An Extended Analysis on the Remuneration of Capacity under Scarcity Conditions

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ABSTRACT

This paper extends a recent analysis which investigated the impact of scarcity adders produced by operating reserve demand curves on the financial viability of generation units in the Belgian market. Our paper is inspired by practical considerations related to the implementation of the mechanism in European electricity markets. We are specifically interested in: (i) the extent to which the mechanism rewards flexible resources for being available 'when and where' needed, as required by European competition law; (ii) the sensitivity of the mechanism to certain parameters that require regulatory judgment; (iii) the interaction of the mechanism with indirect capacity mechanisms; and (iv) the ability of the mechanism to provide long-term investment signals. We find that the restoration of nuclear capacity in the Belgian market would suppress scarcity adders to near-zero values. We show that the increase in value of lost load would have a minor impact on scarcity adders when capacity shortages are negligible. We find that the removal of strategic reserve from the Belgian market would have a significant impact on scarcity adders. We find strong positive correlation in consecutive imbalance increments, and show that this correlation can result in noticeable impact on the computation of scarcity adders. We demonstrate that the back-propagation of scarcity adders is essential for providing a long-term investment signal to flexible resources.

Keywords: Flexibility, energy-only markets, renewable integration, operating reserves

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1. INTRODUCTION

The "Operating Reserve Demand Curve" (ORDC) was introduced in the Electric Reliability Council of Texas (ERCOT) in 2014 as an "energy-only" instrument for dealing with adequacy. The method is well documented in theory and practice (e.g. (Potomac, 2017a, 2016; Hogan and Pope, 2017) and references therein). The general conclusion of these market analyses is that ORDC behaves as expected.[1] Various recommendations for improving both the

1. It is crucial to delineate the expectations of ORDC pricing. As the name indicates, ORDC refers to a demand curve. As is the case for cost functions, demand functions can refer to the long term or to the short term. ORDC refers to the demand for operating reserve, which is a short-term service. One may wish to distinguish the instantaneous demand for operating reserve from a long-term signal for adequacy. The latter is explicitly meant to induce investment. ORDC should thus be judged in terms of signaling the capability of the system to provide short-term services, such as balancing, that are essential for adequacy in the short to medium term. The implication is that ORDC should not be evaluated by its capability to provide a long-term signal,

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method and the market design which supports ORDC can be made, but none of the findings question the fundamentals of the approach.

Papavasiliou and Smeers (2017) analyze the possible transposition of ORDC to the European context, focusing on the particular case of Belgium. The analysis presented by Papavasiliou and Smeers (2017) was requested by the Belgian Commission for the Regulation of Electricity and Gas (CREG), and simulated the potential impact of ORDC-based scarcity adders[2] in the Belgian electricity market over a period of 18 months, from January 2013 until September 2014. The study was partially motivated by concerns triggered by an unscheduled outage of approximately 4 GW of nuclear capacity in Belgium during the fall of 2014. As the total capacity of the Belgian system amounts to 14765 MW, this outage represented a significant portion of the domestic power generation fleet.

In February 2016, nuclear power production was completely restored back to service. In response, the CREG commissioned an extension of the original study[3] of Papavasiliou and Smeers (2017). The goal of the extension is to investigate the effect of the restoration of nuclear capacity on the Belgian market during the 9-month period from September 2015 until March 2016, as well as the sensitivity of scarcity adders on a number of factors. Besides these immediate objectives, the present analysis constitutes an opportunity to arrive to additional insight on the properties of scarcity pricing, based on the obtained numerical results.

In what follows, we describe the objectives of the present analysis in the backdrop of the original analysis of Papavasiliou and Smeers (2017):

(i) The first study concluded with a rather high value for scarcity prices. This high value was due to the fact that the generation capacity in Belgium was low during the simulation interval of the first study, and reflected true scarcity in the system. An obvious concern of the regulator is to verify that this high adder disappears when capacities return to normal. Indeed, scarcity pricing should only provide additional revenue to producers when justified by the state of the market. To the extent that scarcity pricing can be interpreted as a mechanism that evaluates scarcity instantaneously, a necessary condition for the policy to comply with EU principles on capacity payments is that the adder should vanish when capacities return to normal. Motivated by this fact, the Belgian regulator requested an assessment of the impact of scarcity pricing on the electricity market under a baseline scenario running from September 2015 until March 2016 (referred to as the *reference* horizon).

(ii) The second goal is to provide an assessment of the impact of ORDC on the reference horizon with the value of lost load (VOLL) of 3000 €/MWh replaced by a VOLL of 8300 €/MWh. This value is the VOLL estimate of the Belgian Federal Planning Bureau, as indicated in page 13 of Table 3 of Devogelaer (2014).

(iii) Discussions on incentives to invest or maintain capacities in Europe are mainly divided between advocates of capacity and energy-only markets. Belgium and Sweden current-

even if it contributes to it. The same remark can be rephrased in terms of risk. ORDC refers to short-term risk that occurs because of random net demand. Long-term risks due to the evolution of demand because of economic conditions or the extent of the penetration of decentralized generation are a different matter. The power system is subject to different risk factors, and ORDC only addresses some of these factors. With that being said, long-term adequacy, when it is not properly addressed, progressively transforms into a short-term issue. Our past work (Papavasiliou and Smeers, 2017), as well as its extension presented in this paper, demonstrate that adequacy is not only a matter of investment for the long term, but can also become an issue when economic or political energy events, combined with an incomplete market design (in the case of this paper, the improper pricing of reserves), induce premature retirement of units that cannot be justified economically.

2. ORDC-based scarcity adders applied to the Belgian market will be referred to as *scarcity pricing* in this paper.
3. We will refer to the study of Papavasiliou and Smeers (2017) as the *first study.*

ly operate a "strategic reserve". Strategic reserve has been put in place in Belgium since 2014. This reserve comprises plants that do not participate in the market, but can be activated in case of scarcity, as determined by the system operator. Höschle and De-Vos (2016) provide a description of the mechanism. Strategic reserve is essentially a temporary capacity market that is evaluated on a periodic basis and that needs to be approved by European competition authorities. An interesting question is to explore the interaction of scarcity pricing with strategic reserve. It is specifically relevant to assess the consequences of the elimination of strategic reserve, if it were to be rejected or significantly modified for reasons driven by Belgian or European policy. In this context, the Belgian regulator requested an assessment of the impact of the removal of strategic reserve on scarcity prices.

(iv) Another point of interest is related to the back-propagation of scarcity prices. *Back-propagation* refers to the extent to which scarcity pricing affects the full volume of market transactions. Even though the scarcity adder is applied to the real-time market (which corresponds to a small part of the market), it creates an upward pressure on all forward markets due to arbitrage. The degree of back-propagation is relevent to the stakeholder debate on scarcity pricing, since generators and consumers obviously have competing interests. The Belgian regulator, on the other hand, is interested on understanding how different degrees of back-propagation affect incentives to invest.

(v) It is sometimes argued that ORDC pricing resolves the missing money problem without the discussion on design parameters, which is inherent to capacity markets. In this paper, we discuss a design decision related to scarcity pricing which can affect the level of the adder, although it is less crucial in our opinion than those of capacity markets. This design decision relates to the assumed degree of correlation between imbalance increments. The analysis of the first study was conducted under the assumption of stochastic independence between increments of imbalance during successive intervals of time. Instead, Hogan (2015) assumes perfect correlation in imbalance increments. These two approaches represent limit cases in a range of possible options regarding assumed correlations. Independent increments may be questionable during the very short periods of time (not longer than 15 minutes) that are considered in the evaluation of operating reserve. This is especially true when wind production and solar irradiation can remain auto-correlated over much longer periods. The question, then, is to quantify the auto-correlation of imbalance increments, and to assess its impact on the adder. Motivated by this fact, the Belgian regulator requested an analysis that would verify or refute the independence of increments in imbalance, and an analysis of the impact of correlations on the computation of the scarcity adder.

2. METHODOLOGY

2.1 A Short Review of Scarcity Adders

Papavasiliou and Smeers (2017) provide a detailed discussion about the relative merits and criticisms of energy-only markets versus capacity remuneration mechanisms in the European electricity market. It is specifically noted that capacity remuneration mechanisms have recently raised concerns among European policy makers as potentially balkanizing the European electricity markets, and as possibly hiding State Aids that contravene European law. On the other hand, energy-only markets rely on price spikes for remunerating capacity. In the presence of inelastic demand, these price spikes are somewhat unpredictable in magnitude and frequency. Furthermore, these price spikes can be easily muted by regulatory interventions such as price caps or the mobilization of emergency capacity. The muting of price spikes can result in increasing risk for power generation capacity investments. An interesting paradox is that the technologies which are undergoing the gravest economic woes due to the integration of renewable resources and the resulting depression of energy prices are those technologies which are most suitable for balancing the highly variable and unpredictable fluctuation of renewable energy supply, namely combined cycle gas turbines.[4] This indicates a fundamental inconsistency in the valuation of flexible reserve capacity, where 'flexible' refers to capacity that is capable of varying its output rapidly, and in short notice.

Operating reserve demand curves have been introduced as a potential remedy to how reserve capacity is valued (Hogan, 2005), and thus as a potential remedy to the missing money problem that arises in energy-only markets. The idea of ORDC scarcity adders is to introduce a component to the real-time energy price which reflects the value to the system of keeping a certain amount of fast-responsive generation capacity on standby. This standby capacity reduces the instantaneous loss of load probability. The ORDC adder essentially reflects the willingness of the system operator to pay for increments of reserve capacity in tight conditions. By construction, the adder is adaptive to the amount of generation capacity that is available in the system. Excessive availability of reserve capacity pushes the adder to zero, thereby leaving the energy price unaffected. This is what one would expect under normal operating conditions. Instead, under tight conditions when the amount of available reserve capacity in the system becomes scarce, the adder increases. This reflects the added value to the system of increments in standby reserve. Units that can respond under such tight conditions are remunerated for helping the system. Provided that forward markets can properly back-propagate the real-time value of electricity, a long-term investment signal thus emerges. The precise formula that is applied in order to compute the scarcity adder is presented in an online appendix.[5]

Several US system operators combine capacity markets and scarcity pricing. Potomac (2017b) discusses the case of MISO. MISO implements both capacity markets and an ORDC adder which is in the same spirit as ERCOT, but which is not calibrated in the same way. The analysis shows that the calibration of the ORDC is a question of its own. Chang et al. (2018) further discuss different examples of ISOs in North America that implement both scarcity pricing and capacity markets or related instruments.

Whereas the ORDC adder is developed as a correction to the energy price for a US-type two-settlement system that simultaneously auctions reserve capacity and energy, the implications in the level of investment of introducing the adder to the European market would need to be analyzed more carefully. Instead, the current study assumes fixed capacities, and is focused on an analysis of how the adder would have impacted the Belgian real-time electricity price, and the resulting profitability of existing combined cycle gas turbines.

2.2 A Short Review of the Methodology of the Original Study

The focus of the original study of Papavasiliou and Smeers (2017) was to develop an accurate model of the Belgian market, which could accurately predict the available reserve in the computation of the scarcity adder. This would provide an accurate estimate of what the scarcity adder would have been, if the design had been introduced in the Belgian market.

4. See Abada et al. (2018) on the issue of risk and investment in the ongoing European energy transition.
5. https://perso.uclouvain.be/anthony.papavasiliou/public_html/OnlineAppendix.pdf.

TABLE 1
Profitability of CCGT units before and after introducing ORDC price adders, and average adder benefit. Original study interval: January 2013–September 2014. Bold font indicates units that are not able to recover their fixed investment costs.

	Profit no adder (€/MWh)	Profit with adder (€/MWh)	Adder benefit (€/MWh)	Load factor (%)
CCGT1	**3.0**	9.2	7.3	55.2
CCGT2	**0.7**	**2.9**	11.4	14.0
CCGT3	**0.5**	8.4	6.6	71.1
CCGT4	**3.1**	9.8	8.9	51.3
CCGT5	**0.3**	**4.6**	5.6	52.1
CCGT6	**3.2**	7.1	8.3	31.7
CCGT7	**0.4**	**2.4**	14.4	8.0
CCGT8	**0.5**	6.6	7.2	46.1
CCGT9	**1.7**	9.5	6.9	69.1
CCGT10	**1.0**	6.1	5.9	58.4
CCGT11	**1.0**	**3.4**	6.4	18.7

The methodology employed in the first study can be summarized as follows. The study consisted of a validation phase and a simulation phase. In the validation phase, we use historical data of market clearing prices and market clearing volumes in the Belgian market in order to calibrate our market model, and in order to decide on the level of modeling detail for the various resources that were accounted for in the model. These modeling decisions are made under the constraint of data availability, since the data that was available to us was in aggregate form (with generators of the same fuel type being aggregated as a single resource), whereas data for combined cycle gas turbines and coal units was available on a unit-by-unit basis.

Upon validating our market model against a number of benchmarks, we proceeded with the computation of the scarcity adder for the study interval from January 2013 until September 2014. The average adder for the study amounted to 5.3 €/MWh. Results are summarized in Table 1. The CCGT units that are mentioned in the table correspond to all the CCGT units that were operating in Belgium at the time of the study interval (January 2013–September 2014). The conclusions of the original study can be summarized as follows: *(i)* based on the observed market outcomes of the original study period, none of the existing combined cycle gas turbines of the Belgian market appear to be profitable investments, thereby confirming the concerns that motivated the first study, and *(ii)* the introduction of price adders that reflect the true value of scarce flexible capacity restores economic viability for most combined cycle gas turbines in the Belgian market.

3. ASSUMPTIONS OF THE NEW STUDY

The present report extends the results of the original study in the following directions: *(i)* The Belgian market is tested with nuclear power units back in operation. The reference horizon for the new study ranges from September 2015 until March 2016. *(ii)* The reference horizon is tested for the case where the VOLL used for the computation of the adder is changed from 3000 €/MWh to 8300 €/MWh. The value of 8300 €/MWh is the estimate of the Belgian Federal Planning Bureau for the value of lost load (Devogelaer, 2014). *(iii)* The reference horizon is tested for the case in which strategic reserve would not be available to the Belgian transmission system operator.

We assume the same requirements for primary reserve (FCR), secondary reserve (aFRR) and tertiary reserve (mFRR) as in the original study: 55 MW for primary upward and downward reserve, 140 MW for secondary upward and downward reserve, and 350 MW for tertiary reserve.[6]

The time resolution of the new model is 15 minutes, compared to the original model which was cast in 1-hour time steps. This enables a more accurate simulation of the actual Belgian system, which operates a balancing market with 15-minute time intervals. Specifically, for the day-ahead unit commitment model that we employ, we use 15-minute resolution for dispatch decisions, and hourly resolution for unit commitment decisions. Reserve capacity commitment is modeled with daily resolution, reflecting a transition of the Belgian market to day-ahead clearing of reserve capacity.

The CREG has provided detailed information on the amount of strategic reserve that was available during the horizon of the study. Since the strategic reserve was not mobilized during the interval of the new study, neither in the day-ahead market nor in real time, we remove the strategic reserve units from the simulation in order to accurately model the commitment and dispatch of the remaining fleet. Nevertheless, we account for the availability of strategic reserve when computing adders, because the presence of these capacities in reserve indeed implies a modification of the LOLP. The units that were available as strategic reserve for 2015 included[7] Seraing (485 MW), Vilvoorde (265 MW), Angleur (50 MW), Izegem (20 MW) and Esche-sur-Alzette (357.1 MW), as well as 358.4 MW of demand response, thereby totaling a strategic reserve capacity of 1535.5 MW.

The original study partitioned generators into three categories. *(i)* Non-dispatchable resources do not react to price. The output of these resources is based on historical data. These include nuclear (6078 MW), wind power (978 MW), waste (320 MW) and water (93 MW). *(ii)* Dispatchable resources are approximated through an affine supply function. We use the same parameters for the affine supply function approximation as in the original study. These resources include blast furnace (323 MW), non-wind renewable resources (106 MW), gas-oil (5 MW), and turbojet (212 MW). *(iii)* Certain resources are represented with a unit commitment model. These include coal (764 MW) and CCGT (4365 MW, not including the strategic reserve units).

Pumped hydro resources are modeled by optimizing the pumping and production of hydro power over the horizon of one day. We use equal production and pumping capacity for the pumped hydro resources. We assume that pumped hydro reservoirs are completely empty every day at midnight.

We simulate the operation of the system by solving for the optimal commitment and dispatch of the system with a one-month horizon, in order to avoid border issues with the end and beginning of each day.

We assume that all types of reserve, including primary reserve, are offered with daily resolution. We have observed that changing the resolution of reserve capacity decisions from

6. The 350 MW of tertiary reserve capacity correspond to the reserve capacity that needs to be made available by thermal units (EBridge, 2014). There are also 261 MW of tertiary reserve capacity sourced from demand response. This capacity is accounted for in the computation of the scarcity adders. This capacity is not included in the reserve requirements of the unit commitment model, because these reserves are not sourced from thermal units.

7. http://www.creg.be/fr/producte9.html.

monthly to daily granularity has significantly accelerated the solution time of the mixed integer linear programs that solve the monthly system scheduling problem. This is expected, because the temporal coupling among consecutive days is weakened, thereby resulting in daily scheduling problems that are nearly independent of each other. Consequently, we no longer employ the receding horizon heuristic that was used for the resolution of the unit commitment problem with monthly horizon in the original study. We use a relative optimality gap of 10^{-5} for the resolution of the unit commitment model.

We proceed by reporting on the results of the model applied under the baseline scenario as well as the various what-if scenarios that were suggested by the Belgian regulator. In order to provide material for the discussion of back-propagation later in the text, we report results with and without back-propagation in all simulations.

4. RESTORATION OF NUCLEAR CAPACITY

The analysis of the contribution of scarcity pricing in the first study is summarized in Table 1. The results underscore the short-term role of the instrument. Given the outage of nuclear capacity and the high cost of gas, the energy market did not provide sufficient operating reserve. This is a market failure. The adder was instrumental for preventing the mothballing or dismantling of CCGT capacities that were needed in order to provide this operating reserve and hence to ensure the adequacy of the system. This corrects the market failure. The counterpart of that finding is that the scarcity adder should drastically reduce, or vanish entirely, when market conditions remunerate the short-term fixed and variable costs of CCGT units. This attribute of scarcity pricing is in line with the State Aid argument invoked against a generalized use of capacity payments in the EU. According to European competition authorities, there is State Aid if public authorities organize a payment that discriminates between producers/technologies, and that is not justified by the state of the generation system. We argued before that the scarcity adder reflects scarcity in the system due to the outage of a large fraction of the nuclear fleet. This statement must be confirmed by showing that the payment disappears when capacity has been restored and when fuel prices have restored the short-term economics of the CCGT units on the energy market. This is demonstrated in the present section.

The profits reported in this section are computed by adding up the simulated profit over the seven months of the study, and dividing by the number of hours in the study times the capacity of each unit. The reported profits are obtained after subtracting a fixed operating and maintenance cost of 7.04 $/kW-year (EIA 2012 estimate). The running investment cost of CCGT units is assumed equal to 5.6 €/MWh. This is based on an overnight cost of 676 $/kW (EIA 2012 estimate), the 2012 average exchange rate of 0.778 /$, continuous discounting at a rate of return of 8%, and an investment horizon of 25 years. These assumptions are based on the first study (Papavasiliou and Smeers, 2017). The units in the present paper are numbered so that they correspond to the results reported in the first study, meaning that CCGTi in the present paper corresponds to CCGTi in the first study.

In order to test for the possibility that the adder may not fully back-propagate to forward markets and provide material for the later discussion of this issue, we report results for two boundary cases. In the first case, we compute generator revenues assuming that the adder fully back-propagates to the day-ahead time frame, and is therefore also applied to the entire amount of day-ahead transactions. We also report results for the case where the adder does not

TABLE 2
Profitability of CCGT for the reference case of the new study (with nuclear plants restored). Profits are reported without scarcity adders (second column), with scarcity adders that do not back-propagate to the day-ahead market (third column), and with scarcity adders that fully back-propagate to the day-ahead market (fourth column).

	Profit no adder (€/MWh)	Profit with adder no back-propagation (€/MWh)	Profit with adder full back-propagation (€/MWh)
CCGT1	10.6	10.6	10.8
CCGT2	9.2	9.3	9.4
CCGT3	9.8	9.8	10.1
CCGT5	9.5	9.5	9.8
CCGT6	9.2	9.2	9.4
CCGT8	9.4	9.4	9.7
CCGT9	11.0	11.0	11.3
CCGT11	9.2	9.2	9.4

back-propagate to the day-ahead price, and is therefore only applied to the change of generator output from the day ahead to real time.

In Table 2, three CCGT units have been removed from the original fleet of Papavasiliou and Smeers (2017).These units, Seraing, Vilvoorde, and Esche-sur-Alzette, have been moved to strategic reserve. From the results of the table, one can conclude the following. *(i)* All CCGT units attain profits that are comfortably above their hourly equivalent investment cost. *(ii)* The impact of the scarcity adder on generator profitability is negligible. The average adder over the duration of the study amounts to 0.3 €/MWh. This demonstrates that, in conditions of abundant capacity resulting from the restoration of nuclear capacity, the scarcity adder has a negligible effect on energy prices. This attribute is compatible with the adaptive nature of the adder.

The fact that the profits of CCGTs are improved compared to the original round of simulations (January 2013–September 2014) is a consistent observation for all cases that were tested in the new study. There are two factors that are notably different in the new study, compared to the first study, and which might contribute to this observation. *(i)* There is a notable drop in natural gas prices, as indicated in Figure 1, which is the data source for our study.[8] *(ii)* The average CCGT capacity which is active in the energy market has dropped since Vilvoorde, Seraing and Esche-sur-Alzette have moved to strategic reserve and a certain amount of CCGT capacity has been scrapped. The first factor is clearly favorable for the profitability of CCGT units, since it reduces their variable costs. The second factor could also be argued to favor CCGT units, since it relieves competitive pressure and opens up market share for the surviving CCGT units. This interpretation is further supported by the comparison of the load factors of CCGT units in Table 3. Note that *all* units increase their load factors, and for some units this increase is quite significant (for example, CCGT2 and CCGT11 increase their load factor more than threefold).

Note that the CCGT capacity retired from the energy market comprises plants that are effectively dismantled, and others that joined the strategic reserve. The latter units provide

8. https://my.elexys.be/MarketInformation/SpotZtp.aspx.

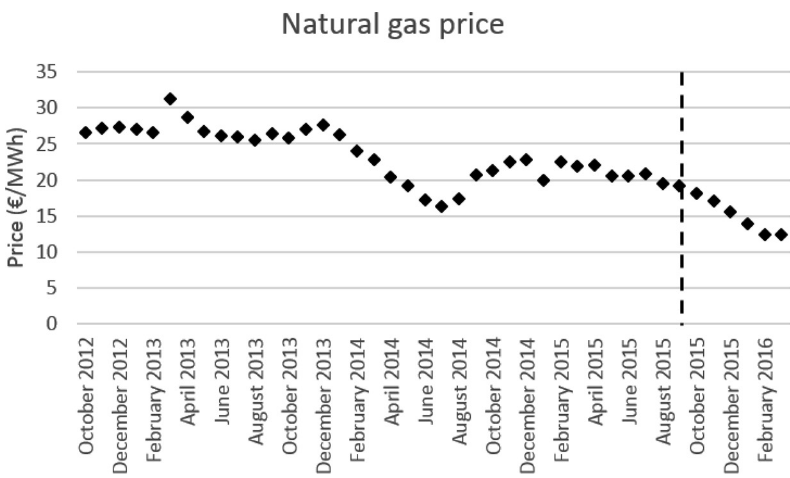

FIGURE 1
The evolution of natural gas prices (source: SpotZTP). The dashed line indicates the beginning of the study interval, which runs from September 2015 until March 2016. Note that the price of natural gas during the study interval is at its lowest value since October 2012.

TABLE 3
Load factors (in %) of CCGT units, expressed as the fraction of average output to available capacity.

	Original study	New study
CCGT1	55.2	58.3
CCGT2	14.0	48.5
CCGT3	71.1	73.2
CCGT5	52.1	58.2
CCGT6	31.7	46.6
CCGT8	46.1	55.7
CCGT9	69.1	69.5
CCGT11	18.7	62.3

services to the TSO. Concretely, they contribute to keeping the adder low but have no impact on the energy price. On the contrary, the removal of plants from both the energy market *and* from strategic reserve increases the adder and the price on the energy market. The following section further explores the role of these reserve plants by investigating the impact of fully retiring them.[9]

Moving beyond the assumptions of the base case, we consider a VOLL of 8300 €/MWh, instead of a VOLL of 3000 €/MWh, for the computation of the adder. The average adder amounts to 0.7 €/MWh, as compared to 0.3 €/MWh in the base case. The profitability of CCGT units is listed in Table 4. Similarly to the base case, the inability of the adder to

9. The intermediate status of units in strategic reserve between being commercially viable and being dismantled may have a counterpart in the market. One indeed sees "infrastructure companies" acquiring distressed capacities from utilities in order to obtain the option of intervening in times of scarcity ("Blackstone Does what RWE Can't Do by Reviving Dutch Plant", Bloomberg, July 7th, 2017). In physical terms, these plants will intervene in the energy market when the system is tight, which is when the scarcity adder effectively becomes active.

TABLE 4

Profitability of CCGT for the case with VOLL = 8300 €/MWh. Profits are reported without scarcity adders (second column), with scarcity adders that do not back-propagate to the day-ahead market (third column), and with scarcity adders that fully back-propagate to the day-ahead market (fourth column).

	Profit no adder (€/MWh)	Profit with adder no back-propagation (€/MWh)	Profit with adder full back-propagation (€/MWh)
CCGT1	10.6	10.6	11.2
CCGT2	9.2	9.3	9.8
CCGT3	9.8	9.8	10.6
CCGT5	9.5	9.5	10.3
CCGT6	9.2	9.2	9.8
CCGT8	9.4	9.4	10.2
CCGT9	11.0	11.0	11.8
CCGT11	9.2	9.2	9.9

back-propagate implies that the adder has a negligible impact on generator profits, whereas the full back-propagation of the adder has a noticeable impact on generator profits. As we demonstrate in the next section, the impacts of the increase in VOLL on the adder are less pronounced than the impacts of removing strategic reserve.

5. STRATEGIC RESERVE

Strategic reserve is a particular version of capacity mechanism. Its principle is that the TSO procures the services of additional reserve capacities on top of those available from the energy market, when it evaluates that these capacities are necessary for meeting peak demand in the coming years.[10] Scarcity adders and strategic reserve pursue related, yet not identical, goals.

The aim of scarcity adders is to provide a permanent and ex ante incentive to build or keep necessary capacity and flexibility in the system. The physical reality of the power system implies a demand for operating reserve. Those providing operating reserve should thus be remunerated in line with the scarcity of the supply for that service. The economic reality of the present system is that operating reserve is a *public good*: all users of the system benefit from it, whether they pay or not. This implies that the market will not reveal the demand for reserve. The demand for reserve will therefore need to be specified by a regulator acting on the basis of technological and economic information. This is achieved when the operating reserve demand function is constructed on the basis of LOLP and VOLL. Scarcity adders then use the LOLP to instantaneously measure the capability of the system to provide those services, and use the VOLL to transform this measure to a remuneration.

One can note that scarcity pricing meets all of the common recommendations of EU authorities. *(i)* It is based on transparent notions, those of LOLP and VOLL. *(ii)* The remu-

10. Plants that owners would dismantle because of economic conditions are obvious candidates to be part of the strategic reserve. The TSO determines the needed capacity on the basis of a probabilistic study (LOLE evaluation) conducted on different scenarios of demand and capacity availability in the Belgian and neighboring systems (see ELIA (2017) for the 2017–2018 planning). The analysis is conducted using computational tools developed by RTE (the French TSO) based on Monte Carlo simulation of unit commitment problems. The retained plants are selected together with other instruments in an auction.

neration of capacity is non-discriminatory. This means that the adder remunerates all capacities that are generating, or that are available for providing reserve, regardless of the technology or the ownership of the plant. *(iii)* The remuneration of flexibility is also non-discriminatory. This means that flexible plants are rewarded for a higher ramping capability and for contributing more to the operating reserve.

By contrast, strategic reserve is neither an incentive to invest or retain capacity, nor a permanent instrument. It is an administrative means of retaining existing capacity because of current system and economic conditions. Strategic reserve compensates ex post for the market failure that led to the insufficient capacity, but does not correct for it ex ante. It is also non-permanent, as it needs to be redefined on a periodic basis, and sufficiently in advance of the winter. Furthermore, it is less transparent, because it is based on an ex ante evaluation of LOLP, as opposed to a real-time evaluation of LOLP. This requires delicate forecast assumptions. Lastly, it requires a non-automatic approval where opinions can differ on the need for the existence of strategic reserve, its size, and the possibility of discrimination between plant owners implied by its composition.[11] This implies that the process is procedural, and therefore prone to evaluation errors.

Hogan (2013) argues that scarcity pricing and capacity markets are not mutually exclusive. When used together, a benefit of scarcity pricing would be to reduce the need for capacity markets and the numerous ex ante assumptions that it requires. The same argument can be invoked about the interaction of scarcity pricing and strategic reserve. It is thus interesting to explore whether a combination of scarcity pricing with strategic reserve can correct some of the shortcomings of the latter.

In this section we test the impact of combining strategic reserve with scarcity pricing, and the possibility of a rejection of the strategic reserve by European or national authorities. Concretely, we remove the strategic reserve from the system for the months of November 2015–March 2016. The removal of the strategic reserve has a noticeable impact, especially during the winter months. The average value of the adder is 4.4 €/MWh, compared to 0.3 €/MWh for the base case. The amount of capacity that can be made available in 7.5 and 15 minutes is presented in Figure 2. The impact of the adder is noticeable when there is full back-propagation of the adder. The CCGT profit results are reported in Table 5. Without back-propagation, the impact of the adder on profits remains negligible, despite the elevated adder. The impact of retaining the strategic reserve on generator profits therefore drastically depends on the extent of back-propagation. However, the difference in impact is much higher than in Table 2, where the impact of the adder remained negligible irrespectively of back-propagation.

As shown in section 4, CCGT units do not need the adder in order to remain in the system when nuclear capacity is restored and gas prices are low. On the other hand, the high adder found when scrapping the capacities of the strategic reserve also expresses that these

11. Purely administrative errors can also contribute towards creating uncertainty. Notwithstanding its introducing strategic reserve in 2014, Belgium had not (as of July 2017) notified the mechanism to EU Competition Authorities, with the result that one did not know whether it would be approved on time for contracting the plants before the peak of the next winter. It was not even clear that the Commission would approve the mechanism as the Commission was also investigating a German proposal for strategic reserve. Approval for both the Belgian and German strategic reserves came on February 7, 2018 (the reader is referred to the European Commission press release, issued on February 7, 2018, "State aid: Commission approves six electricity capacity mechanisms to ensure security of supply in Belgium, France, Germany, Greece, Italy and Poland"). This type of delay (and even uncertainty on the final outcome) increases revenue risk for generators, especially if plants made available for strategic reserve are prevented from returning to the energy market if they are not retained in the strategic reserve, or if this reserve is rejected at an EU level.

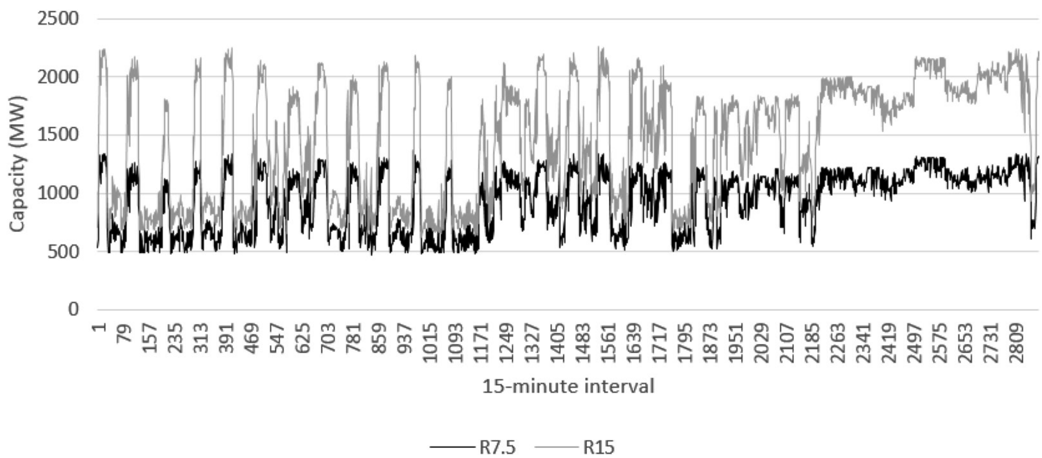

FIGURE 2
The available capacity in 7.5 minutes and 15 minutes for December 2015 for the case without strategic reserve.

TABLE 5
Profitability of CCGT for the case without strategic reserve. Profits are reported without scarcity adders (second column), with scarcity adders that do not back-propagate to the day-ahead market (third column), and with scarcity adders that fully back-propagate to the day-ahead market (fourth column).

	Profit no adder (€/MWh)	Profit with adder no back-propagation (€/MWh)	Profit with adder full back-propagation (€/MWh)
CCGT1	10.6	10.6	15.2
CCGT2	9.2	9.3	12.6
CCGT3	9.8	9.8	14.6
CCGT5	9.5	9.5	14.1
CCGT6	9.2	9.3	12.8
CCGT8	9.4	9.4	13.9
CCGT9	11.0	11.0	15.8
CCGT11	9.2	9.2	13.2

units, which did not contribute to the energy market by construction of the strategic reserve, are in fact necessary for the system. When dropping these units, the adder drastically increases, thereby sending the signal that the system needs to reconstruct the capacities dropped by the elimination of the strategic reserve. In the absence of back-propagation, there would be no signal for reconstructing the reserve capacity that was unduly dropped. In short, the potential dismantling of strategic reserve creates a risk that would not have been existent if the system could properly price scarcity. Scarcity pricing compensates for this risk, in case it materializes.

It may be useful to reword the preceding discussion on the high profits in case of back-propagation by clearly asserting that these results cannot be interpreted as windfall profits that would violate paragraph 230 of the European Commission guidelines on State Aid (European Commission, 2014). We first note that we did not find excessive profits from the application of scarcity pricing so far. The first study of Papavasiliou and Smeers (2017) did not lead to windfall profits under high gas prices with back-propagation and a high adder. The present study does not reveal windfall profits with low gas prices and back-propagation, since the scarcity adder is near zero when strategic reserve is kept. However, some may argue that scarcity pricing with back-propagation leads to windfall profits in case the strategic reserve capacity is not implemented and in case some generators move forward with their threat of closing down the plants that were supposed to be included in the strategic reserve. The correct interpretation of the figures is that the observed high profits are the results of the capacity shortage caused by the misleading signal sent by the market when plants are not remunerated for their availability.[12]

6. IMBALANCE CORRELATIONS

Both scarcity pricing and strategic reserve require the assessment of LOLP. The only difference between the two instruments is that LOLP is priced when implementing scarcity pricing, whereas strategic reserve only sends a signal to endow the existing system with additional capacity. In both cases, one needs to guarantee a proper computation of the LOLP.

The software ANTARES of the French TSO RTE (ELIA, 2017), which underpins the analysis of the Belgian TSO for strategic reserve, models plant availability through hourly constant levels. Recently, there has been a growing interest in the analysis of the fine time structure of ramping calls in markets with an increasing penetration of renewable resources. Describing plant operations over shorter time intervals enables a more dynamic representation of the behavior of plants. Scarcity pricing implemented in ERCOT works on time intervals of 30 minutes. Each interval is decomposed into two successive periods of 15 minutes, in order to represent differences of plant flexibility. This allows modeling some of the reserve dynamics. Similarly, we work on 15-minute time granularity, which is the granularity of the balancing intervals in the Belgian system. We decompose balancing intervals into two successive periods of 7.5 minutes. This corresponds to the response times of secondary and tertiary reserve in Belgium.

ERCOT models reserve activation by a normal distribution at the end of each balancing interval. The call for reserve response during the first half of the balancing interval is inferred by a proportionality rule. The demand for reserve in the two halves of the balancing interval is thus determined by a single random draw for each balancing interval. The two calls on reserves are thus perfectly correlated. Papavasiliou and Smeers (2017) assume an independent normal distribution for the reserve activation for each half of the balancing interval. The reserve activation for the entire balancing interval is the sum of the reserve activations in the two halves of the balancing interval. The two calls on reserve activation are thus perfectly independent. These are just examples that provide a starting basis for analysis. Solar and wind generation are increasingly represented by stochastic processes or ramping events that can adapt to finer time granularity and enable more sophisticated cross-interval dependency.

6.1 Evidence of Positive Correlation of Imbalances

The system imbalance metering signal provided to us by CREG for the duration of the study interval corresponds to 15-minute resolution. The correlation coefficient for imbalances

12. See EDF Luminus statements in “Libre Belgique” of August 23, 2017, http://www.lalibre.be/economie/libre-entreprise/les-neufs-candidats-a-la-reserve-strategique-d-electricite-rejetes-599c743acd706e263f89d9d8.

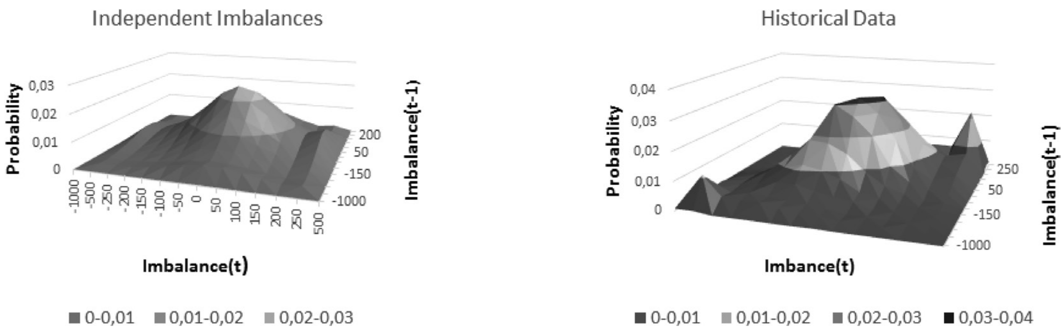

FIGURE 3
The probability density function of imbalances in consecutive time periods under the assumption of independent imbalances (left panel), and based on the observed data.

in consecutive time periods amounts to 0.642. The left panel of Figure 3 presents the probability density function of consecutive imbalances X_t that would be obtained if imbalances would be independent and identically distributed according to the *marginal* empirical distribution of $\mathbb{P}[X_t]$ derived from the data. The right panel presents the *joint* probability density function of $\mathbb{P}[X_{t-1},X_t]$, as observed in the data. If consecutive imbalances were indeed independent, the two density functions should exhibit some similarity. This is clearly not the case, since the figure on the right panel indicates that large positive (respectively negative) imbalances are likely to be followed by large positive (respectively negative) imbalances.

6.2 Accounting for Positive Correlations in ORDC Adder Computations

The positive correlation among consecutive imbalances suggests that the computation of the scarcity adder should be adjusted accordingly. In particular, we are interested in how the positive correlation of imbalances affects the interplay between the 7.5-minute and 15-minute components of the total adder.

We consider three different approaches towards computing the loss of load probability in a 7.5-minute horizon given a certain amount of capacity that can respond within 7.5 minutes. These alternatives are: *(i)* fully independent increments of imbalance (Papavasiliou and Smeers, 2017); *(ii)* fully correlated increments of imbalance (Hogan, 2013); and *(iii)* increments of imbalance which are calibrated against the empirically observed correlation. The third case is an intermediate of the boundary cases (i) and (ii). For all cases, it is assumed that the 15-minute uncertainty is distributed as a normal distribution. The detailed formulas for the three cases are presented in the online appendix.

Fully independent increments of imbalance. This approach assumes that the 15-minute uncertainty is the sum of independent, identically distributed normal random variables.

Fully correlated increments of imbalance. This approach assumes that the 15-minute imbalance is the result of a linear evolution of the imbalance. In other words, the increments of imbalance are assumed to be perfectly correlated.

The distinction between cases (i) and (ii) is presented in Figure 4. The essential difference is that lower correlation between the increments of imbalances implies a higher variance for 7.5-minute imbalance, *given* a certain standard deviation for the 15-minute imbalance. Said otherwise, approach (ii) will result in lower 7.5-minute adders than approach (i), since in order to get a certain standard deviation for 15-minute imbalances, it is necessary to have a

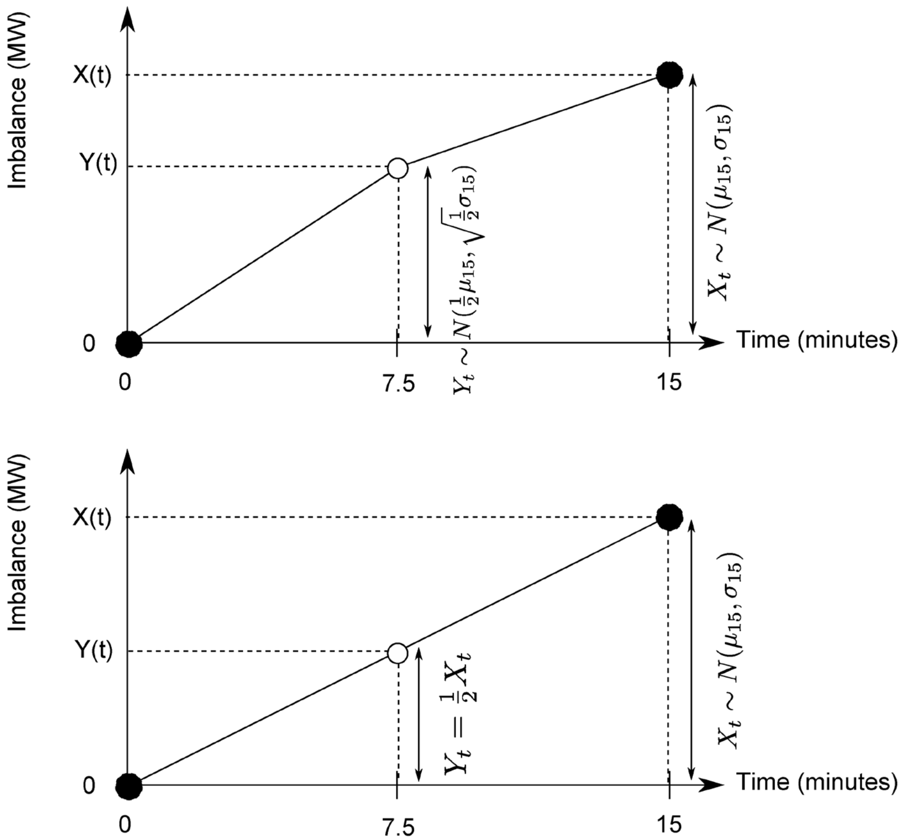

FIGURE 4

The upper panel corresponds to independent increments. The lower panel corresponds to fully correlated increments.

higher variance for the 7.5-minute imbalance for the case of independent increments than for the case of fully correlated increments.

Partially correlated increments of imbalance. The third approach that we consider is an intermediate case between approaches (i) and (ii), for which we use empirical data in order to fit a conditional distribution that describes the dependence between consecutive imbalance increments. Specifically, we use kernel density estimation for estimating the cumulative distribution function of the increment of imbalance from minute 7.5 to minute 15 for a given imbalance interval. The detailed explanation of this approach is provided in the online appendix of the paper.

6.3 Comparison of Scarcity Adder Values

We analyze the impact of the correlations on the computation of the adder using net regulation value (NRV) data.[13] We have access to NRV data with 1-minute resolution. We

13. The NRV data are a measure of net capacity shortfall which is available in the ELIA website with 1-minute resolution (as opposed to the net capacity shortfall data that was provided by CREG with hourly resolution for the first study). NRV data exhibit a similar positive correlation as the one observed in Figure 3. The net regulation volume is found in the following address: http://www.elia.be/en/grid-data/data-download.

TABLE 6
Scarcity adders computed using (i) independent increments of imbalance, (ii) fully correlated increments of imbalance, and (iii) partially correlated increments of imbalance. All values are in €/MWh.

	Independent	Correlated	KDE	15-minute contribution
Reference	0.47	0.26	0.26	0.25
No SR	3.18	1.88	1.89	1.84
VOLL 8300	1.35	0.74	0.75	0.72

use data from June 2015 until November 2016 for the calibration of the probability density functions.

The scarcity adders are presented in Table 6. The second, third and fourth column present the total adder for the three different methods discussed in the previous section. The fifth column presents the contribution of the 15-minute adder to the total adder. There are two major conclusions from this analysis. *(i)* The two boundary approaches of fully correlated and fully independent imbalances produce notably different results. The fully independent approach tends to result in higher adders, because given a certain level of 15-minute standard deviation it implies a higher level of 7.5-minute standard deviation. *(ii)* The partially correlated approach produces results that are intermediate between the independent and fully correlated approach, but rather closer to the fully correlated approach. This is due to the strong correlation of consecutive imbalances which has already been noted in Figure 3. Note that the 15-minute adder has the greatest contribution to the total adder.

The fact that the fully correlated approach and the KDE approach produce nearly identical results suggests that the simplicity of the fully correlated approach would make it preferable in terms of practical implementation.

7. BACK-PROPAGATION AND FORWARD MARKETS IN EU AND US MARKET DESIGNS

The preceding sections have illustrated the fundamental differences on the impact of scarcity pricing depending on the extent to which it back-propagates. This section argues why full back-propagation conveys the most meaningful signal, by relying on *(i)* a comparison between the European and US market designs, *(ii)* the basic notion of arbitrage-free markets, and *(iii)* EU recommendations.

The implicit argument for opposing back-propagation is inherent in the separation of energy and services in the European market. The former is handled by the power exchange, and the latter by the TSOs. In this view, real-time operations provide services that enable the energy transactions concluded in the day ahead, which is viewed as the spot market. One should pay for the service, and that closes the issue of coupling between day ahead and real time. Large industrial consumers comply with this argument based on the distinction between commodity and sales services for objecting to back-propagation. We use the insights provided by the US market design and the basic requirement of arbitrage-free market design in order to explain that reasoning in terms of commodity and sales services does not apply to electricity.

(i) Comparison with the US market. In the US market design, the spot market is the real-time market, and the day-ahead market is a forward market. The forward market being an

expectation of what would take place in the spot market, the day-ahead energy price should incorporate the adder.

The energy and service markets, even though separated in the founding principles of the EU power market, are linked by the physics and the economics of power plants. Referring to physics, most plants offer some capacity that is used in both the energy and reserve markets. Similarly, referring to flexibility, all plants offer some ramping capability that is used both in load following and reserve. The economic implication is that any remuneration for both capacity and ramping capacity should be the same in both markets, in order to avoid creating arbitrage. Thus, an adder that can be obtained on the service market by a given capacity of a certain generator should also be obtained by that same capacity of the same generator on the energy market. Any organization that violates this basic principle would imply incentives to move to one or the other market. These incentives could only be countered by quotas or measures of equivalent effects. By definition, these are not market measures. Note that this argument clarifies the distinction between commodity and sales services. Some units produce both the commodity and the service in electricity. This creates the need for ensuring the no-arbitrage condition. There is usually no such relation in commodities.

(ii) Arbitrage-free markets. The argument of no arbitrage implies that scarcity in the energy market and on the service markets should be related, in order to avoid creating structural arbitrage in the market. This is what the back-propagation of scarcity prices achieves. This principle underpins all US restructured markets. Furthermore, US markets provide a mechanism of virtual trading (Hogan, 2016) for steering the day-ahead market as close as possible to a forward market.[14]

(iii) European Commission guidelines. We note that the operating reserve demand curve targets *capacity*. The ORDC results in an adder that is a payment to the "mere availability of generation capacity", as stated in paragraphs 218, 219 and specially 225 of the European Commission guidelines on State Aid (European Commission, 2014). This remuneration is obtained by a *clearly defined* instantaneous LOLP computation, which is one of the methods recognized by the Commission for measuring insufficient capacity.[15] The mechanism then only applies *when and where* necessary (paragraph 221), in the sense that it depends on the instantaneous available capacity and demand. It applies to all plants, whether conventional or renewable, provided that they provide the same capacity services (paragraph 226). Moreover, the remuneration goes to zero when capacity is sufficient (paragraph 231). Back-propagation is implicitly imposed by paragraph 225 of the guidelines, because the remuneration is due to all plants for their availability, regardless of whether this availability is committed in real time or in the day-ahead time frame.

As discussed by Papavasiliou and Smeers (2017),the importance of real-time signals is well recognized by European competition authorities, even if the European market is not organized accordingly. In order to resolve the contradiction of a spot market that clears on expectations of spot transactions and not on the transactions themselves, the day-ahead market is followed by intra-day markets. These intra-day markets aim at enabling actors to adjust to

14. Section II in Potomac (2017a) and Potomac (2016) document the extent to which day-ahead prices are effectively forwards of real-time prices in ERCOT. The graphs illustrate and the discussions explain the convergence that makes day-ahead prices expectations of real-time prices. The virtual trading mechanism that underpins that property is effectively implemented in ERCOT as well as in other restructured US ISOs.

15. See footnote 93 or paragraph 218 of (European Commission, 2014), section 3 of (European Commission, 2015), and (European Commission, 2016).

additional information that arises between day ahead and real time. Intra-day markets may therefore naturally evolve into spot markets in European market design when they become more liquid.[16] Notwithstanding, real time in Europe is currently conceived as a balancing mechanism that agents are encouraged to avoid, *not* as a real-time market that could price scarcity. There is also no mechanism intended to convey real-time signals to the day ahead. The best that one can thus hope for, given the existing EU design, is to back-propagate scarcity in the day ahead by allowing agents to include the opportunity cost of real-time corrections in their day-ahead bids. This goes against the fundamental principles of scarcity pricing, which measures observable scarcity in the spot market in real time, when tight constraints of the system are effectively active. In contrast, opportunity costs included in day-ahead bids are neither observable by the TSO nor by the regulator. Opportunity costs are even challenging to quantify for generators, since they depend on the risk aversion of individual producers. This is a subject in itself, which suggests that the role of balancing in European market design will need to be revisited.

8. CONCLUSIONS

We can summarize the observations of our paper as follows. *(i)* CCGT units appear to be able to cover their investment costs over the studied period, possibly due to the drop in natural gas prices and the reduced competition which results from the recent elimination of CCGT capacity in Belgium. *(ii)* The adders are negligible during the study period, when strategic reserve is kept in the capacity mix. Average adders amount to 0.3 €/MWh. *(iii)* The removal of strategic reserve from the capacity mix has an important impact on adders. Average adders amount to 4.4 €/MWh. *(iv)* The increase of VOLL from 3000 €/MWh to 8300 €/MWh has a lesser impact on adders than the removal of strategic reserve. Average adders amount to 0.7 €/MWh. *(v)* We find that there is a significant positive correlation among consecutive values of imbalances. We analyze two boundary approaches towards estimating the LOLP, which correspond to fully independent increments of imbalance and fully correlated increments of imbalance. These approaches result in considerably different values of scarcity adders. This is due to the fact that, for the same level of standard deviation in 15-minute uncertainty, the different approaches imply different levels of 7.5-minute uncertainty. The latter approach is in line with the high positive correlations observed in imbalance data.

Our study illuminates certain implementation details which can significantly impact the performance of scarcity pricing based on operating reserve demand curves. An important remaining question is to investigate how the adder behaves when certain aspects of existing market design are not fully compatible with the theory underpinning scarcity pricing, as is the case in European markets. Future research on the application of the mechanism should therefore focus on determining how certain market design choices influence the ability of the scarcity adder to back-propagate, and thereby send a long-term investment signal.

16. However, this is difficult to imagine, given that these markets are organized in different ways. Abbassy et al. (2010) discuss a case that is still far from back-propagation in the sense of a forward market. The situation may have evolved and an analysis of intra-day trading would in any case require a study that goes well beyond the scope of this paper. One can finally conclude that convergence will not occur in markets where balancing is organized on the basis of different up and down prices which depend on whether the system is short or long.

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