Energy Policy 91 (2016) 113–127

Contents lists available at ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

The electricity generation adequacy problem: Assessing dynamic effects of capacity remuneration mechanisms

Nicolas Hary [a,b,*], Vincent Rious [b,c], Marcelo Saguan [b,c]

[a] MINES ParisTech, PSL-Research University, CERNA-Centre for Industrial Economics, 60 Boulevard Saint Michel, 75006 Paris, France
[b] Microeconomix, 5 rue du Quatre Septembre, 75002 Paris, France
[c] Florence School of Regulation, Robert Schuman Centre for Advanced Studies, European University Institute, Via delle Fontanelle, 19, 50014 Firenze, Italy

HIGHLIGHTS

- A study of the dynamic effects of CRMs on generation investments is provided.
- Capacity market and strategic reserve mechanism are compared.
- Both CRMs reduce the cyclical tendencies prone to appear in energy-only market.
- The capacity market experiences fewer shortages and generation costs are lower.

ARTICLE INFO

Article history:
Received 16 April 2015
Received in revised form
23 November 2015
Accepted 28 December 2015

Keywords:
Electricity market
Generation investment
Capacity remuneration mechanism
System dynamics

ABSTRACT

Following liberalization reforms, the ability of power markets to provide satisfactory incentives for capacity investments has become a major concern. In particular, current energy markets can exhibit a phenomenon of investment cycles, which generate phases of under and over-capacity, and hence additional costs and risks for generation adequacy. To cope with these issues, new mechanisms, called capacity remuneration mechanisms (CRM), have been (or will be) implemented. This paper assesses the dynamic effects of two CRMs, the capacity market and the strategic reserve mechanism, and studies to what extent they can reduce the investment cycles. Generation costs and shortage costs of both mechanisms are also compared to conclude on their effectivity and economic efficiency. A simulation model, based on system dynamics, is developed to study the functioning of both CRMs and the related investment decisions. The results highlight the benefits of deploying CRMs to solve the adequacy issue: shortages are strongly reduced compared to an energy-only market. Besides, the capacity market appears to be more beneficial, since it experiences fewer shortages and generation costs are lower. These comparisons can be used by policy makers (in particular in Europe, where these two CRMs are mainly debated) to determine which CRM to adopt.

1. Introduction

Power market reforms in recent decades and in particular development of competition on the generation side have changed the way investment decisions are made (Dyner and Larsen, 2001). In previous regulated systems, investment risks were passed through the tariffs to the consumers. Since only one player was involved, coordination in generation investments was not an issue. Now, investors perform their own development planning in reaction to complex and hardly predictable price signals, aiming to earn the highest profit. It makes coordination in investments more complex, which can lead to long-term inefficiencies.

Literature has shown that many market failures can disturb the achievement of an optimal level of investment under the so called "energy-only" market design (Hobbs et al., 2001; De Vries, 2004; Bidwell and Henney, 2004; Joskow, 2007). Moreover, it has shown that generation adequacy is not only about investing in the optimal amount of capacity but also about doing it at the right time.[1] Indeed, the dynamic aspects of generation investments also matter

* Corresponding author at: Microeconomix, 5 rue du Quatre Septembre, 75002 Paris, France.
E-mail address: nicolas.hary@microeconomix.com (N. Hary).

[1] In theory, it also requires to optimally invest in specific types of technologies (base, peak… to deal with flexibility issues in particular) and in specific locations (to limit congestions). These two requirements are not studied in this paper.

http://dx.doi.org/10.1016/j.enpol.2015.12.037
0301-4215/

regarding the adequacy issue.[2] In particular, the risk of cyclical tendencies in generation investments, known as boom and bust cycles, has been highlighted (Ford, 1999, 2001, 2002; Green, 2006; Arango and Larsen, 2011). These tendencies are materialized by phases of undercapacity and overcapacity. Such phases are prejudicial to society since more shortages than the optimal level are required during undercapacity phases and more generation capacity than the optimal amount is built during overcapacity phases. Undercapacity phases are explained by the tendency of investors to delay their investments. This is mostly due to uncertainties, impossibility to predict futures prices in a perfect way and risk aversion (De Vries, 2004). Investors tend to wait for clearer signals of profitability to be sure their plants will be profitable (Dixit and Pindyck, 1994). Long lead time, capital intensiveness and irreversibility of investments also intensify these effects. Conversely, once investments seem to be profitable enough, players are prone to overinvest. A herd behavior or an underestimation about competitors' decisions can explain this (Green, 2006). Such underestimation can be intentional, investors being skeptical about completion of competitors announced power plants, or unintentional, investors having limited information about competitors' decisions (Ford, 2001).

Therefore, to provide optimal investment signals and solve these adequacy issues, new mechanisms called capacity remuneration mechanisms (CRM) have been (or are going to be) implemented. The debates and discussions currently taking place in Europe on this topic mostly focus on two mechanisms, the capacity market and the strategic reserve mechanism.[3] These two mechanisms are studied in this paper. In the capacity market (also known as capacity requirements), an obligation of installed capacity is computed several years in advance, equal to the peak demand forecast together with a capacity margin. This obligation can be proportionally shared between suppliers in the case of a decentralized capacity market or borne by a single buyer (for instance the TSO[4]) in the case of a centralized capacity market. A new market for capacity is then created, juxtaposed to the commodity energy market, to exchange capacity credits and reach this capacity obligation. This design has been selected in France or in Great-Britain. In the strategic reserve mechanism, the TSO sets, several years or months in advance, the amount of required strategic reserves based on the difference between estimated peak demand (plus a capacity margin) and what the market would otherwise provide without the mechanism. These reserves are provided through a competitive tender and are deployed only as a last resort to avoid shortages. It has been implemented in Sweden and in Finland and recently in Belgium. Germany is also considering the introduction of this mechanism (McGraw Hill Financial, 2015). Besides, the European Commission (2013) recommends the implementation of a strategic reserve mechanism which it assesses as less distortionary for the energy market and easier to implement.

One of the key questions in the current literature involves assessing the performances of these CRMs and comparing them to select the best one to implement. For instance, in Europe, the implementation of these mechanisms has to be validated by the European Commission based on the comparison of several economic criteria. Several authors have thus compared qualitatively the different CRMs with regard to a selection of economic criteria (e.g. provision of adequate incentives, feasibility, risks of market power abuse), mainly from a static point of view (e.g. Finon and Pignon (2006)). Moreover, due to the importance of the investment cycles as described in the literature, the performances of these CRMs also have to be assessed dynamically, in particular to study to what extent they can reduce these prejudicial cyclical tendencies. To this end, simulation models are needed. Indeed, to gain an understanding of the dynamics of the industry, Gary and Larsen (2000) showed that inclusions of information feedback loops, instead of equilibrium assumptions, are fundamental. Therefore, equilibrium models cannot be used anymore to understand and model the cyclical tendencies (of course, the same can be said about optimization models, e.g. minimizing costs). Among the different simulations models, Systems Dynamics (SD) modeling, a methodology developed by Forrester (1961), is the main model used in the current literature to model these feedback loops and to study dynamic aspects of investments. SD enables to study inter-relationships among the different components, understand feedback mechanisms and then assess the dynamic responses. Thus, using this methodology, cycle behaviors can be analyzed, as well as the influence of CRM on such cycles. For instance, Olsina et al. (2006), Syed Jalal and Bodger (2010), De Vries (2004), Kadoya et al. (2005) and Hani et al. (2006) have applied SD to study the investment dynamics in electricity markets and to highlight the cyclical behavior. A more extensive review of SD models in generation capacity simulation can be found in Teufel et al. (2013).

Literature has also used this method to study and compare the dynamic properties of CRMs in order to select the most effective one to implement. For instance, Assili et al. (2008) and Park et al. (2007) study how an improved variable capacity payment mechanism can reduce investment cycles. De Vries and Heijnen (2008) compare capacity payments, operating reserves pricing and capacity markets under uncertainty of the future growth load. They show that all these mechanisms perform better than a competitive energy-only market, capacity obligations having the strongest stabilizing effect, both with respect to investment and prices. Hobbs et al. (2007) assess the capability of the capacity market in the PJM system to reduce investment cycles. They show that a downward sloping demand curve on the capacity market reduces fluctuations in installed capacity, compared to a vertical curve. Hasani and Hosseini (2011) compare the capacity payment mechanism and the capacity market through nine technical and economic indicators (in particular regarding shortages, electricity prices and revenues of peak technology). Hasani and Hosseini (2013) develop a SD model to compare different designs of capacity payment in the Iranian power market, in particular assessing the reserve margin and the generation expansion costs. They find that a capacity payment mechanism with different payments for each region according to the regions' reliability indices shows lower capacity expansion costs and enables to avoid shortages. Finally, Cepeda and Finon (2011) study the problems related to long-term security of supply in regional electricity markets when different CRMs are implemented. They find that the lack of harmonization between local markets in CRMs may lead to undesirable side effects.

However, the current literature can be improved on two points.

[2] Stoft (2002), amongst others, outlines this idea: "Economics focuses on equilibria but has little to say about the dynamics of a market. Once economics shows that a system has a negative feedback loop so that there is a point of balance, it considers its job done. Engineers move beyond this stage of analysis to consider whether a system will sustain oscillations and, if not, whether it is over- or underdamped. Economics understands that investment dynamics can produce "cycles" but has faith that rationality will generally prevent this".

[3] Other CRMs are discussed in the literature (and sometimes implemented). These mechanisms can be sorted into two types: the price-based mechanism (where policymakers set a price and let the market determine the corresponding volume), like the capacity payments (Oren, 2000) and the reliability payments (Olsina et al., 2014), and the volume-based mechanisms (in which a regulating authority sets a desired amount of installed capacity and lets the market reveal the right price), like the long-term forward contracts (Cramton and Stoft, 2008), the reliability options (Vazquez et al., 2002), the capacity market (Batlle and Rodilla, 2010) or the strategic reserve mechanism (Finon et al., 2008).

[4] Transmission System Operator: it is in charge of operating, maintaining and developing the power transmission grid.

First, the strategic reserve mechanism, one of the main CRMs implemented and discussed in Europe, is rarely studied from a dynamic point of view. Thus, policymakers cannot compare this mechanism with other CRMs to select the best one to implement. Moreover, in the studies mentioned above, comparisons are often based on an adequacy criterion (i.e. to what extent the CRM can reduce shortages). However, the efficiency of the mechanism, i.e. the costs to build and operate power plants to reduce shortages, is often disregarded. Yet, efficiency is one of the main criteria to consider from an economic point of view, in particular when maximizing the social welfare: CRMs have to reduce shortages but not at any cost for society. Policymakers should decide which CRM to implement regarding not only the effectiveness criterion (i.e. the adequacy) but also the efficiency one (i.e. the investment and generation costs).

These two missing points are studied in this paper. Its purpose is to assess the dynamic effects of the capacity market and the strategic reserve mechanism, two of the main CRMs considered in Europe, and to compare them with regard to the effectiveness and efficiency criteria. The most suitable and convenient method to study these dynamic aspects of investments is SD modeling, which is used in this paper. To the knowledge of the authors, the results of this study should not be dependent on the original modeling choice, as long as the model is a SD simulation. As a consequence, the model chosen in this paper is based on Hobbs (2005) and Hobbs et al. (2007) as it is well exposed and explained in the original papers, and then easily tractable. This original model, where only the capacity market is studied for the PJM system,[5] is expanded to consider a strategic reserve mechanism and an energy-only market. Moreover, in order to be able to compute the generation costs accurately, a bidding behavior based on avoidable costs and endogenous shutdown decisions are added. The model used in this paper simulates investment decisions in a liberalized market regime under uncertainty on the load growth. Three different market designs are studied: the energy-only market (as a reference case), the capacity market and the strategic reserve mechanism. Then, these market designs are compared based on social welfare using Monte-Carlo simulations for different growth loads. This social welfare is evaluated thanks to total generation costs and shortage costs.

This paper is organized as follows: Section 2 presents the model used in this paper to study players' decisions under the energy-only market, the capacity market and the strategic reserve mechanism. Results of these simulations and comparisons of market performances are outlined in Section 3. Finally, Section 4 concludes the paper.

2. Model

This section introduces the model developed to assess the performances of both strategic reserve mechanism and capacity market. In a first part, an overview of the model is given, and then each market (the energy-only market and both CRMs) is described more precisely. Finally, the last section introduces the main parameters used in the simulations as well as the way simulations are run and indicators computed.

2.1. Overview of the model

To study investment decisions in liberalized power systems and how CRMs can modify these investments, a model based on system dynamics modeling is used. It is based on the research developed by Hobbs (2005) and Hobbs et al. (2007). The logic of the original model is kept in this paper. It is presented in Fig. 1 on a simplified causal-loop diagram. In this diagram, typical for SD modeling, a causal relationship between two system variables is depicted through an arrow. The (+) symbol describes a positively related effect (an increase in the first variable will cause an increase in the second one). The (−) symbol specifies the contrary.

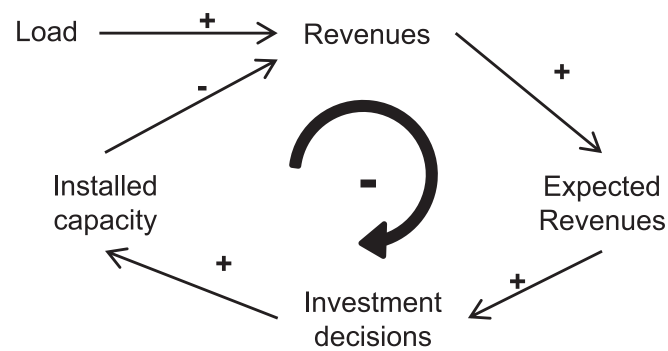

Fig. 1. Simplified diagram of the model.

Each year, revenues (from the energy market and/or from CRM) are computed. These revenues are used by players to assess expected revenues and future profitability of their plants and then to make investment decisions. These decisions will in turn impact the installed capacity, which will result in changes in revenues. Then, a negative feedback loop can be noticed, which could lead to an equilibrium in theory.

The main assumptions made by Hobbs (2005) are kept here: annual time step is used, perfect competition is considered (there is no strategic behavior), only peak technology is modeled (which is characterized by a lead time of four years), revenues from the energy market are assessed thanks to an exogenous function (and not by modeling a short-term energy market), expected profits are computed thanks to previous and current profits. Moreover, load is summarized by the annual peak load and is expected to increase at an average constant growth rate. However, uncertainties, due to economic growth rate deviation or weather conditions, are added to this average load growth rate and modeled thanks to two independently random variables which are normally distributed with mean zero and standard deviation of σ_g and σ_w.

In the original model, only the capacity market is modeled. The modeling of this mechanism is improved in this paper to consider a more complex bidding behavior (based on avoidable costs). Two other market designs are added: the strategic reserve mechanism and the energy-only market, which is used as a reference case to assess cyclical tendencies. Moreover, to compute more realistic generation costs and then to improve the comparison of the efficiency indicator, power plant closures are now endogenous (investors decide whether to close their plants, regarding expected profitability). Increasing O&M (Operating and maintenance) costs are modeled to reflect aging of plants. Thus, it is more and more costly to operate these plants and investors may prefer closing them and building new ones. Fig. 2 indicates how these maintenance costs increase with age. They are constant during the first half of assumed lifetime of the plant and exponentially increase after. Maintenance costs are assumed equal to annualized investment cost of a plant at the end of the assumed lifetime of the plant (20 years).

The three market designs are introduced thereafter. The aim of this study is to compare the two CRMs, i.e. the capacity market and the strategic reserve mechanism (the energy-only market is introduced as a reference design). To facilitate the understanding of

[5] PJM Interconnection is a Regional Transmission Organization (RTO) operating the electricity system including the wholesale market in the North-East of USA.

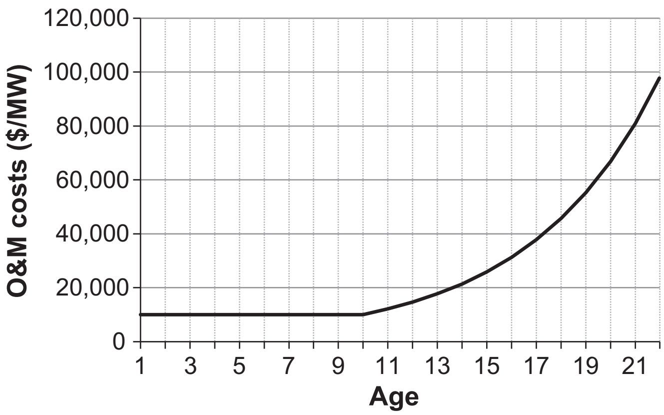

Fig. 2. Evolution of O&M costs in function of age of plants.

these markets, the energy-only market model is presented first. Both CRMs are then introduced. Main equations of these models are exposed in Appendix A.

2.2. Energy-only market

Fig. 3 describes in a simplified way how the energy-only market is modeled in the paper. The different stages are described thereafter.

2.2.1. Revenues from the energy market

In this paper, revenues from the energy market are computed in the same way as Hobbs (2005) did. He considers that annual profits, defined as revenues earned from the energy and ancillary services markets minus variable costs, can be expressed as a function of the ratio of installed capacity over peak load (Fig. 4). The smaller this ratio is, the larger profits are, since capacity becomes scare and expensive actions (e.g. demand response) or shortages are needed.

2.2.2. Investment and shutdown decisions

To decide whether they invest or close plants, investors have to assess future profitability of their power plants. Since four years are necessary to build a plant, investment decisions are made four years ahead. To simplify the model, the same assumption is made for plant closures. Fig. 5 describes the different steps of the decision process, which are explained below.

First, investors have to compute expected profitability of their

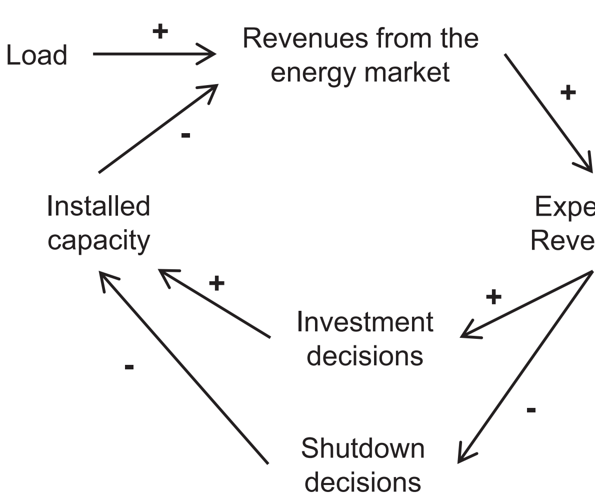

Fig. 3. Simplified diagram of the energy-only market.

plants. As Hobbs (2005) modeled it, players base this computation on eight years of past and future profits, from year $y-3$ to year $y+4$ (y is the current year when decisions are made). For years $y-3$ to y, profits from the energy market are known since those years have already passed or are in process. For years $y+1$ to $y+3$, they are unknown and have to be estimated based on expected demand and future available capacity. Players can partially anticipate the future demand, based on the peak load during the current year y and the average peak load growth. However, they cannot anticipate the uncertainties due to economic growth rate deviation or weather conditions. Furthermore, the future available capacity can be accurately estimated since investors know plants under construction or which are going to close (as such decisions have already been made and often released, through media or TSO reports). For the year $y+4$, the profits are assumed to be the same as the profits during year $y+3$. Then, given those profits, investors attach a set of weights to each year of profits to represent how they assess future profitability. For instance, they can only consider profits in year $y+4$ or they can consider eight years of profits. Thus, investors can compute the weighted average of these profits to assess the expected profitability.

To model players' decisions regarding investments or shutdowns, a rational economic behavior is modeled, which leads players to balance their expected profits and their avoidable costs. As avoidable costs are different considering investments or shutdowns, decisions differ: for investment decisions, avoidable costs are investment, O&M and variable costs; for shutdown decisions, investment costs are sunk and only O&M and variable costs can be avoided. In both cases, as the function used to compute revenues from the energy market (Fig. 4) already takes into account variable costs, they are not considered thereafter.

For investment decisions, players compare the expected profits during the economic lifetime of the plants with investment and O&M costs. The previously computed profitability is assumed to remain constant during the economic lifetime. The net present value (NPV) is then computed. If it is positive (expected profits cover at least avoidable costs), investors decide to add new capacity in the system. Otherwise, no investment decision is made. As done in previous literature on this subject, the more investors expect a high profitability, the more they invest. However, a saturation level is generally considered to limit capacity additions. Since participants expect a high attractiveness for investing, they are aware of the potential danger of a wave of massive investments.[6] Moreover, when NPV is slightly negative, some investments are still attractive for players with lower financing or investment costs. According to this reasoning, a linear function is proposed to model the relationship between NPV and the investment decisions (Fig. 6). This function is defined by three parameters: capacity addition when NPV is zero, maximum capacity addition and NPV at which this maximum addition is reached.[7]

Regarding shutdown decisions, each year players decide whether to continue running their plants or to decommission them, considering expected profits and O&M costs (depending on the age of the plant). If these costs appear to be higher than expected profits, they will decide to close their plants. Otherwise, plants will run one more year. Moreover, as for investment decisions, there is a maximal amount of capacity which can be decommissioned each

[6] It is particularly true in concentrated market where participants can limit investments to avoid low prices which could endanger their capacities in place. There are also constraints, in particular financing constraints or land constraints, which can limit investments (Olsina et al., 2006).

[7] To the knowledge of the authors, there are no precise values of these parameters for current power systems in the literature. A sensitivity analysis will be carried to test several values for these parameters in the following simulation.

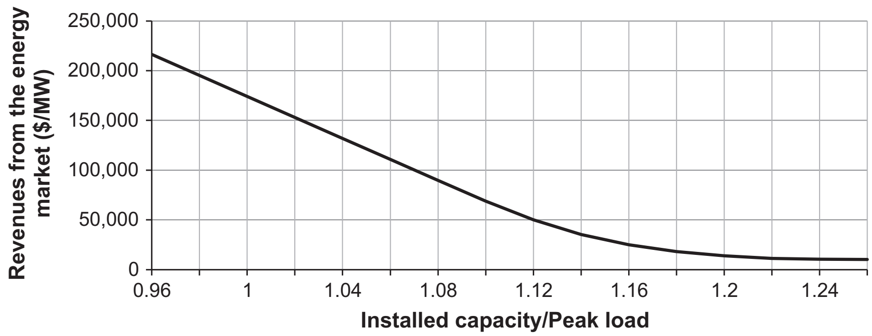

Fig. 4. Revenues from the energy market (from Hobbs (2005), based on PJM system).

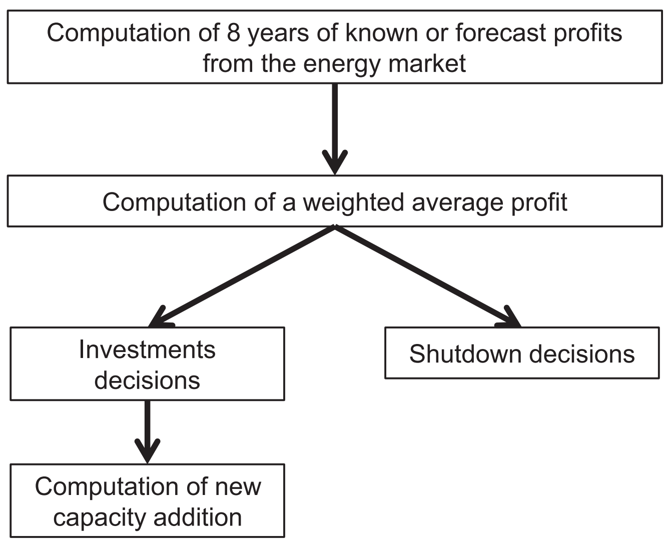

Fig. 5. Steps of the decision process.

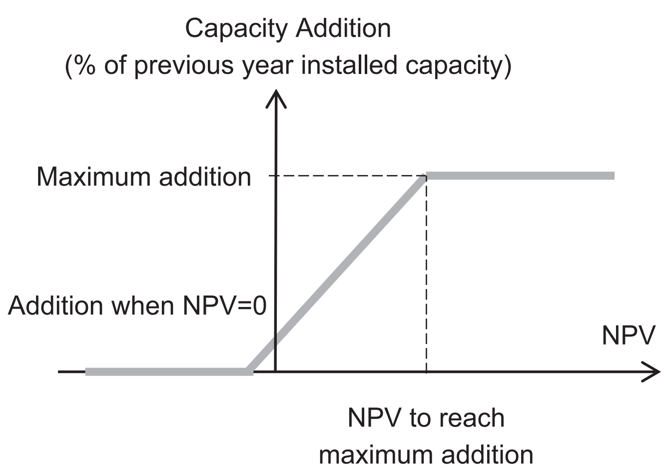

Fig. 6. Relationship of capacity addition to NPV.

year (players are partially aware of competitors' shutdown decisions and they do not close all their capacity in the same year). At last, once investors have come to a decision about shutdowns and investments, the installed capacity for year $y+4$ can be determined. Then, the next year demand is computed, and the decision loop starts again.

2.3. Capacity market

Added to the traditional energy market, a new market for

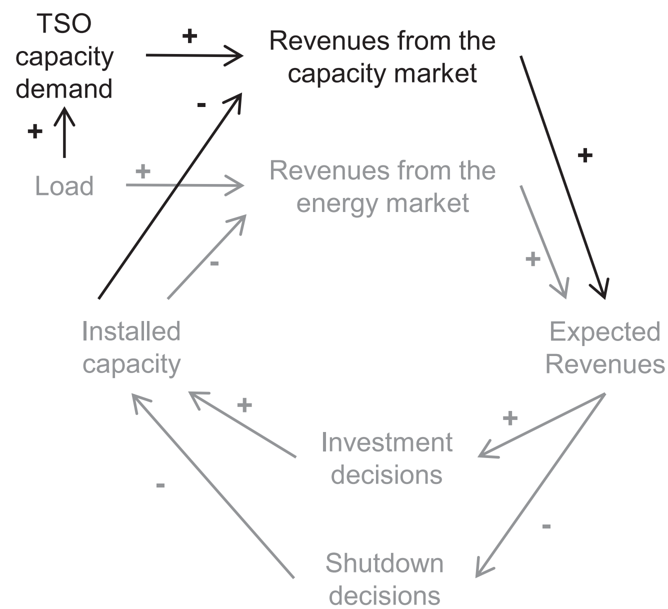

Fig. 7. Simplified diagram of the capacity market.

capacity is implemented (Fig. 7). In the model, a centralized capacity market is considered (similar to the one implemented in Great-Britain). Several years ahead, the TSO assesses the capacity need to deal with the peak load. Then, it contracts this capacity through an auction in which players offer existing or new capacity. A capacity price is then determined, which creates complementary revenues for plants. This price plays an important role since it coordinates investment and shutdown decisions: if there is a lack of capacity, the capacity price will rise to attract new investments. Otherwise, it will decrease to force expensive plants to close or to postpone investments. Thus, the capacity market is believed to solve investment issues in the energy-only market.

Compared to the previous energy-only model, a new step is added to the model which simulates the capacity market. The auctions for capacity available in year y are considered to take place four years ahead (which is the lead time for peak technologies). The capacity market is modeled by a supply curve, determined by offers made by players (which is described below), and a demand curve, resulting from the TSO capacity requirement (see Fig. 8). This demand curve is characterized by a maximum price and by a target capacity corresponding to the expected peak demand plus a margin.[8] Matching supply with demand will

[8] As for investors in the energy-only market, the TSO has not a perfect foresight of future load and cannot anticipate future uncertainties due to economic growth rate deviation or weather conditions.

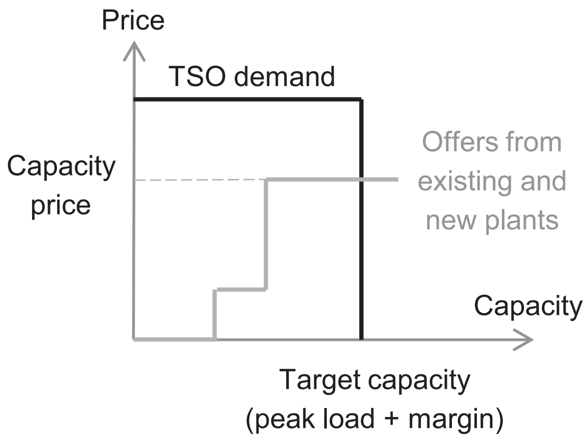

Fig. 8. Capacity auctions.

determine a price for capacity. As capacity price is now a component of players' revenues, it has to be included in expected profitability computation. Like profits earned on the energy market, eight years of capacity prices are considered to estimate profitability. For years $y-3$ to $y+3$, prices are known as auctions have already taken place. For year $y+4$, capacity price is assumed to be the same as in year $y+3$. As previously, investors compute an expected profitability from these eight years of profits. To compute the offers that they make on the capacity market, players have to balance their expected profits (earned on capacity and energy markets) and their avoidable costs.

- For existing capacity, the only avoidable costs are O&M costs for the year $y+4$. The economically rational offer price has to guarantee that players will cover these costs thanks to profits from the energy market and from the capacity market. Profits from the energy market can be estimated from the previous computation, based on the ratio of installed capacity over peak load. If they are greater than costs, players will bid zero on the capacity market (they do not need revenues from the capacity market to break-even). On the contrary, if expected profitability from the energy market is less than O&M costs, players will bid the difference on the capacity market. Thus, if their offer is accepted, they will at least cover their avoidable costs (provided that they correctly estimate revenues from the energy market). In all cases, players offer all their available capacity.
- For new investments, contrary to existing capacity, investment decisions are still pending and investment costs are considered as avoidable. Therefore, expected profitability during the economic lifetime of assets has to cover both investment and O&M costs. Players are assumed to use a NPV method to compare expected profits from both capacity and energy markets and avoidable costs. If NPV is positive, investors will invest and bid zero on the capacity market. Otherwise, investors will bid considering the project's expected net present value shortfall. Indeed, as the capacity price is guaranteed for a single year only, investors cannot rely on a capacity price above expected capacity price for the rest of the economic lifetime (but only for the first year). Therefore, to break-even for sure, they have to bid the total shortfall on the first year auction, in addition to the expected capacity price.[9] Investors always offer the maximum capacity addition, as defined on Fig. 6, on the capacity market (which can be totally or partially refused according to capacity demand and offers from existing capacities).

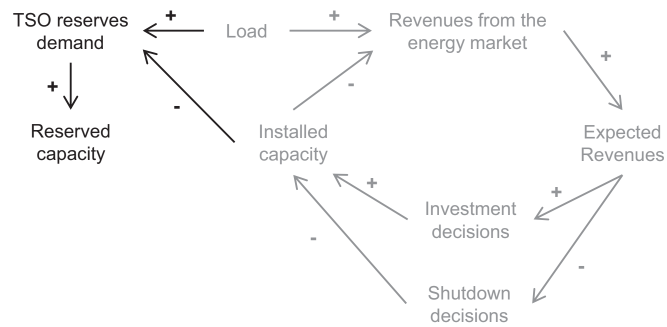

Fig. 9. Simplified diagram of the strategic reserve mechanism.

Therefore, having computed the supply and demand curves, a capacity price can be determined. Players with accepted offers will invest or will keep their plants in operation. Players with refused offers will close their plants or will not invest.

2.4. Strategic reserve mechanism

A strategic reserve mechanism, as described in Fig. 9, consists of a set of generation units kept available for emergencies by an independent agent, typically the system operator. Contracted capacity is taken out of the market and is only activated in last resort to avoid shortages. The agent determines the amount of capacity to contract, resulting from expected load and investment and shutdown decisions on the energy market, and contracts it through an auction.

Therefore, capacity can be sorted into two exclusive markets: one for strategic reserves, called strategic reserve mechanism below, and one for non-reserved capacity, called energy market below. These markets are exclusive since capacity on the energy market cannot participate in strategic reserves auctions and so its sole profits comes from the energy market. Reciprocally, reserved capacity cannot sell energy on the energy market, except in last resort when the TSO requires it. Conditions of deployment and use of reserved capacity have to be well defined to minimize interferences with the energy market.[10] Here, strategic reserves are deployed when there is no more available capacity on the energy market and they are sold at the energy market price cap. Therefore, for a producer on the energy market, there is no difference in its revenues in times of shortage or high tension. Fig. 10 illustrates how these two exclusive markets are modeled, as well as the links between them and the investment and shutdown decisions.

Players can only invest on the energy market (investments on the strategic reserve mechanism seem too risky to happen, as players cannot sell energy and the reserves price is guaranteed for only one year). They participate in the energy market year after year until they expect to be in deficit (i.e. their expected profits from the energy market are lower than their costs). Thus, players attempt to pass their capacity on to strategic reserves and make offers for their plants on the strategic reserve mechanism. If their offers are not accepted, plants will be decommissioned. Otherwise,

[9] For instance, if the avoidable costs are \$150,000/MW-year, the expected profits from the energy market \$60,000/MW-year and the expected profits from the capacity market \$80,000/MW-year, investors have to earn the shortfall between costs and expected revenues on the first year auction. If the economic lifetime of the plant is 20 years, the total shortfall equals 20*(150 000-60 000-80 000)=\$200,000/MW, when discounting is not regarded. The project will break-even if it can earn this shortfall on the first year auction, addition to the expected capacity price. Thus, the economically rational offer would be: (\$80,000+\$200,000)/MW (see Wilson (2010) for more explanations).

[10] For instance, if contracted capacity is deployed at a price lower than the highest supply bid, it will increase the disincentives to invest for producers on the energy market.

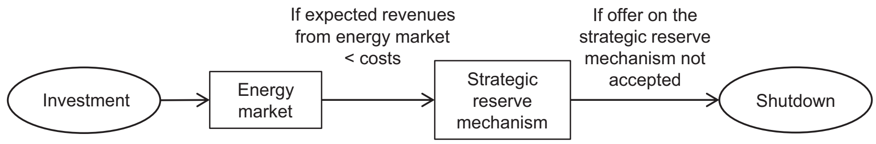

Fig. 10. Energy market and strategic reserve mechanism.

plants will become reserved capacity and they make offers every year on the auctions until their offers are refused.[11]

For the energy market, there is no major difference with the energy-only market described previously. Since strategic reserves are considered to be deployed only when shortages occur and are sold at the energy market price cap, existing plants on the energy market generate the same revenue no matter whether shortages happen or whether strategic reserves are deployed. Thus, the profits earned on the energy market can be computed thanks to the function described in the Fig. 4, provided the system margin is computed with the capacity available on the energy market, and not with the total system capacity (which includes reserved capacity). Then, as previously, generation companies compute an expected profitability and decide consequently to invest or to decommission their plants, four years ahead (with the same parameters as for the energy-only market).

The strategic reserve mechanism works differently. Every year, to ensure that the system provides enough capacity and prevents shortages, the TSO can reserve capacity which will produce only at last resort. First, the TSO estimates future demand (as previously, the TSO has not a perfect foresight of the future load and cannot anticipate the future uncertainties due to economic growth rate deviation or weather conditions) and future capacity on the energy market (the TSO is assumed to hold auctions once players make their investment or shutdown decisions, so it knows exactly future available capacity four years ahead). Then, if the margin is expected to be under the target margin, auctions will be organized to contract enough reserves to reach this target. However, the TSO cannot contract extensive volume of reserves compared to existing capacity (the energy market would be distorted if a large share of plants were reserved). Thus, a maximal volume of reserves is modeled, as well as a reserve price cap on the auctions to protect consumers. Two categories of players can bid on these reserves auctions: players who have capacity on the energy market and decide to shut down (because expected profitability on the energy market is not high enough to break-even) and players who already have capacity on the strategic reserve mechanism. As previously, players bid their avoidable costs,[12] i.e. their O&M costs, and offer all their available capacity. If offers are accepted, they will at least cover their avoidable costs. Otherwise, they will shut down their reserved plants.

2.5. Parameters for the reference case

Most data used in this model are the same as Hobbs (2005) used for his model, based on the PJM system. As the aim of this study is not to predict future evolutions of a precise power system but to compare different market designs, these data are not updated. Table 1 presents the main parameters taken for the reference case.

[11] In order to insure credibility of this mechanism, once plants enter into the reserves market they cannot return to the energy market.

[12] Reserved capacities are paid their variable costs when they are deployed. Thus, they do not make any profit by selling energy and their sole revenues come from the auctions.

2.6. Simulation and indicators

The model is implemented on Matlab®. It is run for 30 years, for the three market designs. Afterwards, some economic indicators are computed to assess the performances of each market design over the last 25 years of simulation. This time horizon is consistent regarding the current literature (e.g. Hasani and Hosseini (2011) consider 30 years, Olsina et al. (2006) consider 20 years, De Vries and Heijnen (2008) 25 years…). Moreover, the first five years of the simulation are overlooked to avoid any potential transition effects due to the initialization.

To evaluate these market designs, the social welfare should be used. Since demand is considered as inelastic, it can be computed through the cost of shortages and the costs of generation[13] (see De Vries (2004)). Below, effectiveness refers to shortage costs and efficiency to total generation costs. In this paper, curtailed demand is used as a proxy of shortage costs.[14] Effectiveness is assessed in respect to the system margin. Arbitrarily, shortages are considered to happen whenever the system margin is less than a certain threshold.[15] For each year of the simulation, curtailed demand compared to peak demand is computed. Then, these values are averaged over the last 25 years of the simulation. At the end, the result stands for the mean curtailed demand by year as % of peak demand. Efficiency is estimated through costs indicator. Investment and O&M costs are considered.[16] For each year, these costs are computed and divided by peak demand. Then, the average value is calculated over the last 25 years of simulation. The final result is expressed in $/MW of peak load.

Moreover, as two kinds of uncertainties are introduced in this model,[17] Monte Carlo simulations are run to compare the performances under various demand growth scenarios. For each simulation (i.e. for the 30 studied years), 60 random variables are drawn (one for each uncertainty and for each year). Then, the model is run for the three market designs over these same 30 years of peak load and indicators are computed and compared. Therefore, the differences in the results can only be linked to differences in terms of market design, and not in terms of input data. This process is repeated 400 times: these 400 simulations are called scenarios below.

3. Results and discussions

In a first section, cyclical tendencies in the three market designs

[13] Mathematical definition of these two indicators can be found in Appendix A.

[14] In theory, shortage costs can be computed by assuming a cost for load reduction, known as VOLL in literature. However, there is no consensus on VOLL value. To avoid giving a larger weight to shortages or generation costs (by assuming an inadequate VOLL value), these two values are assessed separately.

[15] To deal with maintenance operations and outages, installed capacity has to be greater than peak demand. Thus, shortages can happen even if the system margin is positive.

[16] Variable costs are not considered here. Indeed, they are the same in the three mechanisms most of the time, except when one market design experiences shortages and other market designs do not curtail demand. However, these variable costs during curtailed hours are insignificant compared to other costs.

[17] Economic growth rate deviation and weather conditions are modeled thanks to two independently distributed normal random variables with mean zero and standard deviation of σ_g and σ_w.

Table 1
Main parameters for the reference case.

Parameters	Value for the reference case
System margin target	15% of load
Shortage margin (margin below which shortages happen)	10% of load
Peak load growth	1.7%
Peak load growth standard deviation	1%
Weather standard deviation	2%
WACC	10%
Investments costs	$600,000/MW
O&M costs	See Fig. 2
Years considered to compute expected profits for investments decisions (y is the year when decisions are made)	$y-3$ to $y+4$
Weight given to each year profit to compute average profit for investments decisions	Each year has the same weight
Years considered to compute expected profits for shutdowns decisions (y is the year when decisions are made)	$y-3$ to $y+4$
Weight given to each year profit to compute average profit for shutdown decisions	Each year has the same weight
Maximum capacity addition (see Fig. 6)	10% of previous year installed capacity
NPV to reach maximum capacity addition (see Fig. 6)	$400,000/MW
Capacity addition when NPV=0 (see Fig. 6)	1.7%
Maximum capacity shutdowns	20% of previous year installed capacity
Maximum amount of reserved capacities[a]	15% of previous year installed capacity
Price cap on capacity market	$200,000/MW
Price cap on strategic reserve mechanism	$400,000/MW

[a] An average value compared to current maximum reserved capacity in Sweden and Belgium is considered. In Sweden, reserve capacity cannot exceed 2000 MW (compared to a peak load of about 25,000 MW) (CREG, 2012). In Belgium, the reserve capacity was 1200 MW during the winter 2014/2015 (compared to a peak load of 13,000 MW) and is expected to reach 3500 MW for the winter 2015/2016 (CREG, 2015). However, this important amount of reserved plants is mainly due to technical constraints on nuclear plants (which are independent from the economic conditions on the energy market).

are discussed based on simulation results. Then, efficiency and effectiveness comparisons are introduced. Finally, the robustness of the results is studied through a sensitivity analysis.

3.1. Study of the cyclical tendencies in the three markets

To study the cyclical tendencies in the energy-only market and to what extent the CRMs can reduce them, the evolution of the system margin (computed as the total installed capacity – i.e. capacity on the energy market+reserves if any – over the peak load) for one average scenario of load growth is presented here. Only the last 25 years are drawn. Two different system margins can be computed, regarding whether the actual peak load or the expected peak load (as computed at the time when decisions are made) is used. Performances regarding capacity adequacy depend on two factors: (1) how markets provide adequate incentives to have enough installed capacity regarding the expected peak load and (2) how this expected load differs from the actual load. This second point does not depend on the considered market, but only on random deviations. Thus, to perfectly understand how markets work, focus is made on the first factor and on the expected system margin. Fig. 11 describes the evolution of this expected system margin for 25 years of one scenario of load. For the strategic reserve mechanism, the margin on the energy market (i.e. without considering reserved capacity) is also plotted.

The adequacy performances of each market present major differences. In this scenario, the energy-only market experiences high cyclical investment and shutdown decisions. These cycles are mainly due to herd behavior, bounded rationality (modeled by the way players compute expected profitability) and incomplete information (about future load and competitors' decisions). Compared to the results available in the literature, these cycles are here exacerbated since endogenous decommission is considered. If low profits are expected, players can close their plants which makes the margin decrease quickly (and more quickly than in current literature where plants cannot be decommissioned if profits are low). It is also to be observed that the average margin, which is around 7–8% here, is well different from the 15% target margin. Indeed, revenues earned from the energy market when margin is equal to 15% are not high enough to attract new investments (revenues for this margin are around $30,000/MW while the annualized investment cost is around $70,000/MW). Thus, the implementation of a CRM is required if policy makers want to reach this target margin.

When a capacity market or a strategic reserve mechanism is implemented, the cyclical behavior is well reduced and the system experiences fewer shortages. For the capacity market, the system margin is always equal to the 15% target margin. This result seems

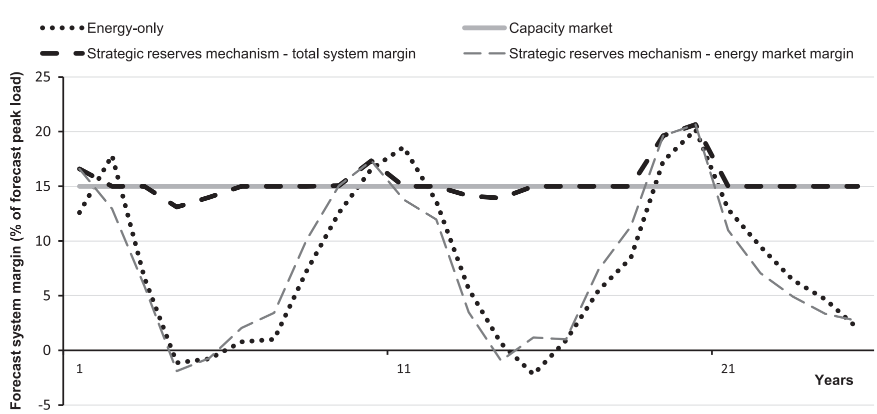

Fig. 11. Evolution of the expected system margin for one scenario of load growth.

logical since the capacity market explicitly defines a target to reach. If there are not enough plants, the capacity price will rise so that new plants or existing plants will break-even. In some extreme cases (which is not the case here), this 15% target cannot be reached if the capacity price reaches the price cap. The results of the strategic reserve mechanism (the “total system margin” line), if better than those of the energy-only market, show a lesser ability of the CRM to reduce cycles compared to the capacity market. Undercapacity phases are reduced but there are still overcapacity phases. Indeed, in the energy market, there is no explicit target for the system margin and the energy price is the only signal to coordinate decisions and to give incentives for investments or shutdowns, like in the energy-only market (since reserved capacity is considered not to interfere with the energy market). Therefore, this price leads to the same consequences as in the energy-only market, i.e. cyclical behavior and a mean margin well below the 15% target. It can be noticed with the “energy market margin” line which describes the decisions made on the energy market. However, contrary to the energy-only market, the TSO is able to react as a last resort by contracting strategic reserves to avoid shortages. Thus, phases of undercapacity are reduced compared to the energy-only market, but in a less effective way than the capacity market since the total system margin is not always equal to the 15% target margin. Three parameters limit the well-functioning of the reserved capacity in this respect. First, the model imposes that the TSO cannot contract above 15% of existing capacity, even if large shortages are expected. Second, since only the capacity which will be decommissioned can participate to the reserves auctions, offers can be lower than the TSO's demand. Finally, the reserve price cap could be reached, which would limit accepted capacity. Therefore, there is an important difference between the capacity required to reach the target margin and capacity which is actually accepted.

Moreover, when focusing on the overinvestment phases, the strategic reserve mechanism does not perform any better than the energy-only market. Overinvestments are still likely to happen if investors expect large profits. There is no signal to avoid this and the TSO cannot force players to postpone their investments. Most importantly, these overcapacity phases may undermine the well-functioning of the whole mechanism with regard to shortage risks. It is noticeable in Fig. 11: after the overcapacity phases around year 1 and year 10, there is not enough reserved capacity to reach the 15% target. Indeed, after an overcapacity phase, there is no reserved capacity and there is a risk that no investments take place for some years, whereas large decommissions are likely. In the beginning, these decommissions are not dangerous for the security of supply since the system margin is still above the 15% target margin. However, once it decreases below the 15% target, the TSO needs reserved capacity to offset not only decommissioned capacity but also the increase of peak load. However, only plants which are decommissioned the same year can participate at the auctions. Thus, the TSO cannot acquire enough capacity to offset the increase of peak load and the system margin decreases below the 15% target. This margin decreases until investments take place. Thus, after an overcapacity phase, the TSO may not be able to deal with peak increase and some shortages may happen during several years.[18]

The actual system margin is presented in Fig. 12. As explained previously, actual margins are different from the expected ones due to growth uncertainties and the functioning of CRMs is less perceptible. For instance, in year 19, the capacity market experiences some shortages whereas the strategic reserve mechanism does not, because growth deviations made the actual load higher than expected capacity. These shortages are not due to an ineffective capacity market but to a particular deviation growth. However, the same general conclusions can be drawn when assessing the actual system margin.

In conclusion, for this particular scenario, both CRMs can limit underinvestment phases which happen in the energy-only market. However, the strategic reserve mechanism appears to be less effective in some cases, due to several limiting factors. Furthermore, this mechanism cannot deal with overinvestments, which is not the case for the capacity market. These overcapacity phases are prejudicial since they may undermine the well-functioning of the strategic reserve mechanism and cause shortages later on. Moreover, since the strategic reserve mechanism does not modify the way investors make their decisions on the energy market, the adequacy performances of this mechanism highly depend on revenues earned from the energy market and on cycle characteristics. If the cycles are smoother than those on Fig. 11, the mechanism will perform better considering effectiveness since overinvestment is less likely to happen and less reserved capacity is needed. On the contrary, if cycles are stronger, the performances of the strategic reserve mechanism will be able to worsen. Regarding the capacity market, as it explicitly defines a target margin, it will always reach this target and its results are less dependent on the cyclical hypothesis.

3.2. Economic comparisons of the capacity market and the strategic reserve mechanism

The analysis of previous results shows that the capacity market seems to be more effective, for one specific random scenario. Monte Carlo simulations are run to verify this statement for various load scenarios. Moreover, efficiency is computed and compared for both CRMs. Four hundred simulations of demand growth scenarios are run. For each scenario, the efficiency difference between both CRMs is computed, as well as the effectiveness difference. Then, they are displayed in a figure similar to the Fig. 13, based on the signs of these differences. Each point depicts the efficiency and effectiveness differences compared to the capacity market for one scenario of demand growth. Three cases can be identified. In quarter 1, the capacity market experiences less shortages and total generation costs are lower than for the strategic reserve mechanism; one can conclude on the superiority of the capacity market based on these criteria. In the opposite case (quarter 3), the strategic reserve mechanism is a better mechanism. In the last cases (quarters 2 and 4), no conclusion can be directly drawn.

The results for the reference case are displayed in Fig. 14. Most scenarios (in 326 out of 400 scenarios) are in quarter 1, where the capacity market is more effective and more efficient than the strategic reserve mechanism. The remaining situations stand for scenarios where the strategic reserve mechanism has the same effectiveness as the capacity market but is less efficient.[19] Regarding the effectiveness indicator (i.e. the curtailed demand), the superiority of the capacity market has been explained in the previous section. One should also notice that the differences are weak (about 2% of peak load every 10 years on average). Two

[18] However, this is not the case after every overcapacity phases (in some cases, NPV can still be positive even if there is a overcapacity phase, depending on previous and expected loads and installed capacity).

[19] In a very few cases (not in the reference case but in some cases of the sensitivity analysis), the strategic reserve mechanism can be slightly more effective. Indeed, it happens in particular scenarios when uncertainties make load higher than expected. If the strategic reserve mechanism experiences overinvestment during this period of unexpected high peak, the actual system margin will be larger than in the capacity market and there will be less shortages (like in year 19 in Fig. 12).

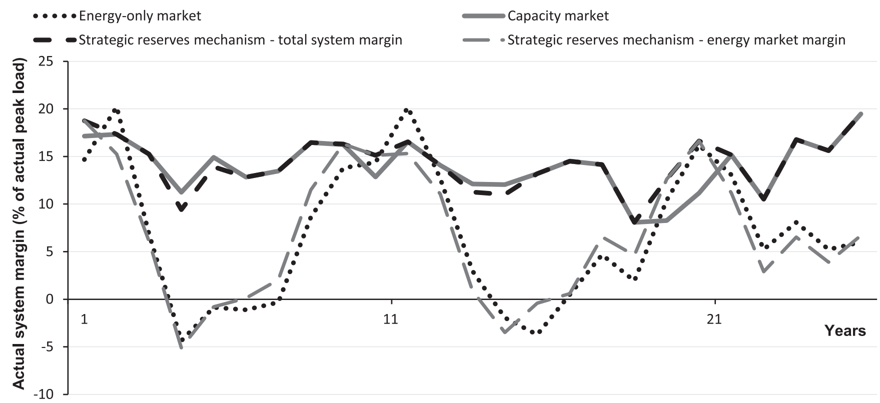

Fig. 12. Evolution of actual system margin for one scenario of load growth in the reference case.

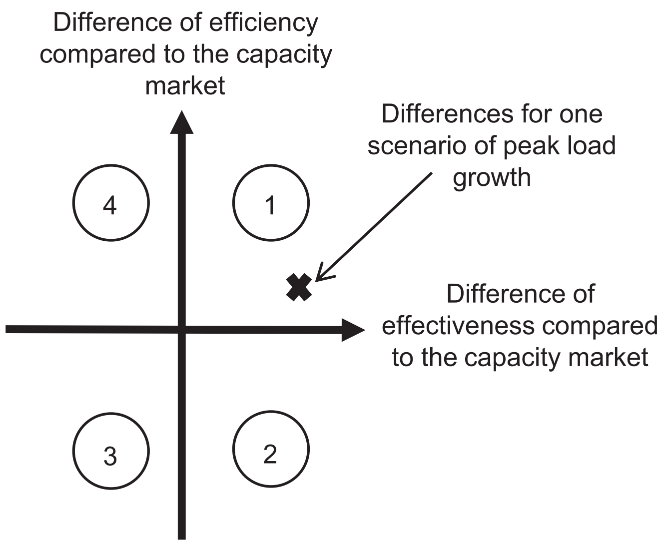

Fig. 13. Graphical depiction of differences of indicators for each load scenario.

reasons can explain that: first, the strategic reserve mechanism succeeds in providing enough reserved capacity most of the time, as well as the capacity market; secondly, since shortages are assumed to happen below a 10% margin, this mechanism can provide less than the 15% target and still not experience any shortages. Regarding total generation costs, the superiority of the capacity market is clear. Generation costs are about 25% higher with a strategic reserve mechanism compared to a capacity market. The costs of reserved capacity explain these differences. As Fig. 12 shows, the TSO needs a large amount of reserved capacity to avoid shortages (for each scenario, the average of reserved capacity is about 10% of existing capacity). Since reserved capacity is mainly old plants which are decommissioned from the energy market, their O&M costs are important. Thus, it results in significantly higher total generation costs to avoid shortages. In the capacity market, plants are younger since an arbitrage is made between existing capacity and new capacity during the capacity auctions. If the existing capacity is too old and more expensive than new capacity, it will close and new investments will take place. In the strategic reserve mechanism, there is no similar arbitrage and the reserved capacity is necessarily old and expensive. Therefore, for this reference case, the capacity market appears to be more effective and more efficient than the strategic reserve mechanism. Shortages are less likely to happen and the total costs of generation are less important.

3.3. Sensitivity analysis

In this section, robustness of previous results is tested through a sensitivity analysis. Main parameters which can modify the efficiency and effectiveness of the strategic reserve mechanism are tested here. These alternative cases, presented in Table 2, are run for the same load growth scenarios as for the reference case. Results are presented in Table 3. The averages of efficiency and effectiveness indicators for the 400 scenarios are computed for the reference and alternative cases, as well as the numbers of

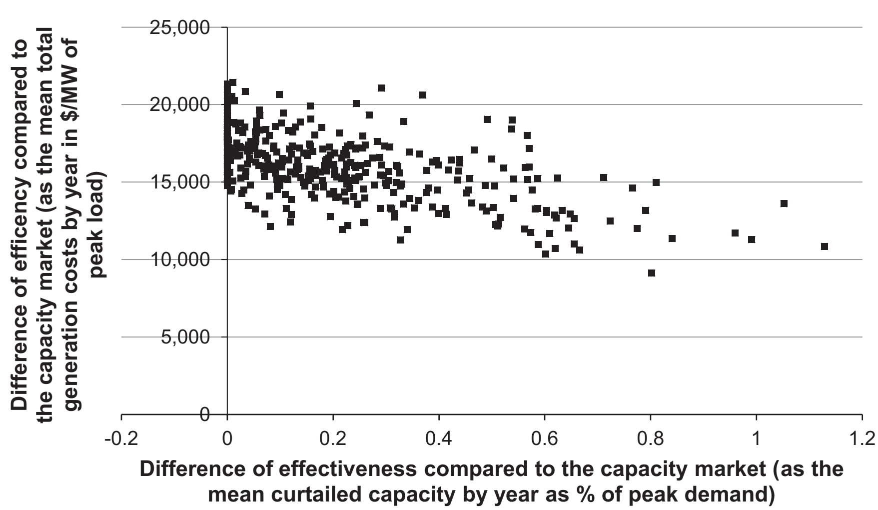

Fig. 14. Comparisons of effectiveness and efficiency.

Table 2
Alternative cases.

Alternative case	Varying parameter	Value
1	Maximum amount of reserved capacities	20%
2	Maximum amount of reserved capacities	10%
3	Maximum capacity addition (see Fig. 6)	15%
4	Maximum capacity addition (see Fig. 6)	7%
5	Peak load growth	4%
6	Peak load growth	0,5%
7	NPV to reach maximum capacity addition (see Fig. 6)	\$600,000/MW
8	NPV to reach maximum capacity addition (see Fig. 6)	\$200,000/MW
9	Price cap on both market/mechanism	\$300,000/MW
10	Price cap on both market/mechanism	\$200,000/MW
11	Years considered to compute expected profits for investment decisions	y to $y+4$
12	Maximum capacity shutdowns	10%

Table 3
Results for the base and alternative cases.

	Mean difference of efficiency	Mean difference of effectiveness	Number of scenarios in quarter 1	Number of scenarios in quarter 2 or 4[a]	Number of scenarios on the line between quarters 1 and 4 (i.e. same effectiveness but different efficiency)
Ref	0.206	16,006	326	0	74
1	0.016	17,813	99	5	296
2	1.158	11,380	400	0	0
3	0.269	14,538	340	5	55
4	0.123	20,331	300	0	100
5	0.044	19,268	182	0	218
6	0.367	13,942	365	2	33
7	0.136	20,728	311	0	89
8	0.243	11,607	342	5	53
9	0.212	15,704	331	0	69
10	1.371	7930	400	0	0
11	0.046	17,407	195	8	197
12	0.159	16,069	289	0	111

[a] For each case, there is no scenario in the quarter 3.

scenarios in each quarter of Fig. 13.

In each alternative case, the capacity market is still more efficient and more effective than the strategic reserve mechanism, since mean differences of each indicator are positive and the great majority of scenarios are in quarter 1. For some alternative cases (1 and 5), most of scenarios are the same regarding the efficiency indicator. However, for these cases, the capacity market is still more effective.

In cases 1, 2, 9 and 10, the varying parameters do not modify how the capacity market works and consequently its effectiveness and efficiency.[20] Differences between these cases are only due to a different functioning of the strategic reserve mechanism. These differences are mainly explained by the arbitrage between the adequacy objective and the costs to reach this target. To reduce shortages, more reserved capacities are required, which increases total generation costs (since reserved plants are expensive). For alternative cases 9 and 10, a lower reserve price cap means that old and expensive plants cannot be reserved anymore. Thus, in some years, the TSO does not succeed in contracting enough strategic reserves and more shortages happen (the effect is especially noticeable for case 10 where curtailed demand is about 6 times larger compared to reference case). In return, it leads to lower total generation costs since less expensive strategic reserves are used. The same effect appears in cases 1 and 2. When the maximum amount of reserved capacity is 20%, the efficiency difference is quite reduced whereas the effectiveness difference increases.[21] The contrary effect appears with a small amount of reserved capacity. In cases 3, 4, 7, 8 and 12, a different cyclical tendency is studied. Indeed, the different varying parameters change the way investors react to an expected profitability (for instance, in case 8, they are prone to invest more compared to the reference case for the same NPV). In cases 4, 7 and 12, the herd behavior is reduced: investors tend to react less severely. Undercapacity phases are then avoided and the TSO succeeds in reserving enough capacity. In cases 3 and 8, a more important herd behavior is modeled. Cyclical tendencies are more pronounced than in Figs. 11 and 12. As explained previously, these larger phases of overinvestment undermine the well-functioning of the mechanism. Moreover, more cyclical tendencies lead to significant phases of undercapacity that the TSO cannot avoid entirely by reserving capacity. Finally, other parameters, which modify the way both CRMs work, are studied in cases 5, 6 and 11: the functioning of both markets is modified but differences in terms of efficiency and effectiveness remain similar.

To conclude this section, as the strategic reserve mechanism does not change the way players make decisions on the energy market, the same consequences happen as in the energy-only market, namely cyclical tendencies and a mean system margin well below the 15% target. Therefore, the TSO has to contract large strategic reserves which are necessarily old and expensive. Moreover, these cycles can undermine the well-functioning of this mechanism in cases of overcapacity (since the TSO cannot contract enough reserves to offset the load growth) and in cases of large undercapacity (since the limits of this mechanism – volume or price – are likely to be reached). On the contrary, for the capacity market, there is an explicit volume target which is always reached. Moreover, this target margin can be reached in a more efficient way (i.e. investments and O&M are less important) with the capacity market since there is an arbitrage each year between existing capacity and new investments. Thus, social welfare is smaller when a strategic reserve mechanism is implemented compared to a capacity market. These results can help policy makers when they have to decide whether to implement a capacity market or a strategic reserve mechanism.

4. Conclusion and policy implications

The objectives of this paper are to study how CRMs, namely the capacity market and the strategic reserve mechanism, can correct the cyclical tendencies and the investment issues prone to happen in energy-only markets and then to compare these two CRMs. These comparisons are based on social welfare, which is evaluated thanks to total generation costs and shortage costs. System dynamics modeling is used to simulate functioning of both CRMs. Based on simulation results, both CRMs succeed in reducing the cyclical tendencies which appear in the energy-only market, in particular regarding the underinvestment issues. However, the strategic reserve mechanism cannot deal with the overinvestment phase, contrary to the capacity market. When comparing these two mechanisms, the capacity market appears to experience fewer shortages and to present lower total generation costs (investment and O&M costs) than the strategic reserve mechanism, i.e. the

[20] In theory, the capacity price cap can change the performances of the capacity market but in practice, this price cap is almost never reached.

[21] However, with a larger amount of reserved capacity, the possible distortions on the energy market are likely to increase.

social welfare is higher with a capacity market compared to a strategic reserve mechanism.

These results highlight the importance of assessing the dynamic aspect of the capacity mechanisms. Due to several particular factors, the achievement of an equilibrium state in power systems regarding the investment issue is not certain and some cyclical tendencies appear in the energy-only market. That is why capacity mechanisms have to be assessed and compared not only from a static point of view but also with a dynamic aspect. Moreover, from these results and based on our assumptions and data, the capacity market appears to be more beneficial than the strategic reserve mechanisms from the economic point of view, since it decreases shortages at lower costs. These results have direct implications for policy-makers when they decide whether they have to implement a capacity market or a strategic reserve mechanism. Regarding the case studied in this paper, implementing a capacity market will result in a higher social welfare. In the opposite, the European Commission recommends the implementation of a strategic reserve mechanism which it assesses as less distortionary for the energy market and easier to implement. These two criteria could be handled in a future version of modeling in order to weigh them against the current results.

Acknowledgments

This research has benefited from the support of Microeconomix and was part of the works realized for several European energy utilities. The views, assumptions and opinions expressed in this article are those of the authors and are not binding for Microeconomix or its clients.

Appendix A

Notation

Indices and sets

$y \in N$ set of years considered in the model (N=30years)

Parameters

τ Average peak load growth
α_i and β_i weights considered to compute the expected profitability
OMC(k) annual O&M costs for a plant which was built k years ago ($/MW)
WACC Weighted Average Cost of Capital
LT Lead time of peak technology, which is also how many years in advance the capacity market and the strategic reserve mechanism are organized
IC Investment costs ($/MW)
$S_{\max}$ Maximum shutdown capacity per year (% of installed capacity)
$I_{\max}$ Maximum capacity addition per year (% of installed capacity)
m System margin target (% of peak load)
SM Shortage margin (% of peak load)
σ_g Standard deviation of the economic growth parameter
σ_w Standard deviation of the weather conditions parameter

Variables

For all market-designs

$L_{WN}(y)$ Weather-normalized peak load during year y (MW)
$L_A(y)$ Actual peak load during year y (MW)
$L_F(y, z)$ Forecast peak load during year y, as computed in year z (MW)
$K(y)$ Total installed capacity during year y (MW)
$K_M(y)$ Total installed capacity except reserved capacity during year y (MW)
$K(y, v)$ Installed capacity which became operational during year v and is available during year y (MW)
$ER(y)$ Actual revenues from the energy market during year y ($/MW)
$ER_F(y, z)$ Expected revenues from the energy market during year y, as computed during year z ($/MW)
$EP_E(y)$ Expected profitability from the energy market as computed during year y ($/MW)
$NPV(y)$ Net Present Value computed during year y ($/MW)
$S(y)$ Shutdown decisions made during year y (MW)
$I(y)$ Investment decisions made during year y (MW)

For the capacity market only

$CP(y)$ Capacity Price during year y ($/MW)
$EP_C(y)$ Expected profitability from the capacity market as computed during year y ($/MW)
$NPV_{corrected}(y)$ Net Present Value corrected to compute the offer price for new investments during year y ($/MW)
$P^{capacity}_{existing}(y, v)$ Offer price on the capacity market during year y, for capacity which became operational during year v ($/MW)
$Q^{capacity}_{existing}(y, v)$ Offer quantity on the capacity market during year y, for capacity which became operational during year v (MW)
$P^{capacity}_{new}(y, v)$ Offer price on the capacity market during year y for new capacity ($/MW)
$Q^{capacity}_{new}(y, v)$ Offer quantity on the capacity market during year y, for new capacity (MW)
$Q^{capacity}_{cleared\ existing}(y, v)$ Accepted quantity on the capacity market during year y, for capacity which became operational during year v (MW)
$Q^{capacity}_{cleared\ new}(y, v)$ Accepted quantity on the capacity market during year y, for new capacity (MW)
$P^{capacity}_{cleared}(y)$ Market price on the capacity market during year y ($/MW)
$K^{capacity}_{needed}(y)$ Capacity requirement defined by the TSO during year y (MW)

For the strategic reserve mechanism only

$P^{preserve}_{reserved}(y, v)$ Offer price on the reserves auction during year y, for capacity already reserved and which became operational during year v ($/MW)
$Q^{reserve}_{reserved}(y, v)$ Offer quantity on the reserves auction during year y, for capacity already reserved and which became operational during year v (MW)
$P^{preserve}_{left}(y, v)$ Offer price on the reserves auction during year y for capacity which has just left the energy market and which became operational during year v ($/MW)
$Q^{reserve}_{left}(y, v)$ Offer quantity on the reserves auction during year y, for capacity which has just left the energy market and which became operational during year v (MW)
$Q^{reserve}_{cleared\ reserved}(y, v)$ Accepted quantity on the reserves auction during year y, for capacity already reserved and which

became operational during year v (MW)
$Q^{reserve}_{cleared\ left}(y, v)$ Accepted quantity on the reserves auction during year y, for capacity which has just left the energy market and which became operational during year v (MW)
$K^{reserve}_{needed}(y)$ Reserves requirements defined by the TSO during year y (MW)
$K_{reserves}(y, v)$ Reserved capacity during year y and which became operational during year v (MW)
$R(y)$ Total reserved capacity during year y (MW)

Equations

The following equations describe how the different markets work (i.e. the players' decisions regarding investments and shutdowns) during year y.

Load (Identical for the three market design)

$$L_{WN}(y)=L_{WN}(y-1)*(1+\tau+g) \tag{A.1}$$

$$L_A(y)=L_{WN}(y)*(1+w) \tag{A.2}$$

g (resp.w) is assumed to follow a normal distribution function $N(0,\sigma_g^2)$ (resp. $N(0,\sigma_w^2)$).

Energy-only market

Revenues from the energy market

$$ER(y)=f\left(\frac{K(y)}{L_A(y)}\right);\ f \text{ depicted in Fig.4} \tag{A.3}$$

Expected future profitability

$$ER_F(y+X, y)=f\left(\frac{K(y+X)}{L_F(y+X, y)}\right) \text{ for } 1 \le X < LT \tag{A.4}$$

$$L_F(y+X, y)=L_{WN}(y)*(1+\tau)^X \text{ for } 1 \le X < LT \tag{A.5}$$

$$ER_F(y+LT, y)=ER_F(y+LT-1, y) \tag{A.6}$$

$$EP_E(y)=\frac{\sum_{i=0}^{3}\alpha_i*ER(y-i)+\sum_{j=1}^{LT}\beta_j*ER_F(y+j, y)}{\sum_{i=0}^{3}\alpha_i+\sum_{j=1}^{LT}\beta_j} \tag{A.7}$$

NPV

$$NPV(y)=\sum_{k=1}^{L}\frac{EP_E(y)-OMC(k)}{(1+WACC)^{LT+k-1}}-IC \tag{A.8}$$

Investment decisions

$$I(y)=g(NPV(y))*K(y+LT-1),\ g \text{ depicted by Fig.6} \tag{A.9}$$

$$K(y+LT, y+LT)=I(y) \tag{A.10}$$

Shutdowns decisions
See Fig. A.1
Future capacity

$$K(y+LT)=K_M(y+LT)=K(y+LT-1)+I(y)-S(y) \tag{A.11}$$

Capacity market

Revenues and expected profitability from the energy market are computed as for the energy-only market (Eqs. 3–7).

Expected future profitability from the capacity market

$$CP(y+4)=CP(y+3) \tag{A.12}$$

$$EP_C(y)=\frac{\sum_{i=0}^{3}\alpha_i*CP(y-i)+\sum_{j=1}^{LT}\beta_j*CP(y+j)}{\sum_{i=0}^{3}\alpha_i+\sum_{j=1}^{LT}\beta_j} \tag{A.13}$$

Bids for existing capacity

$$P^{capacity}_{existing}(y, v)=\max\left(0; OMC(y-v+1+LT)-EP_E(y)\right) \tag{A.14}$$

$$Q^{capacity}_{existing}(y, v)=K(y+LT-1, v) \tag{A.15}$$

Bids for new investments

$$NPV(y)=\sum_{k=1}^{L}\frac{EP_C(y)+EP_E(y)-OMC(k)}{(1+WACC)^{LT+k-1}}-IC \tag{A.16}$$

$$NPV_{corrected}(y)=NPV(y)-\frac{EP_C(y)}{(1+WACC)^{LT}} \tag{A.17}$$

$$P^{capacity}_{new}(y)=\max\ (0; -NPV_{corrected}(y)) \tag{A.18}$$

$$Q^{capacity}_{new}(y)=I_{max}*K(y+LT-1) \tag{A.19}$$

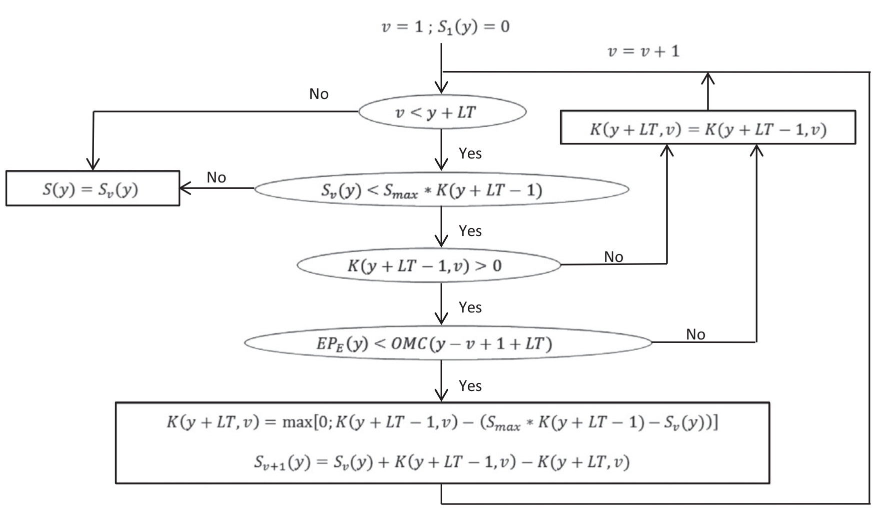

Fig. A.1. Equations of the shutdown decisions.

Auctions

$$K_{needed}^{capacity}(y)=L_{WN}(y)*(1+\tau)^{LT}*(1+m) \quad (A.20)$$

The offer curve is built thanks to the prices and quantities previously computed. The demand curve is defined by $K_{needed}^{capacity}$ and the price cap on the capacity market (inelastic demand). Then, the auction is solved and the different solutions $Q_{cleared\ existing}^{capacity}$, $Q_{cleared\ new}^{capacity}$ and $P_{cleared}^{capacity}$ are computed.

$$K(y+LT,\ v)=Q_{clearedexisting}^{capacity}(y,\ v) \quad (A.21)$$

$$S(y)=\sum_{v=1}^{y+LT-1}[K(y+LT-1,v)-K(y+LT,\ v)] \quad (A.22)$$

$$K(y+LT,\ y+LT)=I(y)=Q_{clearednew}^{capacity}(y) \quad (A.23)$$

$$CP(y+LT)=P_{cleared}^{capacity}(y) \quad (A.24)$$

Future capacity

$$K(y+LT)=K_M(y+LT)=K(y+LT-1)+I(y)-S(y) \quad (A.25)$$

Strategic reserve mechanism

Revenues from the energy market

$$ER(y)=f\left(\frac{K_M(y)}{L_A(y)}\right),\ f \text{ depicted by Fig.4} \quad (A.26)$$

Expected future profitability

$$ER_F(y+X,\ y)=f\left(\frac{K_M(y+X)}{L_F(y+X,\ y)}\right) \text{ for } 1 \le X < LT \quad (A.27)$$

Once ER and ER_F are computed, investment and shutdowns decisions are made as for the energy-only market (equations 6 to 10+Fig. A.1).

Future market capacity

$$K_M(y+LT)=K_M(y+LT-1)+I(y)-S(y) \quad (A.28)$$

Bids for capacity already on the strategic reserve mechanism

$$P_{reserved}^{reserve}(y,\ v)=OMC(y-v+1+LT) \quad (A.29)$$

$$Q_{reserved}^{reserve}(y,\ v)=K_{reserves}(y+LT-1,v) \quad (A.30)$$

Bids for plants which were on the energy market and decided to shut down

$$P_{left}^{reserve}(y,\ v)=OMC(y-v+1+LT) \quad (A.31)$$

$$Q_{left}^{reserve}(y,\ v)=K(y+LT-1,v)-K(y+LT,\ v) \quad (A.32)$$

Auctions

$$K_{needed}^{reserve}(y)=\max\ [0;(1+m)*L_{WN}(y)*(1+\tau)^{LT}-K_M(y+LT)] \quad (A.33)$$

The offer curve is built thanks to the prices and quantities previously computed. The demand curve is defined by $K_{needed}^{reserve}$ and the price cap on the reserve mechanism (inelastic demand). Then, the auction is solved and the different solutions $Q_{cleared\ left}^{reserve}$, $Q_{cleared\ reserved}^{reserve}$ and $P_{cleared}^{reserve}$ are computed.

$$K_{reserves}(y+LT,\ v)=Q_{clearedleft}^{reserve}(y,\ v)+Q_{clearedreserved}^{reserve}(y,\ v) \quad (A.34)$$

$$R(y+LT)=\sum_{v=1}^{y+LT}K_{reserves}(y+LT,\ v) \quad (A.35)$$

Future total capacity

$$K(y+LT)=K_M(y+LT-1)+R(y+LT) \quad (A.36)$$

Once all investment and shutdown decisions have been made, the simulation starts again for year $y+1$.

Indicators

At the end of the 30 years, the following indicators are computed:

Effectiveness

$$EFV=\text{mean}_y\left(\frac{\text{Curtaileddemand}(y)}{\text{peakload}(y)}\right) =\text{mean}_y(\max\left(0;SM-\frac{K(y)}{L_A(y)}\right)) \quad (A.37)$$

Efficiency

$$EFY=\text{mean}_y\left(\frac{\text{Investmentcosts}(y)+OM\text{costs}(y)}{\text{peakload}(y)}\right) =\text{mean}_y\left(\frac{K(y,\ y)*IC+\sum_{v=1}^{y-1}[OMC(y-v+1)*K(y,\ v)]}{L_A(y)}\right) \quad (A.38)$$

References

Arango, S., Larsen, E., 2011. Cycles in deregulated electricity markets: empirical evidence from two decades. Energy Policy 39 (5), 2457–2466.

Assili, M., Javidi, D.H.M., Ghazi, R., 2008. An improved mechanism for capacity payment based on system dynamics modeling for investment planning in competitive electricity environment. Energy Policy 36 (10), 3703–3713.

Batlle, C., Rodilla, P., 2010. A critical assessment of the different approaches aimed to secure electricity generation supply. Energy Policy 38 (11), 7169–7179.

Bidwell, M., Henney, A., 2004. Will the new electricity trading arrangements ensure generation adequacy? Electr. J. 17 (7), 15–38.

Cepeda, M., Finon, D., 2011. Generation capacity adequacy in interdependent electricity markets. Energy Policy 39 (6), 3128–3143.

Cramton, P., Stoft, S., 2008. Forward reliability markets: less risk, less market power, more efficiency. Util. Policy 16 (3), 194–201.

CREG-Commission de régulation de l'électricité et du gaz, 2012. Study (F) 121011-CDC-1182 on capacity remuneration mechanisms.

CREG-Commission de régulation de l'électricité et du gaz, 2015. Etude(F) 150604-CDC-1422 sur les mesures à prendre afin de disposer du volume adéquat de moyens de production conventionnels pour assurer la sécurité d'approvisionnement en électricité de la Belgique.

De Vries, L., 2004. Securing the Public Interest in Electricity Generation Markets. The Myths of the Invisible Hand and the Copper Plate (Ph.D. thesis). Delft University of Technology, The Netherlands.

De Vries, L., Heijnen, P., 2008. The impact of electricity market design upon investment under uncertainty: the effectiveness of capacity mechanisms. Util. Policy 16 (3), 215–227.

Dixit, A., Pindyck, R., 1994. Investment Under Uncertainty. Princeton University Press, Princeton.

Dyner, I., Larsen, E., 2001. From planning to strategy in the electricity industry. Energy Policy 29 (13), 1145–1154.

European Commission, 2013. Commission staff working document. Generation Adequacy in the Internal Electricity Market – Guidance on Public Interventions.

Finon, D., Pignon, V., 2006. Electricité et sécurité de fourniture de long terme. La Recherche D'instruments Règlementaires Respectueux du Marché Electrique. Revue ISMEA Economie et Société, série Energie, no. 10.

Finon, D., Meunier, G., Pignon, V., 2008. The social efficiency of long-term capacity reserve mechanisms. Util. Policy 16 (3), 202–214.

Ford, A., 1999. Cycles in competitive electricity markets: a simulation study of the western United States. Energy Policy 27 (11), 637–658.

Ford, A., 2001. Waiting for the boom: a simulation study of power plant construction in California. Energy Policy 29 (11), 847–869.

Ford, A., 2002. Boom and bust in power plant construction: lessons from the California electricity crisis. J. Ind. Compét. Trade 2 (1), 59–74.

Forrester, J.W., 1961. Industrial Dynamics. MIT press.

Gary, S., Larsen, E., 2000. Improving firm performance in out-of-equilibrium, deregulated markets using feedback simulation models. Energy Policy 28 (12), 845–855.

Green, R., 2006. Investment and generation capacity. In: Lévêque, F. (Ed.), Competitive Electricity Markets and Sustainability 2; 2006, pp. 21–53.

Hani, Th., Bialek, J., Cherkaoui, R., 2006. Modeling generation capacity margin as a dynamic control problem, IEEE Power Engineering Society General Meeting. Montreal, Canada.

Hasani, M., Hosseini, S.H., 2011. Dynamic assessment of capacity investment in electricity market considering complementary capacity mechanisms. Energy 36

(1), 277–293.
Hasani, M., Hosseini, S.H., 2013. Dynamic analysis of various investment incentives and regional capacity assignment in Iranian electricity market. Energy Policy 56, 271–284.
Hobbs, B., 2005. Affidavit of Benjamin F. Hobbs on behalf of PJM Interconnection, L. L.C. submitted to the Federal Energy Regulatory Commission.
Hobbs, B., Hu, M.-C., Iñón, J., Stoft, S., Bhavaraju, M., 2007. A dynamic analysis of a demand curve-based capacity market proposal: the PJM reliability pricing model. IEEE Trans. Power Syst. 22 (1), 3–14.
Hobbs, B., Iñón, J., Kahal, M., 2001. A review of issues concerning electric power capacity markets. Project report submitted to the Maryland Power Plant Research Program. Maryland Department of Natural Resources. Baltimore, The Johns Hopkins University.
Joskow, P.L., 2007. Competitive electricity markets and investment in new generating capacity. In: Dieter Helm (Ed.), The New Energy Paradigm. Oxford University Press, Oxford.
Kadoya, T., Sasaki, T., Ihara, S., Larose, E., Sanford, M., Graham, A.K., Stephens, C.A., Eubanks, C.K., 2005. Utilizing system dynamics modeling to examine impact of deregulation on generation capacity growth. Proc. IEEE 93 (11), 2060–2069.
McGraw Hill Financial, 2015. Power in Europe, issue 698.
Olsina, F., Garcés, F., Haubrich, H.-J., 2006. Modeling long-term dynamics of electricity markets. Energy Policy 34 (12), 1411–1433.
Olsina, F., Pringles, R., Larisson, C., Garcés, F., 2014. Reliability payments to generation capacity in electricity markets. Energy Policy 73, 211–224.
Oren, S., 2000. Capacity payments and supply adequacy in competitive electricity markets. In: Proceedings of the VII Symposium of Specialists in Electric Operational and Expansion Planning (SEPOPE). Curitiba, Brazil.
Park, J., Ahn, N.-S., Yoon, Y.-B., Koh, K.-H., Bunn, D.W., 2007. Investment incentives in the Korean electricity market. Energy Policy 35 (11), 5819–5828.
Stoft, S., 2002. Power System Economics: Designing Markets for Electricity. IEEE Press, Piscataway, NJ.
Syed Jalal, T., Bodger, P., 2010. The development of a system dynamics model to evaluate electricity generation expansion in New Zealand. In: Proceedings of Australasian Universities Power Engineering Conference (AUPEC 2010), Paper 68.
Teufel, F., Miller, M., Genoese, M., Fichtner, W., 2013. Review of System Dynamics for electricity market simulations. KIT Scientific Publishing, Deutschland.
Vazquez, C., Rivier, M., Pérez-Arriaga, I.J., 2002. A market approach to long-term security of supply. IEEE Trans. Power Syst. 17 (2), 349–357.
Wilson, J., 2010. Forward capacity market CONEfusion. Electr. J. 23 (9), 25–40.