Commission de Régulation de l'Electricité et du Gaz
Rue de l'Industrie 26-38
1040 Bruxelles
Tél.: +32 2 289 76 11
Fax: +32 2 289 76 09

COMMISSION DE REGULATION
DE L'ELECTRICITE ET DU GAZ

# NOTE

**(Z)160512-CDC-1527**

on

*"Scarcity pricing applied to Belgium"*

carried out in application of Articles 23, §2, second paragraph, of the Law of 29 April 1999 concerning the organisation of the electricity market

12 May 2016

# TABLE OF CONTENTS

# I. Introduction

Renewables are characterised by important investment cost, low fixed cost and variable cost close to zero. The massive introduction of large amount of renewable energy has led to overcapacity and has exacerbated the missing money problem reflecting the difficulties of remunerating the marginal generation unit in an energy only market with a marginal pricing principle.

This introduction contributed to the lowering[1] of the average electricity price to levels that may put at risk the profitability of new large scale generation units (mainly CCGT) in pure energy only markets even in the absence of excess generation capacity.

Additional revenues linked to ancillary services and re-dispatching are becoming more and more important for the profitability of these units.

This study was launched at the time when Belgium experienced a lack of generation capacity (several nuclear units, totalling a capacity of up to 4000 MW, were out of the market for several reasons) and where some CCGT were announced to be mothballed.

The implementation of a strategic reserve based on units to be mothballed (and which cannot anymore come back into the market) with a reduced interaction with the market (when this reserve is activated, balancing prices go above 3000€) constituted an important and quick reaction on this issue.

In an energy only market, it is expected that market players reflect scarcity in their bidding behaviour, leading to high price spikes which in principle should remunerate producers for the missing money.

The number of occurrences of these (very) high prices spikes of pure energy only markets are difficult to anticipate for producers and therefore difficult to be taken into account (or not adequate for) in a business plan, and at the same time very high price spikes are always politically sensitive, although they should not be.

Nobody says how producers should reflect scarcity in their bids. With the way day-ahead market are organised, there is a high competitive pressure to bid at marginal price.

[1] Together with a reduction of the consumption, and a decrease of $CO_2$ and coal prices

In addition, in an energy only market, it is extremely difficult for an NRA to distinguish between bids reflecting scarcity and the exercise of market power, which may be more acute in scarcity conditions. As long as market power may be considered as an issue, this difficulty may prevent efficient scarcity bidding.

So at this stage the question is: do we rely on scarcity bidding, with all related risks, or do we prefer a market mechanism which provide this scarcity price signal in a more neutral way, to all market players, leaving their bidding behaviour unchanged?

To this end, the CREG has asked the Center for Operations Research and Econometrics, “CORE” in short, of the Université Catholique de Louvain, to perform a study on the “Remuneration of Flexibility using Operating Reserve Demand Curves: A Case Study of Belgium”. This study is shown in Appendix 1.

This note presents a general introduction and description of the analysed method and its application to Belgium, the main results of the study and possible developments.

# II. General method description

In electric systems, reserves are needed to maintain system security, and in particular to cope with unexpected changes in demand and/or generation. System security is a public good. (selective curtailment may change this reasoning) and so it is extremely difficult to establish a market (market failure) for the remuneration of reserves which require administrative measures linked to the risks of free riding behaviour. Indeed, the determination of the needed volume of reserves and the attribution of the share of this volume to a specific market player is nearly impossible and therefore also the corresponding costs allocation.

The remuneration of reserves for their availability constitute a departure from the pure energy-only market principle and a kind of capacity remuneration.

In Belgium, the total volume of reserves is approximately equal to 1000 MW, traditionally linked to the tripping of the large nuclear generation units, owned by one market player, with several units bigger than 400 MW. Therefore, it was decided to procure and socialise the costs of reserves for a volume of 400 MW and to put an obligation for the additional reserve requirements to this large market player.

In pure energy only market, reserves may never be remunerated at all (their remuneration is even more challenging than the remuneration of the marginal unit leading to the missing money problem) and therefore, given what has been said on the public good nature of reliability, it is natural to further explore adequate (less) administrative measures for their remuneration, as they are the weakest element of energy only markets.

In the US, “Operational Reserves” are a subset of the installed capacity that is both available and standing by to produce energy on short notice. They correspond approximately to secondary and fast tertiary reserves in Europe.

The method followed in this study was proposed by William Hogan (based on the Operational Reserve Demand Curve or ORDC) and implemented in Texas. This method was considered interesting enough to study its application in the Belgian context in more detail. In a nutshell, this method or mechanism provides scarcity prices remunerating all units active in periods of scarcity through the addition of a price adder to the balancing price in period of scarcity. Markets players may then be remunerated for scarcity without being forced to reflect scarcity in their bids.

The principle of scarcity pricing with ORDC curve may be described as follow: when there is load curtailment (not a blackout) and the system has just the minimum of contingency operating reserves, then any increment of reserves would correspondingly reduce the load curtailment. Hence the price of operating reserves should be set at the value of loss of load (VOLL in short) during these periods. At any other level of operating reserves, set to protect the system from events in the immediate future, the value of an increment of operating reserves would be the same VOLL multiplied by the probability that the net load would increase enough in the coming interval to reduce the reserves to the minimum level where load would be curtailed to restore contingency reserves.

With this method, the pricing of scarcity and of reserves is more related to demand and the way consumers value electricity than to the costs of these reserves: this pricing or valuation of reserves is technology neutral and independent from the way they are provided. It also avoids to pay for reserves prices which are not economically justified.

The idea with the scarcity adder is to replace infrequent and unpredictable very high price spikes by smaller, but more frequent scarcity signals. This may incentivise the participation of demand in flexibility mechanism.

It is based on the assumption that, although it is difficult to forecast requirements for installed capacity many years ahead (as requested for most CRMs), it is a comparatively easier and more easy task for a TSO to forecast operating reserve requirements and availability for the next instant or part of an hour.

ORDC may be seen as an alternative to CRMs, with a key advantage linked to a possible cross-border implementation in the context of an integrated European energy market.

The study awarded to the CORE has as main objective to study the profitability of CCGT in Belgium and to examine the results of the application of the ORDC proposal on the profitability of these units.

This method may be seen as a way to transfer a part of the investment costs to shorter time frames while preserving at the same time short term operational efficiency (most efficient units should be dispatched) as a function of their location and congestion, while providing in parallel a better remuneration in zones where scarcity is a concern.

Implemented together with a support of renewable resources based on a premium instead of feed-in, this adder should result more in a reallocation or redistribution of profit in favour of more flexible units/demand instead of an average (total) price increase.

At this stage, in order to be able to continue the exploration of the impact of the implementation of an ORDC approach on the Belgian (or even European) market, several questions have to be answered in relation with the exact goal of this implementation which may range from a more market based way for the (replacement of the) remuneration of current capacity reserve costs by a price signal in favour of flexible generation/demand to the remuneration of capacity allowing a proactive energy transition towards new solutions for generation, storage and demand. A replacement/alternative to nuclear should indeed preferably come from the market, not from support schemes or even from open tenders for the remuneration (of investment and fixed costs) of alternative solutions.

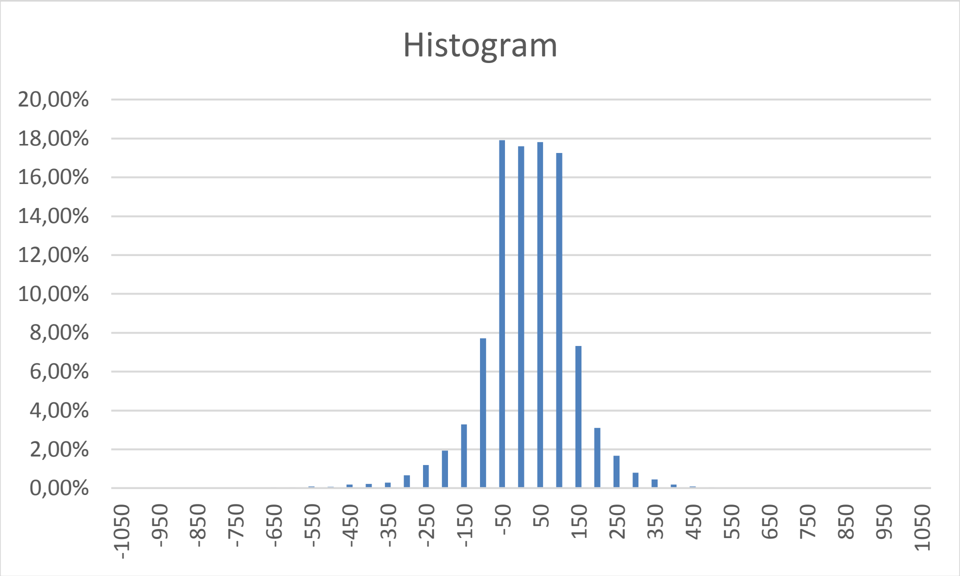
The ability of this method to provide a price adder close to zero when there are enough flexible reserves in the market is critical for its acceptance.

# III. Method applied to Belgium

The price adder computed with this method is mainly determined by the Value of Loss of Load (VOLL in short) which represent the value of electricity for market players (this value has been estimated around 8300 € recently for Belgium) and by the probability of not being able to feed the load, or the Loss of Load Probability, LOLP in short. This loss of load probability is linked to the volume of reserves and to their ability to compensate unexpected mismatch between generation and demand.

The estimation of the loss of load probability curve as a function of the volume of available reserves at a given time horizon is based on the distribution of the volume of reserves activated by Elia (mainly tertiary). This estimation of the volume of available reserves is based on hourly data, and has been interpolated to shorter time periods (7.5, 15, 30 and 60 minutes) under certain assumptions.

The picture below shows the distribution curve (hourly data) of the volume of reserves activations made by Elia in 15 minutes from January 2013 till end September 2014.



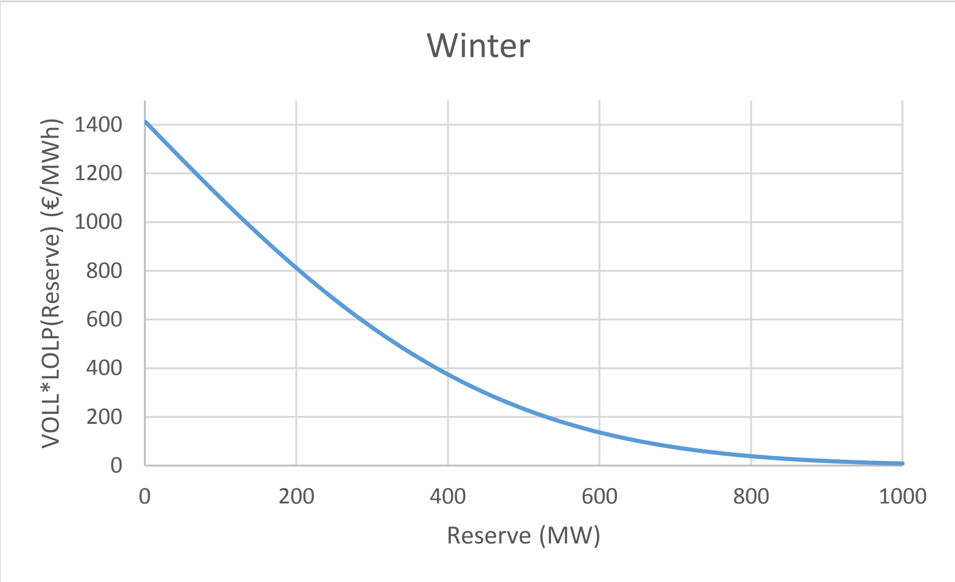

Several normalised probability distribution curves have been computed (see table 3 of the CORE study) for different seasons and different intervals of the day.

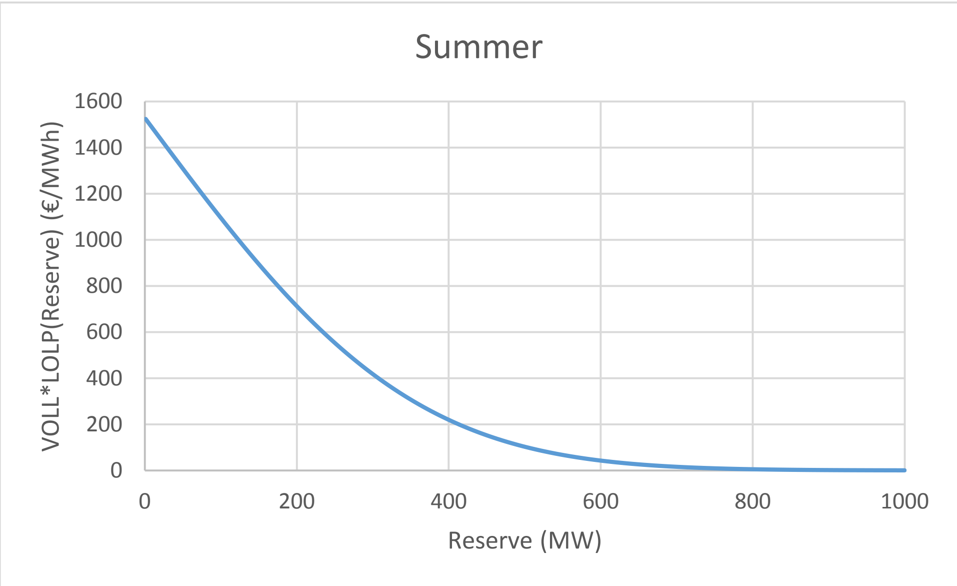
The probability that available reserves may not meet the load will vary in time with increasing renewable penetration, with the participation of demand and with other changes in the functioning of the electric system. So, the need and the frequency of the re-evaluation of the loss of load probability based on TSO behaviour has to be determined carefully before the implementation of this mechanism.

Equation 10 of the CORE study paper gives the relation for the computation of the price adder. This formula can be approximated by the following formula: the ORDC adder is approximately equal to the VOLL multiplied by the LOLP corresponding to the volume of reserves that can be made available in the requested time horizon. So this adder mainly remunerates flexibility.

It can be seen in formula 10 of the CORE study that the price adder for a given time horizon may be approximated by the VOLL multiplied by the LOLP for a given available reserve level.

The following picture presents the (approximated) price adder as a function reserve capacity available in the requested time horizon, ie. the VOLL multiplied by the loss of load probability as a function of reserve capacity. The result is shown for hours 11-14 which exhibit the greatest standard deviation. Results for winter 2013/2014 and summer 2014 are shown.

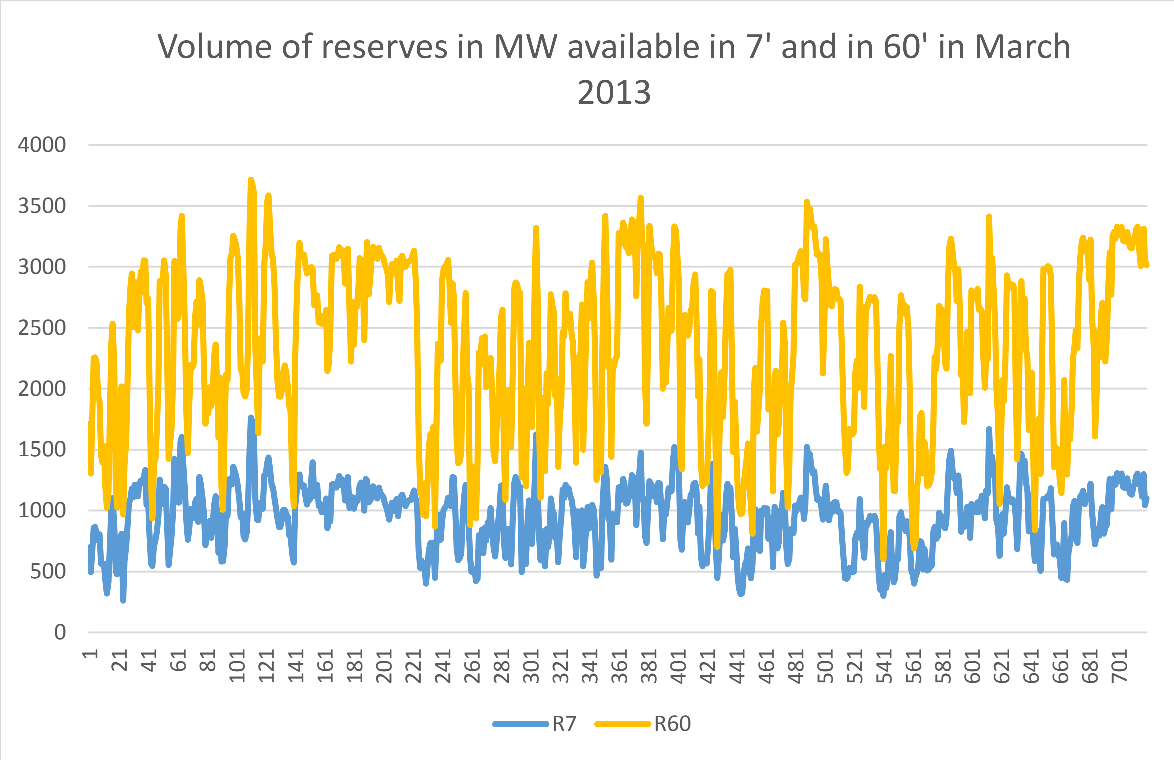


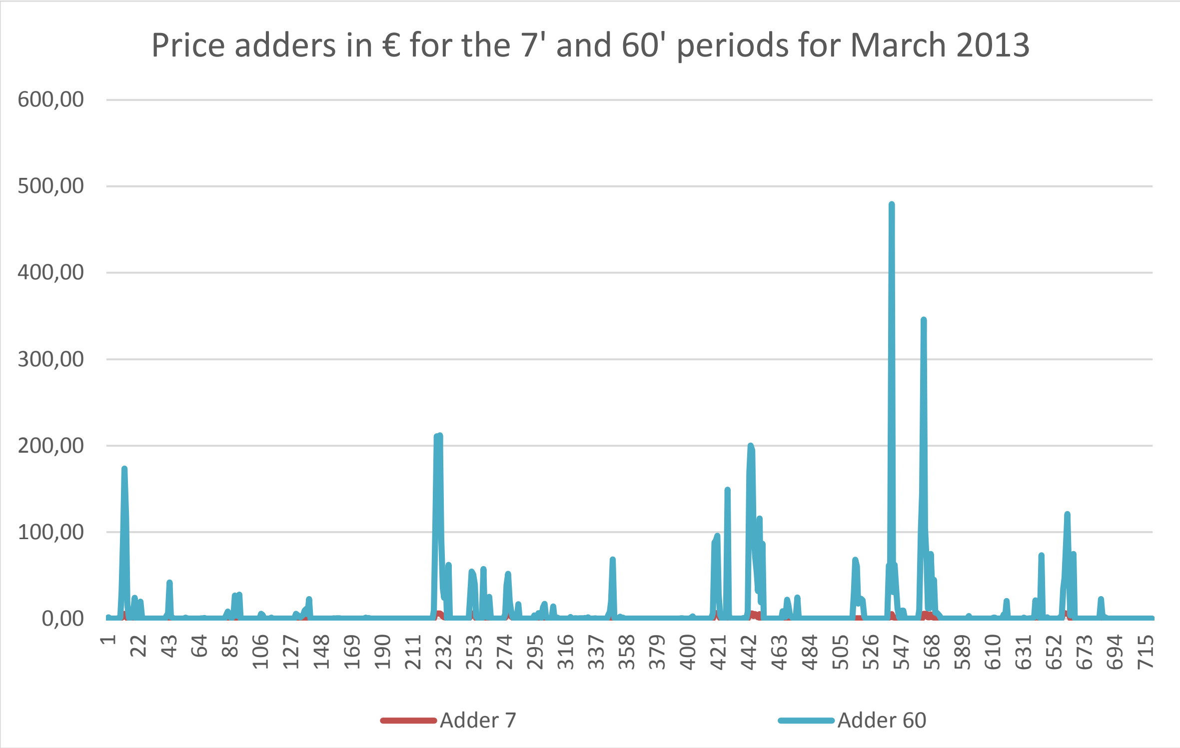

These figures confirm that this price adder is only a function of the value of loss of load – the value of electricity for consumers - and of the loss of load probability – the uncertainty that net demand fluctuations cannot be met – which is based on past TSO behaviour (and not on a given volume of reserves).

The first curve for the winter period reveals that when the total Belgian imbalance shows an excess of generation capacity and imports, the ORDC curve is shifted to the left and the 0 MW reserve value corresponds to less than a 50% loss of load probability. This is especially the case for the winter situation.

In order to determine the price adder, the amount of available reserves in a given time frame is continuously (every hour here) computed. The next picture illustrates this computation for the volume of reserves available in the 7' and 60' time horizon made for the month of March 2013.




These availabilities result in a price adder for the month of March 2013 which is presented on the next picture.




The average price adder for all the hours of the month is equal to 0,38 € for the 7' price adder, to 9,01€ for the 60' price adder and to 7,93€ for the combined price adder.

It can be seen that with the ORDC proposal, and its statistical approach, frequent price spikes of a lower magnitude replace a very few high prices spikes difficult to anticipate.

The combined price adder is computed on the basis of formula (11) of the study. The recourse to a combined 7' and 60' price adder was driven by the ORDC training material for the ERCOT market (slide 34). There they use a mix of 30 and 60 minutes for a blend of reserves that can react immediately and reserves that are fully available within 30 minutes. A mix of 7 and 60 minutes has been used for Belgium since secondary reserve in has fully reacted within 7 minutes. The use of other time horizons (ex. 7' combined with 15') should be examined carefully in relation with the data available in operation and the IBSP of 15'.

The price adder is always positive. It has to be added to the imbalance price for an increase of generation output. Downward regulation price should not be affected.

In the CORE study, a time horizon of 60 minutes has been used for the computation of the volume of activated reserves for reasons linked to the volume of data to be processed. But tertiary reserves are activated in Belgium with a delivery time of 15 minutes, secondary reserves have to be deployed in 7 minutes and the imbalance settlement period, called IBSP, is 15 minutes. For these reasons, an implementation of this mechanism should be based on the calculation of reserves using 15 minutes data and the implications of this modification should be studied.

The impact of reactive balancing, which allows market players to react to the imbalance signal within the current 15 minutes' period (without knowing the applicable imbalance price). In particular, the absence of gaming possibilities of market players on the expected volume of reserves should be analysed.

# IV. Study results

The proposed implementation of the ORDC considers the inclusion of a price adder in the balancing time frame for the remuneration of flexibility with a time span of delivery of 7 minutes combined with a delivery in 60 minutes, with a VOLL of 3000€[2], and a capacity shortfall in a 60 minutes' horizon estimation based on the activation of reserves made by Elia. From the 60 minute reserve activation data, shortfall for 7.5, 15, 30 and 60 minutes has been estimated under certain assumptions.

The main conclusions of the study are that 1) amortized CCGT were able to cover their short-run operating costs (margin in in the range of 0,9 – 3,9 €/MW.h ) for the study period (January 2013 till September 2014), assuming that these units participate in the reserves markets, but not their long-term investment costs. (Of course, if these units are not involved (directly or indirectly) in reserves contract, some of them may not to be profitable without the price adder (to be checked), and 2) that the addition of a scarcity adder for the remuneration of flexibility (in the 7 min timeframe and 60 min timeframe) is able to not only remunerate operating costs but also to remunerate investment costs of new CCGT units. Of course, if these units are not involved in reserves contract (5€/MW.h less), none of them seems to be profitable without the price adder.

Costs linked to the procurement of reserves (secondary and tertiary) capacities are supposed to be unchanged with the application of the scarcity price adder. In particular, results presented in table 4 of the study takes into account the revenues linked to reserve contract such as tertiary reserve (approximately 16 M€ for 350 MW on the basis of CREG internal confidential information) and secondary reserves (which amounts to approximately 29 M€ for a volume of

[2] 3000€ is based on the maximum bid price in CWE day-ahead markets; 8000€ could be more representative of the Belgian VOLL

140 MW from the same source of information). This amounts to 45ME or 1€/MW.h or 1,5 €/MW.h in function of the generation park.

Running investment costs of CCGT are estimated in the study to 4.5€/MW.h. which corresponds to 15,8 M€ per year for a unit of 400 MW.

The average adder for the duration of the study amounts to 6.06 €/MW.h or 21,2 M€/year for a CCGT of 400MW. This is the average increase in revenues that can be expected, for example, by base-load units that produce a constant output if the adder back-propagates to forward energy prices. The period analysed by the study has seen relatively deep negative CSS.

If balancing prices propagate to other time frames (the way this will occur is still unclear: co-optimisation of energy and reserves or the institution of a real-time market for reserve capacity could be two options to consider) and to the day-ahead market in particular, the current adder should result in an average price increase of 6,06 €/MW.h. This propagation (via arbitrage…) to other time frames is critical to avoid that market players (producers) "wait" the balancing time frame for being better remunerated.

Finally, it should be stressed that this study does not take into account the impact of strategic reserve.

It is important to indicate here that the study was targeted towards CCGT, and that the application of this approach to other generation units, batteries or demand has still to be studied. The applicability of this method to other generation/demand means will require real-time information related to the capability of these means to deliver the required response in time.

An implicit assumption of the study is that market players (producers and if feasible consumers) all available capacities to the balancing mechanism. This obligation exists in Belgium but this may not be the case in other countries.

# V. Conclusions

Current study results are encouraging. In 2013 and 2014, Belgium was importing a lot of energy and some scarcity was experienced, while at the same time large negative CSS where observed during the period. The proposed adder provides a long term price signal enough to invest in new CCGT units or a transition towards a new energy system.

Nevertheless, other studies, checks and parallel runs are needed before any implementation. In particular, the pertinence (importance) of the price signal provided by the scarcity mechanism should be evaluated in other market conditions (and maybe improved on the basis of 15' data). Indeed, today's situation of Belgium has totally changed, as far as generation adequacy is concerned, with the return in the market of several nuclear units and with an improvement of the CSS due to a gas price crash which makes CCGT more profitable.

The application of this approach to other generation units, storage or demand has to be validated.

The scope of application of the proposed mechanism, Belgium only or involving several countries will also have an important impact on the implementation design. Current EU developments linked to the balancing guideline and scarcity pricing seems to be encouraging and a collaboration with neighbours on these issues should be explored.

With the comeback of nuclear units until 2023 -2025, new questions linked to the transition to a less centralised generation system with more renewables arise and in particular how to foster such a transition in a market based, technology neutral way.

Finally, a detailed implementation study to be made by Elia together with parallel runs simulations should be considered before implementing this mechanism.

So, the following tasks/studies are possible extensions of the current study which may be of relevance before a decision of implementation:

- The return of all nuclear generation units was unexpected and the results of the application of the proposed model to the new current situation should be studied. In particular, the application of the method on the beginning of 2016 (January-April) should be performed. The period from September 2014 to end 2015 should also be explored together with the check of the validity of the different assumptions made in the study (VOLL, 7min & 15' scarcity price adder, 15 minutes' data, reactive balancing implications) taking into account the impact of strategic reserves (it is expected that this impact should lower the computed price adder).

- The condition for the propagation of the balancing price to other time frames should be examined. The implementation of a local solution, such as the implementation of a real time market for reserve capacities, involving Belgium only, should be explored first. In a second step, co-optimisation of energy and reserves (with opportunity costs compensation), may also be explored. The implementation of this second solution may be considered as more difficult as this imply a modification of the day-ahead market coupling algorithm (Euphemia). If there is some European appetite for this kind of mechanism, a cross-border implementation of co-optimisation may also be envisaged.

- The application of this concept to two zones coupled in real time and the determination of the impact of this coupling and in particular of the volume of available cross-zonal capacity on the scarcity signal should be studied. This extension is especially important if cross-zonal (border) participation is considered as a pre-requisite for the implementation in Europe of this kind of mechanism. A possible cooperation on this issue with neighbours should be explored.

For the Commission for Electricity and Gas Regulation:

| | |
|---|---|
| Andreas TIREZ | Marie-Pierre FAUCONNIER |
| Director | Chairwoman of the Board of Directors |

# APPENDIX 1

# Remuneration of Flexibility using Operating Reserve Demand Curves: A Case Study of Belgium

*Anthony Papavasiliou*, and Yves Smeers**,*

**ABSTRACT**

Flexibility is becoming an increasingly important attribute of conventional generators due to the challenges imposed by the unpredictable, highly variable and non-controllable nature of renewable supply. Paradoxically, flexible units are currently being mothballed or retired in Europe due to financial losses. We investigate an energy-only market design, referred to as operating reserve demand curves, that rewards flexibility by adjusting the real-time energy price to a level that reflects the value of capacity under conditions of scarcity. We test the performance of the mechanism by developing a model of the Belgian electricity market, which is validated against the historical outcomes of the market over a study period of 21 months. We verify that (i) based on the observed market outcomes of our study period, none of the existing combined cycle gas turbines of the Belgian market can cover their investment costs, 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.

**Keywords:** Flexibility, Energy-only markets, Renewable integration, Operating reserves, Capacity remuneration, Unit Commitment

*Corresponding author. Center for Operations Research and Econometrics, Université catholique de Louvain. E-mail: anthony.papavasiliou@uclouvain.be.

**Center for Operations Research and Econometrics, Université catholique de Louvain.

## 1. INTRODUCTION

The remuneration of flexible capacity is a growing challenge of electricity market design. The problem can be seen as resulting from three parallel phenomena. First, ambitious renewable energy integration targets, especially in the EU, create the need for flexible capacity. At the same time the penetration of renewable energy depresses energy prices and hence also the revenue of the gas-fired units with flexible operating characteristics that today provide the much needed flexibility. Last, capacity mechanisms are seen with reluctance by EU authorities that advocate energy-only markets. This paper investigates the extent to which an economically justified remuneration of reserve capacity through operating reserve demand curves (ORDC) could provide the needed support for keeping the flexible capacity in the system. Operating reserve demand curves were introduced by Stoft (2002) and advocated by Hogan (2005) in order to support the remuneration of capacity in restructured US electricity markets. ORDC is an energy-only mechanism. This paper explores the possible application of ORDC in a European context. The question was raised by the Belgian regulator and the discussion therefore addresses the Belgian market; but we believe that our treatment could be adapted to all European countries functioning under the so called "Market Coupling" design.

The North American Electric Reliability Council defines security as the ability of the electric system to withstand sudden disturbances such as electric short circuits or the unanticipated loss of system elements. In this paper we concentrate on reserves for dealing with contingencies and net load forecast errors. Taken in this sense, security of supply is always a public good that is procured by the system operator on behalf of electricity market agents. In order to overcome free riding, the system operator procures reserves that ensure an appropriate level of security. These are adjusted to satisfy certain engineering criteria, such as the "one day in 10 years" criterion that stipulates a reliability of service of 99.97%. Such reliability criteria have been challenged by economists as corresponding to an excessively high valuation for power and potentially over-providing reserves (Telson, 1975), but they have been widely applied in practice. The recent proliferation of renewable resources has led to scrutiny over the appropriateness of fixed reserve requirements, as opposed to dynamic reserve criteria that reflect the real-time conditions of the system (Papavasiliou and Oren, 2013). We remain in this context as ORDC values reserve as a function of real-time conditions of the system but we address an economic problem: we want to assess whether the integration of renewable resources shifts a sufficient amount of value from energy markets into reserve markets, such that flexible units[1] providing reserves earn sufficient revenue to ensure their economic viability. Such a finding may imply the need to introduce new mechanisms for capturing this value and organizing its transfer to flexible plants. These mechanisms should naturally be dynamic and reflective of the real-time conditions of the system, which justifies the consideration of ORDC. Also of interest in the EU context, these mechanisms should also preferably be of the energy-only type, which is the case for ORDC that values flexibility through the sole price of energy.

### 1.1 Rewarding Capacity versus Rewarding Flexibility

Beyond free riding associated to the public good character of reserve, which complicates the provision of an appropriate level of security, electricity markets struggle inherently with supporting capacity investment due to several market failures. Economic theory predicts that real-time prices should be sufficient to reflect the value of scarce flexible capacity, lending support to the notion of energy-only markets. The principle is that real-time deviations for power balance will induce changes in equilibrium prices; agents that are flexible enough to respond to such changes immediately will be rewarded for supporting the system through their reaction. The issue is to have a market design that conveys these principles in practice. The difficulties are well known: (i) there is a need for instantaneously balancing supply and demand (electricity is probably the only good for which the standard economic assumption of "free disposal" does not hold), (ii) demand is extremely inelastic in the short term because of lack of storage, therefore leading to highly variable prices, and (iii) it is largely impossible to prevent customers whose valuation falls short of the real-time price from consuming power. The closest design to the theoretical ideal of real-time energy-only markets is value of lost load (VOLL) pricing (Stoft, 2002), where provision is rationed randomly under conditions of scarcity and the price is set to an administratively determined estimate of VOLL. However, VOLL pricing also raises issues: the estimation of VOLL, although crucial for the performance of the resulting mechanism, is notoriously difficult. Moreover, energy-only markets require price spikes in order to support investments but it is difficult if not often impossible to attribute the occurrence of such spikes to the exercise of market power or true scarcity[2]. The result is that regulatory ceilings in energy market bids or clearing prices undermine the function of energy-only markets, resulting in missing money and capacity shortages. In short, energy only markets are seen as creating a perilous investment environment, especially for large generating units.

[1]The study presented in this paper is focused on conventional thermal units. The problem would have to be restated in a system with smaller units for which one needs to be able to capture and measure flexibility.

[2]Recently demand bids have been observed to set the price in the Belgian electricity market.

Capacity payment mechanisms are the usual contenders of energy only markets. In analogy to fixed reserve requirements that represent a static approach towards ensuring security of supply, capacity markets in their simplest form could be interpreted as a static economic mechanism for supporting flexible capacity. In vanilla capacity mechanisms, capacity requirements are set by the regulator and an auction is conducted in order to determine an equilibrium price for each unit of installed capacity. Capacity payments are a price-based method of achieving the same goal as capacity requirements that may err significantly in terms of installed capacity if the capacity price is not estimated correctly (Oren, 2000). Capacity requirements fail to "pay for performance", i.e. reward resources only if they deliver their promised capacity under scarce real-time conditions. In practice, installed capacity requirements (Cramton and Stoft, 2005) are geared towards overcoming the challenge of paying for performance by scoring generators based on their availability in conditions of scarcity. Even though capacity mechanisms are generally perceived as providing more reliable investment signals, as opposed to the volatile price spikes of energy-only markets with inelastic demand, capacity markets typically fail to discriminate resources with respect to flexibility. Moreover, the determination of capacity targets is often contestable and non-transparent. Last but not least, capacity markets have been criticized for suppressing economic signals for proliferating demand response.

The debate over energy-only markets and capacity mechanisms is long-standing, with diverse outcomes in practice. Levin and Botterud (2015) provide an up-to-date classification of scarcity mechanisms and capacity markets that are utilized by the eight major electricity market operators in the Unites States (CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM and SPP). The debate between energy-only markets and capacity mechanisms is also lively in Europe, and is driven to some extent by the ambitious renewable integration targets of the European Commission (Commission, 2009a) and the goal of a common Internal Electricity Market (Commission, 2009b). An energy-only design is especially favored by the European Commission, as it is perceived as being less centralized and is in line with market coupling and the design of a common European energy market. Instead, capacity markets are criticized as balkanizing the European market design. European markets are currently organized as follows (CREG, 2012): (i) Energy-only markets are in place in Belgium[3], Germany, the Netherlands, Great Britain; (ii) capacity payments are instituted in Spain, Portugal and Ireland; (iii) capacity requirements are imposed in Sweden and Finland; (iv) France is transitioning from an

[3]Belgium recently introduced strategic reserve, which is mothballed capacity that has been re-commissioned in order to address supply shortages. In principle strategic reserve impacts long-run investment incentives, although there has been minimal impact on short-term operations in the Belgian system.

energy-only market to a decentralized capacity market.

### 1.2 Operating Reserve Demand Curves

In order to overcome the challenges associated with energy-only markets, Hogan proposes a correction of energy prices through adders that reflect the true value of flexible capacity (sufficiently flexible to provide operating reserve) that stems from reducing the loss of load probability (Hogan, 2005), (Hogan, 2013). The proposed mechanism is motivated by an effort to align the valuation of reserve capacity with the operating practices of system operators. The value of operating reserve capacity stems from its ability to decrease the probability of lost load.

Economically, energy and reserve prices are linked by an arbitrage which equalizes the price for reserves to the opportunity cost of keeping capacity out of the energy market. An abundance of reserve (and hence a zero value) at some moment of time would imply that all the capacity should remain in the energy market (where its gross margin, which is equal to the electricity price minus the fuel price, would also be zero). In contrast, scarce reserve has a non-zero value that should modify the energy price set by the marginal plant in order to induce some capacity of that plant to move to reserve. As argued previously, the price of reserve should vary according to the level of operating reserve capacity that is available in the system at any time. Given this arbitrage relationship between energy and reserves, energy prices should reflect the scarcity value of reserve. This is what the ORDC does by setting the real-time price of electricity at a level that ensures that a price-taking agent offering energy and reserve capacity would, in equilibrium, dispatch its unit according to a socially optimal schedule. Note that this adjustment is a real time phenomenon that reflects the instantaneous situation of the system. ORDC thus does not play any role in the day ahead or before the day ahead to procure reserve capacity.

Hogan lists a number of attractive features of the proposed mechanism for a US system where energy and ancillary services are co-optimized in real time by an Independent System Operator. Under the ORDC design, short-run efficiency is achieved through the co-optimization of reserves and energy, while long-run efficiency is achieved through the increase of energy prices under scarcity conditions. An attraction of the proposed design as compared to installed capacity targets is the fact that the real-time energy market better reflects scarcity conditions whereas in installed capacity designs numerous forecasts are required in order to set target levels for installed capacity. Energy price spikes resulting from ORDC are more frequent and of smaller magnitude than VOLL pricing, thereby rendering payments for scarce capacity less volatile and more predictable. Market power can be mitigated by imposing an offer cap on generators since, in contrast to energy-only markets without an operating reserve demand curve, prices for energy and operating reserves can increase and provide scarcity rent even if generators do not submit high bids in the energy market[4]. As in energy-only markets, the VOLL is estimated by the regulator. The proposed design has been adopted in the Electric Reliability Council of Texas (ERCOT), and generated notable adders in the summer of 2015. The implementation of the mechanism is currently under consideration in a number of other US markets.

US and EU markets are not designed in the same way and a first question is whether ORDC can be implemented in the EU electricity market design where the power exchange is cleared independently of reserve dispatch. In a US-style market design where energy and ancillary services are co-optimized in real time by an Independent System Operator, the proposed adjustment to the energy price could either be added ex post to the real-time energy price (as is currently the case in Texas), or the system could be dispatched in real time with the operating reserve demand function included in the objective function. Because both balancing and reserve are the responsibility of Transmission System Operators, this mechanism could be implemented in European balancing markets to accurately signal the real-time conditions of the system; this would maintain the existing structure of these markets. However, two features of the European market would have to be reconsidered. The European balancing market should function as a two-settlement system whereby balancing responsible parties should be able to deviate from their schedule and receive the balancing price for their deviation. In addition, the value of scarce capacity needs to be propagated to earlier stages[5]. This issue is rather subtle (it appears in US market design in the context of discussions about the role of the day ahead market as a forward market) and is left for further investigations.

### 1.3 Research Goal and Outline

Belgian power production capacity connected to the ELIA grid amounts to 14765 MW. Between September 2014 and mid-October 2014, four nuclear units in the Belgian system were retired from service simultaneously due to technical malfunctions, amounting to a total unplanned outage of approximately 4000 MW. In light of these events and the paradoxical retirement and mothballing of flexible capacity in Belgium, the Belgian Regulatory Commission for Electricity and Gas (CREG)

[4] Recent observations in Belgium have shown that scarcity rents are possible even if generators bid at marginal cost CREG (2016).

[5] Pools co-optimize energy and reserve in multi-product auctions, thereby aligning the day-ahead energy price to the price of reserve capacity. In energy-only exchanges, this price alignment requires that agents be able to mark up their day-ahead energy bids by the opportunity cost of reserving their capacity for the real-time market.

issued an investigation about whether adequate incentives are in place in order to attract investment in flexible power generation in the country. The question that is addressed in this study is how electricity prices in the Belgian market would be impacted if ORDC price adders were introduced in the market.

The paper is structured as follows. In section 2 we describe the methodology that we have used for conducting our analysis. In section 3 we present a model of the Belgian electricity market, which is validated against 21 months of historical observations of the Belgian market. In section 4 we present the results of our analysis. In section 5 we conclude and discuss directions of future research.

## 2. METHODOLOGY

We first provide a detailed exposition of the idea of operating reserve demand curves. We then outline the organization of our study.

### 2.1 The Idea of Operating Reserve Demand Curves

The ORDC is a real-time mechanism where the decision is to be made of optimally trading off the allocation of capacity between the provision of energy and the protection of the system against uncertain shortfalls in available capacity. The basic model that motivates the proposed mechanism can be described as a two-stage stochastic program (Hogan, 2013). Consider a probability space $(\Omega, \mathcal{F}, f)$ consisting of a set of outcomes $\Omega$ and a discrete probability measure $f$. The set of outcomes represents the uncertainty faced by the system operator due to unanticipated net demand fluctuations and contingencies. The model (dual variables are listed on the left side) is stated as:

$$\begin{aligned}
& \max \int_{x=0}^{d} MB(x)dx - \int_{x=0}^{\sum_g p_g} MC(x)dx + \\
& \sum_{\omega} f_\omega \cdot (VOLL \cdot \delta\omega - MC(\sum_g p_g) \cdot \delta_\omega) \qquad (1)\\
\text{s.t.} \quad (\lambda): \quad & \sum_g p_g \geq d \qquad (2)\\
(\mu_\omega): \quad & \sum_g r_g \geq \delta_\omega, \forall \omega \in \Omega \qquad (3)\\
(\rho_g): \quad & p_g + r_g \leq P_g, \forall g \in G \qquad (4)\\
(\gamma_\omega): \quad & \delta_\omega \leq \Delta_\omega, \forall \omega \in \Omega \qquad (5)\\
& p_g, r_g, d, \delta_\omega \geq 0 \qquad (6)
\end{aligned}$$

where $\Delta_\omega$ corresponds to the additional demand that appears under outcome $\omega$ and $\delta_\omega$ corresponds to the amount of $\Delta_\omega$ that is actually served. The marginal cost function of the system that corresponds to a system-wide output of $\sum_g p_g$ is described by $MC(\cdot)$ and $r_g$ corresponds to the amount of reserve provided by a generator. The marginal benefit of consumers is represented by a decreasing function $MB(\cdot)$, with $d$ corresponding to the power consumption of loads.

Assuming an interior solution for a marginal generator ($p_g > 0$ and $r_g > 0$ for some $g$), one obtains from the KKT conditions

$$\begin{aligned} \lambda &= MC(\sum_g p_g) + \sum_\omega f_\omega MC'(\sum_g p_g)\delta_\omega + \rho_g \\ &= MC(\sum_g p_g) + \sum_\omega f_\omega MC'(\sum_g p_g)\delta_\omega + \sum_\omega \mu_\omega \end{aligned} \tag{7}$$

The following cases can now be considered for a given contingency $\omega$: either (i) the amount of committed reserve does not suffice for covering the net load deviation, $\Delta_\omega > \sum_g r_g$, or (ii) the reserved capacity suffices for covering the demand deviation, $\Delta_\omega < \sum_g r_g$. As a technicality, consider also the degenerate case (iii) where the reserved capacity exactly covers the demand deviation, $\Delta_{\omega_0} = \sum_g r_g$ (this possibility corresponds to a single outcome, which is denoted $\omega_0$ where both $\sum_g r_g \geq \delta_\omega$ and $\delta_\omega \leq \Delta_\omega$ hold as equalities). In the first case, since $\delta_\omega < \Delta_\omega$ we conclude that $\gamma_\omega = 0$. In the second case, since $\delta_\omega < \sum_g r_g$ we conclude that $\mu_\omega = 0$, while $\mu_{\omega_0} \geq 0$ and $\gamma_{\omega_0} \geq 0$ in the third case. This yields

$$\sum_\omega \mu_\omega = \sum_{\omega:\Delta_\omega \geq \sum_g r_g} \mu_\omega - \gamma_{\omega_0} \tag{8}$$

Given that $\delta_\omega > 0$ for every realization, the KKT conditions give $\mu_\omega + \gamma_\omega = f_\omega(VOLL - MC(\sum_g p_g))$. Case (iii) is degenerate in the sense that we can select any non-negative value of $\mu_{\omega_0}$ and $\gamma_{\omega_0}$ satisfying $\mu_{\omega_0} + \gamma_{\omega_0} = f_{\omega_0}(VOLL - MC(\sum_g p_g))$. Selecting $\mu_{\omega_0} = f_{\omega_0}(VOLL - MC(\sum_g p_g))$ we obtain

$$\begin{aligned} \sum_\omega \mu_\omega &= \sum_{\omega:\Delta_\omega \geq \sum_g r_g} f_\omega(VOLL - MC(\sum_g p_g)) \\ &= LOLP(\sum_g r_g) \cdot (VOLL - MC(\sum_g p_g)), \end{aligned} \tag{9}$$

where $LOLP(R) = \mathbb{P}[\Delta_\omega > R]$ is the loss of load probability given reserve level $R$, i.e. the probability that an unforeseen shortfall in capacity or increase in demand exceeds the level of reserves. Substituting back to equation (7), and ignoring the term $\sum_\omega f_\omega MC'(\sum_g p_g)\delta_\omega$ due to its second order effect (for example, the term vanishes if at the optimal solution the marginal cost is constant), we obtain

$$\lambda = MC(\sum_g p_g) + (VOLL - MC(\sum_g p_g)) \cdot LOLP(\sum_g r_g). \tag{10}$$

The first term of the expression corresponds to the equilibrium competitive price that is obtained by an energy-only dispatch that ignores reserve. The second term, referred to hereafter as a price adder, corresponds to a price lift that quantifies the value of scarce reserve capacity. This adder indicates how the energy price should be adjusted if individual generators were to voluntarily replicate the socially optimal allocation of their capacity among energy and reserves.

Reserve products are imperfectly substitutable, with faster reserve capacity being capable of covering multiple reserve products (for example, fast-responding capacity can be used for satisfying both secondary as well as tertiary reserve). The methodology presented above can be applied for computing price adders that align incentives in an auction that clears multiple substitutable reserves. Consider reserves with response times $T_1 = \Delta_1 < \Delta_2 = T_1 + T_2$, and suppose that a total reserve capacity of $R_{\Delta_i}$ can be made available by time $\Delta_i$. Then it can be shown that, as long as the pivotal unit has not exhausted its ramp capacity for response time $\Delta_1$, the ORDC price adder needs to be adjusted as follows:

$$\begin{aligned}\lambda = MC(\sum_g p_g) + \frac{T_1}{T_1 + T_2}(VOLL - MC(\sum_g p_g)) \cdot LOLP_{\Delta_1}(R_{\Delta_1}) +& \\ \frac{T_1}{T_1 + T_2}(VOLL - MC(\sum_g p_g)) \cdot LOLP_{\Delta_2}(R_{\Delta_2}),&\end{aligned} \tag{11}$$

where the loss of load probability $LOLP_{\Delta_i}$ is adjusted for the horizon at which the reserve can be delivered, with a deeper time horizon corresponding to greater uncertainty.

### 2.2 ORDC and EU Market Design

The design of the EU market differs in several aspects from the US system for which the ORDC was proposed. This section briefly discusses some issues that we think are important for the analysis. The organization of transmission and the role played by the day-ahead market are the two major divergences between the US and EU systems. We disregard transmission constraints that are somewhat marginal to ORDC and concentrate on the day-ahead market. We first compare the role of ORDC in the US and EU organizations and then elaborate on the clearing of the market. Variations between

ISOs in the US are incidental for our purpose and can be neglected.

*2.2.1 Single and Two Settlement Systems*

The US restructured power market is a two settlement system with added virtual trading. The underlying idea is that there should be a forward market in the day ahead and a spot market in real time. Because of different constraints applying in these two stages, virtual trading is introduced to enable arbitrage between them. ORDC is meant to measure the scarcity of reserve in real time and hence should apply in the real-time market, based on machine availability for energy and reserve determined by the unit commitment.

The EU market is structurally a single settlement market cleared in day ahead. Balancing takes place in real time but is conceived as a correction mechanism; its organization differs from the one of day-ahead and balancing cannot be seen as a spot market following a forward day-ahead market. We argued before that ORDC should be implemented with balancing restructured as the second stage of a two settlement system. Our analysis assumes that ORDC is implemented in real time, seen as a true market that signals the scarcity of capacity in the EU market design using the machine availability for energy and reserve determined before real time. The question is then to simulate this market.

*2.2.2 Market Clearing*

As explained previously, the adder requires knowing the marginal cost $MC(\sum_g p_g)$ and the amount of available reserve within a time interval $T$, $R_T$, in each hour of the horizon. Because we are interested in prospective information, we also wish to be able to conduct the analysis on the basis of a model that can be run under different scenarios. The following motivates our modeling approach on the basis of a comparison of US and EU market clearing in the day ahead.

Generators are subject to indivisibilities (startup and shutdown cost, minimal duration between startup and shutdown, and so on), of which the importance is growing with the penetration of renewable resources. It is well known that there cannot be any true market clearing in the presence of indivisibilities in the sense that one cannot guarantee the existence of linear prices that balance supply and demand. This applies to both the US and EU with the consequence that none of these day-ahead markets clears in the strict sense of the term (even though we retain the term "clearing" for convenience). The unit commitment model is central to market clearing in the US where the ISO simultaneously clears the day-ahead energy and reserve markets on the basis of offers describing economic and technical characteristics of the machines. This produces an efficient (least cost or welfare maximizing) schedule. Because of indivisibilities this schedule cannot in general be supported by a linear price system. This means that dual variables of either the linear or convex hull relaxations of the UC give prices that do not fully support all the efficient dispatch schedules. Uplifts that make whole these generators that should be part of the efficient dispatch but are not supported by the associated price system correct the situation. All generators that are part of the efficient dispatch are thus incentivized to remain in the system. This process, and hence the introduction of ORDC in this process, is easy to model, at least in principle: it entirely relies on a unit commitment model, which is a well known instrument in the profession.

The EU separates the energy and reserve markets into an energy market cleared by a Power Exchange and a reserve auction conducted by the TSO. This means that generators need to arbitrage their allocation of capacities between the energy and reserve markets. This is a first difference with the US where this arbitrage is conducted by the unit commitment. A second difference is that the clearing of the energy market is not made on the basis of bids involving energy costs and machine characteristics. The EU organization requires that generators internalize these machine characteristics into energy bids subject to logical constraints (e.g. all or nothing bids). These are referred to as block bids. The clearing of the EU energy market thus takes place over a mix of flexible bids (without logical constraints) and block bids (with logical constraints). This clearing could be done by a mixed integer program as for the security constrained unit commitment, but again this is not what the rules of the power exchange require. A special purpose mixed integer algorithm (EUPHEMIA) clears the energy market by searching for the mix of flexible and block bids that (i) maximizes welfare (or equivalently here minimizes cost), (ii) satisfies demand, (iii) subject to the additional (and unusual) constraint that there exist linear prices clearing the retained flexible bids and (iv) all the retained block bids are in the money at those prices. Parts (i) and (ii) that deal with quantities are similar to what the unit commitment produces, except that the model is formulated in flexible and block bids. Parts (iii) and (iv) are unusual: they are meant to produce something that resembles linear market clearing prices. As this is impossible, EUPHEMIA also generates some undesired by-product: block bids that are in the money but in excess of what is efficient to satisfy demand. These are referred to as "paradoxically rejected bids". Notwithstanding the sophistication of the method, the EU market design leads to a degradation of the overall welfare compared to a US solution because of the need to transform machine characteristics into block bids and the unusual price constraint in the welfare maximization. This also means that the application of ORDC in the EU system is not as straightforward: the commitment of capacities and their allocation between energy and reserve are not directly coming from a unit commitment model as we discuss now. On the other hand, Van Vyve (2011) argues that EU design without side payments may provide stronger incentives for market players to bid truthfully.

### 2.3 Implication for the Study

The principles underlying EUPHEMIA are well documented in the professional and academic literature and the algorithm can be programmed relatively easily by external parties on the basis of that information. In contrast, the internalization of technical constraints by market players in terms of block bids as well as the allocation of their capacities between the energy and reserve markets (separation of energy and reserve in the EU design) are by nature inaccessible to outside parties. It is thus impossible to reproduce the functioning of the market. One can however argue that EUPHEMIA, by trying to maximize welfare pursues the same objective as the minimization of the cost of the unit commitment. Similarly, one could conjecture that good practitioners should have found some way to construct meaningful block bids. As to the separation of the capacity into energy and reserve, one can also invoke that usual economic assumption that agents properly arbitrage between them. In short, except for the price constraints in the enumeration, EUPHEMIA tries to reproduce what an integrated (energy and reserve) unit commitment does. We thus make the bold conjecture that a pure unit commitment used to allocate capacity to reserve and energy and operating on the basis of the technical description of the machines could be a reasonable approximation to market observation. Needless to say this conjecture must be validated. This is the purpose of the validation component of our analysis.

The situation is quite different for prices. The use of the unit commitment to clear the market in the US leads to a price system that does not induce enough generation and hence requires some additional action through uplift. In contrast; EUPHEMIA by construction leads to a price system that leads to excess generation (just the opposite of a price system derived from the UC) and needs to dispose of some in the form of paradoxically rejected bids. By construction EUPHEMIA is not driven by the objective of reproducing prices similar to those that could be extracted from a UC. As we shall see it is effectively necessary to construct a separate model that mimics the construction of the price system by EUPHEMIA. This is the model presented in section 6.3 of the appendix.

### 2.4 Proposed Methodology

Notwithstanding these differences between the US and EU system, the goal of our study remains to determine how the introduction of ORDC could impact the remuneration of flexible plants in the Belgian electricity market. As indicated in equations (10) and (11), this requires (i) knowledge of the marginal cost of the marginal unit $MC(\sum_g p_g)$ in the real-time market, (ii) quantifying the net load uncertainty which the system faces within a given time horizon $T$ in order to compute the function $LOLP_T(\cdot)$, and (iii) quantifying the amount of reserve $R_T$ that can be made available within a time horizon $T$.

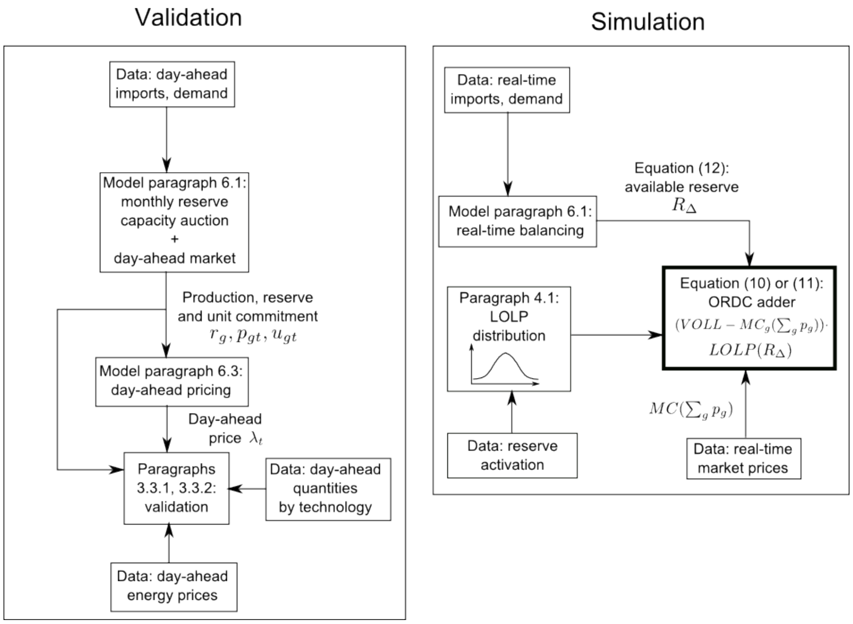
The data that was provided for the study includes day-ahead and real-time prices of the Belgian market, hourly production *by fuel* in both the day-ahead and real-time market, demand in the day-ahead and real-time market, the amount of activated reserve energy (instead, the amount of reserve capacity provided by each unit or the amount of activated reserve energy by unit is not available), production capacity available *by fuel*, and imports/exports in the day ahead and in real time over each interconnection.

The marginal cost of the marginal unit $MC_g(\sum_g p_g)$ is estimated in our analysis by the real-time price. The net load uncertainty within a fifteen-minute horizon is estimated based on the amount of activated reserve energy[6]. A normal distribution is fit to the net load uncertainty in order to obtain the function $LOLP_T(\cdot)$, as explained in section 4.1. The major challenge was to estimate the amount of capacity $R_T$ that is available in real time within a time horizon $T$. This capacity depends on the ramp rates of the specific units that were actually committed at each given hour of the study. This data was not available to us explicitly. We deduce this information by using the data that was provided to us in order to build a bottom-up model of the Belgian electricity market. The Belgian market model that we develop is validated against the data that was provided to us by comparing its predictions to the actual *day-ahead* market clearing price and market clearing quantity of the Belgian market for the duration of the study. The day-ahead and real-time net demand faced by thermal units over the duration of the study exhibit a mean absolute error of 172 MW, which indicates that the day-ahead unit commitment decisions should be close predictors of the units that actually operate in real time[7]. Therefore, by being able to develop a model that closely emulates the outcomes of the

[6]Provided there is no involuntary load shedding, activated reserve energy corresponds to the net load deviation in real time, otherwise it is an under-estimate of net load deviation. Given that involuntary load shedding is rare in Belgium, activated reserve energy is chosen as an accurate proxy of net load deviation.

[7]Note that the smallest CCGT units in the Belgian markets have a capacity of 350 MW. This suggests that a mean absolute error of 172 MW between day-ahead and real-time net demand is unlikely to result in a significant reshuffling of the thermal fleet from day-ahead to real-time operations. In case of increasing renewable energy integration the role of intraday markets

**Figure 1: A schematic diagram of the proposed methodology. The dashed border indicates the validation of the market model.**




Belgian day-ahead electricity market we are able to deduce the individual units that were actually on-line in real time over the duration of the study. This information is then adequate for inferring the amount of reserve capacity that would be available within a time interval $T$, thus enabling us to estimate the ORDC price adder. Previous research on ORDC either ignores individual unit ramp constraints (Levin and Botterud, 2015) (which, we argue, may greatly influence the resulting adder), or applies the analysis without previously calibrating the market model to actual market outcomes (Zhou and Botterud, 2014).

The methodology is explained in further detail in figure 1. The validation process of the Belgian market model is indicated in the left part of the figure, while the simulation of the Belgian market in order to determine price adders is indicated in the right part of the figure. Details about each part of the analysis are provided in the paragraphs that are indicated by figure 1.

The Belgian market model that we develop is based on a unit commitment and dispatch model[8] which is presented in section 6.1 of the appendix. Once our market model is calibrated, we validate it by comparing its ability to explain observed market prices and cleared quantities to competing approaches. The competing approaches are developed in detail in section 3.3.1 (for explaining observed quantities) and section 3.3.2 (for explaining observed prices).

in adjusting the position of the thermal fleet would be expected to become more important, in which case a validation of a candidate market model against day-ahead market historical performance might be less meaningful.

[8]Note that although the market model is presented in a decentralized format, it is solved as a coordinated optimization problem using the solution methodology of section 6.2.

A successful validation of our model against Belgian market data would imply that the model could also be used for examining the impact of ORDC in a prospective study for future conditions of the system[9]. As indicated in figure 1, such an analysis would require, as exogenous input, a forecast of real-time system demand and imports (which could be part of the definition of the scenarios of a prospective study). The computation of $MC(\sum_g p_g)$ in the context of a prospective study is of minor importance since $VOLL$ tends to exceed $MC(\sum_g p_g)$ by at least one order of magnitude, thereby rendering $VOLL \cdot LOLP(R_\Delta)$ as an acceptably accurate approximation of the ORDC adder in equation (10).

Note that this is an open-loop analysis, i.e. we do not account for how the expectation of introducing ORDC feeds back into the capacity that is deployed in the market. A closed loop analysis will be the subject of future investigation.

## 3. MODELING THE BELGIAN ELECTRICITY MARKET

We proceed with a description of the Belgian electricity market. We discuss the calibration of our model, and the validation of our model against historical outcomes of power production and price realizations.

### 3.1 Salient Features of the Belgian Market

The Belgian day-ahead energy market is organized as an exchange and clears power independently of reserves. Belgium participates in the Central Western European (CWE) energy market. Until May 2015 (this includes the interval of time studied in this paper), transmission constraints were represented in the exchange using a transportation model that ignores intra-zonal congestion as well as the physical constraints imposed by Kirchhoff's voltage laws and produce loop flows[10]. The exchange clears at a uniform zonal price. Two types of bids can be submitted to the exchange. Continuous bids correspond to a price-quantity pair for each hour, and clear according to standard rules for uniform price auctions (i.e. bids that are in the money are accepted entirely, bids that are out of the money are rejected entirely, and bids that are on the money may be partially accepted). Block bids correspond to production profiles over the *entire day* and are associated with a bid cost. These bids are intended to represent unit commitment costs and constraints, and are either entirely accepted or entirely rejected.

[9]For example, how would the ORDC be influenced if nuclear units were to be restored in service in the Belgian market?
[10]Flow-based market coupling was introduced in May 2015 with the goal of representing transmission constraints more accurately during the clearing of the market.

According to the rules of the CWE exchange, block bids may be paradoxically rejected (i.e. they may be rejected even though the clearing price would result in a positive profit for the schedule of the bid), but may not be paradoxically accepted (i.e. no schedules that would result in negative profits may be accepted, even if they increase welfare). The exchange seeks a primal-dual market clearing solution that maximizes welfare and respects the aforementioned rules.

Reserve capacity in the Belgian market is cleared in annual and monthly pay-as-bid auctions for reserve capacity. There is a real-time uniform price auction that clears reserve energy in order to balance supply-demand deviations that occur in real time. Reserve in Belgium is classified in three categories[11]. Primary reserve responds immediately to changes in frequency resulting from instantaneously supply-demand imbalances. Secondary reserve reacts within a few seconds, and is expected to provide full response in 7 minutes. Tertiary reserve should be made available within 30-60 minutes after being called upon.

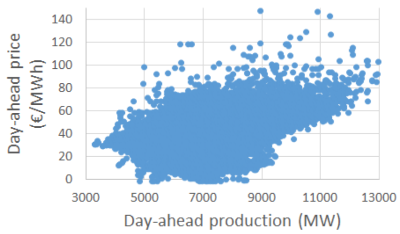
Every resource in the Belgian market is associated with a balancing responsible party. Balancing responsible parties are required to balance their portfolios in real time. The Belgian balancing market settles real-time deviations of balancing responsible parties. An important feature of the balancing market is that resources that are cleared in the reserve capacity markets are *required* to bid in the balancing market, i.e. they are not allowed to opt out. The balancing market is cleared through merit order dispatch at a uniform price. Inter-zonal congestion is not accounted for in the present study and is not discussed further here. This assumption is largely justified by the fact that the Belgian TSO resorts to active transmission elements (line switching, phase shifters, etc.) as a first line of defense against internal congestion, and limits the re-dispatch of units to the greatest possible extent in order to avoid the associated cost.

### 3.2 A Model of the Belgian Market

The study presented in this paper is conducted over a period of 21 months, covering the interval from January 2013 until September 2014. The model proposed in this section is driven by the availability of data. Agents are classified into different categories, based on how they interact with the market clearing price. The data is characterized by hourly resolution. This data includes day-ahead and real-time prices, hourly production *by fuel* in both the day-ahead and real-time market, the amount of activated reserve energy (instead, the amount of reserve capacity provided by each unit or the amount of activated reserve energy by unit is not available), production capacity available *by fuel*,

[11] Each of these three categories includes further sub-categories, this is ignored in order to keep the exposition clear.

**Figure 2: A scatter plot of day-ahead production versus day-ahead price in the Belgian market, January 2013 - October 2014.**




demand in the day ahead and in real time, and imports/exports in the day ahead and in real time over each interconnection[12]. A non-public, commercial database is used for obtaining unit-by-unit technical and economic data for coal and combined cycle gas turbine (CCGT) units. Average prices for reserve capacity in the study interval are also available from publicly available studies[13]. Unit-by-unit outages (scheduled as well as unscheduled) are publicly available at the website of the Belgian transmission system operator. The price of carbon dioxide is obtained from the Intercontinental Exchange. Estimates for emissions rates are obtained from the Energy Information Agency. The price of coal is obtained from a non-public commercial database. The available transfer capacity of the interconnectors linking Belgium to France and the Netherlands is retrieved from the transparency platform of the European network for transmission system operators.

The market model proposed in this section aims at explaining the notable dispersion between production and the day-ahead market clearing price, presented in figure 2. The following factors are conjectured to contribute to the observed variability: (i) outages, (ii) costs and constraints associated to unit commitment, (iii) imports and exports, (iv) reserve requirements, (v) distributed renewable supply that is not metered[14], (vi) pumped storage resources, (vii) combined heat and power, and other must-take resources (viii) fuel price fluctuations, and (ix) market power. We explain how each of these factors is accounted for in our model. By contrast, forward and bilateral commitments of market participants and demand-side bidding are discarded as possible causes of the observed dispersion. Forward commitments should not bind efficient real-time decisions, and demand-side bidding simply produces an observation of the market-wide supply function at a different price-quantity pair.

[12] An interconnection is a corridor linking the Belgian market to its neighboring markets, namely France and the Netherlands. A 1000-MW interconnection of Belgium to the United Kingdom has been commissioned in February 2015.

[13] See *Potential Cross-Border Balancing Cooperation between the Belgian, Dutch and German Electricity Transmission System Operators*, October 8, 2014.

[14] Prior to October 31, 2014, decentralized generation injecting below 30 kV was not accounted for in the measurement of Belgian net load. The significance of distributed generation has steadily increased during the last years. Since November 2014, the Belgian System Operator forecasts net Belgian electric load by accounting for distributed supply. Given the interval of the study presented in this paper, this factor influences our analysis.

### *3.2.1 Generators*

Generators are classified into three categories, depending on their responsiveness to market price: (i) inelastic resources, (ii) dispatchable resources, and (iii) committed resources. We proceed with an explanation of each type.

Nominated resources are resources whose output is not driven by electricity prices, either because the marginal cost of these resources is such that they are always dispatched, or because these are must-take resources. This includes nuclear power (6032 MW), wind power (864 MW), waste (259 MW), and water (101 MW). The production of inelastic resources is fixed to its historical value.

Dispatchable resources are aggregated resources whose production is driven by market price. This includes blast furnace (350 MW), non-wind renewable resources (106 MW), gas-oil (82 MW), and turbojet (213 MW). These resources are characterized by a linear supply function. The non-zero intercept of the linear marginal cost function approximates fixed startup or minimum load costs. The marginal cost function is static, and estimated using least squares. The capacity of these resources is time-varying capacity, and captures the effect of scheduled or unplanned outages. Dispatchable resources are assumed to be capable of providing primary, secondary, and tertiary reserve. The ramp rate of these resources is assumed equal to 4% of their capacity per minute[15]. The model of these resources is provided in the appendix.

Committed generators are resources described by a unit commitment model, whose technical and economic data is available by unit. This corresponds to coal (972 MW) and CCGT (6506 MW). The representation of these resources through unit commitment models is necessary for understanding the behavior of electricity prices in the Belgian market, as explained subsequently. An approximation of these resources through a convex model, such as the one developed for dispatchable resources, was attempted and resulted in a highly inaccurate approximation of the observed market behavior.

The model of committed resources is presented in the appendix. The model accounts for (i) technical minimum, (ii) scheduled and unscheduled outages through a time-varying technical minimum and maximum production limit, (iii) time-varying fuel cost, (iv) ramp rates, (v) minimum up and down times, (vi) startup cost, (vii) minimum load cost, and (viii) a multi-segment marginal cost curve. Committed generators are assumed capable of providing primary, secondary, and tertiary reserve. Committed generators include a separate term for the marginal cost for carbon emissions. Instead, for dispatchable generators this marginal cost is embedded in the calibrated linear supply

[15]This corresponds to an optimistic estimate, based on the ramp rate of CCGT units that are typically rapid.

function.

### *3.2.2 Pumped Storage*

A pumped storage unit arbitrages energy prices by storing electricity in periods of low demand, and releasing stored energy when demand increases. We assume that pumped storage tank is empty at the start of each day. The efficiency of pumped storage is estimated from data at 77%. Outages are represented by a time-varying pumping and production limit, and time-varying storage capacity. The unit obeys ramp rate limits at both production and pumping mode. The unit is assumed to be capable of providing primary, secondary, and tertiary reserve. The parameters of pumped storage (production/pump capacity, storage capacity, ramp rates) are estimated from the actual dispatch of the unit over the study period.

### *3.2.3 Neighboring Markets*

The Belgian market is interconnected to France and the Netherlands. An attempt to model neighboring markets through residual supply functions that are connected to Belgium through time-varying available transfer capacities is not acceptable, since Belgium functions largely as a highway that carries power from eastern to western Europe and vice versa. Thus, the residual supply function at the French border does not correspond to the correct slope (i.e. exports from Belgium to France are increasing with respect to the price in Belgium). Alternatively, aggregate exports over both borders of Belgium can be represented as an *aggregate* export supply function. The resulting supply function, although positively sloped ($P = 39.37 + 0.0056 \cdot Q$ €/MWh), is extremely elastic. Thus, modeling imports through a residual supply function produces an inaccurate model whereby imports can be obtained at a nearly constant price up to the level of available transfer capacity. Given the inaccuracy of the resulting model, imports are instead fixed to their historical values. In order to represent the fact that the system can resort to imports under conditions of stress, the excess import capacity above the historically observed imports is modeled as a linear supply function. The intercept of this supply function is equal to the 90th percentile of the day-ahead price (70 €/MWh) and its slope is set equal to 1.67 €/MWh per MW. Thus, price-elastic imports are used only in case of supply shortage, with the marginal cost of imports rising steeply.

### *3.2.4 Consumers*

For lack of contrary evidence, we assume an inelastic demand. We set the valuation of consumers equal to 3000 €/MWh, which coincides with the price ceiling of the day-ahead market.

### *3.2.5 System Operator*

The Transmission System Operator (TSO) procures five types of reserve in a monthly auction. The demand of the TSO for reserve capacity is fixed, and based on publicly available data[16]. In particular, the TSO procures 55 MW of primary upward and downward reserve, 140 MW of secondary upward and downward reserve, and 350 MW of tertiary reserve.

## 3.3 Validation

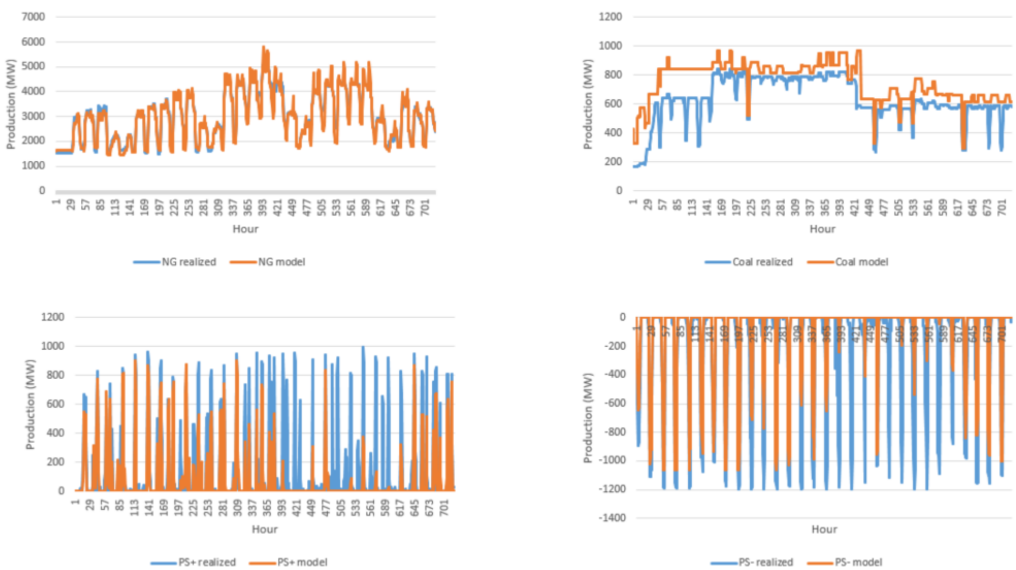
The validation of the market model described above comprises two steps. The first step of the validation process aims at explaining the observed quantities traded in the market, the second step aims at explaining the observed price at which the market clears.

### *3.3.1 Explaining Clearing Quantities*

Figure 3 presents the dispatch of various technologies over January 2013, which corresponds to a month of relatively high demand. We focus on CCGT, coal, pumped storage production and pumping, which are the most complex technologies and whose behavior is expected to be most difficult to capture. The fit is remarkably accurate for CCGT units, whereas coal and pumped storage units present a certain degree of deviations (however, note that CCGT units represent greater capacity). By contrast, June 2013 corresponds to a month of relatively low demand. The fit of the model versus realized outcomes is presented in figure 4. We observe that the model tends to overestimate the production of CCGT units in periods of low demand. One source of inaccuracy is the fact that our model does not account for CCGT units that were decommissioned after October 2014. These units were operational during the interval covered by our study, however they are not present in the database that we use in our study. In order to make up for this mismatch, we scale the capacity of each CCGT unit by the same factor, such that the total CCGT capacity of our database matches the historically available CCGT capacity. This scaling inevitably introduces a certain degree of inaccuracy to our

[16]See *Potential Cross-Border Balancing Cooperation between the Belgian, Dutch and German Electricity Transmission System Operators*, October 8, 2014.

**Figure 3: Production of CCGT (upper left), production of coal (upper right), production of pumped storage (lower left) and consumption of pumped storage (lower right) in reality (in blue) and according to the model (in orange) for January 2013.**




model. Under conditions of low load, our model will therefore tend to operate units at a technical minimum that has been inflated due to the aforementioned deviation. Since ORDC price adders come into effect during tight conditions, this inaccuracy should have minor effects on our results.

In order to further validate our market model, we compare its performance to an alternative approach whereby units are dispatched against the historically observed clearing price. The results of such a dispatch for CCGT units for January 2013 are presented in figure 5. The performance of this model is remarkably worse, compared to the market model proposed in the previous section. This indicates that the day-ahead auction conducted in CWE likely rejects profitable bids, because *given* the historically observed prices the profit-maximizing schedule of CCGT units is quite different from what was actually observed[17].

In table 1 we present the fit of the model with respect to cleared quantities by fuel. We record the root mean square error (RMSE), mean absolute error (MAE) and mean error (ME) of the proposed model and the alternative method for approximating production by maximizing profit against historically observed clearing prices. We confirm that the market model that we propose outperforms the alternative methodology for all technologies and by all metrics of performance.

One final remark can be made based on the reasonably close fit between our proposed

[17] The rejection of bids that are in the money for the sake of increasing welfare can occur according to the European day-ahead market rules. Such bids are referred to as paradoxically rejected bids.

**Figure 4: Production of CCGT (upper left), production of coal (upper right), production of pumped storage (lower left) and consumption of pumped storage (lower right) in reality (in blue) and according to the model (in orange) for June 2013.**

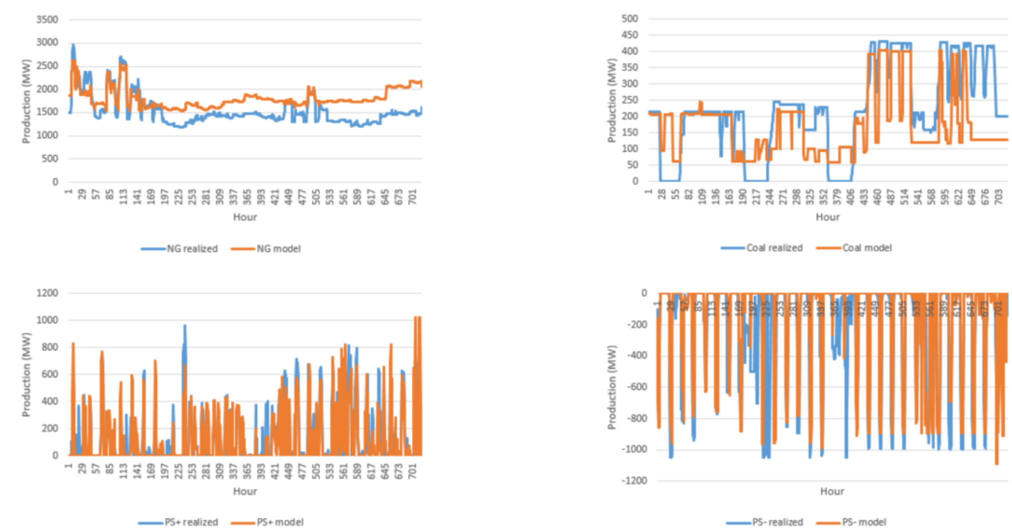
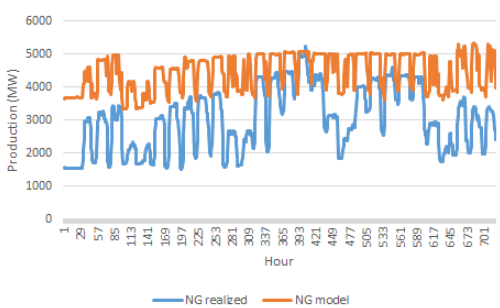



**Figure 5: Production of CCGT in reality (in blue) and according to the model (in orange) for January 2013 according to a model that maximizes profits against historically observed prices.**




model and the historically observed dispatch by technology. Provided our estimated market model parameters (marginal costs of dispatched units, technical and economic parameters of comitted units, fuel and carbon prices, etc.) are accepted as accurate, the fact that the historically observed dispatch closely approximates the result of a centralized unit commitment schedule implies that the CWE exchange produces outcomes that can be regarded as near-optimal from the point of view of economic efficiency.

### *3.3.2 Explaining Clearing Prices*

The observations of the previous section support the conclusion that the market clearing quantities of the Belgian power exchange can be closely approximated by a centralized unit commitment model.

**Table 1: Estimation error (in MW) for various fuels for (i) the proposed market simulation model, and (ii) a model whereby agents maximize profits against market clearing prices.**

| | CCGT | Coal | PS production | PS pump |
|---|---|---|---|---|
| Market model ME | 168.9 | 101.6 | 4.7 | -20.6 |
| Profit maximization ME | 1232.2 | 134.4 | 48.5 | -58.0 |
| Market model MAE | 240.7 | 131.6 | 61.6 | 75.4 |
| Profit maximization MAE | 1392.4 | 147.1 | 159.4 | 157.8 |
| Market model RMSE | 309.9 | 208.7 | 119.3 | 177.9 |
| Profit maximization RMSE | 1541.3 | 232.1 | 294.7 | 336.5 |

In this section we attempt to explain the corresponding prices that support the observed production decisions. For this purpose, we test two approaches that approximate the outcome of the Belgian exchange.

The first approach that we test fixes the unit commitment decisions determined by the centralized unit commitment model, and solves the resulting dispatch problem. The dual multipliers of the power balance constraint are used as an approximation of equilibrium prices in the exchange. Whereas this approach will capture the marginal production costs of the marginal producer, it will fail to capture the intricacies of block bids that were discussed previously.

The second approach that we test is motivated by an attempt to approximate market clearing prices that support both continuous and block bids. The reasoning is as follows: suppose that the centralized unit commitment model provides an accurate approximation of the market clearing production of each resource (which, based on the evidence of the previous section, is a plausible assumption). Then the resulting price produced by the CWE exchange should be such that continuous bids are cleared according to the standard rules of a uniform price auction, and accepted block bids are necessarily in or at the money. If no such prices can be found that are consistent with the production schedule determined by centralized unit commitment, then a reasonable set of prices are those that result in the minimal deviation from the rules of the exchange, i.e. the minimal loss of surplus for accepted block bids. This produces a mathematical program with equilibrium constraints, which is developed in detail in the appendix.

The relative performance of the two models is depicted graphically in figures 6 and 7. We note that the proposed price model captures a fair amount of the observed variability in prices, and explains to some extent the dispersion observed in figure 2. In particular, price dips that occur during the night are due to fact that coal is setting the price, despite the fact that CCGT units are also producing power. This is a result of the fact that CCGT units are committed in order to provide reserve capacity. The technical minimum constraints of CCGT units, combined with the low demand of the system,

**Figure 6: Day-ahead prices in reality (in blue) and according to the model (in orange) for January 2013. The left graph corresponds to the model that account for block bids, the right graph corresponds to the model that ignores block bids.**

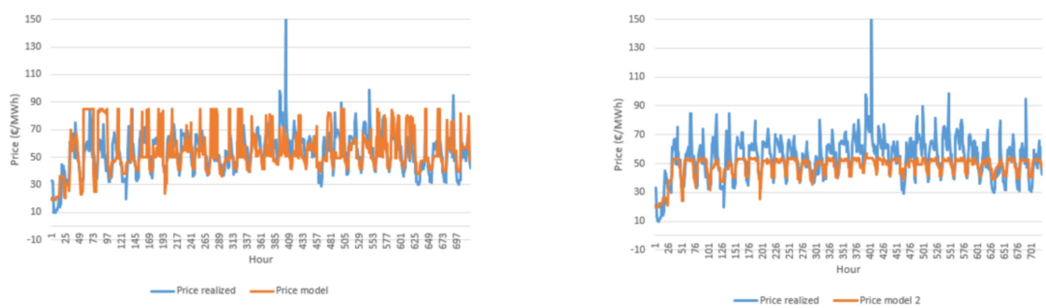
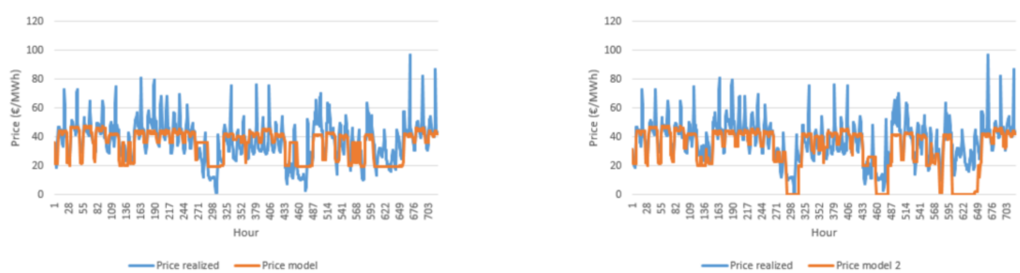



**Figure 7: Day-ahead prices in reality (in blue) and according to the model (in orange) for March 2014. The left figure corresponds to the model that account for block bids, the right figure corresponds to the model that ignores block bids.**




result in coal units being dispatched below their technical maximum and thus setting the market price. Such an effect cannot be captured by a convex model of market behavior. Figure 6 demonstrates that for certain months price jumps during the day can be attributed to the unit commitment costs of CCGT units, and cannot be explained by accounting for marginal fuel costs alone. Nevertheless, it should be noted that these price jumps are not always explained by our proposed model, as shown in figure 7 which corresponds to March 2014.

The overall effect of correcting for block bids leads to a more accurate explanation of the average level of prices, as shown in table 2 where we note that the mean error of the block bid model is lower than that of the linearized model. The equivalent performance of the two approaches in terms of mean absolute error, and the slightly worse performance of the block bid model in terms of mean squared error indicates that although the effect of price jumps on average prices is captured, the block bid model may be less accurate in predicting exactly when these price jumps occur during the day. This can be understood by the fact that multiple market clearing price vectors can recover fixed costs

**Table 2: Estimation error (in €/MWh) for (i) a model that accounts for block bids, and (ii) a model that ignores block bids.**

| | |
|---|---|
| Model with blocks ME | 3.3 |
| Model linearized ME | 8.4 |
| Model with blocks MAE | 10.6 |
| Model linearized MAE | 10.6 |
| Model with blocks RMSE | 14.7 |
| Model linearized RMSE | 14.5 |

that occur throughout the day.

## 4. RESULTS

In this section we follow the methodology of figure 1 for computing adders. In contrast to a model that aggregates units of the same fuel type into a single resource (Levin and Botterud, 2015), the market model presented in the previous section represents each resource individually. This is crucial for the accurate estimation of available reserve, because the ramp limits of individual units are properly accounted for when estimating system-wide available reserve. Moreover, the profitability of each unit can be estimated separately.

### 4.1 Estimating LOLP Parameters

We use observed activated reserve data as an indicator of capacity shortfall in a 15-minute horizon, since this is the time span over which reserves are activated in the Belgian market. If there is no involuntary load shedding, activated reserve energy corresponds to the net load deviation in real time, otherwise it is an under-estimate of net load deviation. Given that involuntary load shedding is rare in Belgium, activated reserve energy is chosen as an accurate proxy of net load deviation. A different LOLP distribution is estimated for different seasons and different intervals of the day, following the current practice of ERCOT[18]. The estimated parameters of each LOLP distribution are presented in table 3.

### 4.2 Estimating Reserves

The amount of available reserves in a given time period depends on which resources are committed for the period in question, and the response time of the required reserve. A greater response time

[18] See *Methodology for Implementing Operating Reserve Demand Curve (ORDC) to Calculate Real-Time Reserve Price Adder*, version 0.7, ERCOT, 2013.

**Table 3: Mean and standard deviation of 15-minute shortfall**

| Seasons | Hours | Mean | St dev | Season | Hours | Mean | St dev |
|---|---|---|---|---|---|---|---|
| Winter | 1, 2, 23, 24 | -31.18 | 96.42 | Summer | 1, 2, 23, 24 | 7.52 | 89.68 |
| | 3-6 | -34.88 | 83.51 | | 3-6 | -3.63 | 79.13 |
| | 7-10 | 8.20 | 103.47 | | 7-10 | 3.03 | 92.52 |
| | 11-14 | -26.39 | 185.15 | | 11-14 | 6.51 | 135.41 |
| | 15-18 | -19.74 | 136.75 | | 15-18 | 0.50 | 127.57 |
| | 19-22 | 7.58 | 102.46 | | 19-22 | 11.40 | 98.22 |
| Spring | 1, 2, 23, 24 | 9.14 | 97.69 | Fall | 1, 2, 23, 24 | -27.84 | 86.06 |
| | 3-6 | -0.45 | 77.12 | | 3-6 | -24.24 | 73.11 |
| | 7-10 | 14.39 | 103.85 | | 7-10 | 19.45 | 97.07 |
| | 11-14 | -17.89 | 168.62 | | 11-14 | -23.08 | 129.76 |
| | 15-18 | -58.75 | 175.45 | | 15-18 | -8.92 | 116.73 |
| | 19-22 | 12.80 | 105.87 | | 19-22 | 6.57 | 94.19 |

increases the amount of reserve that can be made available, while at the same time increasing the amount of uncertainty that the system might face, as demonstrated in figure 8. Given response time $T$, the amount of available reserve in each period is computed as follows:

$$R_T = \sum_{g \in BB} \min(P_{gt} - p_{gt}, T \cdot RR_g) \cdot u_{gt} + \sum_{g \in CB} \min(P_{gt} - p_{gt}, T \cdot RR_g) + DR - IB, \qquad (12)$$

where $BB$ corresponds to committed resources, $CB$ corresponds to dispatched resources, $P_{gt}$ and $RR_g$ corresponds to the production capacity and ramp rate of each resource, $p_{gt}$ corresponds to the dispatch of resources, $u_{gt}$ corresponds to the unit commitment of committed resources, $DR$ corresponds to the amount of demand response that is available as reserve capacity[19], and $IB$ corresponds to the real-time imbalance recorded by the system operator for the period in question. The dispatch of dispatchable and committed resources, $p_{gt}$, and the commitment of committed resources, $u_{gt}$, are provided from the unit commitment model that is described in the previous section. More specifically, the unit commitment model is run against real-time demand adjusted for imbalance (which is used as an estimate of the demand forecast fifteen minutes ahead of real time), in order to represent the corrections that would take place in the intra-day time frame.

Figure 9 presents the amount of available reserves for different horizons for the first month of the case study. The great difference between the amount of reserve that can be made available in seven and sixty minutes underscores the need for modeling individual units separately when attempting to estimate the available reserve capacity for different time horizons. For example, in hour 469 the amount of 7-minute reserve amounts to 81.1 MW, whereas the amount of 60-minute reserve amounts

[19]The Belgian market relies on 27 MW of primary demand response reserve and 261 MW of tertiary demand response reserve.

**Figure 8: The loss of load probability as a function of reserve response time: for greater response time, $t_2 > t_1$, the system faces more uncertainty (note the greater variance of the distribution in the right), but more reserve can be made available ($Rt_2 > Rt_1$).**

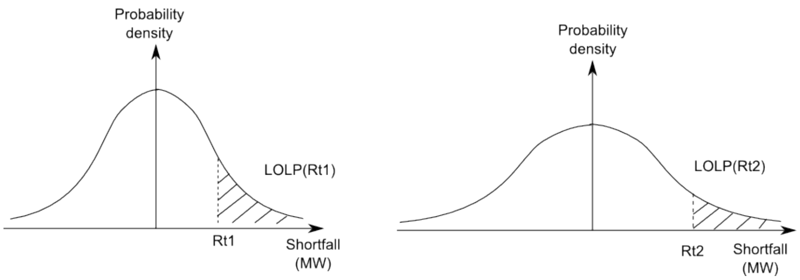
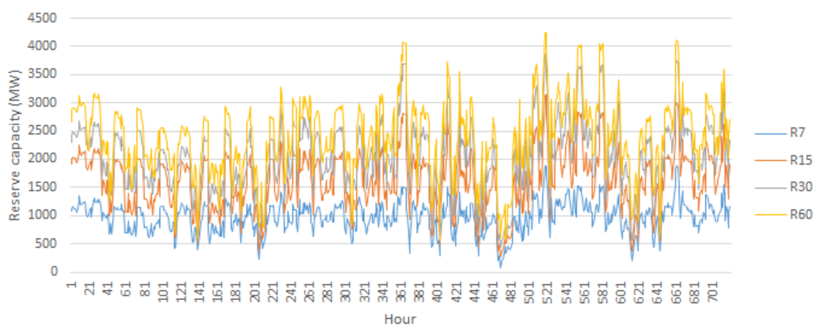



**Figure 9: The amount of available reserve for January 2013 for four different response times: (i) seven minutes, (ii) fifteen minutes, (iii) thirty minutes, and (iv) one hour.**




to 609.5 MW. For the same period, the loss of load probability amounts to 99.4% for a 7-minute horizon, and 80.5% for a one-hour horizon.

### 4.3 Generator Profitability

In order to estimate the profits of individual units, we use the historical energy and reserves prices and the output of the unit commitment model in order to estimate revenues and operating costs. We focus specifically on CCGT units, whose economic viability is questioned despite the fact that these resources are highly suitable (in terms of technical capabilities) for providing flexible reserve capacity to the system. The profits of CCGT units are computed for historical prices as they occurred over the duration of the study, as well as for profits that would have occurred if the ORDC price adder were applied to the energy price. We use equation (11) in order to adjust the price adder for the provision of reserve whose respective delivery times amount to 7 and 60 minutes.

Eleven CCGT units operate currently in the Belgian electricity market. The output of the market model permits a computation of CCGT profits. Table 4 presents the profitability of each unit before and after the introduction of price adders. These profits should be compared against the

**Table 4: Profitability of CCGT units before and after adding ORDC price adders, and average adder benefit. The profit in columns 2 and 3 is computed as the annual profit normalized by capacity and number of hours in the year. The adder benefit in column 4 is computed as the additional income over the entire year per unit of produced energy.**

| | Profit (€/MW·h), no adder | Profit (€/MW·h), with adder | Adder benefit (€/MWh) |
|---|---|---|---|
| CCGT1 | **3.6** | 10.6 | 8.5 |
| CCGT2 | **1.3** | **3.6** | 11.6 |
| CCGT3 | **1.1** | 10.0 | 7.7 |
| CCGT4 | **3.8** | 11.1 | 10.0 |
| CCGT5 | **0.9** | 6.4 | 7.5 |
| CCGT6 | **3.9** | 8.3 | 6.8 |
| CCGT7 | **1.0** | **3.2** | 6.8 |
| CCGT8 | **1.1** | 8.0 | 8.0 |
| CCGT9 | **2.3** | 11.1 | 10.1 |
| CCGT10 | **1.7** | 7.4 | 14.9 |
| CCGT11 | **1.7** | **4.3** | 8.6 |

running investment cost of a typical CCGT unit in order to ascertain the economic viability of CCGT resources. The running investment cost of CCGT is estimated[20] at 4.5 €/MW·h. Profits that do not exceed 4.5 €/MW·h in the table are highlighted in bold font in order to indicate that the given unit is not economically viable. The profit in the first column is computed as the profit over the entire duration of the study given historically realized prices, normalized by the capacity of each unit and the number of hours in the study period. The profit in the second column is computed in the same way, where prices have been adjusted according to the price adder. The final column represents the extra profit earned by each CCGT unit due to the introduction of the adder, normalized by the total output of each unit.

Two notable conclusions can be drawn from the first two columns of table 4: (i) CCGT profits, as estimated by the methodology set forth in the present paper, are sufficient for covering short-term costs for *all* CCGT units, but are not sufficient for covering long-run investment costs of *any* CCGT unit. This observation is aligned with the existing policy debate, which has focused on the fact that the existing market design is not sufficient for covering the long-run investment costs of CCGT resources, although these resources are well suited for supporting the integration of renewable energy resources. On the other hand, if investment costs are considered as sunk, then the results indicate that the mothballing of units is not justifiable since all units earn a positive profit in the duration of the study. (ii) Adders, as computed in the study, could potentially render the majority (eight out of eleven) of CCGT units economically viable. This confirms the fact that these resources add value to the system, although paradoxically the existing market design is pushing these resources

[20] The estimate is based on an overnight cost of 360 €/kW, continuous discounting at rate of return of 10%, and an investment horizon of 25 years.

out of the market.

In the last column of table 4 we present the average adder benefit accrued by each CCGT unit. This adder benefit is computed as the difference of the revenue earned by each unit before and after the introduction of the adder, divided by the total production of each unit over the entire study period. The average adder for the duration of the study amounts to 6.06 €/MW·h. This is the average increase in revenues that can be expected, for example, by base-load units that produce a constant output. By contrast, the adder benefit presented in the last column of the table is effectively higher for *all* CCGT units, and amounts to up to 14.9 €/MWh for CCGT10. Whereas a capacity market would treat CCGT and base-load units identically, the mechanism by design rewards flexible units more handsomely. This effect is a result of the positive correlation of the output of CCGT units with price adders. Stated equivalently, flexible units are able to increase their output under conditions of systems scarcity, and are rewarded accordingly by the ORDC mechanism.

## 5. CONCLUSIONS AND PERSPECTIVES

We have presented a model of the Belgian electricity market which has been validated against observations of the market over 21 months. The goal of developing the model is to assess the impact of price adders resulting from operating reserve demand curves on the profitability of flexible resources. We have used our model in order to verify that flexible resources in the Belgian market are indeed not viable given historical energy and ancillary services prices. We have also verified that the introduction of price adders that correctly reflect scarcity can largely reverse this situation.

The scope of our study is short term, and has neglected the feedback effect of how investors would react to the introduction of operating reserve demand curves. Such a closed loop analysis will be the subject of future research.

## 6. APPENDIX

### 6.1 Agent Models

The notation used in the sequel is summarized as follows:

Decision variables

- $p_t$: production in period $t$
- $r1U, r1D, r2U, r2D, r3$: primary up/down, secondary up/down, tertiary reserve for a month

- $u_t$, $su_t$, $sd_t$: unit commitment, startup and shutdown decisions for committed unit in period $t$
- $d_t$: power consumption of pumped storage / loads
- $e_t$: stored energy in reservoir

Parameters

- $MC(x)$: marginal cost curve of a dispatchable or committed generator, for dispatchable generators we have $MC(x) = a + bx$
- $R$: ramp rate of a dispatchable/committed generator
- $PMax_t$: technical maximum of a dispatchable/committed generator or pumped storage unit
- $PMin_t$: technical minimum of a committed generator
- $SUC$, $MLC$: startup / min load cost of a committed generator
- $UT$, $DT$: minimum up and down times
- $\eta$: pumping efficiency of pumped storage units
- $DMax_t$: pumping limit of pumped storage unit
- $ES_t$: energy storage capacity of pumped storage unit
- $RP_t$, $RC_t$: production and pumping ramp rate of pumped storage units

Prices

- $\lambda_t$: energy price in period $t$
- $\lambda R1U$, $\lambda R1D$, $\lambda R2U$, $\lambda R2D$, $\lambda R3$: price for primary up/down, secondary up/down, tertiary reserve capacity for a given month

*6.1.1 Dispatchable Generators*

Dispatchable resources are described by the following model.

$$\max \sum_{t} (\lambda_t \cdot p_t - \int_{x=0}^{p_t} (a + bx)dx) +$$
$$\lambda R1U \cdot r1U + \lambda R1D \cdot r1D + \lambda R2U \cdot r2U + \lambda R2D \cdot r2D + \lambda R3 \cdot r3 \tag{13}$$

$$\text{s.t.} \quad p_t \geq r1D + r2D \tag{14}$$

$$p_t + r1U + r2U + r3 \leq PMax_t \tag{15}$$

$$r1U \leq 0.5 \cdot R, r1D \leq 0.5 \cdot R \tag{16}$$

$$r2U \leq 7 \cdot R, r2D \leq 7 \cdot R \tag{17}$$

$$r3 \leq 15 \cdot R \tag{18}$$

$$p_t, r1U, r1D, r2U, r2D, r3 \geq 0 \tag{19}$$

The horizon of the model is one month. Reserve capacity decisions are static, meaning that the decision is fixed for the entire month on the basis of a capacity reserve auction. The objective function maximizes profits that accrue from selling power in the energy market and reserve in the reserve capacity auctions. Constraint (14) requires that if a unit is to offer downward reserve it must already be producing power in order to be able to ramp down if needed. Constraint (15) limits the amount of power and reserve offered by a unit by the capacity of the unit. Constraints (16) - (18) determine the amount of reserve that can be offered by a unit as a function of the response time of the reserve and the ramp rate of a unit.

*6.1.2 Committed Generators*

Committed generators are described by the following model.

$$\max \sum_{t} (\lambda_t \cdot p_t - \int_{x=0}^{p_t} MC(x)dx - SUC \cdot su_t - MLC \cdot u_t) +$$
$$\lambda R1U \cdot r1U + \lambda R1D \cdot r1D + \lambda R2U \cdot r2U + \lambda R2D \cdot r2D + \lambda R3 \cdot r3 \tag{20}$$

$$\text{s.t.} \quad p_t - r1D - r2D \geq PMin_t \cdot u_t \tag{21}$$

$$p_t + r1U + r2U + r3 \leq PMax_t \cdot u_t \tag{22}$$

$$u_t = u_{t-1} + su_t - sd_t \tag{23}$$

$$\sum_{\tau=t-UT+1}^{t} su_t \leq u_t, \quad \sum_{\tau=t-DT+1}^{t} sd_t \leq 1 - u_t \tag{24}$$

$$(16) - (18)$$

$$p_t, r1U, r1D, r2U, r2D, r3 \geq 0 \tag{25}$$

$$u_t, su_t, sd_t \in \{0, 1\} \tag{26}$$

The objective function of committed resources includes, in addition to the terms of dispatchable resources, the startup and minimum load costs associated to unit commitment. Constraint (21) limits the amount of power and upward reserve that can be offered by a unit to the technical maximum of a unit, provided the unit is online. Constraint (22) applies an analogous limit on power supply and downward reserve, based on the technical minimum of a unit. Constraint (23) describes the dynamic evolution of the unit commitment status of a generator, as a function of startup and shutdown decisions. Constraints (24) describe the minimum up and down times of the generators. All data required for formulating the above model has been recovered from public or non-public commercial databases, as described in section 3.

*6.1.3 Pumped Storage Model*

The pumped storage unit can be described by the following model:

$$\max \sum_t (\lambda_t \cdot (p_t - d_t) +$$
$$\lambda R1U \cdot r1U + \lambda R1D \cdot r1D + \lambda R2U \cdot r2U + \lambda R2D \cdot r2D + \lambda R3 \cdot r3 \tag{27}$$

$$\text{s.t.} \quad p_t + r1U + r2U + r3 \leq PMax_t \tag{28}$$

$$d_t + r1D + r2D \leq DMax_t \tag{29}$$

$$e_t = 0, t \in \{1, 25, 49, \ldots\} \tag{30}$$

$$e_t = e_{t-1} + \eta \cdot d_{t-1} - p_{t-1} \tag{31}$$

$$p_t - p_{t-1} + r1U + r2U + r3 \leq RP_t \tag{32}$$

$$p_t - p_{t-1} - r1D - r2D \geq -RP_t \tag{33}$$

$$d_t - d_{t-1} + r1D + r2D \leq RD_t \tag{34}$$

$$d_t - d_{t-1} - r1U - r2U - r3 \geq -RD_t \tag{35}$$

$$e_t \leq ES_t \tag{36}$$

$$(16) - (18)$$

$$p_t, d_t, e_t, r1U, r1D, r2U, r2D, r3 \geq 0 \quad (37)$$

Note that pumped storage units incur no intrinsic operating cost, instead they accrue revenue for producing at peak hours and buy back power from the market in low-demand periods. Constraints (28) and (29) impose technical limits based on the maximum production and pump rate of the unit. According to constraint (30), the reservoir of the unit is assumed to be empty at the beginning of every day. The energy stored in the reservoir of the unit evolves according to the dynamics of equation (31). Ramp rates in production for the upward and downward direction are imposed respectively by constraints (32) and (33) respectively. Similarly, ramp rates in pumping mode are imposed through constraints (34) and (35). Constraint (36) imposes a limit on the amount of energy that can be stored in the reservoir of the unit. The production and pump limits, efficiency, and ramp rates of the pumped storage unit are estimated from the dispatch of the unit over the study period. Note that nothing precludes the possibility that the unit produces and pumps power simultaneously, a phenomenon that is actually observed in the data.

### 6.2 Solution Methodology

The resolution of the market model of section 3 requires solving a unit commitment problem over an entire month. A direct resolution of the problem through branch and bound results in an excessive run time. Similarly, a dual decomposition algorithm that relaxes the generator coupling constraints results in numerical instability and slow convergence. In this section, we present a heuristic method that converges within a reasonable amount of computing time within an acceptable optimality gap. The approach is motivated by the need to decompose the problem in order to accelerate its resolution. In particular, a receding horizon heuristic algorithm is used, which can be described as follows:

1. Initialize the commitment of all units for all hours to ‘on’
2. For $iter = 1 \ldots IterLimit$
    - For $day = 1 \ldots 30$
        - Solve the entire model for the entire horizon, with unit commitment decisions fixed for all days except today and tomorrow
        - Fix commitment for today only, step one day forward

The receding horizon heuristic is observed to outperform the aforementioned alternatives (branch and bound and dual decomposition) in terms of best solution found within three hours of running time, which was the run time limit set for each month.

### 6.3 Approximating CWE Clearing Prices

In this section we describe a model for approximating the prices of the Belgian power exchange, *given* market clearing quantities by resource. The set of producers is partitioned between continuous bids $CB$ and block bids $BB$. Continuous bids include dispatchable resources, as well as coal units that are anyways expected to run and are therefore more easily represented through continuous bids. Block bids apply to CCGT units. This model receives as input a predetermined vector of *daily* production and unit commitment for each resource, represented as $p^\star_g = (p^\star_{g1}, \ldots, p^\star_{g,24})$ for $g \in CB \cup BB$ and $u^\star_g = (u^\star_{g1}, \ldots, u^\star_{g,24})$ for $g \in BB$.

$$\min \sum_g ss_g \tag{38}$$

$$\text{s.t.} \quad p_{gt} = p^\star_{gt}, g \in CB \cup BB \tag{39}$$

$$0 \le p_{gt} \perp MC_g(p_{gt}) - \lambda_t + sr_{gt} \ge 0, g \in CB \tag{40}$$

$$0 \le sr_{gt} \perp PMax_{gt} - p_{gt} - r1U^\star_g - r2U^\star_g - r3^\star_g \ge 0, g \in CB \tag{41}$$

$$ds_g = \sum_{gt} \lambda_t \cdot p^\star_{gt} - TC_g(u^\star_g, p^\star_g) + ss_g, g \in BB \tag{42}$$

$$ds_g \ge 0, g \in BB \tag{43}$$

Constraint (39) fixes the production of all resources to their optimal values. Given a market clearing price $\lambda_t$ for each period (to be determined), the dispatch of continuous bids that follows the rules of a uniform market clearing auction can be described by the optimality conditions of equations (40)-(41), where $sr_{gt}$ corresponds to the scarcity rent of a continuous bid. Note that reserve commitment decisions have also been fixed to their optimal values.

For block bids, their fixed schedule is associated with a total cost $TC_g(u^\star_g, p^\star_g)$. The daily surplus of a block bid is described by $ds_g$ and must be non-negative. If a price vector $(\lambda_1, \ldots, \lambda_{24})$ that produces a non-negative daily surplus cannot be found, then the surplus shortage $ss_g$ of block $g$ becomes non-zero. The objective of the model is to find prices $\lambda_t$ such that the supply shortage over all block bids is minimized. This model attempts to find prices that respect the day-ahead clearing decisions while respecting, as closely as possible, the rules of the exchange.

## ACKNOWLEDGEMENTS

The authors benefited from discussions with Pantelis Capros, Jacques Gheury, William Hogan, Shmuel Oren, Alain Marien, and Resmi Surendran. The authors acknowledge the financial support of the Belgian Regulatory Commission for Electricity and Gas (CREG). The first author has been supported by the Engie Chair on Energy Economics and Energy Risk Management.

## REFERENCES

Commission, E., 2009a. Directive 2009/28/EC of the european parliament and of the council on the promotion of the use of energy from renewable sources and amending and subsequently repealing directives 2001/77/ec and 2003/30/ec. Official Journal of the European Union.

Commission, E., 2009b. Directive 2009/72/ec of the european parliament and of the council of 13 july 2009 directive 2009/72/ec of the european parliament and of the council concerning common rules for the internal market in electricity and repealing directive 2003/54/ec.

Cramton, P., Stoft, S., August - September 2005. A capacity market that makes sense. The Electricity Journal 18 (7), 43–54.

CREG, October 2012. Capacity remuneration mechanisms. Tech. Rep. (F)121011-CDC-1182, Belgian Regulatory Commission for Electricity and Gas.

CREG, 2016. Study on the price spikes observed on the Belgian dayahead spot exchange Belpex on 22 September and 16 October 2015. Tech. rep.

Hogan, W., 2013. Electricity scarcity pricing through operating reserves. Tech. rep., JFK School of Government, Harvard University.

Hogan, W. W., September 2005. On an ‘energy only’ electricity market design for resource adequacy. Tech. rep., Center for Business and Government, JFK School of Government, Harvard University.

Levin, T., Botterud, A., 2015. Electricity market design for generator revenue sufficiency with increased variable generation. Energy Policy 87, 392–406.

Oren, S. S., 2000. Capacity payments and supply adequacy in competitive electricity markets. In: 7th symposium of specialists in electric operational and expansion planning.

Papavasiliou, A., Oren, S. S., May / June 2013. Multi-area stochastic unit commitment for high wind penetration in a transmission constrained network. Operations Research 61 (3), 578–592.

Stoft, S., 2002. Power System Economics. IEEE Press and Wiley Interscience.

Telson, M. L., Autumn 1975. The economics of alternative levels of reliability for electric power generating systems. The Bell Journal of Economics 6 (2), 679–674.

Van Vyve, M., 2011. Linear prices for non-convex electricity markets: models and algorithms. Tech. rep., Center for Operations Research and Econometrics, Université catholique de Louvain.

Zhou, Z., Botterud, A., January 2014. Dynamic scheduling of operating reserves in co-optimized electricity markets with wind power. IEEE Transactions on Power Systems 29 (1), 160–171.