hobbs et al., 2005) has an elastic demand curve with three segments: a horizontal one at the maximum capacity price, a downward sloping segment centred at the desired reserve margin and whose slope is determined by the “DELTA” parameter, and a third horizontal stretch at null price. This demand curve is not the addition of the capacity demanded by all consumers and load serving entities that look for contracting capacity (what, as said, would lead to an inelastic curve), but an administratively-set one: the regulator signs the contracts on behalf of the total demand. The value corresponding to the central point of the sloped segment is the Average Uncovered Fixed Cost of a Peaker (AUFCP), which represents the part of total annualized fixed costs of a typical peaking-unit that are not covered by selling its energy into the market (because of reasons as the ones explained in section 0, such as price caps). The maximum capacity price is twice this value: therefore if the real reserve margin is distributed with the same probability above and below the desired quantity, the capacity price will take, on average, the same value as AUFCP. This is the demand curve used for this study.

Fig. 3 A Comparison of capacity mechanisms: Capacity Payments and Capacity Markets with elastic and inelastic demand



Concerning the offers from the agents, existing capacity and new capacity must be differentiated.

About the first, it is considered that existing groups are paid, throughout their whole life, the capacity price resulting in the capacity market where they were committed. Therefore, all agents are supposed to offer their existing capacity at null price: even peaking-units, if they were committed, are on average recovering their total costs.

For new capacity, some simplifications have been made. In reality, the agents would offer to the capacity market a growing stepwise function (each step representing a discrete increment in capacity, corresponding to one or several generation assets) that reflects the higher capacity price needed for making each new investment profitable. This may be a result of debt costs growing with the size of the investment, energy market price drops expected as a result of new capacity entering the system, or higher risk aversion when investments are bigger. These steps may as well correspond to different technologies, if the different costs among them are considered (what may include different debt costs)

or if some kind of portfolio optimisation is represented. The simplification made here is the following: each agent will only offer its most profitable technology.

In a capacity market, *firm* capacity is traded. Hence, all capacity values in the capacity market are considered to be firm. Therefore, agents' offered capacity must be transformed from installed to firm. For representing this, each technology's load factor has been used (and will be called, from now on, the *firmness factor*).

For calculating each agent's offer, giving that at this stage of the simulation all discount rates have already been calculated, the profitability (NPV) of a single megawatt of all technologies is computed for a wide range of capacity prices. This profitability is undervalued with each technology's firmness factor, to model the fact that capacity prices are paid for firm capacity. The technology having a positive NPV for the lowest capacity price is the offered one, what aims at modelling that the agents offer the most profitable technology for the minimum capacity price.

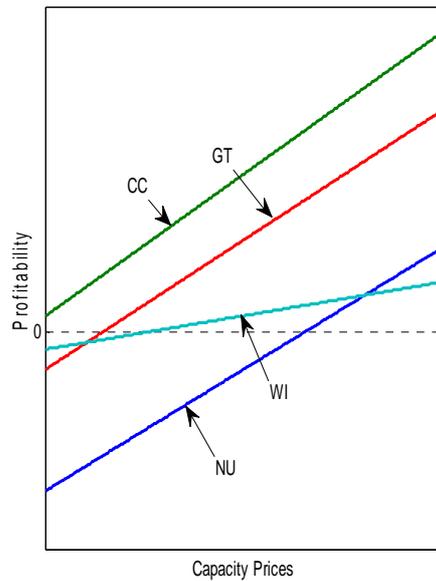
A simplification has been made here: offering the first technology in having a positive NPV (when the capacity price is increasing starting in null price) implies supposing that this technology is the most profitable one for all possible capacity prices. But this may not be true. This can be seen in Fig. 4 Profitability vs. Capacity Prices for different technologies, where an example of the per-megawatt profitability versus capacity prices for different technologies has been represented (both in the same units, €/MW for instance). In this case, wind (WI) is the second most profitable technology (after combined cycle gas turbines, CC) for low capacity prices, the third for medium prices (open cycle gas turbines, GT, become more profitable) and the fourth for high values (where nuclear's profitability is higher).

These lines' slopes are affected by the technologies' fixed to variable costs relation: a technology with a high relation (high fixed costs and low variable costs, such as nuclear) will probably get a high margin selling energy into the market, but covering its fixed costs will require most of this margin. Therefore, these technologies become more profitable for high capacity prices, which cover part of those high fixed costs.

The technologies' firmness has an even bigger effect upon these slopes. This is because the capacity market price is paid for firm capacity, so given two technologies with the same fixed to variable costs ratio, but different firmness, the one with low firmness may be the most profitable one for low capacity prices but may become less profitable than the firmer one for high capacity prices. In Fig. 4 Profitability vs. Capacity Prices for different, as renewables are less firm than thermal power plants, its relative profitability decrease while capacity prices increase. Also, the much slighter differences in thermal technologies' slope due to the fixed to variable costs relation can be observed (all have the same firmness in this model).

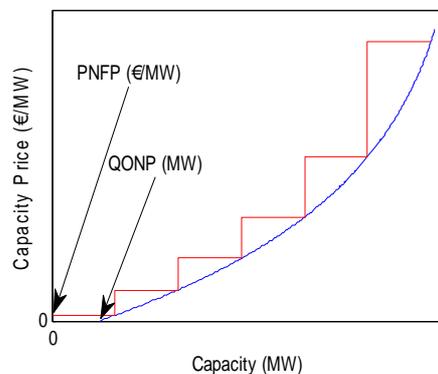
Doing the above-mentioned simplification implies supposing the same firmness for all technologies, what has been done for all thermal technologies. For renewables, a smaller firmness is used for calculating the NPV, but if they are the most profitable technology (in Fig. 4 it would mean moving the "WI" line upwards to overpass the "CC" curve for low capacity prices), it is supposed to be the invested technology (although thermal technologies can become more profitable for high prices due to their greater slope). The differences in slopes due to the fixed to variable costs ratios, given that its influence is much slighter, has not been considered.

Fig. 4 Profitability vs. Capacity Prices for different technologies



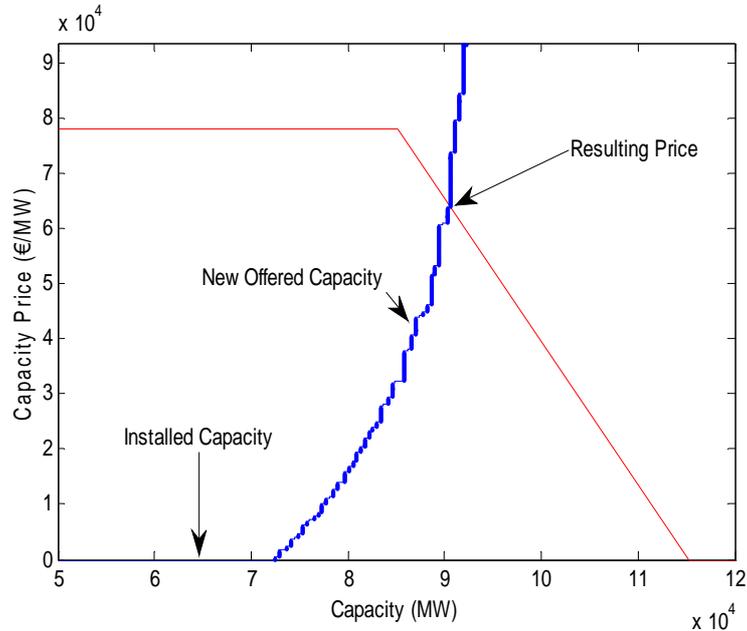
Once having the invested technology, with the NPV values obtained for the range of capacity prices (and corresponding to that technology), the quantities the agent is willing to offer at each capacity price is obtained entering in the same curve as in the previous method (the one in Fig.2). With this, a continuous offer function is obtained, i.e. the quantities the agents would offer at each price if no minimum sizes for new plants were considered. Then, this curve is transformed into a discrete offer function (a step-wise one) using the size of a new plant of the corresponding technology. This is represented, for the sake of example, in Fig. 5. In it, two specific quantities have been identified: QONP and PNFP, which are now described. The first stands for Quantity Offered at Null Price and, if positive, represents the amount of megawatts the agent would be willing to build without receiving any capacity price (what corresponds to a positive profitability at null price, as seen for combined cycles in Fig. 4). The second quantity is the Price Needed for the First Plant, that is the asked capacity price for building the first plant. This value would be null if QONP is greater than the corresponding technology's plant typical size.

Fig. 5 Example of continuous and discrete offer functions



With all agents' offers (stepwise functions), the aggregated supply curve is calculated and its intersection with the demand curve computed. An example is shown in Fig. 6. Offers are accepted in ascending price order until both curves intersect, and the resulting capacity price is that one. In case of several offers at the resulting price, *pro rata* assignation is done.

Fig. 6 Example of capacity market



All committed new groups are converted to asked permits, which have an administrative delay, and once obtained, all of them start the building process. After the building period, the new plants enter in the generation portfolio of the agent, closing the simulation loop.

5. Study Case

5.1 System modelling description

This study case has been performed for a large-scale electric power system similar to the Spanish one: capacity-constrained rather than energy-constrained, with no possible new investments in hydro capacity, although some previous hydro power plans already exist. Investments are only considered in thermal and renewable technologies. Thus, the horizon of the study is 25 years (it should be longer for considering hydro investments), with a 1-year time resolution. Electricity prices are calculated for every 10-hours block of the 12 periods (months) in which a year is divided. Off-Peak hours are considered to be 70% of total hours, whereas Peak hours are the remaining 30%.

There are eight differently-sized generation companies: C1 to C6 (incumbent companies), CI (independent power producer), and CR (company that only invests in renewables, introduced for modelling the fact that several big utilities are splitting their businesses, originating companies who focus exclusively in renewables). These companies own some already-existing thermal, renewable and hydro capacity, as shown in Table 1.

Table 1: First simulation year installed capacity (GW) per technology and company.

	C1	C2	C3	C4	C5	C6	CI	CR
Nuclear	3.4	3.8	0.1	0	0	0	0	0
CCGT	1.1	2.5	1.8	0.4	0	1.5	1.8	0
Fuel	1.4	2.1	0.8	0	0.6	0	0.1	0
Coal	3.8	0.9	1.6	2.4	0.7	0	0	0
National Coal	1.3	0.1	0	0	0	0	0	0
Gas Turbine	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	10
Other Renewable	0	0	0	0	0	0	0	9.0
Hydro	2.8	4.0	1.0	0.2	0.1	0	0	0

New capacity characteristics are equal for all companies, and take the values shown in Table 2.

Table 2: General characteristics for different generation technologies. Investment costs (IC), variable costs (VC), fixed costs (FC), plant capacity (PC), CO₂ emission rate (ER), life-span (LS) and Firmness (Fir.).

	IC	VC	FC	PC	ER	LS	Fir.
	<i>k€/MW</i>	<i>€/MWh</i>	<i>€/kW</i>	<i>MW</i>	<i>tCO₂/MWh</i>	<i>years</i>	<i>%</i>
Nuclear	1250	11.5	53	1000	0	40	100
CCGT	619	22	29	400	0.37	30	100
Fuel	800	40	21.5	300	0.8	30	100
Coal	1167	14	32	500	0.88	30	100
National Coal	1200	17	32	500	0.95	30	100
Gas Turbine	416	32	20	250	0.65	25	100
Wind	1211	0	28	1	0	25	26
Other Renew.	5000	0	100	1	0	25	33

For the first year, an hourly demand based on the one of the Spanish electricity market has been considered to calculate the loads of the simulation's load blocks. A 3% constant growth is considered for the rest of the following years. Non-supplied energy (NSE) price is 180 €/MWh, the same value as the considered price cap. For every year, an average scenario of hydro production is considered. A carbon price of 25 €/tCO₂ has been supposed.

5.2 Capacity mechanisms characterization

Open Cycle Gas Turbines (OCGTs) have been considered to be the typical peaking units. Its annualized fixed costs (Fixed Costs of a Peaker, FCP) are calculated by computing the yearly depreciation of the asset (its investment costs, IC) throughout its life span (considering a 6% discount rate) and adding it to the annual fixed costs (FC). With the values in Table 2, a value of 52130 €/MW (per year) is obtained. The supposition of 25% of this value being recovered (on average) selling energy to the market is made, as in (Hobbs et al., 2005). Thus, the Average Uncovered Fixed Cost of a Peaker (AUCFP) value is 39000 €/MW. It represents the average amount of money needed by a typical peaker to recover its investment with a fair rate of return, in addition to the money perceived by selling energy into the market. As shown in Fig. 3, this is the value used for the capacity payment and the value corresponding to the desired reserve margin in the capacity market.

For all the previously-installed capacity (the one in Table 1), a capacity payment of 39000 €/MW is considered, no matter the capacity mechanism under study: in the capacity payments case, from the first simulation year on, new capacity receives that same payment; whereas in the capacity market case, new capacity goes to the market but the old one remains in the fix capacity payment regime. Although this may be discussable from a legal point of view, doing it otherwise for the capacity market modelling would make results incomparable to the ones in the other case (the agents with old capacity would have a different source of incomes). And for being legally strict, some kind of Competence Transition Compensations (CTCs) would have to be modelled for the old capacity. For these two difficulties, the capacity payment has been considered for old capacity under the capacity markets scheme.

The demand curve in the capacity market presents a maximum value of $2 \cdot \text{AUCFP} = 78000$ €/MW, starts decreasing in $0.85 \cdot \text{TRM}$ (Target Reserve Margin) and takes null value for $1.15 \cdot \text{TRM}$. The TRM is 1.2, i.e, 20% above each year's peak demand.

5.3 Studied cases

The six cases described in Table 3 have been studied. The first two correspond to the hypothesis that no renewable support mechanism has been implemented, that is, null premium paid for renewable energy. The other four cases correspond to the two premium scenarios: one with a low and one with a high value. This value is perceived by green producers in addition to the energy market price.

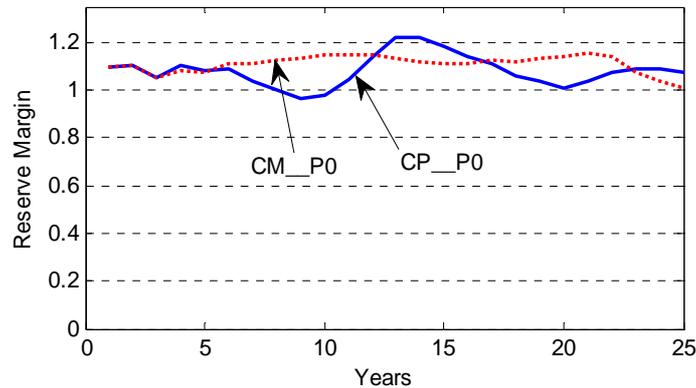
Table 3: Studied cases' description.

Case	Capacity Mechanism	Renewables Premium
CP_P0	Capacity Payments	0 €/MWh
CM_P0	Capacity Market	0 €/MWh
CP_P7.5	Capacity Payments	7.5 €/MWh
CM_P7.5	Capacity Market	7.5 €/MWh
CP_P15	Capacity Payments	15 €/MWh
CM_P15	Capacity Market	15 €/MWh

5.4 Results without renewable support scheme

Firstly, the results with no renewable support will be described. They show that capacity markets are more effective in stabilising reserve margins, dampening boom and bust cycles and levelling electricity prices, as can be seen in figure 7.

Fig. 7 Reserve Margins evolution. No premiums for renewable energy.



As can be seen, the reserve margin in the CM_P0 case stays slightly below the target value (120%). This is due to the fact that not enough capacity is being committed, what is caused by a demand curve whose top flat stretch is too low (78000 €/MW): this means that either the FCP value (52130 €/MW) or the 75% hypothesis made for obtaining the AUFCEP are too optimistic. These are common difficulties the regulator would find, and in reality would be corrected while observing them. This correction has not been modelled here.

In the CP scheme, given that Combined Cycle Gas Turbines (CCGTs) have lower variable costs and therefore they produce for more hours in a year, they recover most of their investment by selling energy into the market, so with a fixed capacity price (i.e. a capacity payment) of 39000 €/MW, agents see them as more profitable than Open Cycle Gas Turbines (OCGTs). All new investments are made in CCGTs. Given that their investment costs are bigger, agents have to wait more until building a new one, causing electricity prices to grow. Then, expected profitability for CCGTs is very high, so agents invest a lot. This causes the boom and bust cycles, which are characteristic of some capital-intensive industries. On the contrary, in the CM scheme, the more stable reserve margins result is consistent with the fact that more peaking units (OCGTs) enter the system: new investments are not only in CCGTs, OCGTs are built as well. The greater presence of OCGTs is due to the fact that the capacity price they perceive can be greater than their AUFCEP, thus making their investment more profitable (without having to rely entirely on selling energy in uncertain peak demand periods). And this (capacity prices over the AUFCEP) happens with a greater probability when the reserve margin falls, creating a stabilising effect.

The last years reserve margins' drop is due to the closures of several national coal power plants (part of the initial capacity agents own prior to the simulation period). In a real market this would be anticipated by the regulator and more capacity would be demanded. But here, this anticipation has not been modelled. However, higher amounts of new capacity are committed these years and reserve margins rise again when this new capacity enters the system after year 25.

In Table 4, it can be seen that last simulation year's share of OCGTs is higher in the CM than in the CP case, replacing CCGTs (other technologies' shares remain similar in both cases).

Table 4: Selected results. No premium cases.
Five first years strongly dependent on initial conditions, hence not considered for results

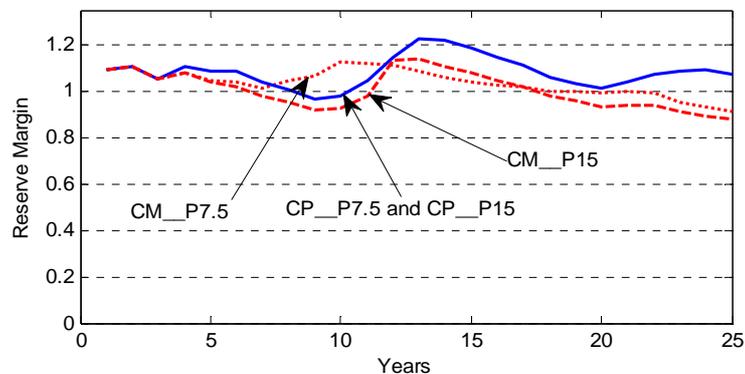
		CP_P0	CM_P0
Mean of Reserve Margins (last 20 years, p.u.)		1.081	1.117
Last year mix share (%)	CCGT	63	46
	OCGT	0.4	16
Mean of Market Prices (last 20 years, €/MWh)	Peak	107	99
	Off-peak	65	64
Total actualized costs (last 20 years, G€)	Market	1096	1022
	Capacity	88	101
	RE Premiums	0	0
	NSE	<0.1	0
	Total	1184	1123
Total emissions (last 20 years, 10¹⁵ t CO₂)		2.185	2.229

As a result of the more constant reserve margins, the electricity prices both in peak and off-peak hours are lower in the CM case (in Table 4, the mean of prices are shown). This causes market costs for consumers (actualized to the final year) to be smaller, although capacity mechanism costs are greater in the CM case. RE Premiums costs for consumers are null in both cases, because no premium is in place. Non Supplied Energy Costs (NSE), which reflect the utility of unserved load in economic terms (valued 180 €/MWh), are null in the CM case, thanks to high reserve margins. Adding all these effects, total costs for consumers, actualized to the final year, are lower in the CM case. But the total CO₂ emissions (added over the last 20 years of the study horizon) are greater under CM, due to the greater emissions rate of Open Cycle Gas Turbines. If the regulator wants to address this problem, renewables promotion is needed. This is assessed in the following section.

5.5 Results with renewable support scheme

Now, the results with both renewable premium scenarios will be described. As can be seen in Fig. 8, under both CP cases, reserve margin curves are the same (and coincident with the one in CP_P0). This is due to the fact that, no matter which premium case, agents do not find renewables profitable. The same happened in the CP_P0 case, so investments are the same that in that case: only in CCGTs. A greater renewable energy premium (greater than 15 €/MWh), could change this fact under the CP scheme.

Fig. 8 Reserve Margins evolution. Both premium scenarios.



On the contrary, in the CM cases, agents see greater profitability for OCGTs and wind turbines than for CCGTs because capacity prices can go above 39 k€/MW. In addition, agents invest less in OCGTs and more in wind turbines when the renewable premium grows. Both premium scenarios make reserve margins fall (compared to the CM_P0 case, where they stayed above 100%) and boom and bust cycles tend to appear again (reserve margin oscillates again) when premiums become bigger. The reason is the constant (and high) value of renewable premiums, which does not depend on the amount of renewable energy that is being produced. These constant premiums make renewables' profitability independent from the quantity of renewable capacity that is installed, ruining the stabilising effect of the capacity market (which is due to the quantity-dependent profitability).

This could be solved by making premiums decrease when the total amount of produced renewable energy increase, creating a stabilising effect. That is, a demand curve for green energy with a similar shape as the one used for the capacity market (except that the axis, in this case, would be green energy premium vs green energy). Then, the stabilising effect would be similar to the one that capacity markets create on total capacity. A Green Certificates Market is a similar approach.

Table 5: Selected results. Both premium cases.
Five first years strongly dependent on initial conditions, hence not considered for results

		CP_P7.5	CM_P7.5	CP_P15	CM_P15
Mean of Reserve Margins (last 20 years, p.u.)		1.081	1.027	1.081	0.986
Last year mix (%)	CCGT	63	30	63	36
	OCGT	0.4	18	0.4	0
	Wind	12	28	12	40
Mean of Prices (last 20 yrs, €/MWh)	Peak	107	106	107	135
	Off-Peak	65	55	65	71
Total actualized costs (last 20 years, G€)	Market	1096	1003	1096	1275
	Capacity	88	98	88	90
	RE Prem.	16	19	32	48
	NSE	19E-5	1E-3	19E-5	5E-3
	Total	1200	1120	1216	1413
Total emissions (last 20 years , 10¹⁵ t CO₂)		2.185	2.188	2.185	1.912

In Table 5, the last simulation year's mix has been represented (only for technologies whose share differs significantly over the different scenarios). It can be seen that, apart from CCGTs, in the CM_P7.5 case new investments are both in OCGTs and Wind, whereas in the CM_P15 case, only in wind power.

The smaller reserve margins cause mean electricity prices in the CM_P15 case to be the biggest, what is as well reflected on the market costs for consumers, as can be seen in Table 5: 1275 G€ vs. 1096 or 1003 G€. As investments are equal in both CP cases, mean prices and market costs are equal as well.

Regarding capacity mechanisms costs within the CM cases, as capacity prices are paid for firm capacity, and in the CM_P15 case there is less firm capacity in the system, the capacity mechanism costs are lower (90 G€ vs. 98 G€). Both concepts are equal under both CP cases because of the same new investments in both scenarios, and they are lower than in the CM cases because the value of the capacity payment is lower than the price resulting from most capacity markets (because reserve margins in the CM cases stay below 120%).

The renewables promotion costs (RE Prem.) double in the CP_P15 case with respect to the CP_P7.5 one, as a result of the premium having been doubled, but installed renewable capacity remaining equal (the renewable capacity installed prior to the simulation horizon). On the CM_P15 case, with respect to CM_P7.5, the greater wind capacity installed, combined with the bigger premium, makes the costs boost 2.5 times.

In the CM_P7.5 case, the NSE costs are very low because a good level of investment in OCGTs is reached, thus maintaining reserve margins stable and above 100% for most years. However, if renewable premiums are greater (CM_P15 scenario), reserve margins fall as has been seen, with a big repercussion on NSE costs (5 times bigger).

Regarding emissions, the CM_P7.5 case has the biggest amount (of these four) because of the greater OCGTs energy production, what is due to this case's greatest OCGTs mix share (18%). On the other hand, as expected, in the CM_P15 case, emissions fall due to large wind penetration.

6. Conclusions

Regulators are concerned about generation adequacy (having *enough* megawatts) and about indicative planning for influencing the mix evolution (having the *good* megawatts). Both problems must be addressed simultaneously, and different tools are suitable for each. This paper studies the possible interactions between some of these tools.

For the adequacy problem, two different capacity mechanisms have been chosen and studied (capacity payments and capacity market with elastic demand curve). Regarding indicative planning, renewables have been considered the *good* megawatts, and the feed-in-premium method has been chosen and studied. All methods' choices have been justified, and the study has been done with a multidisciplinary System Dynamics-based simulation model that explicitly represents the most important aspects of imperfect electricity markets under the long-term perspective. In it, both capacity mechanisms have been combined with three feed-in-premium scenarios: no premium, low and high values.

For achieving enough installed capacity, it seems from our case study that capacity markets are more effective (higher and more stable reserve margins observed) and efficient (from the total costs for consumers perspective) than capacity payments. This is because a wider range of capacity prices can be attained, causing peaking units to enter the system if needed. And this need is expressed by capacity prices growing when reserves margin fall from the target values, what creates a stabilising effect. Concerning the renewables support, as these technologies have relatively high fixed costs, more investment is observed under capacity markets for the same premium value.

From our results, it seems that capacity markets are more desirable for obtaining enough and good megawatts, because more investment is obtained in peaking units, causing reserve margins and prices to be stabilised in acceptable levels. A slight renewables promotion suffices to transfer some of this investment to wind turbines.

Given that feed-in premiums are a fully price-based mechanism, if set too high, they may ruin the stabilising effect that capacity markets (quantity-based) create upon reserve margins. This is the main contribution of our study, and it suggests the need for careful design of policies aiming at addressing the adequacy problem while implementing indicative planning.

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Authors contacts:

Álvaro López-Peña, Efraim Centeno, Julián Barquín

Instituto de Investigación Tecnológica (Escuela Técnica Superior de Ingeniería ICAI

Universidad Pontificia Comillas

C/ Alberto Aguilera, 25

28015 – Madrid

SPAIN

Email: alvaro.lopezpena@iit.upcomillas.es