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MARKET POWER IN THE CAPACITY MARKET? THE CASE OF IRELAND

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30 June 2016

An electricity market coupled with a capacity market is modelled as a two-stage game that allows for strategic behaviour both in the electricity market and in the capacity market. The model is applied to the Irish electricity market, where a capacity market based on reliability options is established by the end of 2017. As Ireland has one dominant firm in the electricity market, there have been concerns that the new market design provides it an opportunity to abuse market power in these two markets. Using Ireland as an example this article examines the kinds of strategic behaviours that can be expected if a capacity market is implemented in an imperfectly competitive market. It is found that the potential for the abuse of market power in the capacity market is significant for the dominant firm in Ireland and that there is no simple way to mitigate it. The relative amount of procured capacity, the amount and characteristics of potential entrants, and the competitiveness of the electricity market are the main determinants of the possibilities and incentives for abusing market power in the capacity market.

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1 Introduction

The electricity generation industry is prone to natural monopolies, and in many countries, electricity markets were initially structured as regulated, state-owned, vertically integrated and geographic monopolies. The electricity market liberalization measures that have taken place in most developed countries in the last decades have aimed at increasing competition through privatization and market restructuring. At the same time, generation and investment decisions have become market-based. Despite deregulation, it is not uncommon for one or a few dominant players to exist in a liberalized electricity market, justifying some regulations – such as price caps that protect consumers from the abuse of market power during times of high demand.

Recently, it has been questioned whether investment decisions based solely on market signals can guarantee adequate generation capacity at all times. Specifically, price caps that are set too low may decrease incentives to invest in peak generators, which are needed only during peak demand hours. Furthermore, increasing amounts of intermittent electricity generation from wind and solar plants exacerbate the adequacy problem, decreasing the revenue and run-time of conventional generators, which are still needed when the sun is not shining and the wind is not blowing. Uncertainty regarding government policies to support renewable intermittent generators also adds uncertainty to investment decisions.

Capacity markets, where payments are allocated to generators based on the capacity they provide, are market-based solutions to ensure adequate capacity. A common design for a capacity market is a multi-unit auction, held annually or more frequently, where all generating firms provide capacity-price bids for their generating units. In response for the capacity payments the winning units typically commit to be available in the market or accept a price cap in the electricity market. As capacity markets are often introduced in imperfectly competitive markets, they may give dominant firm(s) additional opportunities to abuse market power, making the entire market very costly for end users. The following are various ways that market power can be exercised in a capacity market:

1. The firm reduces its supplied capacity in the capacity auction (leaves units out of the auction, de-rates units' capacity by more than necessary, or bids very high prices) to obtain higher capacity payments for its remaining units (economic or physical *capacity withholding* or *supply reduction*).

2. The firm invests in excess capacity (which is otherwise unprofitable) to deter entry

and defend its dominant position in the electricity market (*strategic investment*).

3. The firm bids above the competitive price for the unit that sets the price in the capacity auction to obtain higher payments for its other units while the identities of the winning units remain unchanged (*bid shading* generally or *bid inflating* in procurement auctions).

4. The firm bids below the competitive price to deter entry and benefit later from its dominant position in the electricity market (*predatory pricing*).

This paper examines the consequences of capacity market introduction in an imperfectly competitive market. What kinds of strategic behaviours can be expected, how significant are they, what do they mean for end users, how are strategic behaviours in the electricity and capacity markets connected, and what are the best ways to mitigate market power in the capacity market? First, a model that allows for strategic behaviour both in the electricity market and in the capacity market is developed. As the two markets are highly interconnected, they cannot be modelled independently of each other. Additionally, market entry and exit that may result after the capacity market is resolved need to be taken into account. Thus, there are three basic parts of the model: the electricity market, the capacity market, and the industry dynamics. The challenge of the model is to connect these three parts consistently and keep the model computationally feasible. The model is first used to calculate the competitive benchmark that corresponds to the behaviour of firms in a perfectly competitive market. Then, the most profitable strategic behaviour for the dominant firm is identified, and the amount of market power is quantified as the deviation from the competitive benchmark. This study is restricted to unilateral market power exercised by a single firm.

The developed model is applied to a new Irish electricity market (the I-SEM) that is currently in the design phase and should be operational by the end of 2017. The market power problem is topical in Ireland, as one firm currently dominates the electricity market. It is found that the dominant firm in Ireland would indeed face incentives and possibilities to exercise significant market power in the future capacity market. Its dominant strategy would be capacity withholding, but the main strategy depends on the relative amount of procured capacity. There is no simple way to mitigate market power if further regulations, e.g., bid caps, are to be avoided. The number and characteristics of entrants, as well as the competitiveness of the electricity market, most strongly affect the possibilities of abusing market power. Strategic behaviours in the two markets are connected by entry, but the connection is quite weak.

This article is organized as follows. Section 2 describes the literature from which this paper draws and to which it contributes. Section 3 describes the current and future electricity market designs in Ireland. Section 4 describes the developed model, and section 5 presents the data from the Irish electricity market. Section 6 presents the results of the analysis, and the last section concludes.

2 Related literature

The "missing money" problem, also known as the resource adequacy problem, refers to a situation wherein net revenues from the electricity market are not high enough for the incumbent generators to cover their operating costs or for new entry to cover their investment costs, leading to market exit or inadequate investment and preventing the market from obtaining the desired reliability level of the electricity supply. Detailed discussions of the problem and the reasons behind it can be found in, e.g., Joskow (2008) and Cramton and Stoft (2006). Joskow (2007) presents some empirical evidence of the problem in US electricity markets. A regulatory price cap that is set too low is often mentioned as a primary reason for the missing money problem, but Joskow (2008) notes that price caps are rarely binding (as confirmed in this study) and, rather, there are often several other imperfections in the market that, together with the price cap, keep prices too low from a reliability point of view.

There are several solutions to the missing money problem, ranging from improvements in electricity market designs (see, e.g., Hogan (2005) and Roques (2008)) to introducing strategic reserves and capacity markets. Comparisons of different mechanisms are provided in, e.g., Finon and Pignon (2008), de Vries (2004), and Cramton and Stoft (2006). Capacity markets are market-based mechanisms that allocate additional revenues for generators to prevent the missing money problem. Cramton et al. (2013) provide a good overview of the economics of capacity markets. One of the most prominent and probably the most studied capacity market mechanism is based on auctioned reliability options. This mechanism was first proposed by Vázquez et al. (2002), but similar designs with some modifications are also presented in Cramton and Stoft (2008), Oren (2005), Bidwell (2005), and Chao and Wilson (2004).

It is widely accepted that firms exercise market power in oligopolistic electricity markets, a topic that has also been studied quite extensively. Empirical studies of market power in the electricity market include Wolfram (1999), Green and Newbery (1992), and Sweeting (2007) for Britain; Borenstein et al. (2002), Joskow and Kahn (2002), and Puller (2007) for California; and Mansur (2008) for the PJM electricity market in the Eastern US. Most of these papers use competitive benchmark analysis, which is a standard way to measure market power in the electricity market (see Twomey et al. (2006) for a review of the methods for detecting and measuring market power). In this method, the electricity generating units' cost structures (usually only the marginal costs) are first estimated, and then, the competitive prices when firms do not exercise any market power are calculated.

The differences between the observed or simulated prices and the corresponding competitive prices are interpreted as price mark-ups that result from strategic behaviour. If firms behave strategically in the electricity market, the same can be expected in the capacity market; however, this behaviour has been studied much less. This paper extends the empirical literature on market power in the electricity market by applying competitive benchmark analysis to the capacity market.

Schwenen (2014) is one of the few articles that theoretically examines market power in the capacity market and its relation to strategic behaviour in the electricity market. He uses a simple duopoly model wherein each firm has a single technology to show that introducing a capacity market leads to non-competitive clearing prices in the capacity auction, where the mark-up compensates for any loss of market power in the electricity market. He abstracts from new entry, which is important in linking market power in the two markets. Léautier (2016) compares capacity market design based on financial reliability options with two other market designs using a two-stage model wherein firms first select their capacity in a simple capacity auction and then play a Cournot game in the electricity market. He focuses on investment incentives and market power in an imperfectly competitive electricity market, finding that reliability options reduce market power but do not entirely eliminate it.

This paper expands this theoretical literature by presenting a model that allows for imperfect competition in both the electricity market and the capacity market and addresses strategic behaviour specifically in the capacity market. The model is suitable for empirical studies; it is probably too complicated to be used for general theoretical inferences. The model is applied to the Irish market, and the results cannot be directly generalized. However, the paper contributes to theory by providing results that are valid for one specific case. Thus, if a simpler theoretical model is developed to study market power in the capacity market, it has to be able to explain the empirical findings presented in this paper.

Two common approaches to modelling a spot electricity market are the supply function equilibrium (SFE) method described in Klemperer and Meyer (1989) and Cournot-based models. Examples of the former approach are Green and Newbery (1992), Wolfram (1999) and Baldick and Hogan (2002), whereas the latter approach is used in, e.g., Borenstein and Bushnell (1999), Puller (2007), and Bushnell et al. (2008). While the SFE concept wherein firms compete by simultaneously submitting supply curves seems more realistic for the electricity market than does a Cournot game wherein firms compete in quantity, the disadvantages of SFE are the complexity of solving the equilibrium, the required simplifications to keep the computation feasible, and the multiplicity of equilibria in the absence of uncertainty in demand. The problem with Cournot approach is that in empirical applications, it often results in much higher prices and lower outputs than those that are observed in reality or can be realistically expected.

Klemperer and Meyer (1989) show that the SFE equilibrium with any given demand shock is bounded by the corresponding competitive (Bertrand) equilibrium and the Cournot equilibrium. Allaz and Vila (1993), in turn, show that the existence of forward markets reduces the Cournot equilibrium price in the spot market. The more goods are sold forward the closer the spot price is to the competitive price. Therefore, by using a Cournot model with forward contracts the whole range of equilibria between competitive and Cournot equilibrium can be obtained by adjusting the forward contract coverage. The same range is achieved with SFE method assuming certain demand and it is highly likely that real prices fall within this range. Bushnell et al. (2008) show that the vertical integration often present in the electricity market has the same effect as the forward contract coverage. In this paper, a Cournot-based model similar to that in Bushnell et al. (2008) is used for the electricity market. It is implemented as a mixed integer linear programming problem, as described in Ito and Reguant (2016). The competitiveness of the electricity market is varied by adjusting the forward contract coverage which can then be interpreted as a general measure of the electricity market competitiveness.

The Cournot and SFE approaches can also be used to model capacity auctions, but to avoid approximations and keep the model tractable at the generating unit level, the capacity market is modelled here as a regular multi-unit auction, where firms submit separate price bids for each of their generating units. The strategic behaviour of a single firm in the auction is studied using the approach based on the best-response concept as e.g., Wolak (2000), Sweeting (2007), and Hortaçsu and Puller (2008).

3 Electricity wholesale market in Ireland

3.1 Generators

The main fuel for electricity generating units in Ireland is natural gas. Almost one-half of generators (by capacity) use gas as a fuel (see figure (2)). The five coal units (total 1331 MW) form the second-largest group of fossil fuel–fired units by capacity. The share of wind power is also significant. Wind farms were responsible of more than 20 % of total capacity in 2015, and this share is growing rapidly as most new power plant investments in Ireland are for wind farms.

Figure (3) shows the generation capacities of firms in 2015. ESB owns 44 % of total capacity (wind farms excluded). The two other large firms, SSE and AES, own 14 % and 13 % of total capacity, respectively. Only these three firms hold a diverse portfolio of generating units using different fuel types (see tables (1) and (2)). For example, the fourth-largest firm by capacity, Viridian, owns only two gas units (764 MW) and one small demand response unit (6 MW).

3.2 SEM

The Single Electricity Market (SEM) is the wholesale electricity market that currently covers the whole island of Ireland. It was established in 2007 when the two jurisdictionally separated electricity markets – one in the Republic of Ireland and one in Northern Ireland – were combined into a single market. The SEM is operated by the Single Electricity Market Operator (SEMO), which is a joint venture between EirGrid, the Transmission System Operator (TSO) in the Republic of Ireland, and SONI, the TSO in Northern Ireland. The SEM has two 500 MW cross-border interconnectors to the British electricity market: the Moyle (between Scotland and Northern Ireland) and the East-West interconnector (EWIC, between Wales and the Republic of Ireland).

The SEM is a gross mandatory pool. All generators with more than 10 MW of capacity on the island of Ireland have to sell their electricity to the SEM, and all electricity retailers have to purchase their electricity from the SEM. All cross-border trade in electricity is also carried out via the SEM. In contrast to the largest European electricity markets, where most electricity is traded bilaterally between generators and retailers, electricity traded in the SEM always goes into a transparent pool. All counter-parties receive or pay the same price for traded electricity within a 30-minute trading period.

Electricity buyers and sellers submit their bid offers one day before the actual delivery takes place. The submitted bids are applied for all trading periods in the same trading day. Generators' bid offers consist of commercial offer data and technical offer data. The commercial offer data is a list of 1–10 monotonically increasing price-quantity pairs at which the generator is ready to sell electricity. According to the bidding code (TSC, Trading and Settlement Code[1]) that the market participants commit to follow, generators are obliged to bid their true short-run marginal costs in the commercial offer. Hence, the bids reflect mostly fuel-related costs. The technical offer data list the parameters of generators' technical capabilities and dynamic generation costs and constraints (such as minimum output, ramping rate, no-load cost, and start-up cost).

After receiving the demand and supply bids, the SEMO uses a Market Scheduling and Pricing (MSP) algorithm that calculates the least cost dispatch schedule for the generators. This algorithm is run five times for each trading day: two times before the trading day starts (EA1 and EA2), once on the trading day (WD1) and two times after the trading day (EP1 and EP2). The rationale for several runs is that when more information about factors such as demand, wind farm generation, and required ancillary services becomes available, more accurate market results can be achieved. The results from the last run (EP2) are used as a basis for the financial settlement between market participants. This means that the final market price is available only four days after the physical delivery.

The MSP algorithm resolves the market price (the System Marginal Price, SMP) for each trading period and quantifies how much each generator needs to generate so that the total demand is met at the lowest possible production cost. The generation quantities assigned to each generating unit are referred to as Market Schedule Quantities (MSQs). The SMP consists of two components: a *shadow price* that reflects the short-run cost of the marginal producer and an *uplift* component that indicates the amount needed to cover the start-up and no-load costs if the infra-marginal rent is not enough to cover them. The SMP is the sum of these two components. Typically, the uplift component is highest in high-demand periods (evenings) when some generators are running only for a short time and zero when demand is more stable (nights).

Generating units are dispatched centrally by the TSOs according to the calculated MSQ schedule. The MSP algorithm calculates the unconstrained least-cost solution, but in reality, generators face transmission constraints, voltage and reserve requirements, and

[1] See `www.semcommittee.com` → SEM → Trading and Settlement Code.

unplanned outages, so the actual generation amount is likely to deviate slightly from the MSQ schedule. Generators either receive or pay a separate payment, a constraint payment, that compensates for these deviations, while SMP covers only the cost of the scheduled electricity amount.

Generators also receive capacity payments that are meant to cover their fixed costs. The regulator first decides the total annual pot of capacity payments and then divides it across trading periods and generating units using a specific formula that accounts for the expected total demand and the loss of load probability. The capacity payment is higher in periods when demand is higher and the capacity margin tighter. Only units that are available during a specific trading period receive the capacity payment assigned for that period.

Moreover, generators receive other payments, such as uninstructed imbalance payments and make whole payments (for the remaining deviations between costs of actually dispatched and scheduled electricity), and face charges, such as market operator charges and testing charges. However, the three largest components of generators' revenue are energy payments (based on SMP and MSQ), capacity payments, and constraint payments. Generator payments are mostly paid by electricity retailers, which then pass them on to consumers.[2]

Market participants in the SEM can also trade electricity via the two interconnectors between the SEM and the British electricity market. To do so, the participant first has to purchase the right to utilize capacity in the interconnector. These capacities are allocated in explicit auctions where participants bid the price they are willing to pay for each capacity unit used for importing or exporting. After obtaining capacity in the interconnector, each participant has to find a counter-party for the trade on the other side of the interconnector. Interconnector capacity can also be traded implicitly in the SEM electricity market, where interconnector capacity remaining after the explicit auction is sold. This implicit auction is better suited to benefitting from price differences between the two markets, while the explicit auction is mostly used for hedging existing generation portfolio positions in the SEM. However, price arbitrage over the interconnector in the SEM is not that simple to execute, since it is difficult to predict the electricity price in the SEM. The price is known for certain only four days after the delivery date.

[2]See, e.g., 'SEM-13-067: Trading & Settlement Code - Helicopter Guide' for more details. The document can be found at `www.semcommittee.com` → Publications.

3.3 I-SEM

The European Union (EU) aims at harmonizing, further liberalizing and eventually fully integrating the gas and electricity markets in the EU area. To achieve this goal, a directive and regulation package known as the EU 3rd Energy Package has been published.[3] With this legislation package, the EU also developed the EU Target Model, a detailed list of common guidelines, procedures, and network codes mainly related to the cross-border trading of gas and electricity across Europe. Each EU member state is responsible for complying with this EU-wide legislation.

The SEM in Ireland is not currently compatible with the EU 3rd Package or the Target Model, so a process leading to a new market design has been initiated. The new market designed to meet EU requirements is called the Integrated Single Electricity Market[4] (I-SEM), and it is planned to be fully established by the end of 2017.

The responsibility for developing new market arrangements in the I-SEM is assigned to the SEM Committee (SEMC). The SEMC uses a well-defined decision-making process to design the changes to the current electricity market. Industry consultation is an essential part of this process. In a typical work flow, the SEMC first publishes a consultation document on a specific issue, and after obtaining responses from relevant stakeholders, it makes decisions, which are then published in a decision document that then forms the basis for actual legislation. The design process proceeds gradually from a broad level[5] to more detailed levels.

Compared to the SEM, the main changes in the I-SEM are (1) introducing forward, day-ahead, intraday, and balancing markets, which are cleared before the physical delivery takes place; (2) implementing a new cross-border power flow algorithm; and (3) replacing the current capacity remuneration mechanism with a capacity market based on an auction. The new electricity markets are similar to those already in use in the largest European electricity markets (e.g., EEX and Nordpool), but the new capacity market will be based on reliability options (see Vázquez et al. (2002)), which are studied theoretically much but have less commonly been implemented in practice. However, similar approaches are currently in use in, e.g., Italy, New England (US), and Colombia.

In the new capacity market design, the system operator purchases reliability options from the capacity providers. A reliability option is a financial contract that entitles the

[3]See `https://ec.europa.eu/energy/en` → Topics → Markets and consumers → Market legislation.
[4]See `www.semcommittee.com/` → I-SEM.
[5]See `www.semcommittee.com` → Publications → I-SEM High Level Design Final Decision (SEM-14-085a-e).

option holder (operator) to receive difference payments from the sellers (generators) if the price in the reference market (electricity market) exceeds a predefined strike price. Sold reliability options need to be backed up with physical generation capacity. The operator pays the sellers of the option a price that can then be interpreted as a capacity payment.[6]

In the I-SEM, reliability options are sold in an annual uniform price auction. First, the operator determines the amount of capacity needed to secure the supply of electricity in the market. Then, it carries out an auction wherein it purchases the amount of reliability options that covers this capacity amount. In the auction generators submit a price bid for each of their generating units defining the price at which a reliability option backed up by the capacity of the specific generating unit is offered. All currently existing generating units and new units that are credibly planned to be built before the reliability option delivery year are eligible to back up reliability options. The auction clears at the minimum price (EUR/kW) that is needed to procure the desired amount of reliability option capacity. Generators that have bid less than or equal to the clearing price are then qualified to receive the capacity payment based on their winning capacity.

In response to the capacity payment, the generators commit to pay a difference payment to the operator at all trading periods in which the market price exceeds the predefined strike price. The difference payment equals the difference between the market price and the strike price times the amount of capacity the generator has sold through the reliability options.

If the full generation capacity in the market is sold as reliability options, the strike price effectively sets a price cap in the electricity market. If the market price is higher than the strike price, the difference payment that the generator has to pay equals the additional revenue it would otherwise have received. Electricity buyers are in turn fully hedged against prices higher than the strike price. In short, by selling a reliability option, the generator concedes profits from peak-load pricing but receives an upfront capacity payment. Generators also have the option to not sell reliability options for all or part of their capacity. Then, they do not need to pay the difference payment for that capacity; nor do they receive the capacity payment. They can still operate normally in the electricity market.

[6]The terms related to the mechanism based on reliability options may vary across documents (regarding, e.g., who owns the options and how ownership changes in the transactions). I follow Vázquez et al. (2002), where generators sell (call) options to the operator, which pays them an option fee. The operator then, as a holder of the reliability options, has the right but not the obligation to buy electricity at a strike price (thus, the name "reliability *option*"). In practice, this right is used only when the market price exceeds the strike price.

4 Model

The model consists of two sequential stages. In the first stage, firms sell capacity-backed reliability options in the capacity market and decide which of their incumbent generating units stay active in the market and which new units are built. In the second stage, firms compete in the electricity market, taking the total generation portfolio as given. Because firm's behaviour in the first stage depends on its expected profits in the second stage, the second stage of the model is described below first.

4.1 2nd stage, the electricity market

The time period is one hour and denoted by $h \in \{1, \ldots, 8760\}$. The total electricity demand, D_h^{tot}, varies across hours but is fully inelastic (constant) within each hour. Electricity supplied by wind farms (S_h^{wind}), must-run power plant units (S_h^{must}), pumped hydro storage units (S_h^{pump}), and net import from interconnectors (S_h^{import}) are exogenous in the model. While supply by wind farms and must-run units are exogenous by nature, the operators of pumped hydro storages and the counter-parties using interconnectors are expected to make their supply and demand decisions based on prices that are endogenous in the model. However, as their share of total capacity is minor and their supply seems to follow a regular pattern, it is assumed here that they replicate a constant diurnal pattern over the year based on their average observed behaviour.

The residual demand faced by the power plants, which are dispatched by the market, is then obtained by reducing the exogenous supply from the total demand:

$$D_h^{disp} = D_h^{tot} - S_h^{wind} - S_h^{must} - S_h^{pump} - S_h^{import}.$$

There are N strategically behaving firms that can exercise market power by bidding above their marginal cost. These firms are denoted by $i \in \{1, \ldots, N\}$. Each of these firms operates a portfolio of generating units. In addition to the strategic firms, there are some smaller firms that are assumed to have no market power and to thus behave fully competitively in the electricity market (i.e., they bid their true marginal costs). These small firms are represented by a competitive fringe that has a supply $S^{fringe}(p)$ that depends solely on the electricity price p. The demand faced by the strategically behaving firms is then

$$D_h(p_h) = D_h^{disp} - S^{fringe}(p_h), \tag{1}$$

where p_h is the hourly price of electricity in the wholesale market. Thus, strategic firms face an elastic residual demand.

Strategic firms compete à la Cournot simultaneously selecting produced electricity amounts that maximize their profits given the production of other firms. The periodical short-run profit of firm i in period h in the electricity market is

$$\pi_{ih}^{EM} = P_h\left(Q_h\right)\,(q_{ih} - q_{ih}^f) + p^f q_{ih}^f - DP_{ih}(Q_h) - VC_{ih}(q_{ih}), \tag{2}$$

where

$$0 \leq q_{ih} \leq K_{ih} \quad \text{and} \quad Q_h \equiv \sum_{r=1}^{N} q_{rh},$$

and $P_h(Q_h) \equiv D_h^{-1}(Q_h)$ is the inverse of the residual demand function defined in (1) and represents the market price given the total amount of generation. The variable q_{ih} is the electricity amount generated by firm i in period h, q_{ih}^f is the amount of electricity covered by forward contracts[7], p^f is the unit price of the forward contract, $VC_{ih}(\cdot)$ is the variable cost of the generated electricity, $DP_{ih}(\cdot)$ is the difference payment, K_{ih} is the total available generation capacity of the firm i, and Q_h is the total amount generated by strategic firms.

The difference payment is defined as

$$DP_{ih}(Q_h) = \max\left\{(P_h(Q_h) - p^{strike}) \times k_i, \quad 0\right\}, \tag{3}$$

where p^{strike} is the strike price defined in the reliability options procured in the capacity market, and k_i is the amount of capacity needed to back the reliability options sold by the firm i.

Because forward contracts are typically made months or years before delivery, their prices and quantities (p^f and q_{ih}^f) are known at the time the firm selects the hourly generation in the spot market, q_{ih}. Therefore, in the firm's hourly maximization problem, the term $p^f q_{ih}^f$ in equation (2) is constant. The first-order condition for an inner point solution ($0 < q_{ih} < K_{ih}$) when the equilibrium market price is below the strike price

[7] Note that q_{ih}^f can be interpreted not only as the amount of electricity that is sold forward but also as the amount of financially hedged electricity or the amount of a firm's retail commitment that has a fixed price (see Bushnell et al. (2008) for details). The important point is that the price for this electricity amount does not depend on the spot price in the same time period. To maintain consistency with the related literature, the term forward contracts is used here to refer to this electricity amount.

$(P_h(Q_h) \leq p^{strike})$ is then

$$\frac{\partial \pi_{ih}^{EM}}{\partial q_{ih}} = \frac{\partial P_h\left(Q_h\right)}{\partial q_{ih}} \left(q_{ih} - q_{ih}^f\right) + P_h(Q_h) - MC_{ih}(q_{ih}) = 0, \tag{4}$$

where $MC_{ih}(q_{ih}) \equiv \frac{\partial VC_{ih}(q_{ih})}{\partial q_{ih}}$ is the marginal cost when producing the amount q_{ih}. Note that as $P_h\left(Q_h\right)$ is the market price, the term $-\frac{\partial P_h(Q_h)}{\partial q_{ih}}\left(q_{ih} - q_{ih}^f\right) \geq 0$ can be interpreted as the mark-up on the competitive price $MC_{ih}(q_{ih})$ resulting from strategic behaviour. The mark-up decreases as the amount of electricity sold forward increases.

If instead the equilibrium market price is higher than the strike price $(P_h(Q_h) > p^{strike})$ the first-order condition becomes

$$\frac{\partial \pi_{ih}^{EM}}{\partial q_{ih}} = \frac{\partial P_h\left(Q_h\right)}{\partial q_{ih}} \left(q_{ih} - q_{ih}^f - k_i\right) + P_h(Q_h) - MC_{ih}(q_{ih}) = 0. \tag{5}$$

Compared to equation (4), the term $\frac{\partial P_h(Q_h)}{\partial q_{ih}}(-k_i) \geq 0$ is added to the left-hand side. This means that when the firm has sold reliability options $(k_i > 0)$, it generates more electricity when the price is higher than the strike price than it otherwise would. Thus, as expected, reliability options encourage firms to push the market price down by generating more electricity, to make the difference payment smaller.

Either of the first-order conditions (4) or (5) needs to be satisfied in the equilibrium simultaneously by all firms (same condition for all i) in each period h if an inner point solution exists. The solution for an individual firm can also be in the boundaries ($q_{ih} = 0$ or $q_{ih} = K_{ih}$).[8]

The marginal cost function of a single generating unit is an increasing step function that has one or more steps. The marginal cost function of a firm, $MC_{ih}(q)$, is a horizontal

[8]If the first-order condition (4) is satisfied with $P_h\left(Q_h\right) \leq p^{strike}$, the other first-order condition (5) cannot be satisfied such that $P_h\left(Q_h\right) > p^{strike}$, and vice versa, but there may be hours for which neither of the first-order conditions with the corresponding price constraint is satisfied. In these hours, the market price settles to the strike price, but there is an infinite number of production combinations that result in this market price, and where firms select best-responses to each other. I resolve this multiple equilibria issue by selecting a vector of production quantities that is on the line connecting the equilibria of the two unconstrained first-order conditions. See the literature on Cournot competition with a price cap for details (e.g., Buehler et al. (2010)).

aggregate of the marginal cost functions of the units owned by the firm. Formally,

$$MC_{ih}(q) = \begin{cases} c_{i1}, & \text{if} \quad 0 < q \le \bar{q}_{i1} \\ c_{i2}, & \text{if} \quad \bar{q}_{i1} < q \le \bar{q}_{i2} \\ \vdots & \\ c_{iS}, & \text{if} \quad \bar{q}_{i,S-1} < q \le \bar{q}_{iS}, \end{cases}$$

where c_{is} is the constant marginal cost in step $s \in \{1, 2, \ldots, S_i\}$, $\bar{q}_{is}$ is the generation quantity that is the upper boundary for step s, and q is the generated quantity. Note that $c_{i1} < c_{i2} < \ldots < c_{iS}$, and the marginal cost function is defined only in the range $[0, \bar{q}_{iS}]$. The variable cost function $VC_{ih}(q)$ is then a continuous increasing piecewise linear function that consists of S_i linear segments with increasing slopes.

The supply function of the competitive fringe, $S^{fringe}(p)$, can be obtained by first aggregating the marginal cost functions of firms other than the N strategic firms into a single step function $MC_{fringe}(q)$. The fringe generates electricity with all capacity that has marginal cost below the current spot price p. Formally, the fringe firms supply an amount

$$S^{fringe}(p) = MC^{-1}_{fringe}(p),$$

where $MC^{-1}_{fringe}(p)$ is the inverse of the aggregated marginal cost function of the fringe firms.

All generating units of strategic firms are unavailable for some hours during the year. If a unit is unavailable in a specific hour, it is ignored in the aggregation when constructing the firms' marginal and variable cost functions for that hour. Therefore, the firms' marginal and variable cost functions, $MC_{ih}(q)$ and $VC_{ih}(q)$, as well as firms' total available capacity K_{ih}, vary across hours and thus depend on h.

Firms obtain revenue also from providing ancillary services in the electricity market. It is assumed here that the firms' annual profits from these ancillary services, π_i^{AS}, are proportional to the share of the firm's total generated electricity during the year. The total annual short-run profits from the electricity market for firm i are then

$$\pi_i^{SR} = \sum_{h=1}^{8760} \pi_{ih}^{EM} + \pi_i^{AS}. \tag{6}$$

Firms also face dynamics costs and restrictions (e.g., minimum load, start-up costs, ramping rate) when generating electricity. These are not included in the model as they would complicate the model a lot and increase the computation time enormously.

4.2 1st stage, the capacity market

All currently operating generating units and potential new units that are not yet built participate in the capacity market, which is an annual uniform price auction where a specific amount of capacity is procured in the form of reliability options. The amount of procured capacity, $\bar{K}$, and the difference payment strike price, p^{strike}, are announced before the auction. Firms submit a price bid for each of their generating units. Denoting the units owned by the firm i as $j \in \{1, \ldots, J_i\}$, a bid for firm i is a set of pairs

$$b_i = \{ (b_{ij},\, \delta_{ij}\, K_{ij}) \quad | \quad j = 1, \ldots, J_i \},$$

where $b_{ij} \in [0, \bar{b}]$ is the price bid for the unit j, δ_{ij} is a technology and a unit size –specific de-rating factor, and K_{ij} is the nominal capacity of the unit.

The auction clears with the clearing price p^{cp}, which determines the capacity payment for the winning units. The winning units are all those with price bids less than or equal to the clearing price. Denote the winning units as

$$w_{ij} = \begin{cases} 0, & \text{if} \quad b_{ij} > p^{cp} \\ 1, & \text{if} \quad b_{ij} \leq p^{cp}. \end{cases}$$

The firm capacity that is used as the basis for the difference payment (see equation (3)) and the capacity payment ($p^{cp}\, k_i$) is then

$$k_i = \sum_{j=1}^{j=J_i} w_{ij}\, \delta_{ij}\, K_{ij}.$$

After the auction firms decide which of their incumbent units stay active in the market and which potential new units are built. Active units are available to generate electricity for the market, while inactive units have been closed or have not been built. There are no fixed costs to be paid for inactive units. The activity of unit j owned by firm i is denoted as

$$a_{ij} = \begin{cases} 0, & \text{if the unit is inactive} \\ 1, & \text{if the unit is active.} \end{cases}$$

Vector a_i collects the activities of all units owned by firm i. There is no scrap value or exit cost for those incumbent units that exit the market. Those units that win in the capacity auction and receive the capacity payment commit to be active in the market (if $w_{ij} = 1$, $a_{ij} = 1$). Units that do not win can still operate normally in the electricity market.

There are strategically behaving firms and competitively behaving firms also in the capacity market. Each strategic firm's optimization problem in the first stage is to select such vectors b_i and a_i that maximize the firm's total long-run profits π_i^{LR} which in addition to short-run profits include capacity payment less fixed cost. Formally,

$$\max_{b_i,\, a_i} \left\{ \pi_i^{LR} \right\} = \max_{b_i,\, a_i} \left\{ \pi_i^{SR} - \sum_{j=1}^{J_i} a_{ij}\, FC_{ij} + p^{cp}\, k_i \right\},$$

where FC_{ij} is the fixed cost of the unit, and $p^{cp}\, k_i$ is the capacity payment for firm i. Firms make their decisions sequentially. They first select their bids b_i, then the capacity auction clears, and finally, the active generation units a_i are decided.

Competitive firms in the capacity market bid for each generating unit the exact price that the unit needs to break even in terms of its long-term profits (or zero if the unit does not need a capacity payment to be profitable) given the other units in the market. Furthermore, the competitive units active in the market are those with the highest long-run profits. The sum of their profits would decrease if any of the active units were replaced by a unit that exited the market earlier.[9]

4.3 Equilibrium

Figure (1) summarizes the decision and information flow in the model. Starting from the right-hand side, given a total generation portfolio in the market (a_{ij}) and the capacity market commitments w_{ij} (which determine difference payments) firms' short-run profits are resolved in the electricity market based on a Cournot game. In the industry dynamics phase firms decide which new units enter and which incumbent units exit the market. Firms make these decisions based on their short-run profits and accounting for capacity payments and commitments in the capacity market that are taken as given in this phase.

[9] Note that this is conceptually equivalent to how competitive units behave in the electricity market; they bid their static marginal costs, and units that have bids lower than those of the marginal unit are dispatched. An important difference is that in the capacity market, competitive units' profits and, therefore, their bids depend on the total active generation portfolio in the market.

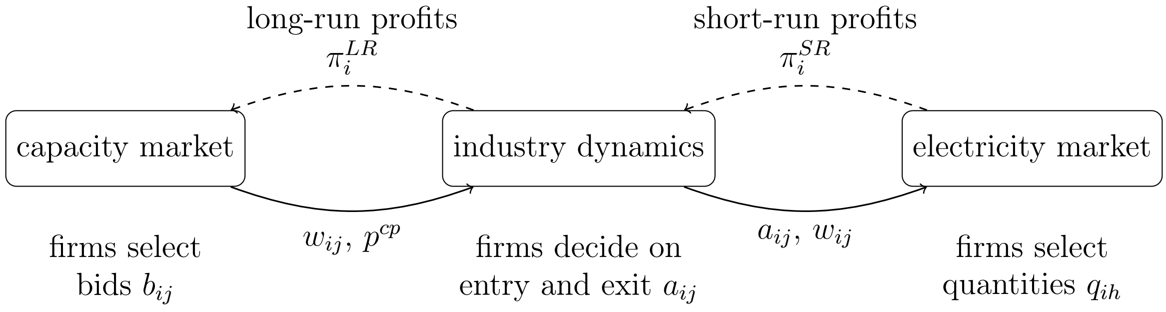

Figure 1: Decision flow in the model.

In the capacity market firms maximize their long-run profits that result after the full entry and exit process has taken place. In this first phase, firms select bids for their generating units and the winning units and the capacity payments are resolved.

The model is in the equilibrium when firms do not want to unilaterally change their behaviour in any of the three phases in figure (1). The equilibrium can be defined as follows:

- Strategic firms in the electricity market select hourly quantities q_{ih} in the electricity market that maximize their short-run profits given other firms' generation quantities (Cournot game equilibrium). None of the firms wants to unilaterally deviate from this quantity in any hour. *(electricity market equilibrium - strategic firms)*

- Competitive firms in the electricity market select hourly quantities q_{ih} in the electricity market so that their short-run costs are just covered. Their short-run profits are zero. *(electricity market equilibrium - competitive firms)*

- Strategic firms in the capacity market select bid vectors b_i in the capacity auction that maximize their long-run profits given other firms' bids (Nash equilibrium). None of the firms wants to unilaterally deviate from its bid. *(capacity market equilibrium - strategic firms)*

- Competitive firms in the capacity market select bid vectors b_i in the capacity auction so that their long-run costs are just covered. Their long-run profits are zero. *(capacity market equilibrium - competitive firms)*

- None of the firms can increase its profits by closing any generating unit that is currently active in the market and does not receive a capacity payment. None of the firms can increase its profits by entering the market with a new built unit. *(equilibrium in entry and exit)*

While a Cournot game in the electricity market has a unique solution, the model has multiple equilibria both in the capacity market and in the entry/exit process. The empirical application in this study is restricted to unilateral market power so there is only one strategic firm in the capacity market. This resolves the multiplicity problem in the capacity market. Multiplicity in the entry/exit game is resolved by making the following assumption:

1. Units enter or exit the market one unit at a time so that the incumbent unit with highest individual losses is closed first (if allowed) and the potential entrant with the highest individual expected profits will enter first.[10] *(entry and exit order assumption)*

Units that win in the capacity auction commit to be available in the electricity market and, thus, are not allowed to exit. Hence, strategic behaviour in the capacity market may affect the entry and exit process outcome making it possibly inefficient.

Furthermore, another assumption is made that reduces the action space considerably for strategic firms in the capacity market:

2. In the capacity auction, if an individual firm sorts its bids for all of its units in ascending order by price to create an increasing bid curve, it always has its units in the same order in the curve. That is, the same unit is always assigned the highest bid, and the same unit always has the second-highest bid, and so on. The order of the units is the same as that in the competitive benchmark.[11] This order assumption holds only for individual firms, not for aggregated bid curve. *(bid curve order assumption)*

The iterative algorithm used to find the solution when ESB is the only strategic firm in the capacity market is described in detail in appendix A.

[10] Another option, e.g., could be that the loss-making unit of a smaller firm exits first and the larger firm enters first. This may lead to different final generation portfolios (more concentrated) in some cases, particularly when the electricity market is very competitive. However, the order used here is probably more realistic.

[11] This approach is similar to that used in Sweeting (2007), where a firm's different strategies in the electricity market are compared by multiplying the price bids for all of its units by the same coefficient.

5 Data

The model is calibrated using historical data from the SEM from the year 2015. The two main data sources are EirGrid, which publishes real-time and historical data on the status of the Irish power system[12] and the SEMO, which publishes detailed trading data such as bids, prices, payments, and generation quantities.[13]

5.1 Demand, exogenous supply, and prices

To obtain the hourly total demand for electricity on the island of Ireland, I use system demand from EirGrid. These data contain the system loads at a 15-minute resolution and include system losses and power imported or exported via interconnectors but exclude some non-centrally monitored generation (such as small-scale CHP) and the load of the four pumped hydro storage units in Ireland. I use an hourly resolution in the model, so I average the values within each hour to obtain the hourly demand.

EirGrid also publishes an estimate of total output of all wind farms in the system at a 15-minute resolution. To use these data, I aggregate them at the hourly level. Figure (4) illustrates the hourly variation in wind power compared to total demand in January 2015. In the hour with the highest share of wind power in 2015, it covered 72 % of total demand (and must-run and wind power together covered 89 %), but the figure indicates that if wind is high during low-demand hours, together with must-run generation, it can cover total demand. I ignore solar energy as its share of total generated electricity in Ireland is negligible.

To account for the supply and demand by pumped hydro storages, I use these units' metered generation data published by the SEMO (Dynamic Reports → Metered Generation by Unit). These data reveal a regular diurnal pattern, where pumped hydro storages are typically loaded every night for approximately 6 hours (between 1 am and 7 am) and the stored electricity is then supplied with some efficiency losses throughout the next day over approximately 14 hours (between 8 am and 10 pm, peaking around 7 pm with demand (see figure (5))). This pattern is fairly regular throughout the year, except during some time periods when one or more of units are not available (probably due to scheduled maintenance or forced outage). These periods of non-availability mostly take place in the summer.

[12]See `www.eirgridgroup.com` → How the Grid Works → System Information.

[13]See `www.sem-o.com` → Market Data → Dynamic Reports, and `www.sem-o.com` → Publications → General Publications.

The correlation between hourly interconnector load and the price difference between the SEM and the British electricity market (SMP and N2EX day-ahead price) was very weak ($\rho = 0.14$) in 2015. Instead, net imports into Ireland can be explained by variation in demand and wind farm production. When total demand in Ireland net of wind energy is high, more electricity is imported from the Great Britain, and vice versa. This suggests that market participants were not noticeably using interconnectors for price arbitrage but mostly for hedging their generation portfolio against demand fluctuations in the domestic market. Figure (5) shows how electricity is typically imported to Ireland in the daytime and exported to the Great Britain at nighttime. When wind power is high, imports are slightly lower and exports slightly higher. The figure also shows that the interconnector capacity is rarely used fully (1000 MW). The loads for both interconnectors are available from EirGrid at a 15-minute resolution.

For the electricity prices (SMP and shadow price) I use the half-hourly data available from the SEMO (Dynamic Reports → Shadow Price and SMP). I use prices from the Ex-Post Initial run (EP2), as the SMP from EP2 is used as a reference price for payments and charges.

5.2 Generating units

I combine generator data from the 'Registered Capacity Report' and the 'List of Registered Units' published by the SEMO (General Publications → Joining the Market). I use the 'Registered Capacity Report' from July 2015 as a basis. Thus, I exclude the three oil units (Great Island 1-3 owned by SSE, with a total capacity of 204 MW), which exited the market in May 2015. I exclude also one multi-fuel unit (North Wall, 163 MW, owned by ESB), which exited in August 2015 but did not generate over the whole year, and two demand response units that started operating after July. I include an 18-MW biomass unit (Lisahally, owned by NIE), which started in July but is listed only in later reports. Otherwise, changes in generation capacity in 2015 were mostly due to the commissioning of new wind farms. For units that report using multiple types of fuel, I determine their main fuel source by drawing from other data sources such as firm websites and then assuming that the unit uses only that fuel.

All registered units in the SEM are classified either as price makers or price takers. Price makers are units that are dispatched based on the market price and usually set the price in the market. Price takers are dispatched by some other logic and take the market price as given. Price takers include wind plants that do not bid in the electricity market;

hydro power plants that typically bid zero; and must-run plants, such as biomass and waste plants, that bid zero or negative prices. Some oil or gas units are also classified as price takers, e.g., two units used in the alumina refinery owned by Aughinish Alumina Ltd. The three peat units in Ireland are also price takers even if they bid positive values. Peat plants are priority dispatched in the SEM and receive additional financial support to cover all their costs. Moreover, some hydro plants are classified as price makers.

Excluding wind, interconnectors, and pumped hydro storages, which are handled separately, I consider all units defined as price takers and price-making hydro units (as they still bid zero) as must-run units, which run continuously regardless of the electricity price. Thus, these include all peat, hydro, biomass, and waste units, as well as the price-taking oil and gas units. Figure (4) shows hourly must-run generation in January 2015. The generated amount is pretty constant over time, but there is some seasonal variation. The total generation of must-run plants ranged from 500 to 700 MW in the winter and 400 to 600 MW in the summer. Seasonal differences come mostly from hydro power plants, which produce noticeably less in the summer, and from peat plants, which were not available for longer periods in summer 2015 (probably due to maintenance). This results in 55 units of coal, gas, oil, distillate, and demand response that effectively set the half-hourly price in the SEM.

I take plant ownership as reported in the 'List of Registered Units' by the SEMO, with some modifications mainly based on information from firm websites. The following modifications are made: I assume that the Dublin Bay generator previously owned by Synergen now belongs to ESB, as do the gas and oil units reportedly owned by Coolkeeragh ESB Ltd. I assume that Viridian owns the gas unit in Huntstown, which is reported to be owned by Huntstown Power Company Ltd. I also combine AES Ballylumford Limited and AES Kilroot Power Limited into the same firm (AES).

5.3 Bidding and marginal costs

As firms are obliged by the bidding code to bid their true short-run marginal costs when trading in the SEM, I assume that firms' bids represent each unit's real marginal costs reasonably well. These bids are publicly available on the SEM website (Dynamic Reports → Generator Offers) for each unit and half-hourly trading period. A bid for a single unit consists of at most 10 price-quantity pairs, but typically, firms use only 1-4 pairs. Firms' bids are usually constant across all trading periods in the same trading day, but they may change slightly between days over the year, mostly due to changes in fuel and carbon prices. From the bidding data, it can be observed that units using same fuel and owned by the same firm typically bid the same way, using the exact same prices or constant price differences. There are more differences in bidding behaviour between units that are owned by different firms even if they use the same fuel type.

Figure (6) illustrates how some bids evolved in 2015. It shows daily bids for units that use distillate as a fuel and bid only one price-quantity pair. AES owns four more units that bid two price-quantity pairs. In those units, the second price level is higher than any of the prices in figure (6), but they follow the same pattern. It can be seen that there are quite large differences in bids between the firms, while the bids submitted by units owned by the same firm are similar. Still, all bids follow the same annual pattern, which reflects changes in the fuel price.

Figure (7) shows similar annual bid patterns for units using different fuels. It only shows the first price level when units bid several price-quantity pairs. Usually, higher price levels just add a constant mark-up to the lower price. The figure shows that in 2015, bids from units using oil and distillate varied the most during the year. They were also highly correlated with each other, as their original fuel source is the same (oil). Gas units' bids also varied somewhat but are less closely correlated with oil and distillate. Peat and coal units' bids remained the most stable.

To simplify calculations and to abstract from changing fuel prices, I select one representative bid curve for each unit and use it for all days and hours over the whole year. I select a day that represents the median bid submitted over the year. I also try to select bids from the same days for all the units if they do not deviate much from the median. If the capacity in bids does not match the registered capacity for the unit, I use the registered capacity.

Figure (8) shows the bid curves formed by aggregating the representative bids of price-making units using a specific fuel. Bid curves are stacked to the right so that the rightmost curve represents the full aggregated bid curve in the market. It shows that when the electricity price increases, the first units dispatched are gas units at a price of around 17 EUR. The first coal units are dispatched at around 25 EUR, and their capacity is fully dispatched soon after (with another small step at 167 EUR). When the price increases above 25 EUR, gas units are increasingly dispatched. Oil and distillate units are started up only after the price reaches 70-100 EUR. The first demand response units become active at around 200 EUR, but their capacity is activated more noticeably only when the price exceeds 300 EUR.

5.4 Capacity payment and fixed costs

Currently in the SEM, to determine the total amount of capacity payments for a specific year, the regulatory authorities first estimate two numbers: the annualized fixed costs of a best new entrant peaking plant and the amount of capacity required to guarantee the security of supply. The total sum of annual capacity payments is the product of these two numbers. For the years 2013-2015, the reference plant for the best new entrant peaker was an imaginary 196.5 MW plant with an Alstom GT13E2 turbine using distillate as a fuel and located in Northern Ireland, with a 20-year lifetime and a forced outage probability of 5.91 %. For the year 2015, its annualized fixed cost was estimated to be 91.88 EUR/kW/year. Reducing the revenue from ancillary services (4.53 EUR) and infra-marginal rent (5.75 EUR, received when capacity is scarce and the marginal plant bids the price cap), the amount used as a basis for the capacity payment was 81.60 EUR/kW/year. The estimated amount of required capacity was 7046 MW.[14]

In 2015, the total generating capacity in the SEM was higher than required in the capacity payment calculation. Therefore, the capacity payments received by existing units were less than 81.60 EUR/kW/year. Using the unit-specific capacity payments published by the SEMO (Dynamic Reports → Capacity Payments by Unit), it can be calculated that the average capacity payment for gas, oil, and distillate units in 2015 was 54.50 EUR/kW/year.

Based on these data, I assume that the fixed cost for a new gas plant is 91.88 EUR/kW/year, as calculated by the regulatory authorities. For existing gas, oil, and distillate units, I assume a fixed cost of 54.50 EUR/kW/year, the actual average capacity payment received by the units in 2015. As few firms have exited the market in recent years, it can be inferred that this amount is enough to cover the fixed costs of several gas, oil, and distillate units that did not generate electricity during the whole year and thus received no other revenue. The fixed costs of coal units are typically higher; I assume that their fixed costs are covered by the capacity payment and the inframarginal revenue. The combined average capacity payment and inframarginal revenue of the five coal units is 119.01 EUR/kW/year. The literature also suggests that the fixed costs of coal plants are at least two times the fixed costs of gas plants (see, e.g., DECC (2013), appendix A; Schröder et al. (2013), table 34; and Tidball et al. (2010), table 15).

[14] See 'SEM-14-070: Decision Paper on Capacity Requirement and Annual Capacity Payment Sum for Calendar Year 2015' for the capacity payment decisions and 'SEM-12-078: Decision Paper on BNE Peaker for 2013' for the detailed cost breakdown for the best new entrant plant. Both documents can be found at `www.semcommittee.com` → Publications.

5.5 Availability and de-rating

I use Monte Carlo simulation to account for availability. I simulate forced outages independently for each hour based on the statistics published by the SEMO in SEM-16-051a, table 3.[15] For gas units, there is a 3.6 % probability of forced outage; for the other units (coal, oil, and distillate units), it is 7.2 %. I assume that there is one maintenance break per year for every unit. The break starts randomly and it lasts for 420 consecutive hours for the gas units and 569 consecutive hours for the other units (calculated from the mean scheduled outages listed in SEM-16-051a, table 3).

Occasional non-availability of generating units in the electricity market is taken into account in the capacity market by de-rating the nominal capacity of each unit in the capacity auction bids so that each unit's actual contribution to the total amount of procured capacity is less than its nominal capacity. I use de-rating factors published in SEM-16-051a, table 4. For gas turbines, the de-rating factors vary from 91.1 % to 95.8 %, depending on the unit's total capacity, and for coal, oil, and distillate units, which use steam turbines, the factors vary from 83.1 % to 91.8 %.

5.6 Ancillary services

In the capacity payment decision paper for the year 2015 (SEM-14-070), it is estimated that the profits that the generating units earn from ancillary services in 2015 is, on average, 4.53 EUR/kW/year. For the 41 price-making units used in the simulations, the total profits from ancillary services are then 36.8 million EUR/year. When the generation portfolio changes, I assume that this total sum stays constant and divide it across the active units in the market in the same proportion as they generate electricity in the electricity market. The profits units gain from ancillary services then range from zero to approximately 15 EUR/kW/year, and their share of total profits is approximately 2 % for each unit.

[15] The SEM consultation document: 'SEM-16-051a: Capacity Renumeration Mechanism: Proposed Methodology for the Calculation of the Capacity Requirement and De-rating Factors' is available at `www.semcommittee.com` → Publications.

6 Analysis

This study is restricted to unilateral market power in the capacity market. It is assumed that only ESB behaves strategically in the capacity auction, while all other firms behave competitively. This isolates the consequences of a single firm's strategic behaviour and enables inferences regarding one firm's possibilities and strategies for abusing market power. If several firms are strategic or collude, the total amount of market power can be substantially larger.

While in the capacity market, only one firm is strategic, in the electricity market, more strategic firms are allowed in order to make the simulated market results more realistic. It is important that the simulated profits in the electricity market are not biased, since they propagate to the capacity market and affect firms' behaviour there. Common practice in electricity market studies is to assume that only the biggest firms in the market behave strategically, while the smaller ones bid more competitively. There is also empirical evidence supporting this difference in bidding behaviour based on firm size (see, e.g., Hortaçsu and Puller (2008)). Here, it is assumed that the seven largest firms by capacity in the SEM in 2015 (ESB, SSE, AES, Viridian, NIE PP, Bord Gais, and Tynagh) behave strategically, while the other firms belong to a competitive fringe. The total capacity of the competitive fringe is then quite small (388 MW, while the strategic firms own 7437 MW), and units in the fringe have relatively high marginal costs. The competitive fringe consists of one 12 MW gas unit, one 3 MW oil unit, 3 distillate units (total 188 MW), and 9 demand response units (total 215 MW). Strategic firms own a total of 41 generating units.

Different amounts of procured capacity in the market are studied, ranging from currently existing capacity to an estimated capacity under the energy-only market design. As there is currently excess generating capacity in Ireland rather than a shortage of capacity, it is likely that the amount procured in the I-SEM is somewhat smaller than the currently existing capacity. However, this study extends to procuring more capacity than the current amount which could be more realistic case in some other market.

As the amount of electricity that will be sold forward (as opposed to the amount sold in the spot market) in the future Irish market cannot be known now and as the share is known to affect how competitively firms behave in the electricity market (see Allaz and Vila (1993)), different values are analysed ranging from the case when all electricity is sold in the spot market (0 % sold forward – the least competitive electricity market) to the case when none of the electricity is sold in the spot market (100 % sold forward – the most competitive electricity market). While these two extreme cases are not realistic, they set boundaries for more realistic values. Based on other European electricity markets, a good guess for the share of electricity sold forward in the I-SEM is 60-80 %. Overall, the share of forward contracts can be interpreted as a common measure of electricity market competitiveness that defines what kind of price mark-ups are available to the firms in the electricity market.

It is necessary to include only the price-making units in the simulations, as the other units are assumed to operate exogenously (interconnectors, pumped hydro storages, wind farms, and must-run units), as described in section 5. Then, there are 41 generating units that are assumed to set prices both in the electricity market and in the capacity market. These units are listed in table (3). They are ordered by fuel type and the first step of the marginal cost function (least cost unit first). It is important to note that when a specific amount of procured capacity is studied below it concerns only the capacity procured from these 41 units. In reality, more capacity would be procured from the market as the excluded units also provide their capacity. For the same reason the total amount of capacity payment would be actually more. Hence, all numerical results of the study cannot be directly compared as such with the real values available later but some adjustments may be needed.

It is assumed in the analysis that the price cap in the capacity auction is set to 140 EUR/kW. In the British capacity auction, the price cap is set to 1.5 times the net cost of new entry (net CONE), accounting for electricity and ancillary market revenue. In Ireland, the annual cost of best new entrant accounting for infra-marginal revenues and ancillary services was estimated to be 91.88 EUR/kW in 2015 (see SEM-12-078 or the discussion in section 5). Using the British formula (a similar multiplier is used in other capacity markets), the auction price cap would be set to approximately 138 EUR/kW in the I-SEM.

6.1 Energy-only market

First, market behaviour without any capacity payment mechanism is studied. Firms then receive revenue only from the electricity market. Starting from the current generation portfolio, there are several units that are rarely needed to meet total demand economically, and these unprofitable units exit the market one by one. Incumbent units' profits increase when the number of units in the market decreases and when prices increase during high demand hours when demand exceeds the generation capacity. The market exit process continues until the marginal unit is able to cover its costs. When price mark-ups available in the market are smaller, more capacity needs to exit the market to make all incumbent units profitable. Table (4) summarizes the simulation results. Of the original 41 units, 13 units are left in the energy-only market in a less competitive market (0-60 % forward contract share). When the market becomes more competitive, revenues fall, and only 12 (80 % forward contracts) or 11 units (100 % forward contracts) are able to stay in the market.

Table (4) shows that when market competitiveness decreases (moving left in the table) firms withhold generation to increase prices. The price mark-up over the competitive price aggregated over hours increases rapidly and can be almost three times the competitive price. This price mark-up is defined here as

$$markup = \frac{\sum_{h=1}^{8760}\{(p_h - p_h^{comp}) * q_h\}}{\sum_{h=1}^{8760}\{p_h^{comp} * q_h\}},$$

where p_h is the simulated strategic price, p^{comp} is the competitive price, and q_h is the amount generated by all firms.

The total expenditure for electricity purchasers decreases from 2675.8 MEUR to 1079.4 MEUR when market competitiveness increases because prices decrease even if more electricity is generated and consumed. The relative change in the consumed electricity between the two extremes is much smaller (19.1 TWh-21.8 TWh) than the change in the generation-weighted average price (139.9 EUR-45.8 EUR) which reflects the inelasticity of demand.

The highest market prices occur for two reasons: either firms behave strategically and withhold generation in order to increase the market price or demand exceeds the total capacity, and the price has to increase in order to reduce the demand. Without forward contracts, the maximum price is 1410.6 EUR/MWh. This is caused by capacity withholding. There are only 4 hours when demand is restricted by the capacity limit. When competitiveness increases and firms generate more electricity, the maximum price is 1379.6 EUR, with a 20-60 % forward contract share, which occurs in an hour when demand hits the capacity limit. As the generation portfolio changes from 13 to 12 and to 11 units, this capacity limit is hit in more hours; therefore, the highest prices increase further (1632.9 EUR and 1868.4 EUR) even if the average price decreases. At first, the number of hours when the market price exceeds 500 EUR/MWh decreases as competitiveness increases because of less generation withholding, but it starts to increase as the number of hours in which demand reaches capacity increases.

Figure (9) shows the unit-specific profits with different amounts of forward contract shares. Competitiveness significantly affects the profits, which range to approximately 700 EUR/kW. However, changes in the total portfolio occur only when the share of forward contracts is 80 % or higher. ESB and NIE PP gain the most from these changes, as they have gas units on the margin ready to replace units that become unprofitable. In a Cournot game, all firms produce a positive amount and use units with lowest marginal costs. Still, the most profitable units in the market are not necessarily those with the lowest marginal costs in the market, as the unit-specific profit depends on the unit's owner and its firm-specific generation portfolio.

Price duration curves with different share of forward contracts are shown in figure (10). Strategic behaviour shifts the duration curve higher in a multiplicative fashion. When the market is fully competitive, firms' stepwise marginal cost functions are tracked exactly, causing corners in the price duration curve. The duration curve based on real observed SMP prices from the year 2015 that is also drawn in the figure is not directly comparable to the other duration curves because the SMP prices account for start-up and other dynamic costs (uplift component), which are not included in the simulation. Moreover, the realized generating unit availability in 2015 was better than assumed in the simulations, reducing the realized prices.

Figure (11) shows how firms change their generation amount when the strategic behaviour increases (to the right in the figure). ESB reduces its generation the most. Other firms that decrease their generation are NIE PP, AES, and SSE. Even if the total capacity of NIE PP is currently not that large when compared to AES and SSE, the reason for its strategic behaviour is that it is quite large among those firms that are left in the energy-only market after the exit process; e.g., SSE and AES have several oil and distillate units that have relatively high marginal costs and therefore become unprofitable early. Smaller firms actually increase their generation. Thus, smaller firms benefit relatively more from the high prices that result from the strategic behaviour of bigger firms. Still, all firms gain from strategic behaviour.

6.2 Difference payment

It is useful to separately examine how introducing a difference payment that firms need to pay when the market price increases above the predefined strike price affects firm behaviours, their profits, and the total generation portfolio in the market. Effectively, this kind of difference payment acts as a price cap set at the level of the strike price. It reduces incentives to increase prices by withholding generation and reduces revenue during hours when the price increases because demand exceeds total capacity, which is something firms cannot avoid and may lead to the 'missing money' problem.

Table (5) lists the changes with respect to table (4) when a difference payment with a strike price of 500 EUR is introduced, assuming that all generating units are committed to paying it. When the forward contract share is low (0-60 %), firms react to the difference payment by generating more electricity in order to keep the market price from exceeding the strike price. The highest prices then decrease, as do firm profits and total expenditure for purchasers. The relative change in firm profits is highest (-2.1 %) in the least competitive market when there are the most hours (57) during which the market price would otherwise exceed the strike price. Firms then generate 0.032 % more electricity, decreasing the average price by 0.92 %, while the price mark-up decreases from 292.1 % to 286.3 %. So, in these cases difference payment mitigates market power.

Instead, if the market is more competitive (forward contract share is 80-100 %) increasing generation has no effect since the market price exceeds the strike price mostly because demand exceeds capacity. Therefore, firms merely face an additional cost. The relative reduction in profits and total expenditures is higher in more competitive markets because profits are then much lower even without difference payment. In the most competitive case, firm profits decrease by 12.9 %, and the total expenditures for end users by 3.1 % (assuming the difference payment is reimbursed to buyers). Still, even if firm profits fall, the total generation portfolio remains unchanged in all studied cases when the difference payment is introduced.

6.3 Competitive benchmark

A competitive benchmark in the capacity market is defined here as the capacity supply curve that is formed by assuming that all generating units in the market bid exactly the amount that they need to break even in the long term. It is created using the algorithm in appendix A by assuming that ESB would also bid competitively. Any deviation from the competitive benchmark that increases firm profits is interpreted as strategic behaviour. Competitive benchmarks for the markets with 0 % forward contract share and 100 % forward contract share are drawn in the figure (12).

The competitive benchmark consists of four parts. Units that are run most of the time are profitable without any capacity payment and bid zero. They form the horizontal part on the left-hand side of the supply curve. Units that are run less frequently bid a positive value between 0 and 60 EUR/kW. The more competitive the electricity market, the higher the capacity payment needed. Therefore, the non-competitive market benchmark is below the competitive market benchmark in the middle of the figure. Units that are mostly idle need capacity payments that cover their fixed costs. These are approximately 60 EUR/kW for gas, oil, and distillate units (with de-rated capacity). These units form the other nearly horizontal part of the supply curve. On the right-hand side of the curve, the highest bids are submitted for ESB's coal units. These have fixed costs approximately two times higher than other fossil fuel units. In the non-competitive case, ESB withholds generation and uses mostly its gas units, which have lower marginal costs than the coal units. Therefore, ESB bids exactly the fixed costs for its coal units. In a more competitive environment, ESB generates more and uses also its coal units more, and with their revenue, part of their costs can be covered. Then, ESB submits lower bids for the coal units in the capacity auction.[16]

6.4 No entry

Figure (13) shows what would be the clearing price in the capacity auction if ESB behaved strategically. Two different strategies can be identified. If less capacity is procured (4000-4500 MW), ESB would push competitors' units out of the market by submitting bids lower than the competitive prices for some of its units and then benefitting in the electricity market from its more dominant position; e.g., when 4500 MW is procured, ESB submits a very low bid for 6 of its gas units. This forces most of the SSE and AES units out of the market, which otherwise would be there. Of the 16 active units in the market, ESB would own 9, leading ESB to gain more in the electricity market than in the competitive outcome. For the end user, the total cost of electricity is higher than it would be in the competitive benchmark, even if the capacity payment would be smaller when this predatory pricing strategy is used.

The figure (13) is drawn using the 100 % forward contract share in the electricity market. If the market is less competitive (80 % or less forward contracts) predatory pricing does not occur. Instead, ESB would accept the outcome that follows the competitive benchmark even when the amount of procured capacity is low. Predatory pricing is a

[16]If some other firm owned ESB's coal units as its only units (or ESB would not have cheaper gas units), they would be more profitable by unit and the firm would submit lower bids for them in the capacity market (probably zero like AES coal units). Total profits in the market would still be lower and total end user costs higher.

dominant strategy in the competitive electricity market because with tighter competition, small changes in bids in the capacity market can significantly affect the resulting total generation portfolio in the electricity market making strategic behaviour in the capacity market more rewarding.

If 4750 MW or more capacity is procured, ESB would use a different strategy. It would submit the highest possible bid for so many units that one of them sets the auction clearing price at the price cap at 140 EUR/kW. If it did not do so, the price would be set by a competitive unit at approximately 60 EUR/kW. This price would just cover the fixed costs of the ESB gas units that are mostly idle in the electricity market, leading them to just break even. Therefore, ESB can gain by sacrificing these units in the auction, and getting the maximum price for its remaining units, even if there are very few of them left that eventually receive a capacity payment.

Since the amount of procured capacity in the I-SEM is likely to be in the range of 5500 MW-7000 MW for the 41 units in the figure, the dominant strategy for ESB would be capacity withholding assuming that there are no new entrants. The same is true regardless of the competitiveness of the electricity market.

6.5 Potential entrants

The effects of having new entrants into the two markets are studied next with 1082 MW, 2164 MW, and 3246 MW of potentially entering new capacity. For 1082 MW, the potential new entrants are 3 gas units (300 MW of nominal capacity each), one oil unit (200 MW), and one distillate unit (60 MW). Each of these new units is owned by a new firm. Thus, there are five new firms participating in the capacity auction and in the electricity market. For 2164 MW, it is simply assumed that each of these five firms would obtain a new generating unit of the same size and using the same fuel. So, there are three firms that each own two gas units, one firm that owns two oil units, and so on. For 3246 MW, one more similar unit is added to each firm.

The marginal costs of these new units are formed by taking the costs (first steps) of the incumbent units separately by fuel type, sorting them, fitting a polynomial curve for the sorted values, and then selecting right number of points from the fitted curve with even intervals. The new units' availabilities and de-rating factors are the same as for incumbent units of the same fuel type, but the fixed costs are higher and taken from SEM-12-078 (see the discussion in section 5). New firms are strategic in the electricity market (participate in a Cournot game) but competitive in the capacity market (as are the other firms, except ESB).

Figure (14) illustrates the simulated capacity market clearing prices with 1082 MW of new capacity and a fully competitive electricity market. Because there are no additional mark-ups available in the electricity market, new units have to submit relatively high bids in the capacity auction. Consequently, it is not profitable for ESB to withhold capacity as aggressively as in the no-entry case. If 6750 MW or more capacity is procured, ESB would accommodate all entry and withhold capacity so that the clearing price equals the price cap, but when 6000-6500 MW is procured, ESB would set a price that is just high enough to keep four new potential entrant units out of the market.[17] Hence, new entry clearly mitigates ESB's market power if the entry is bidding in the price setting area.

In figure (15), the same amount of new capacity is assumed but now there are high mark-ups in the electricity market (0 % forward contract share is assumed). Therefore, new entrants submit very low bids in the capacity auction, with most units bidding zero. This means that ESB can still exercise market power when 6250 MW or more capacity is procured. The area where ESB can exercise market power is still smaller than without entry (see figure (13)) because the new entrants replace capacity at the low-cost end, pushing the competitive benchmark to the right. ESB's strategy relative to the competitive benchmark stays approximately the same. Thus, in this case, entry mitigates market power by reducing the capacity range in which market power can be exercised but still allowing high mark-ups within this range. Varying electricity market competitiveness while having the same amount of new capacity produces market outcomes between these two extremes in figures (14) and (15).

In figure (16), the capacity of new entrants is now three times higher than in the earlier cases. The electricity market is fully competitive with 100 % forward contracts. The new entrants now have a total capacity greater than that of ESB, so ESB is not pivotal in any of the studied different procured capacity amounts. Because of the electricity market competitiveness, the new entrants submit quite high bids. For the same reason, these bids are pretty similar between the units, the price range where new entry is located in the aggregated bid curve is quite narrow (excluding one outlier). ESB can benefit from this by bidding just below the price when most of the new entry would enter the market and gaining from the mark-up. If instead the electricity market is less competitive, the new entrant units bid in a wider price range. This mitigates ESB's market power more efficiently.

[17] A strategic behaviour called bid shading can be seen here, as ESB sets the price as high as possible so that the winning units still remain the same.

To conclude, market entry mitigates market power efficiently if entrants' bids are placed in a price range where the clearing price is set (this is more likely when the electricity market is more competitive) and if the range of the new entrants' bids is wide (this is more likely when the electricity market is less competitive).

6.6 Strategic investment

One possible strategy for ESB is strategic investment wherein it invests in new power plants and submits such low bids for them in the capacity market that it can keep other potential entrants out of the market protecting its dominant position in the electricity market. This is studied by assuming that ESB can invest in three new gas units that have similar marginal costs as ESB's current gas units. It is found that strategic investment is not a profitable strategy for ESB.

If the amount of new capacity is relatively low (e.g., 1082 MW as in figure (14)), the dominant strategy for ESB is to withhold capacity and to set the clearing price at the price cap. With those amounts of procured capacity when ESB finds it profitable to deter entry it can do so with its current units (by withholding less) so new investments are not needed. ESB would invest in new units only when so much capacity is procured that existing capacity and new entry by other firms is not enough to meet demand. In that case, ESB can easily set the clearing price at the price cap with its new entrant.

If there is more potential entry (e.g., 3246 MW as in figure (16)), accommodating the whole entry is costly for ESB and, therefore, deterring entry is the dominant behaviour in larger range of procured capacity. Still, ESB would deter the main part of the new entry only when it can do so with the existing units. Deterring entry with new units is costly for ESB as it has to submit slightly lower bids for them in the capacity market than competitors' new units which all have the same fixed costs. Gains in the electricity market are not enough to cover these costs because when there is considerable market entry, a major part of it would not receive much run-time in the electricity market and, hence, would not affect ESB's profits considerably.

6.7 Downward sloping demand curve

One way to prevent excessively high prices in the capacity auction is to use a downward sloping demand curve for the procured capacity instead of a vertical one as above. Testing this with a demand curve where the amount of procured capacity is decreased by 25 MW when the clearing price increases by one EUR suggests that this does not affect the amount of market power significantly. Prices do not increase that much, but the amount of procured capacity is also lower. The market equilibria are close to what would be achieved with a vertical demand curve where the amount of procured capacity is set lower.

6.8 Lower bid cap for incumbent units

Another way to mitigate market power in the capacity auction is to restrict the bidding of incumbent generating units setting them lower bid cap than for new entrants. The idea is that new entry would then always set the clearing price competitively. This approach is used, e.g., in British capacity auctions (see also, the suggestions in Cramton and Stoft (2008)). It obviously works if new entry bids competitively and more capacity is procured than what is the currently existing capacity in the market. The downside is that if there is excess capacity – which is common – the lower bid cap is often binding leaving the regulator strong responsibility when deciding on the bid cap as it then effectively sets the clearing price by regulation making the whole capacity market meaningless.

Figure (19) illustrates what would happen if incumbent generating units are not allowed to submit higher bids than 60 EUR/kW while potential entrants can bid at most 140 EUR/kW. The lower bid cap is then approximately 65 % of estimated net CONE in Ireland (91.88 EUR).[18] If the electricity market is perfectly competitive (100 % forward contract coverage) the auction clearing price is competitive in every case when the existing capacity is not enough to cover the entire procured capacity. When the electricity market gets less competitive part of the new entry bids lower than 60 EUR while some incumbent units bid exactly 60 EUR which then decreases the capacity range where competitive prices are achieved. The lower bid cap is binding in quite large range (from 250 MW up to 1750 MW) around the level of existing capacity. This range increases in size when the electricity market gets less competitive. In some lower amounts of procured capacity having a lower bid cap changes ESB's optimal strategy; predatory pricing becomes more profitable strategy than capacity withholding in some cases. From the end users point of view this strategy is not as costly as capacity withholding would be.

[18] In the British capacity auction existing units have been restricted to bid at maximum 50 % of net CONE.

6.9 Total cost of strategic behaviour

Figure (17) shows a cost breakdown for different amounts of procured capacity when the electricity market has 80 % forward contracts and there is 2164 MW of new entry. The total expenses in the electricity market do not vary much over procured capacity because the marginal units are mostly idle when more than approximately 4500 MW of capacity is procured. If the market competitiveness changes the electricity market expenses can be considerably higher. The electricity market mark-up varies from 0 to approximately 1500 MEUR when the forwards contract share goes from 100 % to 0 %, respectively. In this particular case the expenses in the electricity market are higher than the expenses in the capacity market if the procured capacity is less than 7500 MW. Otherwise, the capacity market dominates the total expenses. The share of price mark-up in the capacity market ranges from 0 % to 37 % of the total capacity payment.

Table (6) shows the average price mark-up in the capacity market. If there is less entry (1082 MW) the mark-up is lowest with the most competitive electricity market because the entering units then bid in the price setting area (as illustrated in the figure (14)). When the amount of new capacity increases, it mitigates market power generally, but now, the mark-up is lowest in the non-competitive market because the entrants then bid in a wider price range as explained above. The amount of new capacity is the dominating factor and the lowest mark-up in the capacity market included in table is achieved when the amount of new capacity is highest and the electricity market is least competitive. However, this is when the electricity market is most costly because of the strategic behaviour therein.

Table (7) shows the total mark-up in the electricity market and the capacity market together. Mark-up in the electricity market dominates over the mark-up in the capacity market and the total amount of market power in the two markets is lowest when the electricity market is most competitive (7.6 % with 2164 MW of entry) even if the mark-up in the capacity market would be lower with less competition. The total expenses are then also lowest because the total expenses in the electricity market vary practically with the price mark-up there and the total expenses in the capacity market are generally lowest lower the mark-up is (higher the entry).[19]

[19] Data in the tables is sensitive to how the potential entrant units are selected and the results are also affected by the lumpiness of the generating capacity. These explain some non-continuous changes in the data but there should be enough data to identify the general pattern. Also note that the realistic range for Ireland for forward contracts is probably something between 60 % and 100 % and up to 2164 MW of new entry in the auction.

6.10 Residual Supply Index

Residual Supply Index (RSI) is a common firm-specific metric that is used to measure the firm's ability to exercise market power. In the studied market, it is calculated for ESB as follows:

$$RSI_{ESB} = \frac{total\,capacity \quad - \quad ESB's\,capacity}{procured\,capacity},$$

where *total capacity* includes all existing generating capacity in the market and the capacity offered by potential entrants. Thus, the RSI for ESB is the ratio of all other firms' capacity except that of ESB to the amount of procured capacity. Smaller RSI values are assumed to indicate that the firm can exercise more market power. If RSI is less than 100 %, then the firm is pivotal; its capacity is necessary to meet the amount of procured capacity. Often, it is targeted at having RSI of at least 110-120 % for each firm in the market. If it is less then some specific rules may be applied for the firm (such as a lower bid cap in the capacity market).

Figure (18) plots some Lerner indices in the capacity market against the respective RSI values. The plots represent different amounts of procured capacity with an 80 % forward contract share in the electricity market. The Lerner index is the ratio of the price mark-up in the capacity market to the capacity payment and ranges from 0 to 1. A higher Lerner index means more market power and therefore negative correlation between the RSI and the Lerner index is expected. Looking at the figure, the negative correlation seems to be there even if not very strong. The three points on the left-hand side of the curve with low Lerner index values result from price setting by the three coal units from ESB. The price mark-up is small even if the maximum amount of market power is used because they bid much higher prices than the other units. However, there are points where significant market power can be exercised even if the RSI is higher than 110 %.

Interestingly, figure (18) suggests that when the amount of new entry in the market increases, RSI also increases (by definition) but the simulated market power does not decrease by the same proportion. Those parts of the curve when the Lerner index values are high move to the right, as the number of entrants increases. Even if there is considerable market entry, their bids may be placed in such a narrow price range that there is room for the exercise of market power, as explained above. So, at least in this case, RSI seems to be the more reliable measure of market power the smaller the amount of new entry.

7 Conclusion

This article studies the possible consequences if a capacity market is introduced beside an electricity market in an imperfectly competitive market with one or a few dominant players. Generally, if market power can be exercised in the electricity market, it can also be expected in the capacity market. However, this mapping is not one-to-one, as different generating units likely set the price in the capacity market (mostly idle units) than in the electricity market (frequently running units) This means that a firm that is dominant in the capacity market is not necessarily dominant in the electricity market.

In the Irish case, ESB indeed has possibilities and incentives to exercise market power in the I-SEM. The dominant strategies for ESB, considering the likely amount of procured capacity, are capacity withholding and bid shading. Ensuring enough new versatile entry with different technologies and cost structures in the capacity auction mitigates ESB's market power efficiently but not exhaustively. There is still room for considerable market power abuse, even if there is much entry.

Market power in these two markets is connected via entry. The competitiveness of the electricity market significantly affects how potential entrants bid in the capacity market and, thus, the possibilities for dominant firms to exercise market power. Still, there are also several other factors that affect market power, and the pure correlation between mark-ups in the electricity market and in the capacity market is quite weak. Regarding total costs, market power in the electricity market is probably more important than market power in the capacity market.

Bid caps may solve the problem if set properly, but that is not a simple task; e.g., the competitive bids of new entrants can be lower than some incumbent units' bids. Having lower bid caps for incumbent units easily results in an auction clearing price that equals the bid cap, which then puts considerable responsibility on regulators and dilutes the initial goal of letting the market determine prices.

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A Implementation details

The model is implemented in Matlab. To keep the computation time feasible, some linear approximations are used so that fast linear optimization algorithms can be utilized. These approximations are described in detail below. I formulate the firm optimization problem in the electricity market as a mixed integer linear programming problem[20] and use the CPLEX library from IBM[21] to solve for the equilibrium. Because the hourly equilibria do not depend on each other, using parallel computation decreases the total computation time considerably. The capacity market is implemented in iteration loops, where the electricity market is nested in the innermost loop.

A.1 Linear approximations

Following Ito and Reguant (2016), linear approximations are used for the hourly residual demand curves faced by strategic firms. First, a supply curve for the competitive fringe, $S^{fringe}(p)$, is formed, aggregating the bids of the firms belonging to the fringe. This is a step function. Then, power functions[22] are fit for the hourly residual demand functions defined in equation (1) so that $D_h(p_h) = D_h^{disp} - S^{fringe}(p_h) = \alpha_h \, p_h^{\beta_h}$, where α_h and β_h are constants that vary over hours. The linear tangent curves of these nonlinear power functions drawn in the point of the observed hourly price are then used to approximate the hourly residual demands. This approximation method is more accurate when the simulated prices are closer to the observed ones.

As the competitive fringe starts to supply only when the price is higher than some positive value, the method described above leaves an inelastic part for the residual demand function when the price is low. Then, the simulated Cournot equilibrium prices can be much higher than the observed prices, and the local linear approximation is no longer valid. Therefore, some elasticity is also assumed in this part, with a linear extension of the demand curve formed at the upper limit of the inelastic part. This can be interpreted as increasing exports in the future Irish market (where the interconnectors probably are more sensitive to the prices than they currently are) when the prices are lower.

[20] I use the Matlab code provided on the Mar Reguant website (`https://sites.google.com/site/marreguant/`) as a starting point for the electricity market model implementation but then modify and extend the code in several ways.

[21] See `http://www-03.ibm.com/software/products/en/ibmilogcpleoptistud/`.

[22] Ito and Reguant (2016) use a quadratic curve. After trying several simple functional forms, it seemed that here, a power function fit the data best. The residual demand function then has a constant elasticity in each hour. This elasticity mostly varies between -0.05 and -0.25.

Furthermore, it is assumed that there is no entry or exit in the competitive fringe. This ensures that the residual demand faced by strategic firms is never a vertical curve. Otherwise, it is not meaningful to assume Cournot competition between strategic firms. This assumption is not too restrictive if the total capacity of the competitive fringe is relatively small.

Finally, to always find a unique solution for the market equilibrium, the marginal cost functions of the firms, which are step functions, are altered a little to make them strictly increasing. For each horizontal part of the step function, a 0.01 EUR increase in price is assumed over the entire horizontal line segment. Correspondingly, for each vertical part of the step function, a 1-MW increase in capacity is assumed over the entire vertical segment.

A.2 Solution algorithm

The algorithm described below is used to calculate the equilibrium for the full model in the simulations. The algorithm is formulated as a descending-clock auction, but it can be interpreted as a first-price sealed-bid auction, as they are strategically equivalent.[23] There are three nested iteration loops for each set of auction parameters.

1. The auction parameters (the procured capacity, the strike price, and the auction price cap) are announced. The number of forward contracts is common knowledge. All incumbent generation units and all potential entrants are assumed to be active in the market.

2. A bid strategy for ESB is selected. A strategy defines how many of ESB's units are bidding in (lower than the clearing price) and how many of its units are bidding out (higher than the clearing price). Note that the strategy defined this way does not depend on the clearing price. Because of the generation unit bid order assumption, ESB has 15 different strategies.

3. It is assumed that the auction clears with the auction price cap.

4. Capacity payments and difference payment commitments for each firm are calculated. Generating units that are owned by competitive firms and that are not closed are assumed to bid lower than the clearing price, while ESB follows its strategy.

[23]This is not exactly true in this application because of the exit order assumption and the interdependency of the winning units, but the differences do not affect the main results.

5. The annual electricity market is simulated. Firms' short-run and long-run profits are calculated. Profits for individual generating units are calculated.
6. The generating unit that makes the highest losses is identified. If it is owned by a competitive firm, it is closed. If it is owned by ESB, it is closed only if it has been bid out (it is not receiving the capacity payment).
7. Steps 4-7 are repeated until all units that are active are profitable or none of the loss-making ESB units can be closed because of the capacity market commitment.
8. If the sum of the (de-rated) capacities of the units that are active in the market and receive the capacity payment, is higher than the targeted amount of procured capacity, the assumed auction clearing price is decreased by one. Steps 4-8 are repeated until the committed (de-rated) capacity in the market reaches the amount of the targeted procured capacity or the auction clearing price reaches zero.
9. ESB's profits, the last assumed auction clearing price and the total generation portfolio (identities of the active units in the market) with this ESB strategy are saved. Another strategy for ESB is selected, and steps 3-9 are repeated until all possible strategies for ESB are tested.
10. The strategy that results in the highest profits for ESB is selected.

B Tables

firm	peat	coal	gas	oil	dist.	hydro	pump	DR	other	sum
ESB	228	855	2625	53		221	292	18		4292
SSE			464	588	208					1260
AES		476	510		258					1244
Viridian			764					6		770
NIE PP			595						18	613
Bord Gais			445							445
Tynagh Energy			404							404
rest (8 firms)	118		12	169	188			206	17	710
sum	346	1331	5819	810	654	221	292	230	35	9738

Table 1: Registered capacities (MW) of the largest electricity production firms by fuel type in the SEM in 2015 (wind excluded). Source: ‘Registered Capacity Report July 2015’ and ‘List of Registered Units’ by the SEMO.

firm	peat	coal	gas	oil	dist.	hydro	pump	DR	other	sum
ESB	2	3	11	1		19	4	1		41
SSE			1	4	4					9
AES		2	3		6					11
Viridian			2					1		3
NIE PP			3						1	4
Bord Gais			1							1
Tynagh Energy			1							1
rest (8 firms)	1		1	3	3			8	1	17
sum	3	5	23	8	13	19	4	10	2	87

Table 2: Number of generating units of the largest electricity production firms by fuel type in the SEM in 2015 (wind excluded). Source: ‘Registered Capacity Report July 2015’ and ‘List of Registered Units’ by the SEMO.

id	unit name	firm	fuel	MW
C1A	AES Kilroot - K1	AES	Coal	238
C2A	AES Kilroot - K2	AES	Coal	238
C3E	Moneypoint 2	ESB	Coal	285
C4E	Moneypoint 1	ESB	Coal	285
C5E	Moneypoint 3	ESB	Coal	285
G1E	Dublin Bay	ESB	Gas	415
G2E	Coolkeeragh CCGT	ESB	Gas	425
G3S	Great Island CCGT	SSE	Gas	464
G4B	ROI - Whitegate	Bord Gais	Gas	445
G5E	Aghada 2	ESB	Gas	432
G6N	Ballylumford	NIE PP	Gas	247
G7N	Ballylumford	NIE PP	Gas	247
G8T	Tynagh	Tynagh	Gas	404
G9V	VPL	Viridian	Gas	412
G10V	HPC1	Viridian	Gas	352
G11N	Ballylumford	NIE PP	Gas	101
G12E	Poolbeg 4	ESB	Gas	463
G13A	Ballylumford 5	AES	Gas	170
G14A	Ballylumford 4	AES	Gas	170
G15A	Ballylumford B6	AES	Gas	170
G16E	AGHADA CT11	ESB	Gas	90
G17E	AGHADA CT14	ESB	Gas	90
G18E	Aghada	ESB	Gas	258
G19E	Marina	ESB	Gas	95
G20E	North Wall5	ESB	Gas	104
G21E	AGHADA CT12	ESB	Gas	90
O1S	Tarbert 3	SSE	Oil	240
O2S	Tarbert 4	SSE	Oil	240
O3E	Coolkeeragh GT8	ESB	Oil	53
O4S	Tarbert 1	SSE	Oil	54
O5S	Tarbert 2	SSE	Oil	54
D1A	Kilroot GT3	AES	Distillate	42
D2A	Kilroot GT4	AES	Distillate	42
D3A	Ballylumford GT1	AES	Distillate	58
D4A	Ballylumford GT2	AES	Distillate	58
D5A	Kilroot GT1	AES	Distillate	29
D6A	Kilroot GT2	AES	Distillate	29
D7S	Rhode Peaking 1	SSE	Distillate	52
D8S	Rhode Peaking 2	SSE	Distillate	52
D9S	Tawnaghmore Peaking 1	SSE	Distillate	52
D10S	Tawnaghmore Peaking 3	SSE	Distillate	52

Table 3: List of 41 generating units used in the simulations.

Forward contracts	0 %	20 %	40 %	60 %	80 %	100 %
Lerner index*)	0.74	0.70	0.64	0.54	0.34	0.0
Price mark-up**) (%)	292.1	235.8	178.0	118.0	52.5	0.0
Total expenditure (mEUR)	2675.8	2403.8	2098.0	1751.6	1406.5	1079.4
Total generation (TWh)	19.1	19.6	20.1	20.7	21.3	21.8
Total variable costs (mEUR)	572.4	587.4	602.3	616.1	623.4	629.0
Total fixed costs (mEUR)	257.5	257.5	257.5	257.5	248.2	224.2
Weighted average price (EUR/MWh)	139.9	122.5	104.1	84.6	66.1	45.8
Maximum price (EUR/MWh)	1410.6	1379.6	1379.6	1379.6	1632.9	1868.4
Total firm profits (mEUR)	1882.8	1595.8	1275.1	914.9	571.7	263.0
Total nominal capacity (MW)	4158	4158	4158	4158	3988	3830
Number of generating units	13	13	13	13	12	11
Full capacity hours	4	11	19	25	59	131
Hours when price $>$ 500 EUR/MWh	57	39	23	15	21	31

Table 4: Energy-only market simulation results with different shares of forward contracts. *) calculated over hours as in Borenstein et al. (2002), equation (7), **) calculated as Lerner index but with the competitive price in the denominator.

Forward contracts	0 %	20 %	40 %	60 %	80 %	100 %
Price mark-up	-5.8	-2.4	-0.7	-0.1	0.0	0.0
Total expenditure (%)	-1.5	-1.2	-1.0	-1.0	-1.7	-3.1
Total generation (%)	0.032	0.013	0.0038	0.00060	0.0	0.0
Weighted average price (%)	-0.92	-0.50	-0.22	-0.054	0.0	0.0
Total firm profits (%)	-2.1	-1.8	-1.6	-1.9	-4.3	-12.9
Total nominal capacity	0	0	0	0	0	0
Full capacity hours	+10	+4	+1	0	0	0
Hours when price $>$ 500 EUR/MWh	-44	-26	-10	-2	0	0

Table 5: Relative changes w.r.t table (4) when a difference payment with a 500 EUR strike price is introduced.

Forward contracts	0 %	60 %	80 %	100 %
no entry	39.0	38.5	38.5	45.7
1082 MW entry	31.9	32.2	34.8	27.9
2164 MW entry	14.4	20.6	21.6	18.3
3246 MW entry	8.1	15.5	22.4	18.6

Table 6: Average (over procured capacity) price mark-up (%) in the capacity market with different amounts of entry and forward contract shares.

Forward contracts	0 %	60 %	80 %	100 %
no entry	65.7	50.3	39.4	23.1
1082 MW entry	63.2	48.6	36.6	13.2
2164 MW entry	60.9	44.8	32.5	7.6
3246 MW entry	60.4	43.5	32.7	8.4

Table 7: Average (over procured capacity) total price mark-up (%) in the electricity market and capacity market together with different amounts of entry and forward contract shares.

C Figures

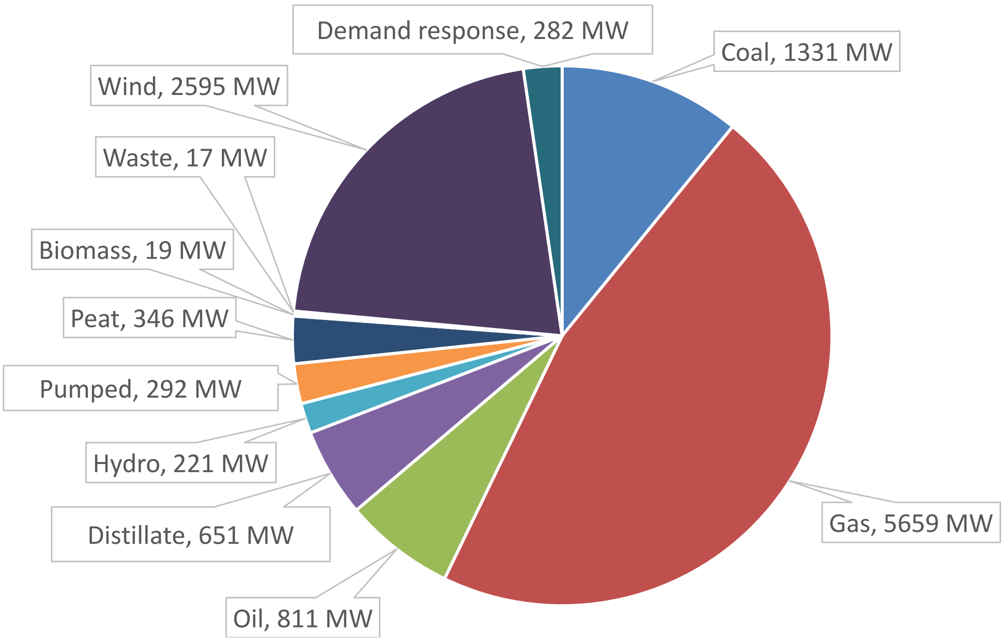

Figure 2: Registered generation capacity by fuel type in the SEM in 2015. The total capacity is 12225 MW. Source: 'Registered Capacity Report July 2015' by the SEMO.

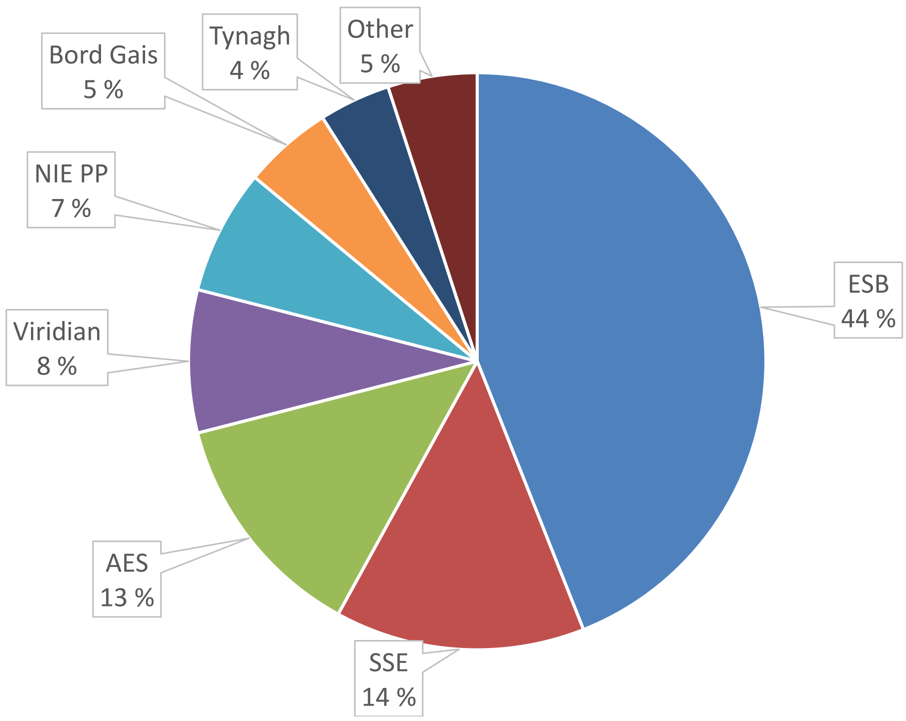

Figure 3: Registered generation capacity (excluding wind and demand response) by firm in the SEM in 2015. Source: 'List of Registered Units' by the SEMO.

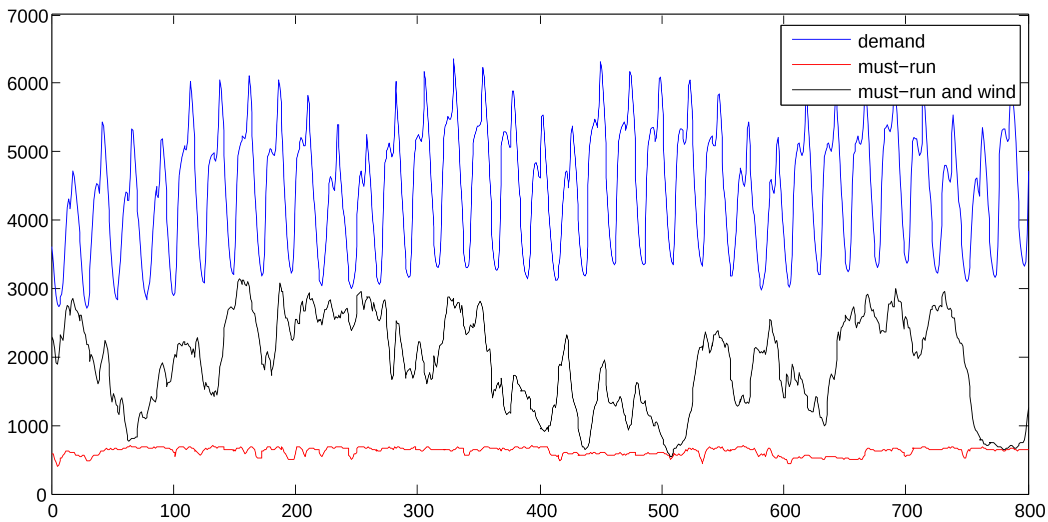

Figure 4: Hourly total demand and supply by must-run generators and wind farms in January 2015 (hours 1-744).

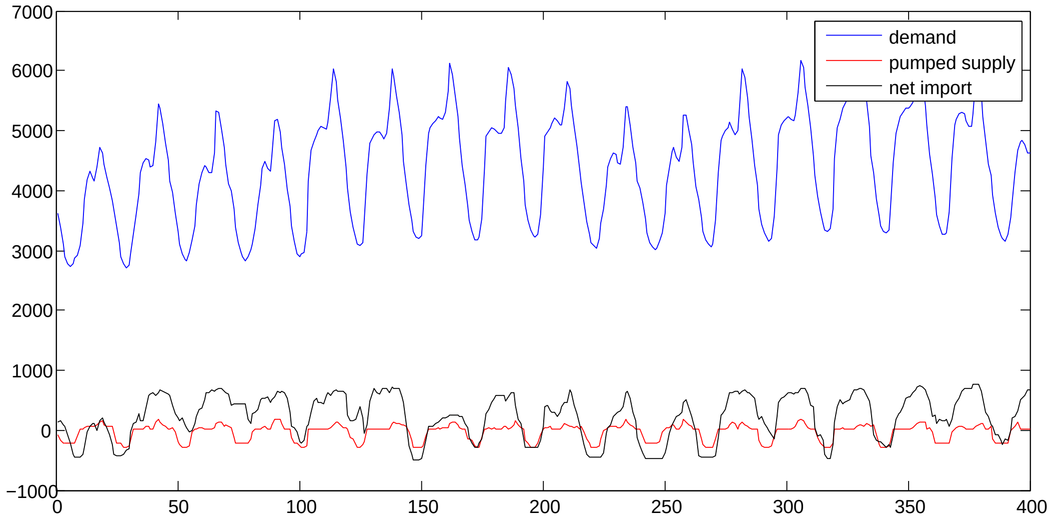

Figure 5: Hourly total demand and supply by pumped hydro storages and interconnectors in the first two weeks of January (hours 1-336) in 2015.

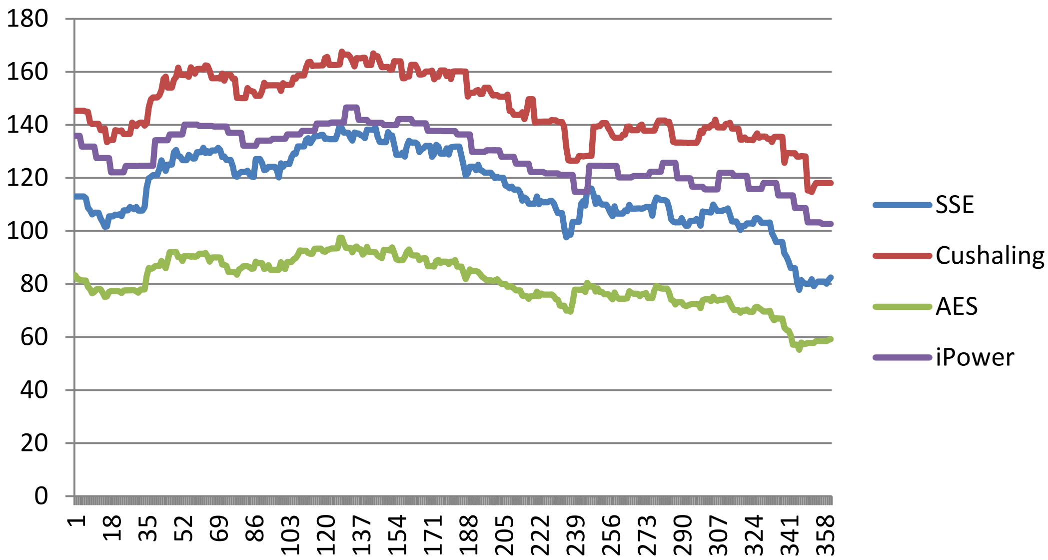

Figure 6: Daily price bids (EUR/MWh) for four firms using distillate as a fuel in 2015. SSE uses same prices for 4 units (52 MW each), Cushaling for 2 units (58 MW each), AES for 2 units (42 MW each), and iPower for one 72 MW unit.

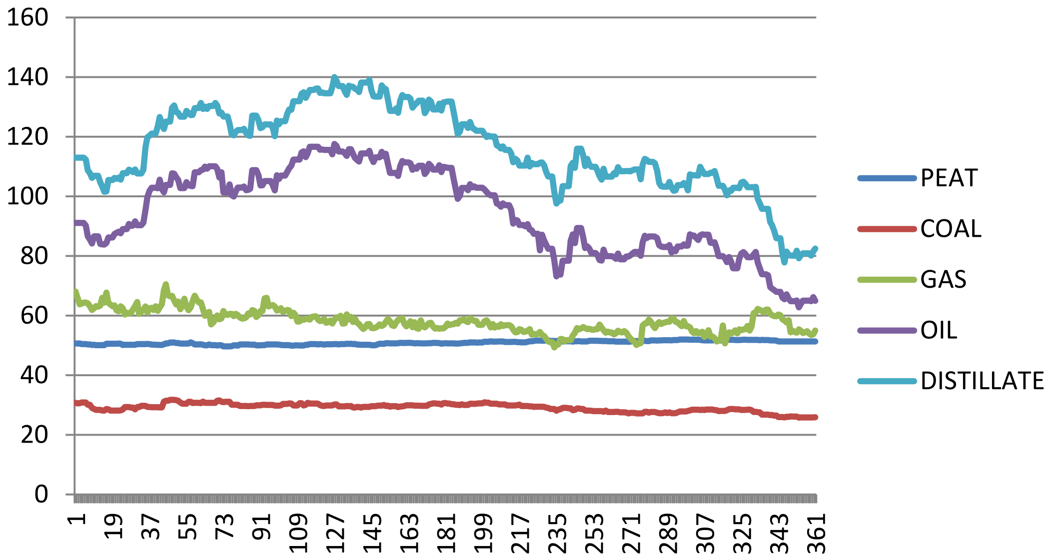

Figure 7: Daily first price bid levels (EUR/MWh) for units using different fuels in 2015.

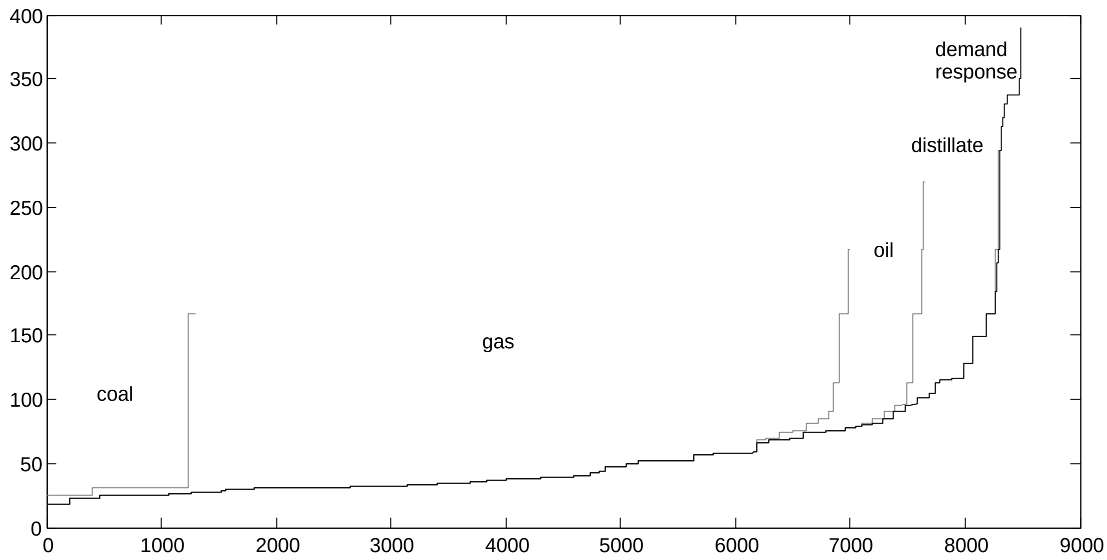

Figure 8: Aggregated representative bid curves by fuel in the SEM in 2015.

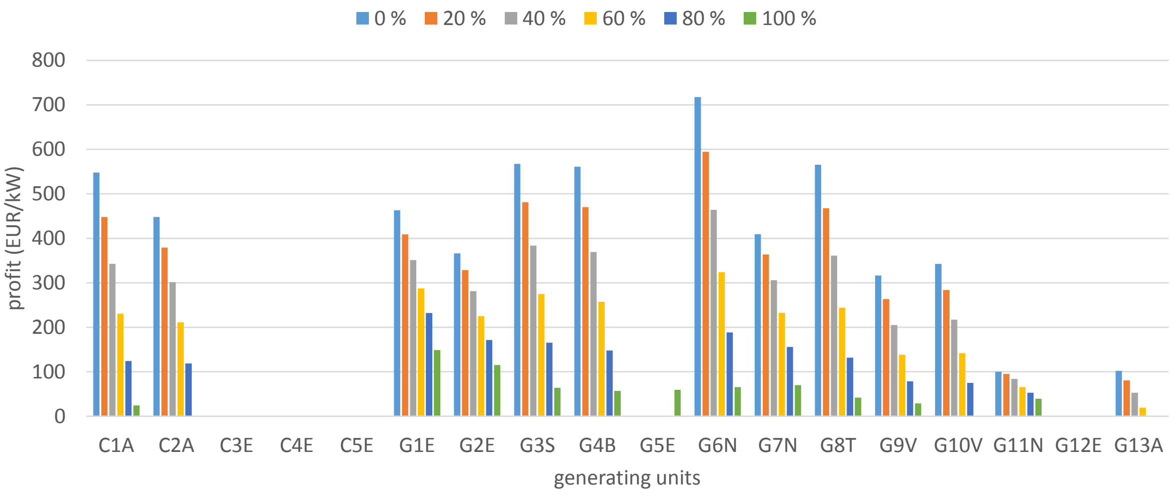

Figure 9: Unit-specific profits with different shares of forward contracts in the energy-only market.

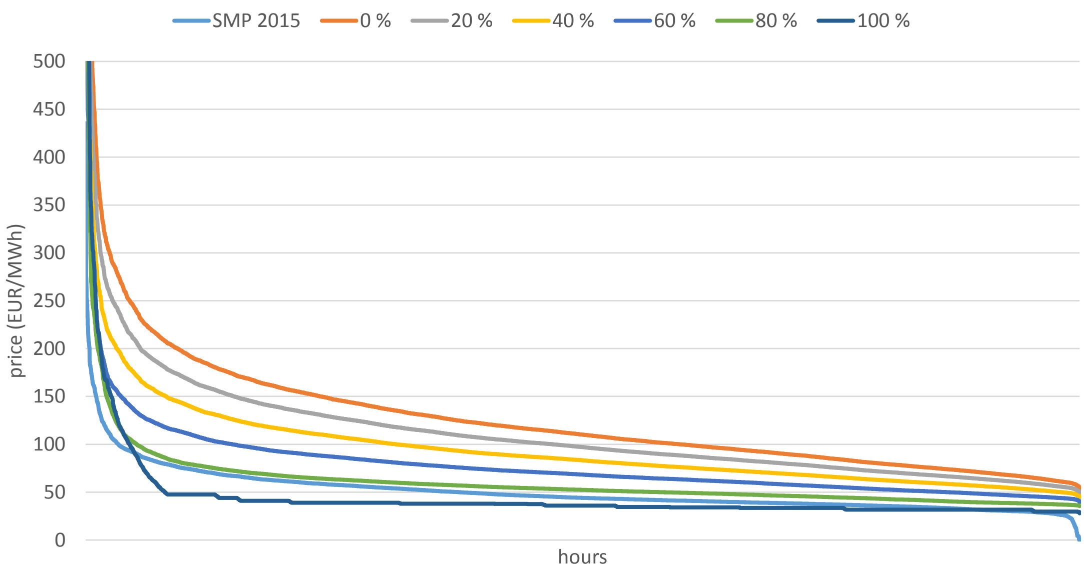

Figure 10: Price duration curves with different shares of forward contracts in the energy-only market.

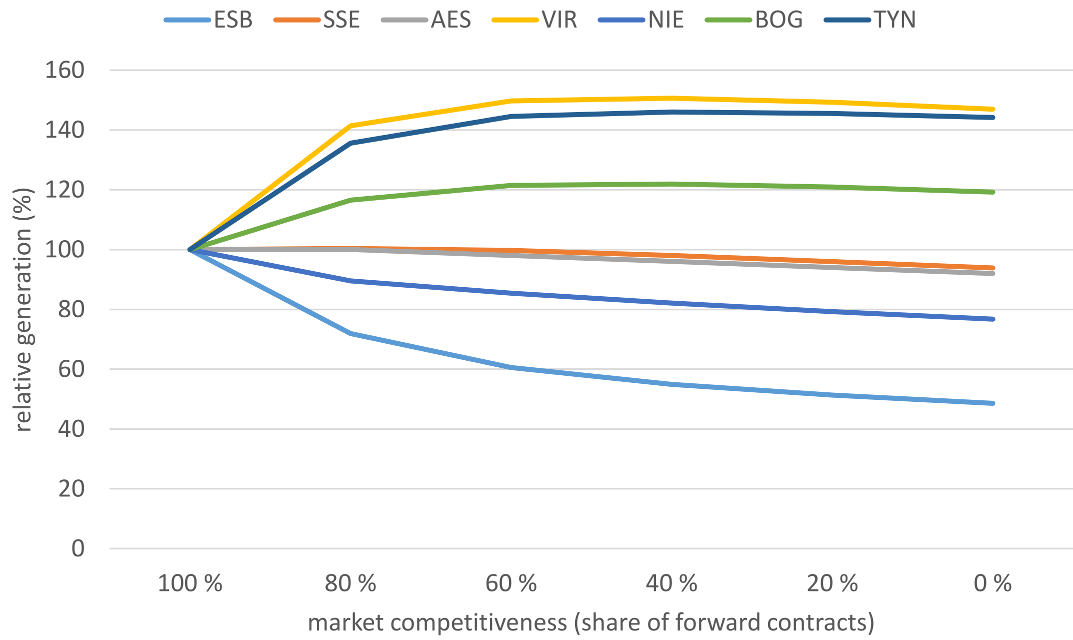

Figure 11: Firm specific total generation with different shares of forward contracts in the energy-only market.

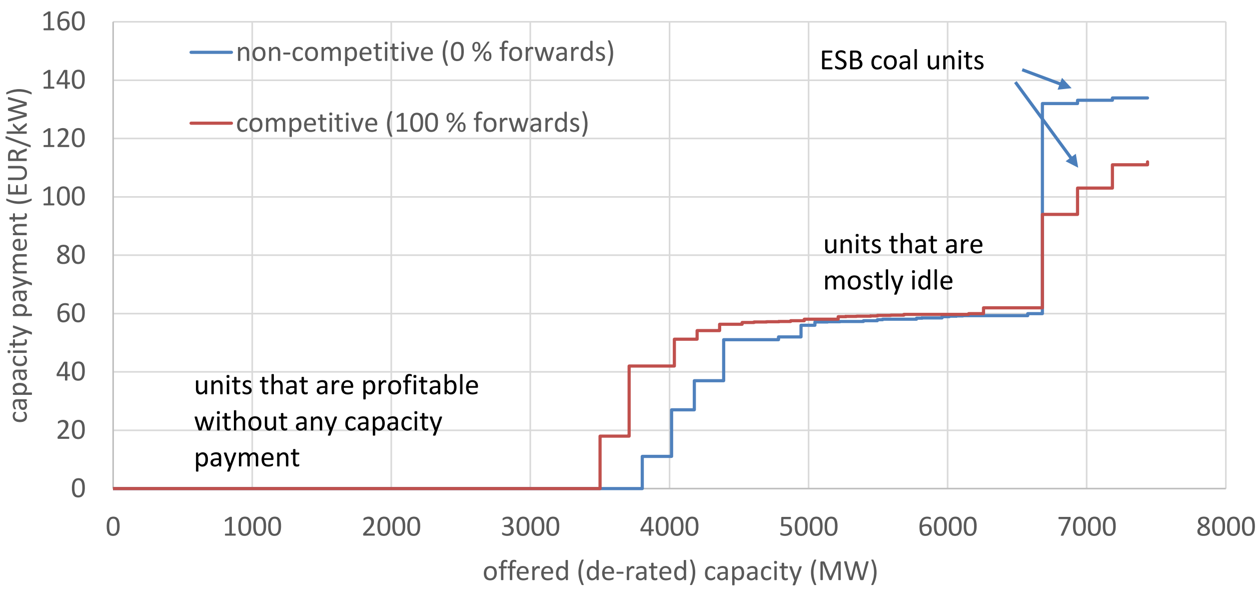

Figure 12: Two competitive benchmarks in the capacity market. No entry assumed.

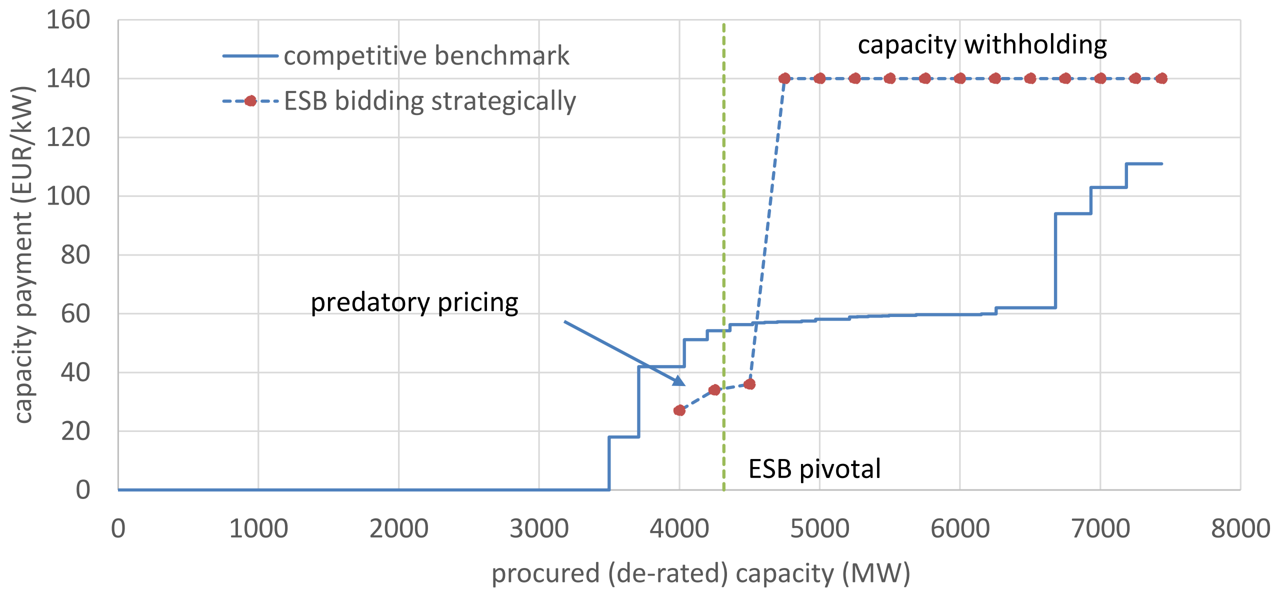

Figure 13: Capacity market clearing price without any entry with different amounts of procured capacity. 100 % forward contract share.

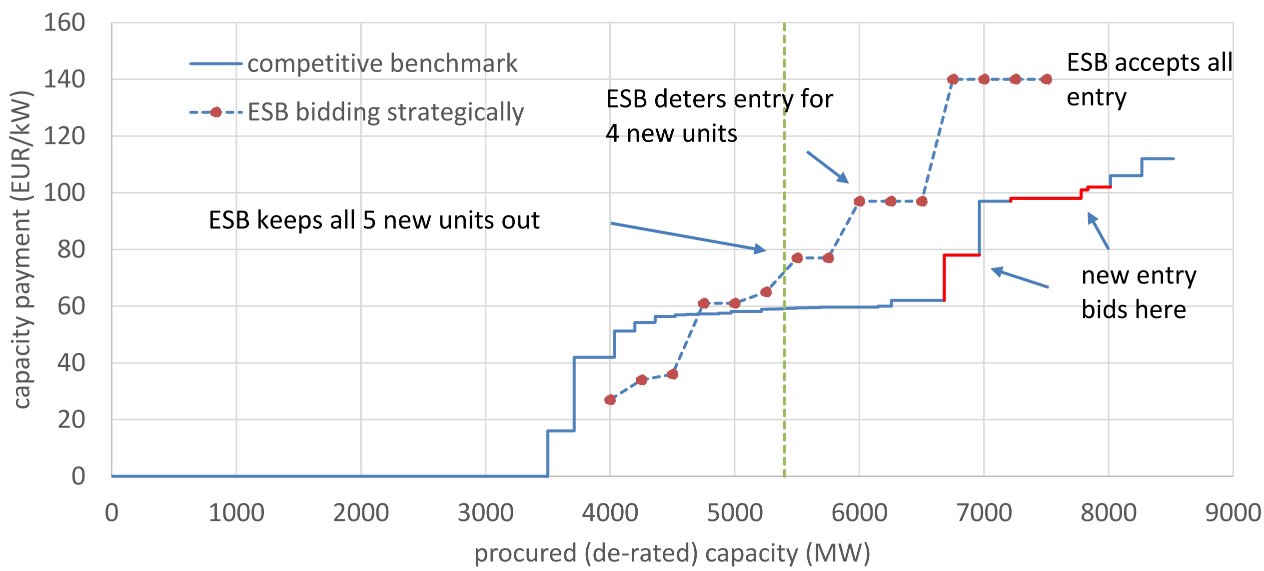

Figure 14: Capacity market clearing price with 1082 MW of new entry with different amounts of procured capacity. Competitive electricity market (100 % forward contracts).

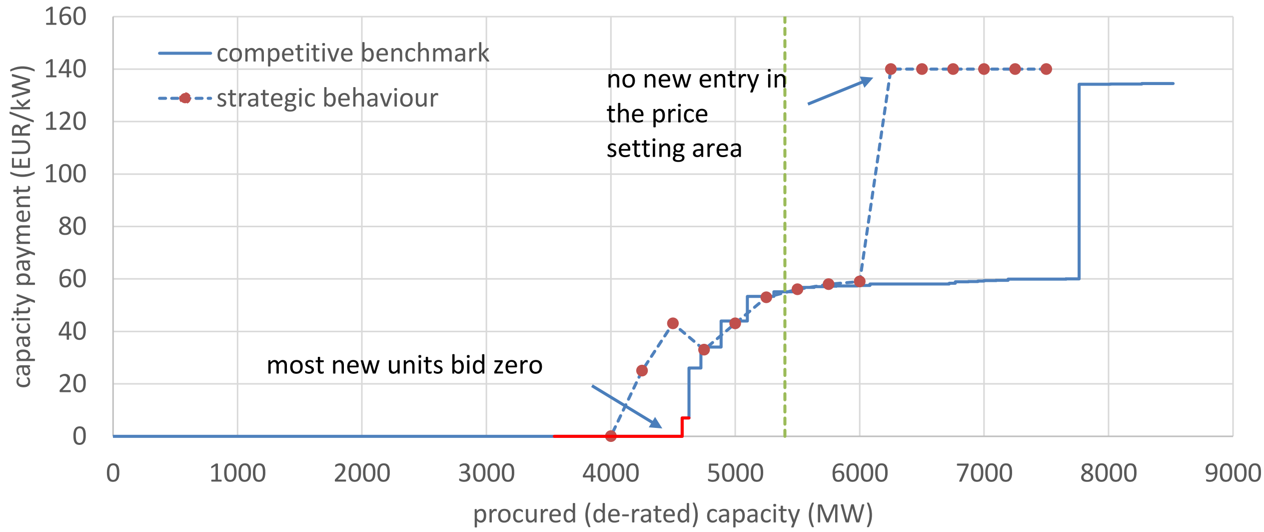

Figure 15: Capacity market clearing price with 1082 MW of new entry with different amounts of procured capacity. Non-competitive electricity market (0 % forward contracts).

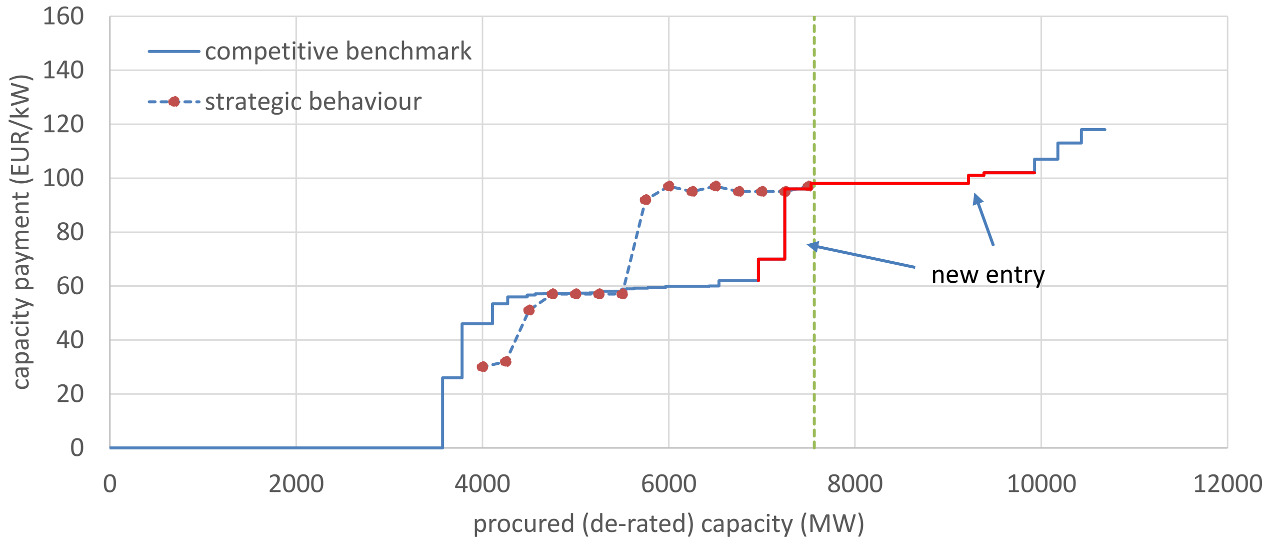

Figure 16: Capacity market clearing price with 3246 MW of new entry with different amounts of procured capacity. Competitive electricity market (100 % forward contracts).

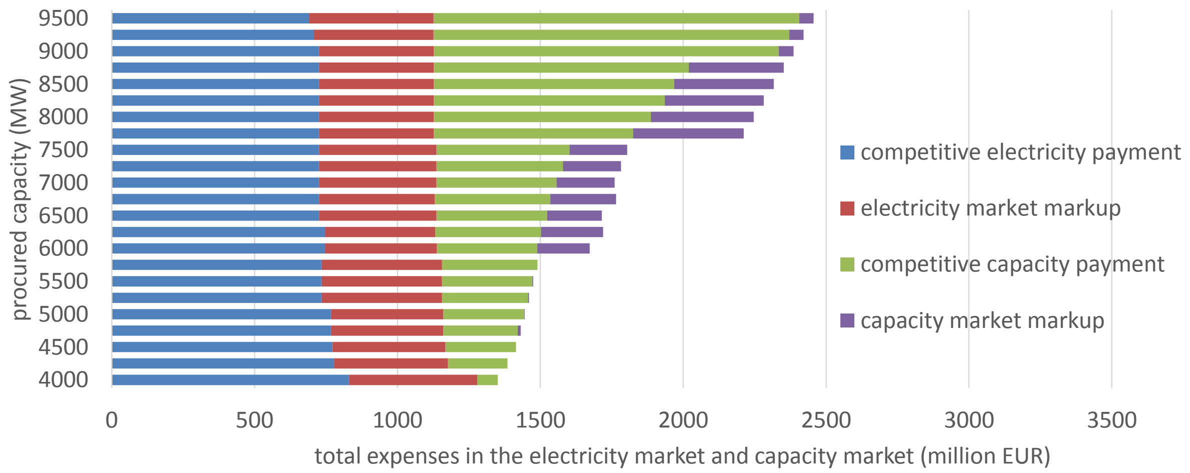

Figure 17: Total cost structures for end users with 2164 MW of new entry and 80 % forward contracts for different amounts of procured capacity.

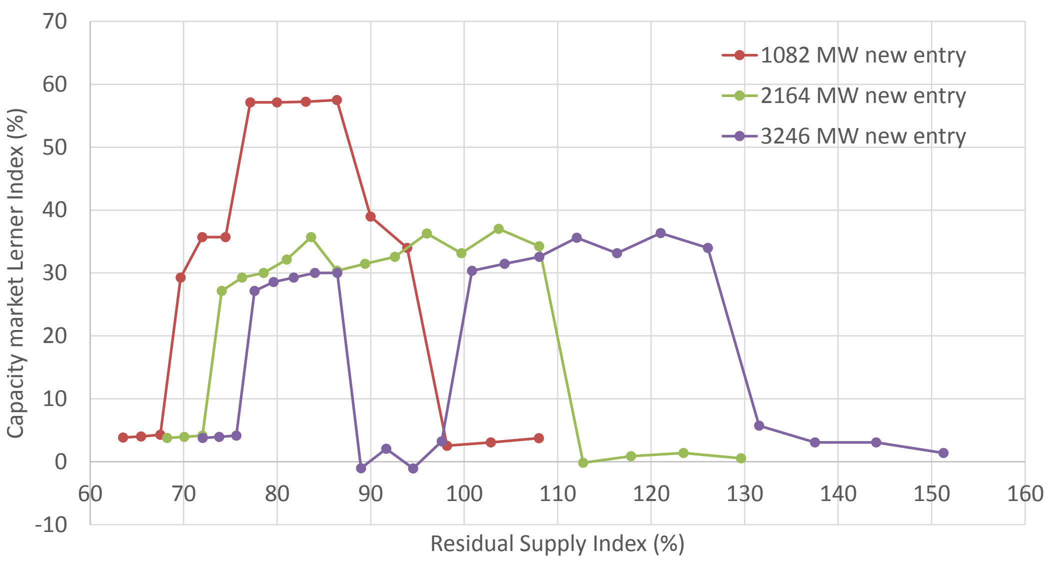

Figure 18: Lerner index in the capacity market vs. Residual Supply Index (RSI) with different amounts of procured capacity. 80 % forward contract share is assumed.

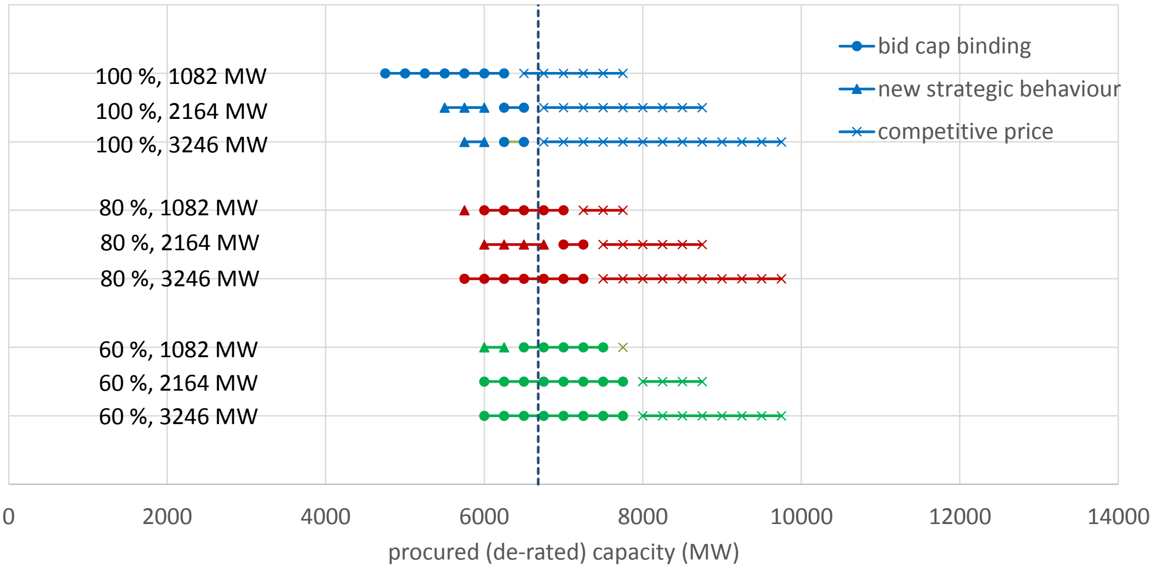

Figure 19: Binding and competitive market results when 60 EUR bid cap is set for incumbent units (except for ESB's coal units). Total capacity restricted by the lower bid cap is 6681 MW.