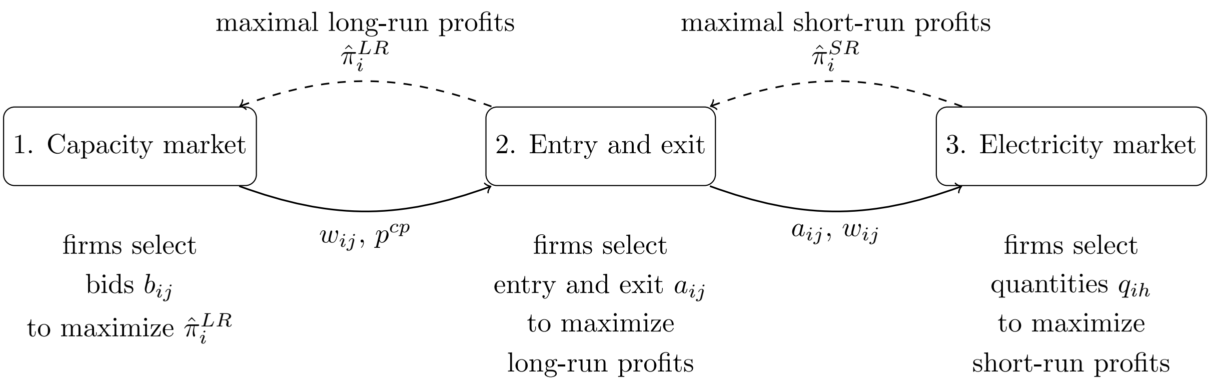
Appendix A: Further details on model implementation

1 Firms' decision flow and equilibrium

Figure A.1 summarizes the maximization problems of the strategic firms. The three stages are nested: the objective function in each stage contains the solution of the maximization problem in the following stage. In the electricity market (3rd stage), given the units active in the market and their capacity-market commitments, firms' short-run profits are determined based on a Cournot game augmented with forward contracting. In the entry and entry phase (2nd stage), firms decide which new units enter and which existing units exit; these decisions are made based on a unit's long-run profits—which include its short-run profits. In the capacity market (1st stage), firms maximize long-run profits which reflect the outcome of the subsequent industry entry and exit process; they choose bids for their generating units—and the capacity auction determines the winning units and their capacity payments. The overall equilibrium occurs where none of the strategic firms wishes to unilaterally change its behaviour in any stage.

Figure A.1: Decision flow and the three stages in the model.



2 Computational implementation

The model is implemented in Matlab. To keep the computation time feasible, some linear approximations are made—so that fast linear optimization algorithms can be used. We formulate the firm-optimization problem in the electricity market as a mixed integer linear programming problem[1] and use the CPLEX library from IBM[2] to solve for the

[1] We use the Matlab code provided on Mar Reguant's 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.

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

equilibrium.[3] The capacity market is implemented in iteration loops, where the electricity market is nested in the innermost loop.

2.1 Linear approximation of residual demand curves

We construct the hourly residual demand curves $D_h(p_h) = D_h^{\text{total}} - S_h^{\text{exog}} - S^{\text{fringe}}(p_h)$ faced by strategic firms as follows. First, we calculate the exogenous supply S_h^{exog} and form the supply curve of the competitive fringe $S^{\text{fringe}}(p_h)$ by aggregating their bids; note that the latter is a step function. Second, we fit power functions[4] for hourly residual demands functions such that $D_h(p_h) = \alpha_h\, p_h^{\beta_h}$, where α_h and β_h are constants that vary over hours. Following Ito and Reguant (2016), we then use the linear tangent curves of these non-linear power functions drawn in the point of the observed hourly price (SMP) to approximate hourly residual demands. Figure A.2 illustrates these curves for one specific hour.

If the competitive fringe starts to supply only at a sufficiently high price, this method means that the residual demand function remains inelastic at a "low" price. In such cases, the power function approximation is no longer valid, and the Cournot equilibrium requires elastic residual demand. To generate some price-responsiveness, we take a linear extension of the demand curve formed at the upper limit of the inelastic part. For the I-SEM, this can be interpreted as increasing exports when the price is lower (as interconnectors probably will be more price-sensitive than in the SEM). Furthermore, we assume no entry or exit within the competitive fringe.

Finally, to guarantee a unique solution, we slightly adjust firms' marginal cost step functions to make them strictly increasing. Specifically, for each horizontal part, a 0.01 EUR increase in price is assumed and, for each vertical part, a 1 MW increase in capacity is assumed.

2.2 Solution algorithm for overall equilibrium

We use an algorithm formulated as a descending-clock auction to calculate the overall equilibrium of the model.[5] There are three nested iteration loops for each set of auction parameters. The steps are as follows:

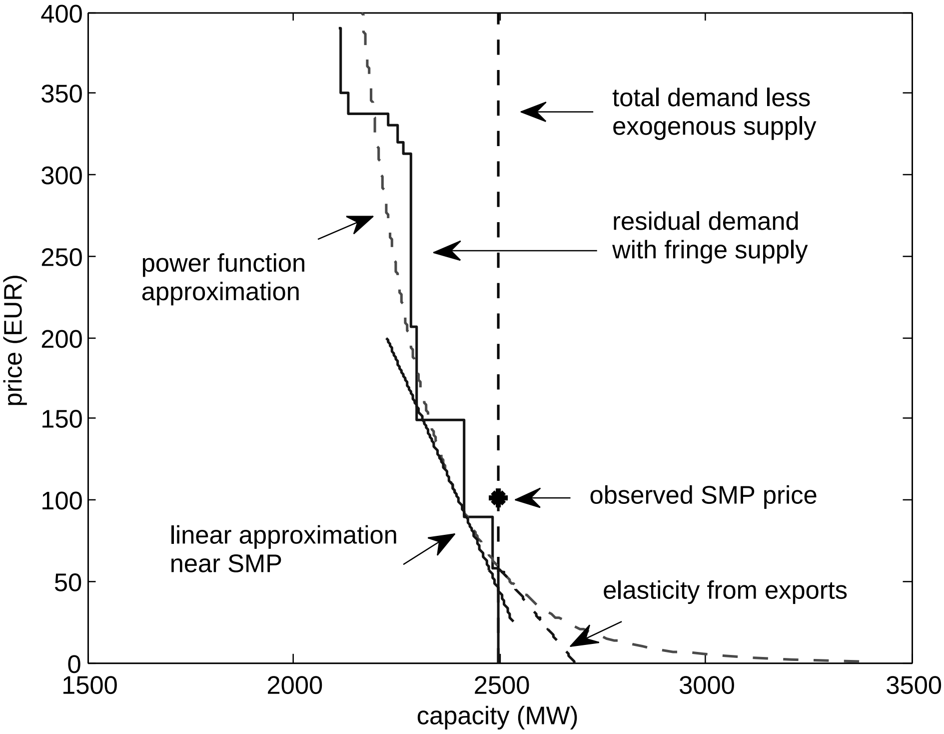
1. The auction parameters are announced: to-be-procured capacity $\overline{K}$, RO strike price p^{strike}, initial bid cap p_1^{cp}. Firms' forward-contract commitments are common knowledge.

[3] Because the hourly equilibria do not depend on each other, using parallel computation decreases the total computation time considerably.

[4] After trying several functional forms, we found that a power function fit the data best. The residual demand function thus has a constant elasticity in each hour, which mostly lies between –0.05 and –0.25. Ito and Reguant (2016) use a quadratic curve.

[5] Given that they are strategically equivalent, this can also be interpreted as a first-price sealed-bid auction; however, this equivalence is not exact in our setting because of the exit-order assumption and the interdependency of the winning units—but these differences do not affect the main results.

Figure A.2: Linear residual demand approximation for one hour.



2. A bid strategy for ESB for any given auction price p_r^{cp} is selected. This defines how many of ESB's units are "bidding in" ($b_{ij} \leq p_r^{cp}$) and how many are "bidding out" ($b_{ij} > p_r^{cp}$). Because of the generation unit bid order assumption, the number of units bidding in (or out) identifies those units, and thus ESB has 15 different strategies in this phase.[6]

3. All incumbent generation units and all potential entrants are assumed to be active in the market ($a_{ij} = 1 \, \forall \, i, j$). It is first assumed that the auction clears at the auction bid cap p_1^{cp}.

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 ($a_{ij} = 1$) are assumed to bid lower than the clearing price.

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 full strategy space for ESB consists of a two-dimensional grid which defines how many units bid in at each auction price (e.g. at 80 EUR ESB bids 0,...,14 units in, at 79 EUR ESB bids 0,...,14 units in, etc.). However, many of these combinations result in too little or too much capacity. In this algorithm, this grid is traversed in an order where the number of units bidding in is first fixed, and the price level is then adjusted from the auction bid cap p_1^{cp} to zero (e.g. ESB bids 3 units in at price 140,...,0 EUR). Such price is found when the required capacity is just reached.

6. The generating unit that makes the highest losses is identified. If it is owned by a competitive firm, it is closed ($a_{ij} = 0$). If it is owned by a strategic firm (only ESB in our unilateral case), it is closed only if it has been bid out ($a_{ij} = 0 \quad \text{if} \quad b_{ij} > p_r^{cp}$, i.e., is not receiving the capacity payment).

7. Steps 4-7 are repeated until all units that are active are also profitable or none of ESB's loss-making units can be closed because of their capacity-market commitment (*Loop 1*).[7]

8. If the aggregate (de-rated) capacities of active units that receive the capacity payment is higher than $\overline{K}$, then the auction clearing price is decreased by one unit ($p_{r+1}^{cp} = p_r^{cp} - \Delta p^{cp}$). 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 (*Loop 2*).[8]

9. The final auction clearing price $p_{\hat{r}}^{cp}$, the total generation portfolio (identities of the active units in the market) and ESB's profits under this strategy are saved. Another strategy for ESB is selected, and Steps 3-9 are repeated until all possible strategies for ESB are tested (*Loop 3*).

10. The strategy that results in the highest profits for ESB is chosen. This also determines the final generator portfolio.

Appendix B: Varying the strike price of reliability options

Our main analysis in Sections 5 and 6 uses a 500 EUR/MWh strike price for the reliability options (ROs), based on the I-SEM consultation documents.[9] The precise strike price in the Irish market varies monthly according to a formula that accounts, e.g., for variations in fuel prices as well as in the EU ETS carbon price; for the I-SEM's first delivery period, it is always at least 500 EUR/MWh. The underlying idea is that the strike price is chosen approximately at the highest marginal cost across generators; in this case, it is based on the marginal costs of the demand response units. Table 2 already shows that this 500 EUR/MWh strike price never actually binds, neither in the competitive capacity market benchmark (CM) nor in the strategic capacity market scenarios (CM0–CM2).

[7] This loop results in a generator portfolio for which the assumed clearing price p_r^{cp} is enough to keep each unit active but in most cases the auction price is so high that there is more capacity than needed.

[8] This loop results in a generator portfolio for which the assumed clearing price is enough to keep each unit active *and* such price level $p_{\hat{r}}^{cp}$ that the target capacity $\overline{K}$ is just reached.

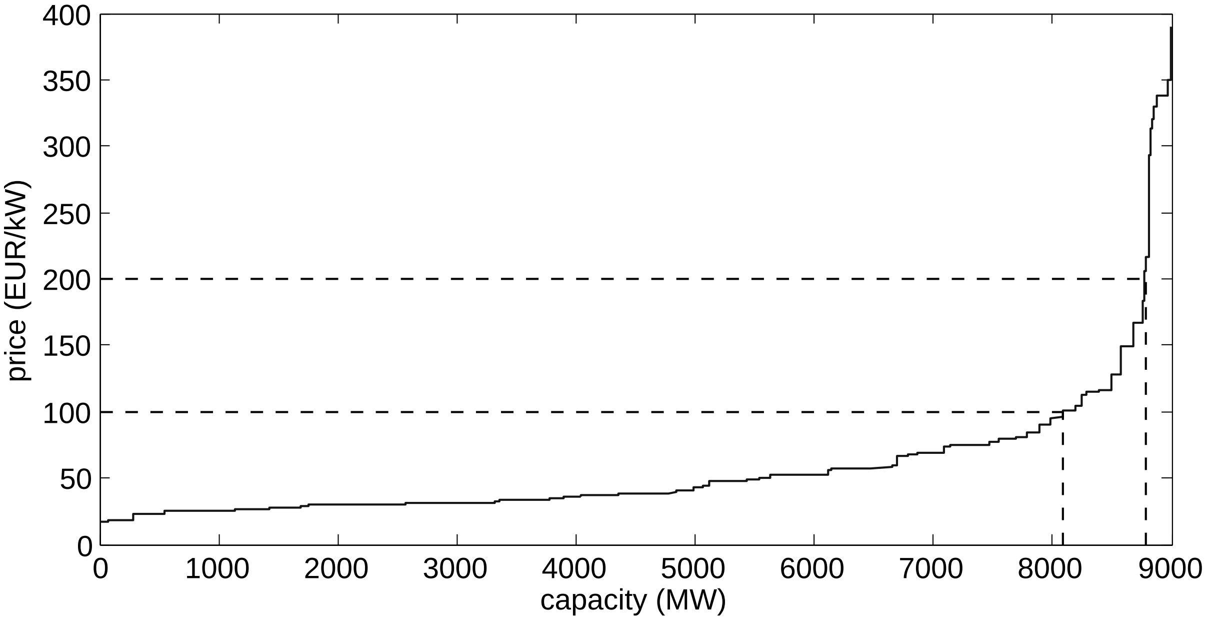
[9] For comparison, the actual market price in the SEM exceeded 500 EUR/MWh only in 4.5 hours during the 2015 year.

This means that the RO design in these cases has no impact on the equilibrium in the electricity market.[10]

We here present further sensitivity analysis by varying the value of the RO strike price. Setting a higher strike price leads to identical results as reported in Table 2 so we here focus on the impact of a lower strike price. Observe that, since the strike price effectively acts as a price cap in the electricity market, a generating unit with marginal cost higher than the prevailing strike price cannot make any money in the electricity market—and is therefore reliant on a capacity payment to be able to stay active. In general, the impact of a tighter price cap in the electricity market is that generating units, as "compensation" tend to require a higher capacity payment.

Figure B.1 shows the aggregate bid curve for 2015 of the price-making units under the old SEM market design; as discussed in Section 2, these bids reflected generators' true marginal costs.[11] The highest bids were indeed submitted by demand response units (200–400 EUR/MWh) followed by distillate units (80–150 EUR/MWh). Hence, 2.4% of total capacity cannot make any money at a strike price of 200 EUR/MWh; this becomes 10% of total capacity at a 100 EUR/MWh strike price.

Figure B.1: Aggrerate supply curve in the 2015 SEM (true marginal costs of all generation units).



We begin by examining how a lower strike price affects the benchmark with a competitive capacity auction (similar to Section 5.2, specifically Figure 3). Specifically, we

[10]In general, an RO design with an arbitrarily high strike price is isomorphic to a capacity mechanism without reliability options.

[11]As explained in Section 4.1, the capacity values in this SEM figure correspond to those of Table 1 (rather than to those of our capacity-auction analysis in Sections 5 and 6).

consider scenarios with 6000 MW procured capacity, 80% forward contracting in the electricity market, and 1 GW entry. Table B.1 shows how a lower strike price reduces the average market price and total buyer costs in the electricity market—but only at a relatively modest rate.[12] Roughly put, the impacts of a "tighter" RO design are qualitatively similar to greater forward contracting in the electricity market but appear to be quantitatively much weaker. The reason is that most units either always (i) bid zero or (ii) bid their losses (i.e., fixed costs) in the capacity auction—and varying the strike price makes little difference to this. The strike price does, however, put an increasingly tight cap on the market price; for example, the 60 EUR/MWh strike price binds in 22% of total hours. Such low RO strike prices currently seem unlikely to be employed in the I-SEM; they again correspond to a situation in which the capacity-market design is, in effect, directly choosing an equilibrium price.

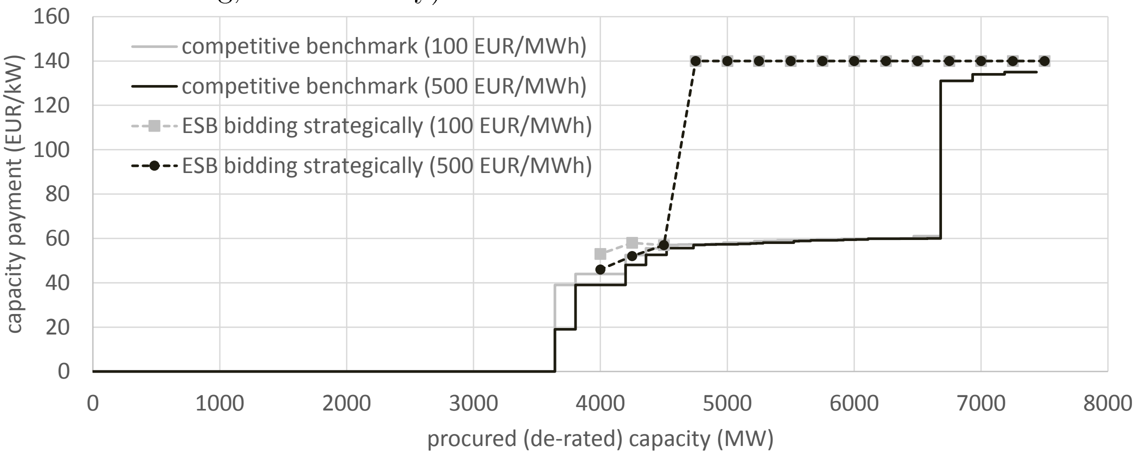
Table B.1: Capacity market with competitive bidding for different RO strike prices (electricity market with 80% forward contracting, capacity market with 6000 MW procured capacity, 1 GW entry).

Strike price (EUR/MWh)	**500**	**200**	**100**	**75**	**60**
Total buyer costs, electricity market (mEUR)	1168.9	1167.4	1150.2	1134.0	1106.3
Total buyer costs, capacity market (mEUR)	351.6	351.6	351.6	351.6	347.5
Weighted average electricity price (EUR/MWh)	54.4	54.3	53.6	52.7	51.4
Maximum electricity price (EUR/MWh)	332.7	200	100	75	60
Hours (of 8760) when the strike price is binding	0	8	119	401	1892
Total variable costs (mEUR)	636.9	636.9	637.0	637.3	630.6
Total fixed costs (mEUR)	405.2	405.2	405.2	405.2	390.8
Capacity auction clearing price	59	59	59	59	59
Number of active generating units	29	29	29	29	29
Active nominal capacity (MW)	5959	5959	5959	5959	5889

Figure B.2 illustrates how a 100 EUR/MWh strike price affects the capacity auction under (1) the competitive benchmark and (2) strategic bidding by ESB. First, as suggested by the previous discussion, with competitive bidding, the impact turns out to be small. The reason is that, if 5000 MW or more capacity is procured, then the clearing price in the capacity auction is set by a unit that is mostly idle in the electricity market. Such a unit does not make significant revenue from the electricity market in any case, and thus needs the capacity market to cover its fixed costs. The clearing price rises appreciably only in cases where 3500–4500 MW capacity is procured. Second, ESB's strategic bidding also remains very similar to that under the 500 EUR/MWh strike price, notably in our baseline scenario where 6000 MW capacity is procured. ESB only bids higher in cases with 4000–4250 MW procurement—for which the underlying competitive clearing price is itself also higher. In any case, these low volumes of procured capacity are unlikely to be empirically relevant for the I-SEM.

[12] The scenario with a 500 EUR/MWh strike price is very similar to the competitive scenario CM reported in Table 2; the only difference is that the former includes 1 GW of entry while the latter has no entry.

Figure B.2: Capacity market with strategic behaviour (electricity market with 80% forward contracting, no new entry).



In sum, our simulations suggest that even substantially lower RO strike prices than the 500 EUR/MWh baseline have only modest impacts on the electricity market as well as total buyer costs. In this sense, the RO design seems quite robust to the choice of strike price but also yields perhaps surprisingly small consumer benefits (relative to a capacity auction without reliability options).

Appendix C: Mitigation: Downward-sloping demand for capacity

Another policy design is for the regulator to instead use a downward-sloping demand curve such that the volume of procured capacity adjusts downwards as the auction price rises. This tends to push down the clearing price, and can thus mitigate the exercise of market power in the capacity auction. However, it also means that the regulator can no longer be certain about the amount of capacity that will be procured.

We explore this by comparing a vertical capacity demand for 6000 MW to a linear capacity demand curve with a slope of —30 MW/EUR, for which we assume that 6000 MW is procured at a clearing price of 70 EUR (which lies halfway between zero and the original bid cap of 140 EUR).[13] Hence, at a 100 EUR clearing price, only 5100 MW is procured, while capacity demand is 6900 MW at a clearing price of 40 EUR.

Again assuming 80% forward contracts, we find that the clearing price falls from the original 97 EUR with vertical demand down to 81 EUR for the –30 MW/EUR slope.

[13]In the first capacity auction in the I-SEM, if the clearing price is zero, 7774 MW is procured. For each one EUR increment in price, approximately 13 MW less capacity is procured. If the clearing price exceeds 82 EUR the procured capacity is constant (6720 MW). (See details in 'Final Auction Information Pack v1.0.pdf' available in `www.sem-o.com` → I-SEM → Publications.) In the British capacity auction similar kinked demand curve is used.

Two other considerations now arise: (i) the auction procures less than the initial 6000 MW—so the outcome is not directly comparable to the case with vertical demand, and (ii) we find that the lower clearing price can deter potential new entrants from actually entering the market.

We can also explore the price implications of using *both* a downward-sloping demand curve and a lower bid cap for incumbents (again using our baseline scenario with 6000 MW initially and 80% forwards). With a bid cap above 100 EUR, we find that the impact of the demand slope is identical to the original case with 140 EUR. Conversely, a bid cap at 80 EUR or below always binds, so adjusting the capacity-demand curve then has no impact on the clearing price. The idea that these two instruments are complementary in mitigating market power is appealing. However, at least in this case, they are effective in different situations: there is no price effect from (i) bid-cap adjustments above 100 EUR, and (ii) demand-slope adjustments with a bid cap below 80 EUR.

In sum, this initial analysis suggests that using a downward-sloping demand curve can, at least in some cases, mitigate market power in the capacity auction—though it can also discourage new entry and needs to be well-coordinated with bid-cap setting.