Provision of Audit Services in compliance with the Ministerial Order no. 4694/2014

Final First Report

PREPARED FOR

Monitoring Committee, in the terms of the Despacho 10622/2014, of 18 August

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29th January, 2016

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This report was prepared for the Monitoring Committee, in the terms of the *Despacho* 10622/2014, of 18 August, from the Office of the Portuguese Secretary of State for Energy. All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group or its clients.

Acknowledgement: We acknowledge the valuable contributions of many individuals to this report and to the underlying analysis, including members of The Brattle Group for peer review.

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I. Executive Summary and Conclusions

Redes Energéticas Nacionais, REN, has retained *The Brattle Group* to conduct a study in compliance with the *Despacho* 4694/2014 of the Portuguese Secretary of State for Energy. This report is the first deliverable of the study and assesses whether the market for secondary reserve was distorted between 2010 and March 2014 because of the way in which the units covered by the *Custos para a Manutenção do Equilíbrio Contratual*, CMEC, participated in the market, and to quantify the impact of any such distortions on the company receiving the CMEC, EDP.

Context for this report

The approval of the *Despacho* 4694/2014 was preceded by two studies from the Portuguese energy Regulatory Authority, ERSE, and the Portuguese Competition Authority, AdC, that drew attention to the significant rise in the costs of the secondary reserve market and the low levels of provision of secondary regulation by generation units covered by the CMEC.

The secondary reserve market is a daily auction run by the System Operator to procure generation capacity to provide secondary regulation reserve. Secondary regulation reserve involves making part of a unit's generation capacity available to the System Operator to balance supply and demand on the system instead of using it to produce energy. The contracted capacity can be automatically dispatched in real time in order to maintain the frequency of the electricity system. The ability of plants to provide secondary reserve and the costs of doing so are, therefore, of a different nature to those involved in participating in the energy market and require a different analytical framework to analyse them.

The AdC stated that the CMEC annual adjustment procedure might help explain this behaviour. The CMEC is a compensation mechanism granted by Portugal to some generation units in exchange for the early termination of the Power Purchase Agreements, PPAs, they had signed with the Electricity System Operator. The initial CMEC compensation was designed to compensate the units for the expected shortfall in their revenues from the market compared to their revenues under the PPAs. The compensation is adjusted annually to reflect the impact of relevant developments, such as changes in fuel prices, the output of the units and so on. The adjustment is based on a simulation of the revenues obtained by the units from the energy market but it includes the *actual* revenues the units obtain from the provision of system services, including secondary reserve.

This study builds on those of the AdC and ERSE in analysing whether the CMEC adjustment has distorted the secondary reserve market between 2010 and mid-2014 and, if so, what the impact of the distortion is likely to have been.

Capacity and costs of providing secondary reserve

We have developed an analytical framework to assess the secondary reserve capacity that should have been available in Portugal and the competitive costs of providing that capacity. This is based on the following considerations.

A unit's ability to provide secondary reserve is less than its maximum nominal capacity and varies over time. The most important determinants of a unit's ability to provide reserve are:

- Its instantaneous production level. If a unit is not already generating, or it is generating at full capacity, it cannot provide reserve since to do so it has to be able to reduce its output as well as increase it.
- The number of generating groups associated with the unit. Generating units in Portugal may cover several turbines which, to some extent at least, can operate independently. The more groups into which a unit is split, the wider the range of reserve that it can, in theory, provide.
- Any constraints on the unit's output. For example, all the CMEC units that provide reserve are hydro units. A lack of water can mean that a unit cannot sustain the level of production required to provide reserve for long periods. Therefore, a unit with water constraints may only be capable of providing reserve for a limited numbers of hours in a day.

We have assessed the cost of providing secondary reserve in Portugal based on the cost guidelines used for regulated entities in the United States, but adjusted to the Portuguese market. The costs of providing reserve primarily relate to the need to operate the unit at a sub-optimal level so as to have capacity available to provide reserve. For instance, capacity that it would have been efficient to dispatch in the energy market may have to be withheld or alternatively a unit may have to run at a loss in the energy market to provide reserve. We have identified four elements that would be reflected in competitive bids to the secondary reserve market:

- Capacity costs: the fixed costs of making the capacity available to provide secondary regulation rather than to produce energy. These costs compensate for the change in fuel costs in the energy market and other risks, such as the potential costs of a higher probability of the unit tripping.

- Service costs: the variable costs of using the unit to provide secondary regulation. They include maintenance and fuel costs related to the provision of reserve.
- Opportunity costs: the net earnings lost by the unit in other markets when it provides secondary regulation.
- Energy margin: many units will make a profit if they are scheduled to provide reserve because the costs that they incur in providing reserve energy are less than the price they are paid for doing so. In a competitive market, such units will reduce their reserve bids by up to the energy margin they expect to make in order to maximise the chance that their bid will be accepted.

Our estimation of these cost elements for individual units is mainly based on the unit's marginal cost of production, as provided by the System Operator's model of Portuguese generation units (VALORAGUA). To this, we have added estimates of the other costs based on the cost guidelines used for regulated entities in the United States.

Using this competitive cost framework, as well as information on the development of the generation park in Portugal and hydrological conditions, we have: *i)* analysed the actual evolution of secondary reserve bids (capacity and price) and overall secondary regulation costs, *ii)* estimated benchmarks for the secondary reserve capacity that each unit could provide and the competitive costs of providing that capacity on an hourly basis; and *iii)* simulated alternative market results based on these benchmarks. The difference between the actual and estimated capacity and costs is a measure of the extent to which the secondary regulation market has been distorted.

Evolution of the capacity and costs of providing secondary reserve

Our assessment indicates that there has been a reduction in the capacity available to provide secondary reserve, at least for a significant part of the period we studied, despite an increase in the nominal capacity of units theoretically able to provide reserve. As explained above, units need to be running to provide reserve so:

- The decline in the production of CCGTs has nearly stopped these units from providing secondary reserve, whilst
- The dry autumn and winter of 2012 led to low levels of hydro production from spring 2011 until autumn 2012, again restricting the ability of hydro units to provide reserve.

Moreover, we consider that the costs of providing reserve increased, at least until the end of 2012. The reduction of the capacity capable of providing reserve implies that it became necessary to use more expensive capacity, which had previously seldom been used. Furthermore, the reductions in production also increased the costs of the remaining capacity, since they increased both the opportunity cost of water and the proportion of hours in which the units had to provide reserve while losing money in the energy market.

Assessment of the risk of distortions in the market

We have assessed the risk of distortions in the secondary reserve market using two criteria. First, we have judged whether it would be rational for the operation of some units to be modified because of the impact of the CMEC. To do this, we have analysed the incentives provided by the CMEC framework and, in particular, the annual CMEC adjustment procedures.

Second, we have also studied if there is any evidence that EDP, in practice, modified the operation of its units by comparing the actual behaviour of the units in the market to our estimation of what their efficient (cost-reflective) behaviour would have been. We accept that our cost estimates rely on a series of assumptions regarding the technical and economic characteristics of the units involved but, nonetheless, consider that our analysis is sufficiently robust to determine whether distortions have occurred, although the quantification of their exact impact may be less certain. We reach this conclusion because our methodology shows that the relationship between estimated and actual bids for non-CMEC units remains constant over time.

Quantification of the impact on the units providing secondary reserve

We have used our estimation of a cost-reflective set of bids and hourly market outcomes to quantify the impact that such alternative bidding behaviour might have had on the units participating in the secondary reserve market. We measure this impact based on the difference between actual and estimated margins between revenues and costs..

Conclusions

Based on our analyses, we have reached the following conclusions:

1. The units owned by EDP that are covered by CMEC were incentivised not to participate in the secondary reserve market because of (a) the annual adjustment of the CMEC and (b) the positive impact that their limited participation had on the secondary reserve revenues earned by EDP's non-CMEC plants. This conclusion is in

line with that reached in the analyses previously made by the Portuguese Competition Authority and the Portuguese Energy Regulator.

2. The units with CMEC appear to have consistently offered less capacity than they had available to provide secondary regulation and that their bids exceeded the true costs of providing that service. We are not aware of any constraints that have limited the provision of reserve by these units.[1]

3. Despite these findings, at least part of the increase in secondary reserve prices observed between 2010 and July 2012 seems justified. The capacity available to provide reserve decreased because of (a) the decline in the energy produced by CCGTs and (b) hydro production constraints due to low rainfall in autumn and winter 2011. This reduction in the capacity available to provide reserve also increased the costs to the remaining capacity of providing reserve, since it increased both the opportunity cost of water and the proportion of the hours in which the units had to provide reserve while losing money in the energy market.

4. We find that it is from September 2012 to September 2013 that the CMEC units' bidding behaviour had the highest impact on the secondary reserve market. Although the secondary reserve price decreased from that moment on, it is during this period that both the units' bids and the actual market price deviate the most from our benchmarks.

5. However, in the absence of detailed information on the costs of individual units, it is not possible to determine whether all of the price increases were justified by these reasons. A key assumption in this regard is whether it would have been reasonable for units to include a risk premium in their secondary reserve bids. We have investigated the impact on our estimates of three different assumptions on risk premiums and assessed the impact of those assumptions on our results.

6. We estimate that, under our base assumptions (including a risk premium of 10 €/MW), the observed deviations of the units' bids from our benchmarks during 2012 and 2013 increased the margins on secondary reserve provision of EDP's non CMEC units by around €5 million per year, if we consider only the variations in the quantity provided. The margins of these units would have been lower with cost-reflective bidding because they would have provided less reserve. If the risk premium is

[1] Our estimations take account of the constraints on the availability of the units to produce energy provided to us by REN. However, we cannot rule out the possibility that there could be other constraints specifically related to the provisions of secondary reserve of which we are not aware.

excluded, then we estimate the increased in the margins of EDP's non-CMEC units would be €11.5 million per year.

7. If we consider also the impact of cost-reflective bidding on the price of secondary reserve, the overall increase in margins is around €15 million per year with a 10 €/MW risk premium and €30 million per year without a risk premium.[2] The impact on margins increases because cost-reflective bidding leads to lower secondary reserve prices and this amplifies the effect of the reduction in secondary reserve provided by non-CMEC units.
8. We also estimate that EDP's CMEC units would have made higher margins during 2012 and 2013 with cost-reflective bidding, if we only consider the variations in the quantity provided. This reflects the fact that cost-reflective bidding would have resulted in the CMEC units providing more reserve. The overall increase in margins would have been around €13 million per year if we assume a risk premium of 10 €/MW, and around €18 million without a risk premium. If we consider also the impact of cost-reflective bidding on the price of secondary reserve, the increase in the margins of EDP's CMEC units nearly disappears because the increase in the quantity of reserve they would have provided is offset by a reduction in the price they would have been paid for providing that reserve.
9. In both cases, it is important to note, however, that because of the annual revenue adjustments applied to CMEC units, the change in the estimated margin does not correspond directly to a change in the profitability of these units.

Recommendations on Market Design and Policy

We have identified several areas of the market design where changes would provide the regulator with better information with which to monitor the secondary reserve market. Specifically, we recommend:

- The publication of guidelines on both the quantity and price that generators are expected to bid. In particular, the guidelines should specify what cost categories CMEC and non-CMEC units can include in their bids.
- The establishment of special requirements for dominant agents in the wholesale market, such as the obligation to provide the regulator with additional information on how their bids are elaborated.

[2] The margin impact would be also significant in earlier years.

- An assessment of whether the regulator's current market monitoring capabilities need to be expanded.
- Aligning the System Operator incentives with the reduction of the system services costs.
- Further harmonization of the system services market design across different countries, particularly between Spain and Portugal.
- Changing the secondary reserve service requirements to increase the reserve capacity that units can provide. For instance, allowing purchasing units such as pumping storage units to participate, or allowing bids by portfolio of units (for example smaller renewable units).
- Assessing whether there is a need for further refinements to the CMEC annual adjustments procedures with respect to how the costs and revenues of secondary reserve are taken into account.

II. Introduction and Scope of Work

Redes Energéticas Nacionais, REN, the Portuguese electricity Transmission System Operator, has retained *The Brattle Group* to conduct a study of the Portuguese electricity secondary reserve market between 2010 and March 2014, as set out in the *Despacho* 4694/2014, of 1 April 2014, from the Office of the Portuguese Secretary of State for Energy. This report is intended to *"identify the existence of an overcompensation risk in the method for calculating the CMEC annual adjustment, regarding the participation in the secondary regulation reserve market, which can cause a distortion of the competition in that electricity market.*"

The Portuguese Competition Authority, AdC, has stated that the over-compensation risk arises because of the possibility that EDP, the company in receipt of the compensation mechanism known as *Custos para a Manutenção do Equilíbrio Contratual*, CMEC, could be obtaining profits higher than those to which they were originally entitled when the earnings transferred to units without CMEC are taken into account.[3] In particular, AdC argues that the efficient provision of secondary regulation by units with CMEC could be detrimental to other units without CMEC, and thus companies operating both types of units could face a conflict of interest.[4]

The Office of the Portuguese Secretary of State for Energy also provided for the establishment of a Monitoring Committee (*Comissão de Acompanhamento*) to assist REN in the preparation

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3 AdC, Recomendação ao Governo, relativa ao regime de Auxílios de Estado denominado por Custos para a manutenção do Equilíbrio Contratual (CMEC)", ¶37:

> *"[...] o risco de sobrecompensação no modo de cálculo da revisibilidade CMEC significa que a empresa beneficiária dessas compensações financeiras possa conseguir obter benefícios superiores àqueles que haviam sido contratados nos CAE. Com efeito, no atual contexto, as margens brutas reais [valor inicial dos CMEC - i.e. Encargo fixo menos margem bruta ex-ante - mais valores da revisibilidade, mais margem bruta ex-post, mais receitas de serviços de sistema reais e mais lucros transferidos para centrais em mercado] podem resultar superiores aos encargos fixos desses contratos.*"

4 AdC, Recomendação ao Governo, relativa ao regime de Auxílios de Estado denominado por Custos para a manutenção do Equilíbrio Contratual (CMEC)", ¶29:

> *"Assim, a gestão eficiente das centrais no mercado de telerregulação pode atuar em benefício da redução da compensação, em favor dos consumidores, mas pode também atuar em potencial prejuízo das restantes centrais operadas pelo grupo EDP em telerregulação. A presença de interesses diversos e conflituantes fundamenta por isso a existência de um conflito de interesses na gestão simultânea das centrais CMEC e das centrais em regime de mercado.*"

and execution of this study.[5] The Monitoring Committee is made up by the Portuguese Directorate General for Energy and Geology, DGEG, AdC, the Portuguese energy Regulatory Authority, ERSE, and the REN Audit Committee, RENAC. [6]

The remainder of this section reviews the context to the *Despacho* 4694/2014 and to this study; providing a background to the CMEC and its annual adjustment procedure, describing what the secondary reserve market is and illustrating the concerns about the secondary reserve market that precede the *Despacho* 4694/2014.

The report is structured as follows:

- section III explains the analytical framework we use to study the provision of secondary regulation reserve and the costs associated with it;
- section IV examines the supply of secondary reserve capacity to the market by reviewing the evolution of the supply curve drivers, both in terms of the amount of capacity available and the cost of using this capacity to provide the secondary regulation services. It also analyses the effect that the ability of units' to switch their reserve obligations after the market has on the market;
- section V assesses the risk of over-compensation. It first analyses the CMEC adjustment framework and identifies some potential sources of distortion. Then it assesses the actual quantities and prices bid against our estimation of the available capacity and costs.
- finally, section VI quantifies what this over compensation could have been based on our estimations of the quantity and cost of providing reserve.

II.A. Context to the Despacho 4694/2014

The *Despacho* 4694/2014 has two main provisions. First, it amends the calculation of the annual adjustments to the CMEC with regard to the revenues the units covered by the CMEC obtain in the secondary regulation reserve market. Second, it modifies the price mechanism for the secondary regulation reserve market.[7]

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5 Despacho 10622/2014, of 18 August, from the Office of the Secretary of State for Energy.

6 RENAC has been created according to the Decree-Law no. 215-A/2012, of 8 October, Article 23.

7 Ruled by the Decree-Law no. 240/2004, of 27 December, modified by Decree-Laws no.s 199/2007, of 18 May, no. 264/2007, of 24 July, and no. 32/2013) of 26 February.

The Portuguese Secretary of State for Energy approved the *Despacho* 4694/2014 after analyses by ERSE and AdC. In March 2013, ERSE expressed concerns regarding the significant rise in the prices of the electricity system services market, in particular the secondary reserve market, particularly since this coincided with an increase in the secondary reserve bid capacity into the market.[8] In November 2013, AdC recommended the Government to modify the method for calculating the annual adjustments to the CMEC.[9] AdC detected low levels of provision of secondary reserve by generation units covered by the CMEC and stated that the CMEC annual adjustment procedure could help explain this behaviour.

II.B. CMEC Framework

The CMEC is a compensation mechanism granted by Portugal to some generation units in exchange for the early termination of the Power Purchase Agreements (PPAs) they had signed with the Electricity System Operator.[10,11] The early termination of the PPAs was promoted as a measure to facilitate the transition to a liberalized electricity market. The CMEC were established in 2007. Currently, 27 hydro units and four coal units (all at one power plant) are covered by the CMEC, although, of these, only 13 hydro units participate in the secondary reserve market.[12]

EDP, the incumbent and former publicly owned electricity utility, was the only company that accepted the early termination of the PPAs. EDP is therefore the only company whose units are covered by CMEC. EDP was controlled by the Portuguese State until it was wholly privatized in May 2012.[13]

The CMEC was designed so that units covered by it would achieve the same remuneration as they would have done had the PPAs not been terminated. The estimation of the revenues under market conditions was carried out using a medium and long term generation model

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8 ERSE, “Análise de custos do Mercado de Serviços de Sistema 2010-2012”, March 2013.

9 AdC, “Recomendação ao Governo, relativa ao regime de Auxílios de Estado denominado por Custos para a manutenção do Equilíbrio Contratual (CMEC)”, November 2013.

10 The CMEC are ruled by the Decree-Law No. 240/2004, of December 27, as revised by the Decree-Law No. 199 / 2007 of 18 May, and by "Procedures for the Calculation of Annual CMEC Revisibility" and the annexed Addendums to the Cessation Agreements signed between REN and EDP Produção, signed on the 15th June 2007.

11 These contracts are known in Portugal as *Contratos de Aquisição de Energia*, CAE.

12 We are counting Venda Nova and Frades as two different units, and assuming that Sines coal power plant is not providing secondary reserve.

13 EDP webpage: http://www.edp.pt/en/Investidores/accaoedp/reprivatizacao/Pages/Fase%208.aspx.

developed by REN, called VALORAGUA,[14] under assumptions on fuel costs, hydrological conditions and the resulting generation levels and the market prices.

The initial compensation is adjusted annually to reflect the actual values of these parameters.[15,16] A new estimation of the units' revenues under market conditions is made using the VALORAGUA model using the actual market prices, fuel costs, hydrological conditions and the generation schedule of the units not covered by the CMEC. The VALORAGUA model estimates what should have been the units' optimal generation profile under the actual conditions, and the resulting revenues.

The adjustment to the CMEC compensation also takes into account the actual revenues, as opposed to the simulated ones, obtained from the provision of system services. These services include the relief of grid technical constraints, and secondary and tertiary regulation.

II.C. The Market for Secondary Reserve

Secondary reserve is capacity available to the System Operator to provide secondary frequency regulation, known in Portuguese as "serviço de telerregulação".[17] Throughout this report we will refer to this service as "secondary regulation" or simply as "regulation" and the capacity provided by units to deliver this service as secondary "reserve". Secondary regulation is provided by the automatic increase or reduction of a unit's active power in response to an Automatic Generation Control (AGC) signal from the System Operator. The System Operator uses secondary frequency regulation to keep the electricity system frequency within an acceptable pre-established range in the short term.

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14 VALORAGUA provides longer-term operation plans by optimizing hydro and thermal power plant operation. The VALORAGUA version in use by EDP and REN for the CMEC annual adjustment is VALORAGUA for Windows 2.0, registered in the ASSOFT (Software Portuguese Association) repertoire with No. 1182/D/04.

15 The adjustment formula is set up in the Decree-Law 240/2004, of 27th December, Annex I, Article 4. See ¶18 of the AdC document for an explanation of the formula (AdC, "Recomendação ao Governo, relativa ao regime de Auxílios de Estado denominado por Custos para a manutenção do Equilíbrio Contratual (CMEC)", November 2013).

16 This annual adjustment will only realize for the first 10 years, and will end in 2017.

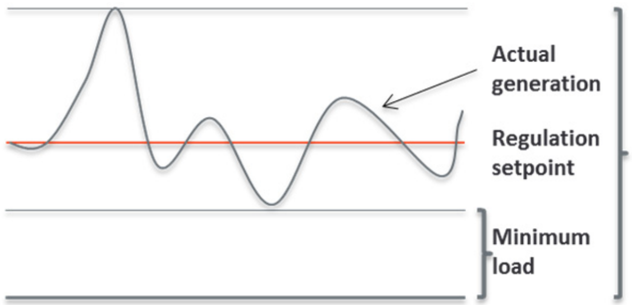
17 This service is also known as secondary frequency control or, under the European Electricity Target Model, Frequency Restoration Reserve (FRR). See for instance, a definition of the FRR in the European Network Code on Load-Frequency Control and Reserves.

https://www.entsoe.eu/fileadmin/user_upload/_library/resources/LCFR/130628-NC_LFCR-Issue1.pdf

Since the activation (or mobilization) of secondary regulation occurs automatically and very rapidly following the receipt of an AGC signal, it has to be contracted ahead of the time of delivery. In Portugal, where secondary reserve is known as "*Banda de Regulação Secundária*", the System Operator organizes a specific daily market where it contracts reserve for every hour of the next day (the "secondary reserve market"). Generation units submit bids specifying the amount of reserve they are willing to provide and the price (in €/MW) they require for providing it. The System Operator allocates the reserve it needs to individual units; but the units are allowed to exchange their allocation with other units after the market.[18]

Secondary reserve is split between "upward" reserve, the ability of a unit to increase its active power production, and "downward" reserve, the ability of a unit to decrease its active power production. A System Operator needs both types of reserve to ensure the safe and secure operation of the system. In Portugal, any unit that participates in the secondary reserve market must be able to provide both types of reserve with a 2 to 1 ratio between upward an downward reserve capacity.[19]

Figure 1: Illustration of the provision of secondary regulation



Source: The Brattle Group.

Secondary regulation needs to be provided by units within the System Operator's control area, in this case Mainland Portugal.[20] Therefore, this market remains national in scope and

18 The System Operator can also allocate secondary reserve commitments outside this market mechanism, if the system had insufficient reserve. This allocation is called "Extraordinary Allocation of Secondary Reserve".

19 For example, if a unit offers 2 MW of upward reserve, it must also have available 1 MW of downward reserve.

20 The European Network Code on Load Frequency Control and Reserves provides for the possibility of cross-border FRR activation agreements between different countries. However, this possibility has not been applied in Portugal.

can be more prone to market power issues. Both ERSE and AdC have already expressed concerns about the dominant position of EDP in this market.[21,22]

II.D. CONCERNS ABOUT THE SECONDARY RESERVE MARKET

The approval of the *Despacho* 4694/2014 was preceded by two studies from ERSE and the AdC that drew attention to the significant rise in the costs of the secondary reserve market and the low levels of provision of secondary regulation by generation units covered by the CMEC.

ERSE released its report concerning the increase in the secondary reserve prices in March 2013. In 2012 the annual average secondary reserve price was 68% higher than in 2011,[23] and the secondary reserve capacity bid into the market increased. On average, prices increased nearly every month from the beginning of 2011 until the third quarter of 2012, and nearly tripled during that period.[24] ERSE concluded that this evolution could be due to a breach of the competition legislation.[25]. Figure 2 shows the evolution of the monthly average secondary reserve price.

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21 AdC, "Recomendação ao Governo, relativa ao regime de Auxílios de Estado denominado por Custos para a manutenção do Equilíbrio Contratual (CMEC)", November 2013, ¶26:

> *"De acordo com as análises efetuadas no passado por esta Autoridade, a EDP tem uma posição dominante no serviço de telerregulação/banda secundária . Para além da EDP, concorrem no mercado de telerregulação/banda secundária apenas três outros operadores (central do Pego, comercializada pela REN Trading, central de ciclo combinado do Pego, comercializada pela Endesa, e central da Aguieira comercializada pela lberdrola)."*

22 ERSE, "Análise de custos do Mercado De Serviços De Sistema 2010-2012", March 2013, p. 17.

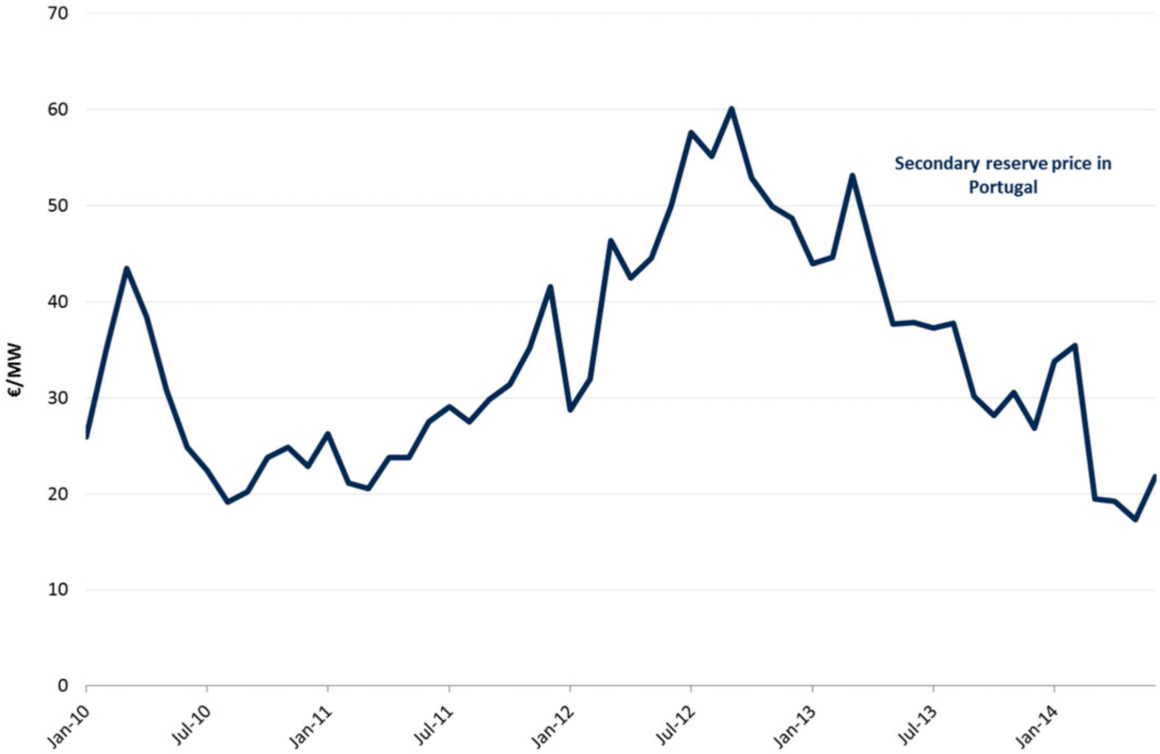
> *"[...] Porém, os resultados de cariz contraditório com a existência de um mercado concorrencial, podem atribuir-se a uma atuação dos agentes eventualmente integrável na esfera de incumprimentos do quadro legal da concorrência."*

23 From 28.16 €/MW in 2011 to 47.40 €/MW in 2012.

24 The price was 20.54 €/MW in March 2011 and reached 60.12 €/MW in September 2012.

25 See footnote 22.

Figure 2: Secondary reserve prices in Portugal

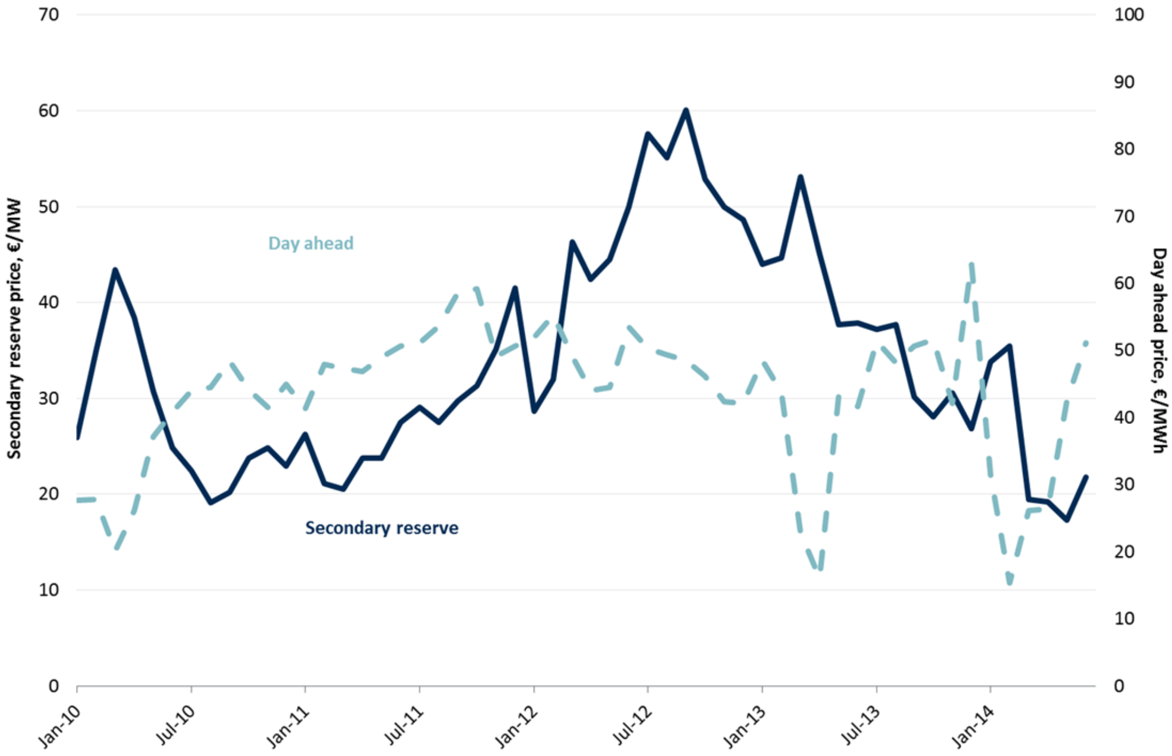


Source: The Brattle Group, from data from REN.

The electricity system services provided by generation units constitute a small share of the cost of the wholesale electricity market.[26] These services are typically provided by units that are already producing electricity. Because of this, system services prices are normally related to the cost of producing energy in the energy market. However, from the beginning of 2012 and until mid-2013, the changes in secondary reserve prices seem to be independent of the changes in the day-ahead market price, as can be seen from Figure 3.

[26] For instance, the three main system services in Portugal (secondary regulation reserve, relief of technical constraints in the grid and balancing energy) constitute a 6% of the day-ahead market price in 2014 and between 6% and 9% in the period 2010-2014. REN, "Síntese Annual Mercado de Electricidade 2010 – 2014".

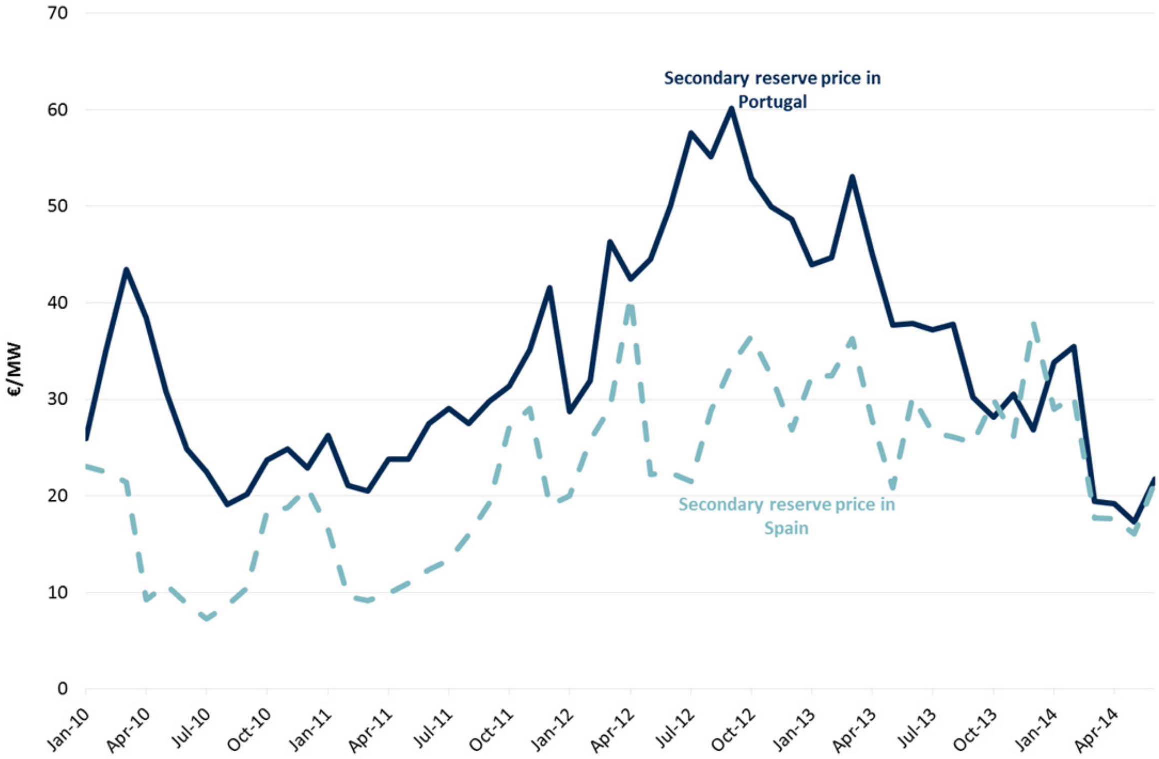
Figure 3: Secondary reserve vs day-ahead prices in Portugal



Source: The Brattle Group, from data from REN.

During the same period, the price for the secondary reserve in Portugal also decoupled from the secondary reserve price in Spain. While there are differences between the two secondary reserve markets that explain why the secondary reserve prices in the two countries are not identical, the prices in Portugal and Spain had followed the same profile until the beginning of 2012. Figure 4 compares the monthly secondary reserve price in Portugal and Spain in the period under study.

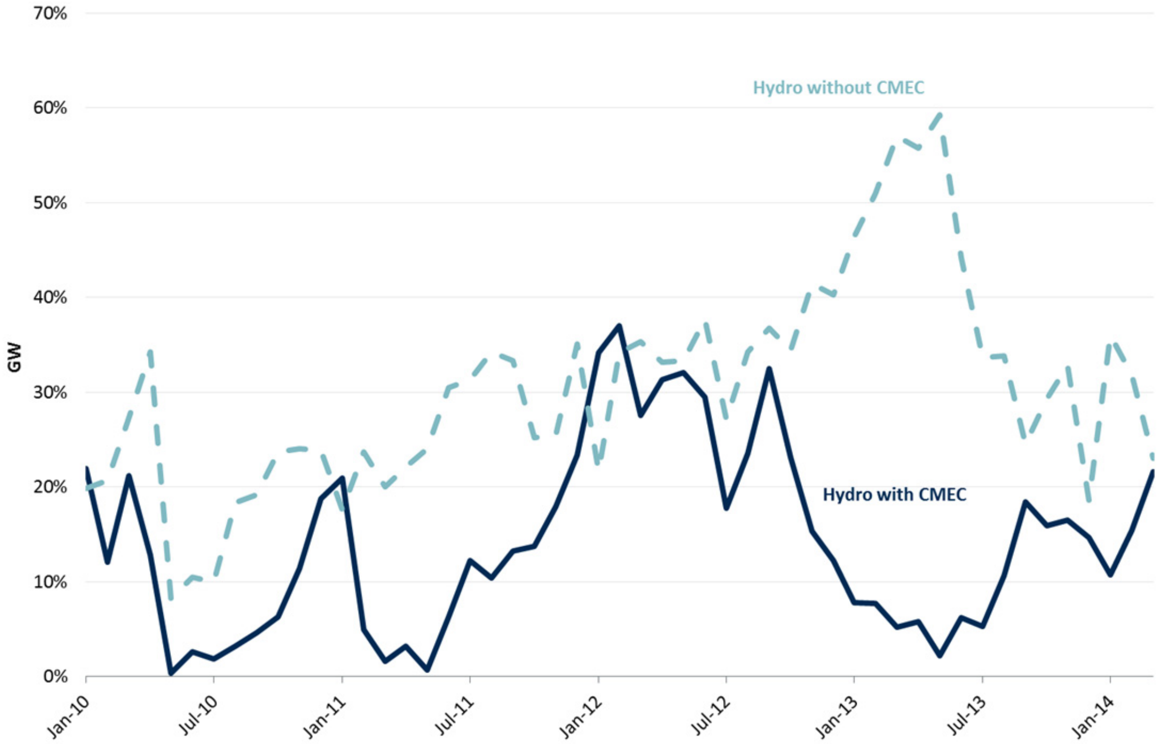
Figure 4: Secondary reserve prices in Portugal and Spain



Source: The Brattle Group, from data from REN and REE.

ERSE also noted in its report that the increase in the secondary reserve price coincided with an increase in the quantity of secondary regulation capacity offered to the market. This increase in the quantity offered came mainly from the hydro units covered by the CMEC. These units had traditionally bid a much smaller proportion of their nominally available reserve capacity into the secondary reserve market than the non-CMEC units, see [Figure 5] and hence had scope to increase the capacity they offered. However, even after the CMEC units increased the reserve capacity they offered, it remained a much lower proportion of their nominally available capacity than for the non-CMEC units.

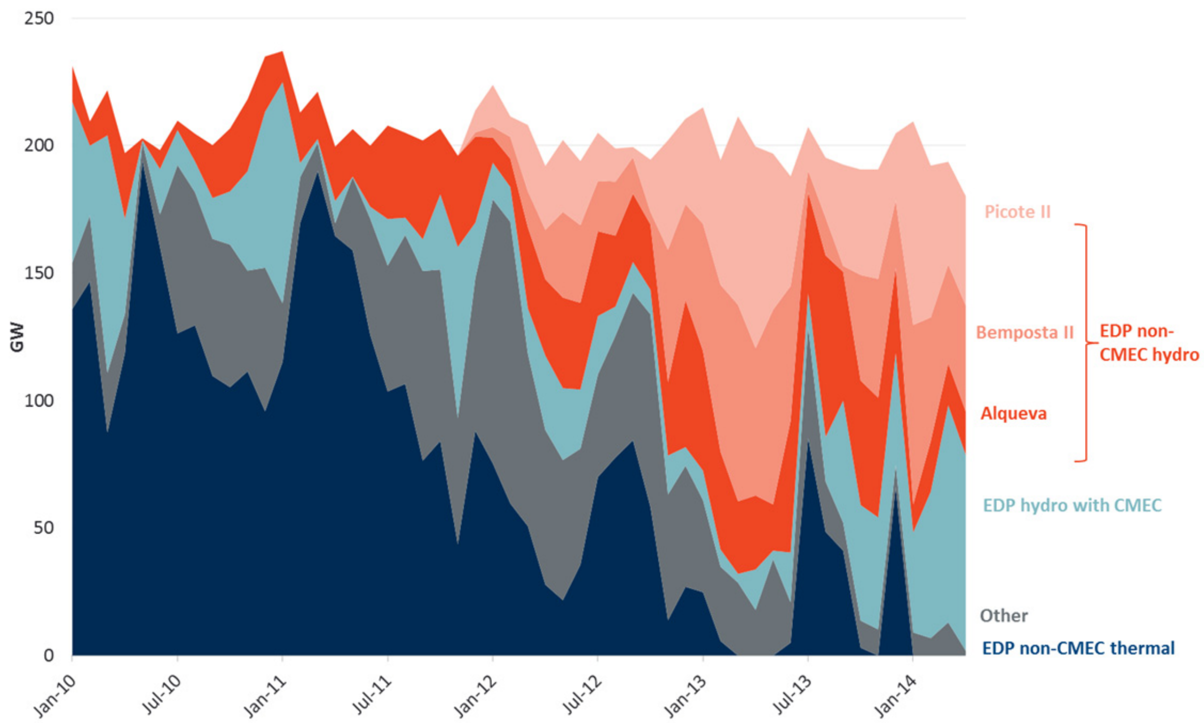
Figure 5: Share of secondary regulation capacity offered into the market by hydro units



Source: The Brattle Group, from data from REN.
Note: Nominal capacity adjusted by units' availability provided by REN

Unsurprisingly, the low participation in the market for secondary reserve by the units with CMEC translates into a small provision of this service. Both ERSE and the AdC identified the low provision of secondary reserve by these units as a potential concern. Figure 6 shows the evolution of the allocation of secondary reserve by different units and groups of units.

Figure 6: Monthly allocation of secondary reserve



Source: The Brattle Group, from data from REN.

III. Analytical Framework and Methodology

The provision of secondary regulation, as described in section II.C, is different in nature to participation in the energy market. The costs involved are therefore different and, hence, a specific analytical framework is needed in order to understand and assess the behaviour of generating units in the secondary reserve market.

The System Operator checks that the bids to the secondary reserve market comply with some formal requirements, such as that they do not exceed the nominal regulation capacity of the units. However, it does not seem to carry out checks on the actual ability of a unit to provide reserve taking into account its operating status.[27] Therefore, we developed a framework that allowed us to estimate the available regulation capacity of the units.

In addition, Portugal has no guidelines on how market agents should form their bids for the secondary reserve market or what costs they are allowed to include. Consequently, we have had to develop our own analytical framework for assessing the provision of secondary reserve in Portugal, as described in the following sections.

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27 Response to Information Requests.

III.A. Capacity Available to Provide Secondary Reserve

The capacity really available to provide secondary reserve in the short term does not necessarily coincide with the units' maximum nominal capacity. While the nominal capacity is the maximum capacity available to the System Operator under optimal conditions, there are some constraints that limit the capacity units can, or are willing to, bid to the market.

The maximum secondary reserve available to the System Operator depends on the units' dynamic characteristics, which are known in advance. REN provides information on the units' maximum secondary regulation capacity, which is based on the following considerations:

- Secondary regulation can only be provided by units capable of responding appropriately to an AGC signal. If a unit has failed to effectively respond to a signal, it may not be suitable to provide the service, even if it should theoretically be able to do so.
- A unit offering secondary regulation should be already generating, because a unit offering secondary reserve must be able to provide reductions in active power, which presupposes a unit is generating, as well as increases in active power.
- Secondary regulation must be provided within five minutes, so a unit's secondary regulation capacity is limited by its ramping rates.[28, 29]
- Commonly, the capacity range within which a unit can operate is narrowed if the unit is providing reserve because of the technical conditions required to modify its generation output.[30]

As the foregoing considerations make clear, the capacity available to provide secondary regulation depends on a unit's production level. A unit's regulation capacity is limited upward by the difference between its maximum capacity when providing reserve and its actual

28 The ramping rate is the pace at which a unit can increase or decrease its generation level. It is normally measured in MW/minute.

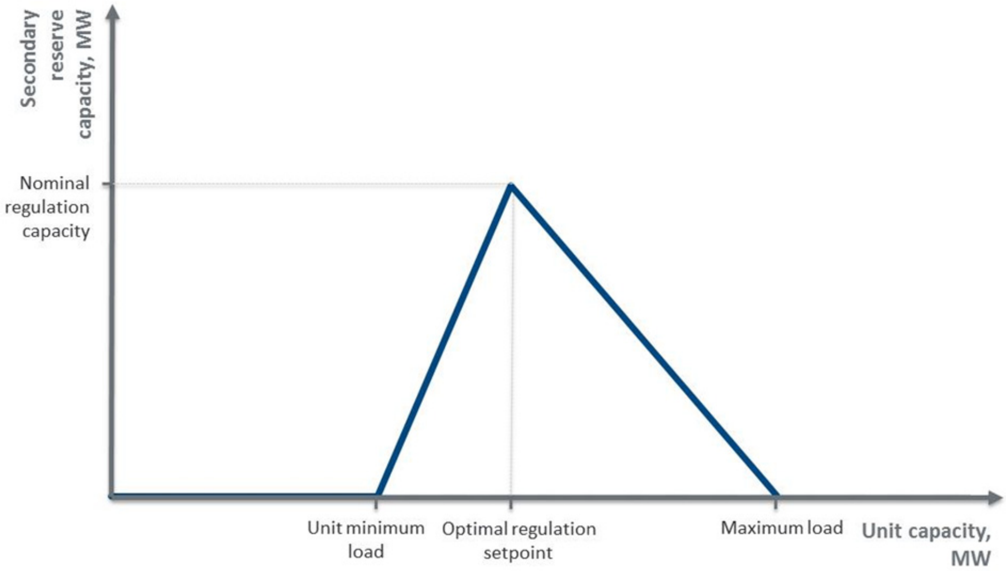
29 Additionally, the ramping rates affect the quality of the service and may influence the System Operator activation of the committed reserves. The faster a resource can ramp up or down, the more accurately it can respond to the AGC signal and avoid overshooting. Alternatively, when a resource ramps too slowly, its ramping limitations may cause it to work against the needs of the system and force the system operator to commit additional regulation resources to compensate.

30 For instance, according to the information provided by REN, the hydro unit Alqueva II has a maximum capacity of 254 MW, but this maximum capacity is only 250 MW if the unit is providing reserve.

production, and downward by the difference between the actual production level and its minimum (stable) load when providing reserve. The level of production that allows the unit to provide a certain regulation capacity is known as a "regulation set point".

Because the Portuguese regulations require the units to be capable of providing a 2:1 ratio of upward to downward reserve, the optimal regulation set point (the set point at which a unit can provide its maximum regulation capacity) is located approximately one third of the way between a unit's minimum load and its maximum capacity.[31] Figure 7 shows the relationship between the secondary regulation capacity and the generation level of a unit.

Figure 7: Generation and reserve capacity of a generation unit



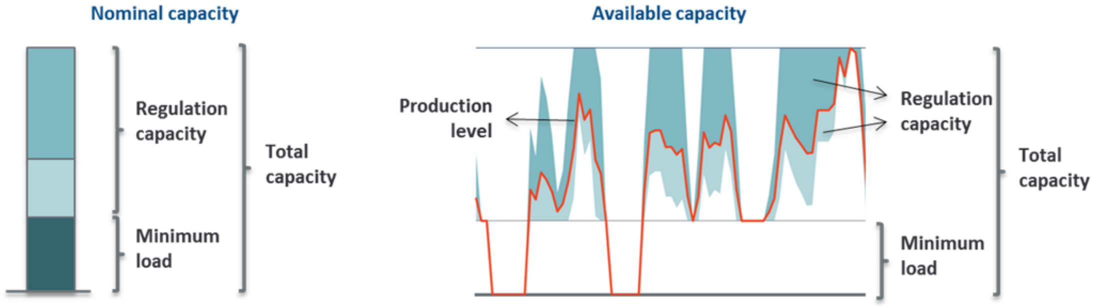
Source: The Brattle Group.

A unit that is fuel constrained, as is normally the case for hydro run-of-river units,[32] may have problems in reaching, or sustaining over time, the optimal regulation set-point. Therefore, such a unit's available regulation capacity is much lower than its nominal capacity. Figure 8 shows the relationship between nominal and available regulation capacity.

31 This is an approximation. Some units' regulation capacity is bounded by the unit's ramping capability, rather than by the units' maximum and minimum capacity.

32 Run-of-river units have a limited capacity to store water, so they may be obliged to produce at full capacity for days, or constrained to produce only a few hours a day.

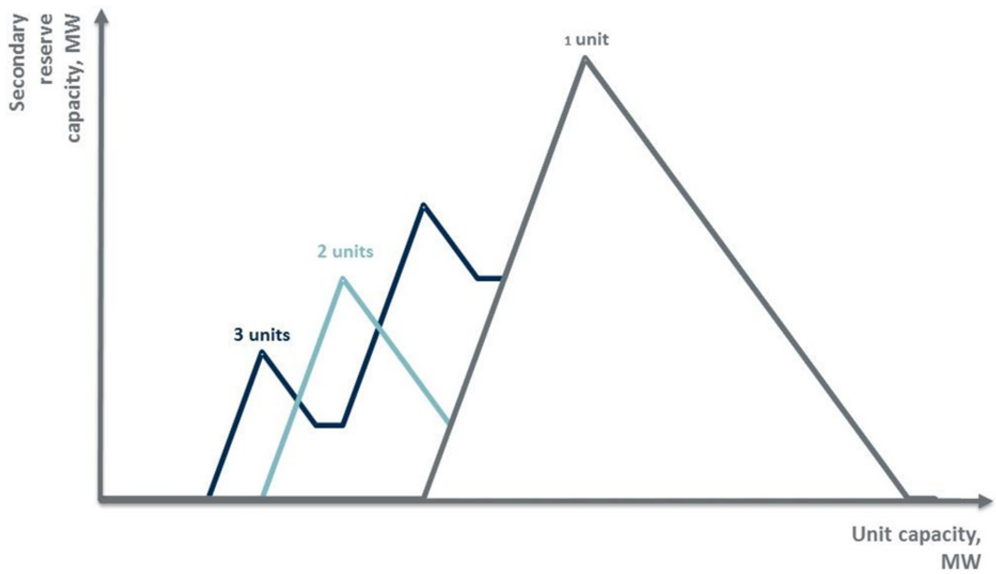
Figure 8: Nominal versus available reserve capacity of a generation unit



Source: The Brattle Group.

Multi-group generation units also have a distinctive relationship between regulation and generation capacity. Units that have more than one generation group, as it is normally the case for hydro units, can provide reserve using one or more of the participating groups. This implies that the reserve such units can provide is greater than that of a single-group unit (because the minimum load at which the unit can operate corresponds to the minimum load of the group, rather than the whole unit). However, since hydro units commonly operate with only some of their generation groups, instead of at full capacity, the reserve that a multi-group unit can provide is less than its nominal total capacity. Figure 9 shows the different secondary regulation capacity profiles of a unit, depending on the number of generation groups.

Figure 9: Generation and reserve capacity of a multi-group generation unit



Source: The Brattle Group.

There are further reasons why units are normally not operated up to their maximum capacity. These reasons include economic factors, such as reduced efficiency, but are mainly of a technical nature. Units operated above their optimal operating level can suffer increased wear and tear, which drives up maintenance costs and the risk of failure.

We have observed that many units had never bid their nominal maximum secondary reserve capacity into the market. Table 1 shows the ratio between the nominal and maximum capacity offered into the secondary reserve market.

Table 1: Nominal vs actual maximum reserve capacity

		Regulation capacity		
Unit	Code	Maximum nominal capacity	Maximum bid	Ratio
Hydro units				
Aguieira	AGUIEI	156,00	112,20	0,72
Alto Lindoso	ALINDO	330,00	300,00	0,91
Cabril	CABRIL	58,00	54,00	0,93
Castelo de Bode	CBODE	84,00	81,00	0,96
Frades	FRADES	91,00	90,00	0,99
Bemposta	BEMPOS	90,00	90,00	1,00
Picote	PICOTE	90,00	90,00	1,00
Pocinho	POCINHO	111,00	103,50	0,93
Régua	REGUA	105,00	105,00	1,00
Torrão	TORRAO	60,00	60,00	1,00
Valeira	VALEIRA	150,00	150,00	1,00
Alqueva	ALQUE	154,00	150,00	0,97
Alqueva II	ALQUEII	190,00	168,00	0,88
Bemposta II	BEMPOS4	116,00	115,50	1,00
Picote II	PICOTE4	145,00	138,00	0,95
Thermal units				
Lares - Group 1	LARES1	225,00	225,00	1,00
Lares - Group 2	LARES2	235,00	225,00	0,96
Pego C.C.- Group 3	PEGO3	97,50	96,00	0,98
Pego C.C.- Group 4	PEGO4	97,50	96,00	0,98
Ribatejo - Group 1	RIBATE1	177,00	150,00	0,85
Ribatejo - Group 2	RIBATE2	177,00	171,00	0,97
Ribatejo - Group 3	RIBATE3	177,00	156,00	0,88
Pego - Group 1	RPG01	58,00	58,00	1,00
Pego - Group 2	RPG02	58,00	58,00	1,00

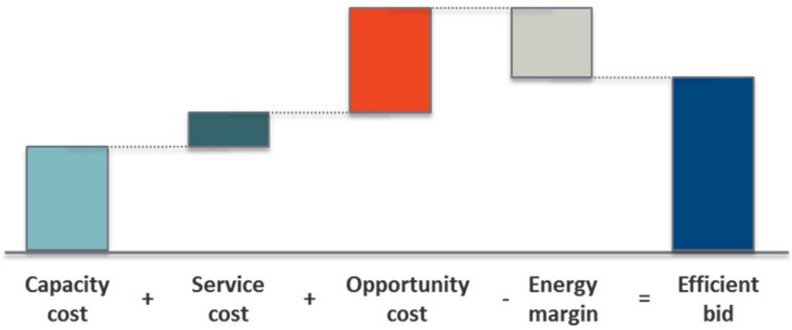
Source: Data provided by REN and bids to the secondary reserve market.
Note: The nominal capacity corresponds to maximum secondary reserve capacity the units have had between January 2010 and March 2014. The maximum bid is the highest total reserve capacity submitted to the secondary reserve market by every unit in a single hour between January 2010 and March 2014.

III.B. COST OF PROVIDING SECONDARY RESERVE

The appropriate analytical framework to study the cost of providing secondary reserve depends on the specific market arrangements in place in every jurisdiction.[33] Portugal has no guidelines on how bids for the secondary reserve market should be formed. We have, therefore, developed a framework for studying the Portuguese market that is based on an adaptation of the United States PJM[34] market cost development guidelines to the regulation service designed to reflect the characteristics of the Portuguese electricity market and the secondary reserve service. [35]

Providing secondary regulation involves modifying the economic dispatch of a generation unit.[36] The costs of providing reserve are, therefore, related to the costs of modifying a unit's generation schedule so that it operates at a sub-optimal level.

Figure 10: Cost structure of regulation services[37]



Source: The Brattle Group.

As shown in Figure 10 above, the costs of providing secondary regulation can be split into the following components:[38]

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33 The framework would depend, for instance, on whether the reserve and the energy markets are optimized together or whether there is a real time energy settlement.

34 A regional market covering all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.

35 The PJM market has guidelines for cost-based offers. In the PJM, agents in areas that are thought to present structural market power may be subject to control over their offers to prevent any exercise of that market power. This is implemented through cost-based offers.

36 The dispatch the unit would follow if it only responded to the price of energy.

37 Adapted from the PJM's cost development guidelines; Power System Economics, Designing Markets For Electricity, Chapter 3-10 (Stoft, 2002), and NYISO Industrial Load Response Opportunities: Resource and Market Assessment—Task 2 Final Report, 2009, section 4-2.

38 Appendix B provides more details on these costs and how we have applied this framework for the assessment of the bids to the Portuguese market.

- Capacity costs:

These are costs of making the reserve capacity available (other than the opportunity costs). They include the increase in fuel (or water) consumption as a result of the reduction in energy efficiency because the unit is operating at a lower load than the optimum; and an allowance for the risks of participating in the market.[39]

- Service costs:

The use of the unit to provide regulation services involves other costs related to the changes in the output level required to the unit. These costs are the increase in variable O&M costs and the increase in fuel consumption during non-steady-state operations.

- Opportunity costs:

When a unit provides regulation, it foregoes the net earnings that it could obtain by participating in other markets. If the unit would not otherwise be running because its costs are above the energy market price, the net earnings would be negative. We include an uplift to reflect this situation.

- Energy margin:

This is the difference between the energy price units are paid and their marginal production cost for the reserve energy used (activated). While the energy price is the same for all units, the activation production costs vary by unit. The units are only entitled to sell/purchase this energy if they provide secondary reserve, and thus internalise this margin in their bids. Thus, the energy margin should be deducted from the capacity costs in order to estimate the competitive bid.

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39 This element is called margin/risk adder in the PJM regulations. We will refer to it in the report as risk premium.

The risk includes the potential costs of a higher probability of the unit tripping (costs of unbalances, penalties for non-performance of the reserve, lost revenues in the markets) and the potential negative margins due to the uncertainty of the costs of providing regulation.

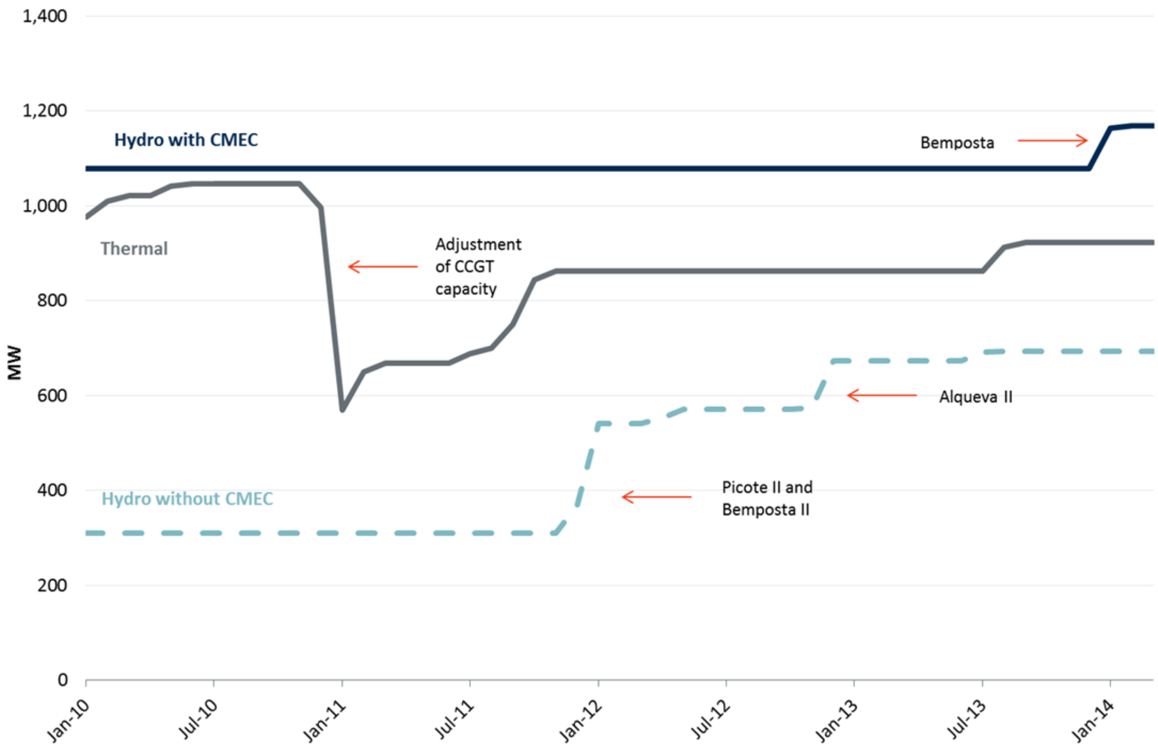
As described by the PJM, "These risks include the uncertainty in the costs of providing regulation service and the potential increased risk of a unit tripping because it is operating in a non-steady-state condition." PJM, A Review of Generation Compensation and Cost Elements in the PJM Markets, p.23. 2009

IV. Analysis of the supply to the secondary reserve market

IV.A. Capacity to provide the service

The evolution of the factors explaining the availability of the generation units to provide secondary reserve points toward a reduction in the actual capacity available to provide the service, at least for a significant part of the period.[40] Although the nominal capacity of the units has increased with the incorporation of new units, the decline in the production of CCGTs (see below) has nearly stopped these units from providing secondary reserve.

Figure 11: Evolution of the nominal secondary reserve capacity



Source: The Brattle Group, from data from REN.
Note: the drop in the thermal units' capacity from November 2010 is due to a series of revision of the CCGT regulation capacities.

During the period under study three new hydro units were commissioned (Bemposta II and Picote II in December 2011, and Alqueva II in December 2012) and an existing hydro unit was adapted to provide reserve (Bemposta in January 2014).

However, as explained above, units needed to be producing in order to be able to provide reserve. The dry autumn and winter of 2012 led to low levels of hydro production from the spring 2011 until the autumn 2012. It is reasonable that the reduction in the production of

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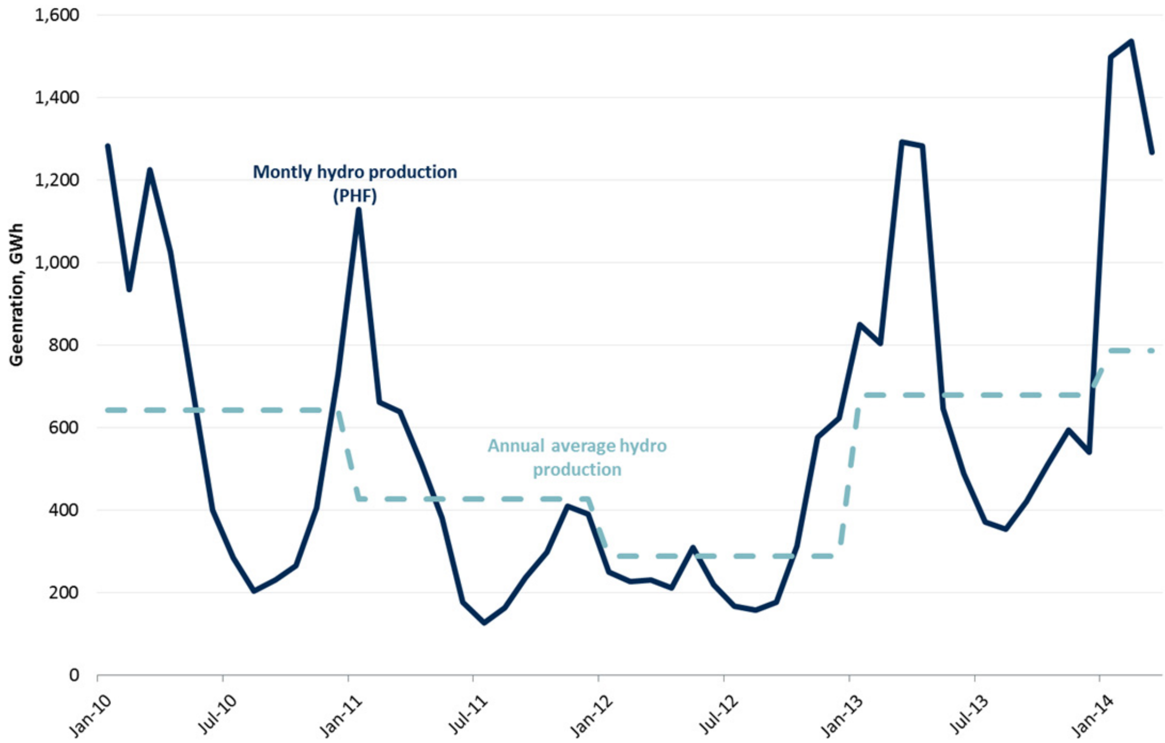
40 Appendix A shows the main characteristics of the units capable of providing reserve.

hydro units reduced their capacity to provide reserve. Figure 12 shows the monthly production of hydro units that provide secondary reserve in Portugal.

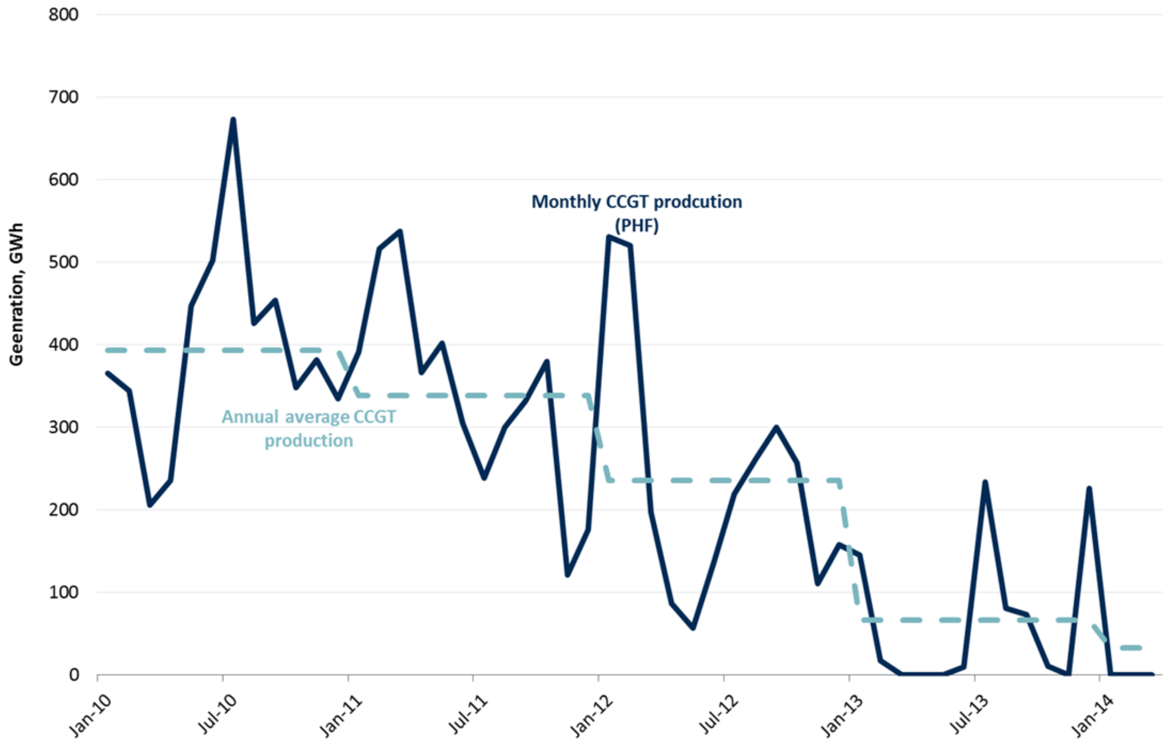
Figure 12: Monthly generation schedule of hydro units providing secondary regulation



Source: The Brattle Group, from data from REN.
Note: Generation according to the PHF schedule.

The production of the CCGTs also decreased during the study period, but unlike hydro production, it did not recover. The decline in the output of CCGTs, which is common to many countries in Europe, has been driven by increases in subsidized renewable generation, the evolution of natural gas prices compared to other generation sources and decreases in the electricity consumption as a consequence of the economic crisis. CCGTs provided 60.0% of secondary reserve in 2010; but by 2014 this share had fallen to only 2.8%. Figure 13 shows the evolution of the monthly production of CCGTs.

Figure 13: Monthly generation schedule of CCGT units providing secondary regulation



Source: The Brattle Group, from data from REN.
Note: Generation according to the PHF schedule.

Despite the likely reduction in the total capacity of Portuguese units able to provide reserve —associated with the decline in their production— there was a significant increase in the quantity of secondary regulation capacity offered to the market during 2012.[41,42] This increase came mainly from the hydro units covered by the CMEC, and was not related to the commissioning of the new units mentioned above. We have analysed this increase by determining the total capacity offered into different price ranges, as shown in Figure 14.

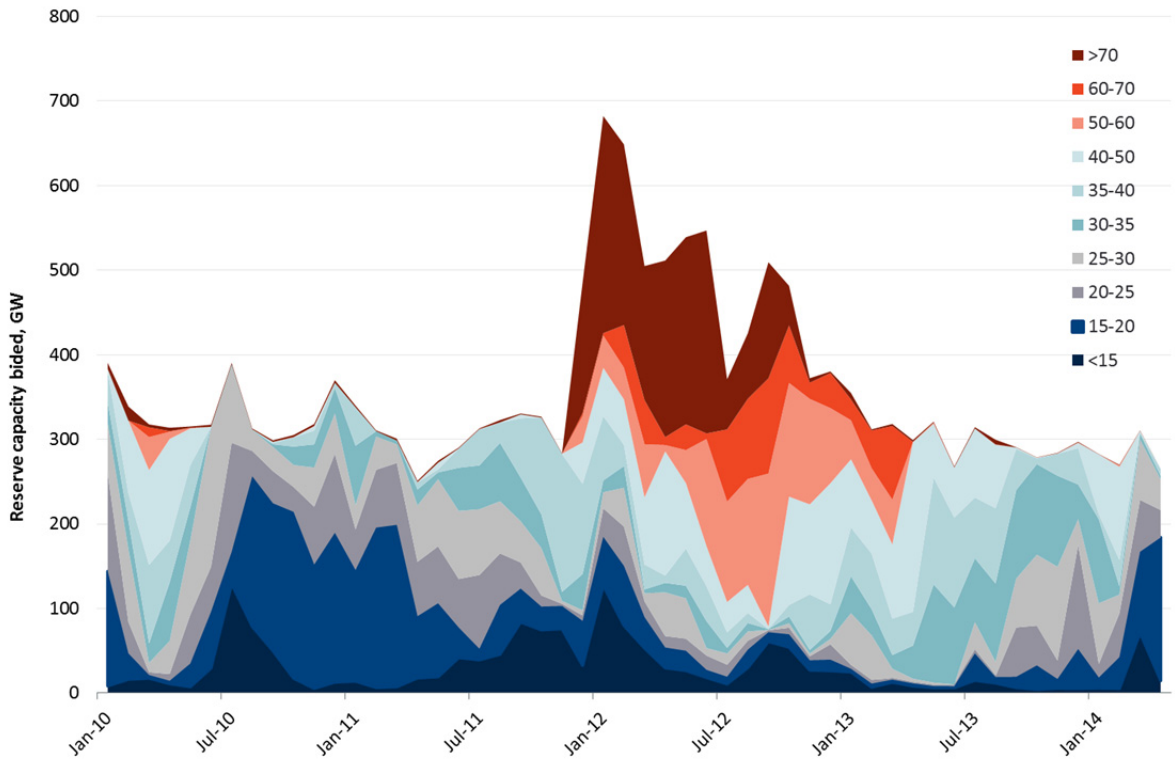
This demonstrates that most of the increase in capacity was associated with bids that were above 70 €/MW. This is a relatively high price, which had not been used to any great extent in earlier years, and it was above most of the hourly prices in the secondary regulation market at that time.[43] Since capacity that is offered above the typical clearing price for a market does not affect the market outcomes, it seems that increase in the supply was notional rather than real.

41 ERSE, "Análise de custos do Mercado De Serviços De Sistema 2010-2012", March 2013.

42 The total capacity offered to the market more than doubled between October 2011 (327 GW) and January 2012 (682 GW).

43 The maximum price in January 2012 was 79 €/MW.

Figure 14: Capacity offered to the secondary reserve market per range of price



Source: The Brattle Group, from data from REN.

IV.B. Evolution of Cost Drivers

The evolution of the factors affecting the cost of the secondary reserve points towards an increase in the cost of providing the service, at least until the end of 2012. The reduction of the generation capacity capable of providing reserve implies that it became necessary to use capacity that had previously seldom been used because it was more expensive. Furthermore, the reductions in production also increased the costs of the remaining capacity.

If a hydro unit has less water inflows, it will use that water to produce in the hours with the highest prices. This increases the opportunity cost of the water if it has to be used for another purpose, such as providing secondary regulation. Therefore, it is only to be expected that the reduction in hydro production led to an increase in the bids of the hydro units and an increase in the price of the secondary reserve. As Figure 15 shows, the increase in the reserve price took place during a period of low hydro production because of a dry autumn/winter in 2011, and only started to come down with the start of the raining season in autumn 2012.[44,45]

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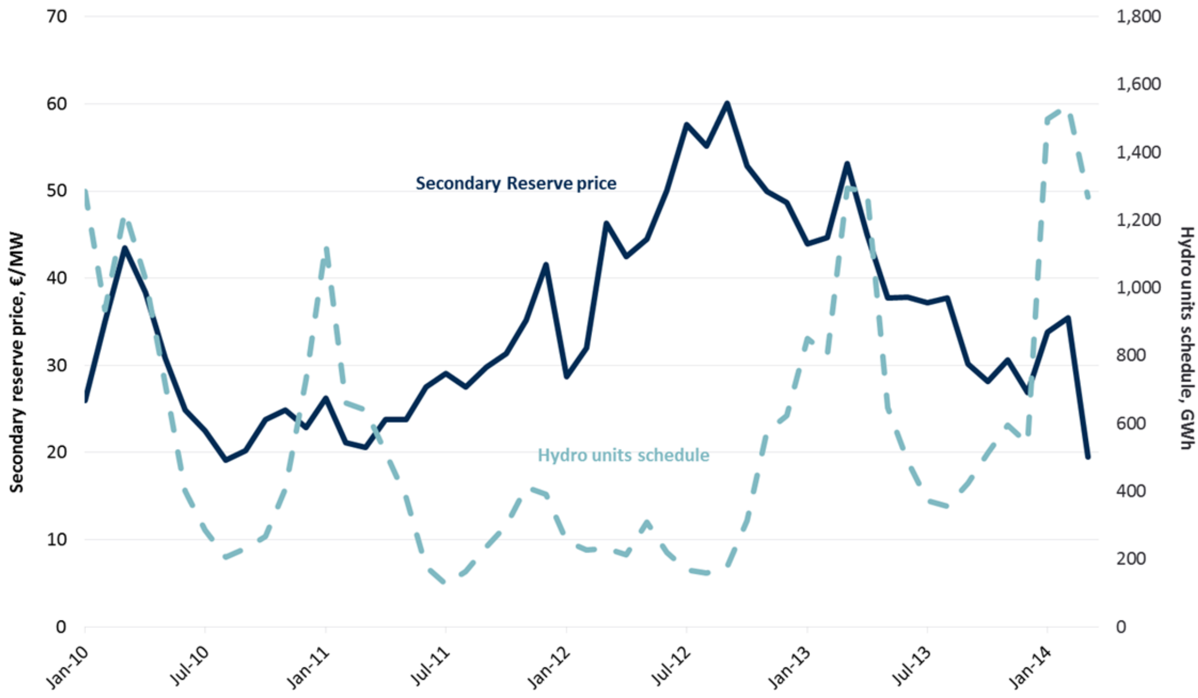
44 The relationship between hydro production and its capacity to provide reserve is not perfect and the available graphical evidence should be interpreted in terms of the correlation between the different time series. First, because this relationship is not linear: when the hydro production is very high, units may be forced to spill over water. Under these circumstances, they cannot provide

Continued on next page

Figure 15: Secondary reserve prices in Portugal and hydro production



Source: The Brattle Group, from data from REN.
Note: Hydro units schedule after the all the intraday market (schedule PHF).

The increase in the opportunity costs of generation is also noticeable in the costs of other system services. Because the same units can provide secondary and tertiary reserve, the price of the tertiary reserve also provides an indication of the cost of providing the secondary reserve: a unit would not provide secondary reserve if it anticipates that it would earn lower revenues than it could obtain providing tertiary reserve. Figure 16 depicts the secondary

Continued from previous page

downward regulation and cannot participate, therefore, in the secondary reserve market. Also, at intermediate levels of hydro production, the number of groups being used to provide the unit's output influences the available level and costs of secondary reserve. Second, because hydro production is not the only factor affecting the price of the secondary reserve, and therefore there cannot be a clear and unique link between the two variables. Indeed, hydro units increased the amount of reserve they provided (albeit at higher prices) despite the reduction in their capacity because CCGT units were even more expensive at that time. CCGT units were seldom able to cover their variable costs in the energy market and required a high price in the reserve market to justify starting up.

45 For a quantitative analysis of the impact of hydro production in the price of secondary reserve we refer to our simulation of market results in section V.B.3.

reserve price together with the spread between the upward tertiary reserve price and the day-ahead market.[46]

Figure 16: Secondary reserve price compared to the balancing energy price spread

Source: The Brattle Group, from data from REN.
Note: The balancing price spread is the difference between the upward regulation reserve price and the day-ahead market.

Additionally, as a consequence of the reduction in the overall production of most units, their schedules started to be more associated with the provision of secondary reserve. This increased the cost of providing secondary reserve because it signalled that the units' decisions on whether or not to generate were determined by their expectation of the level of reserve prices.[47] In normal conditions, reserve is provided by units that are already scheduled in the energy market and only need to be paid the opportunity cost for the upward reserve they

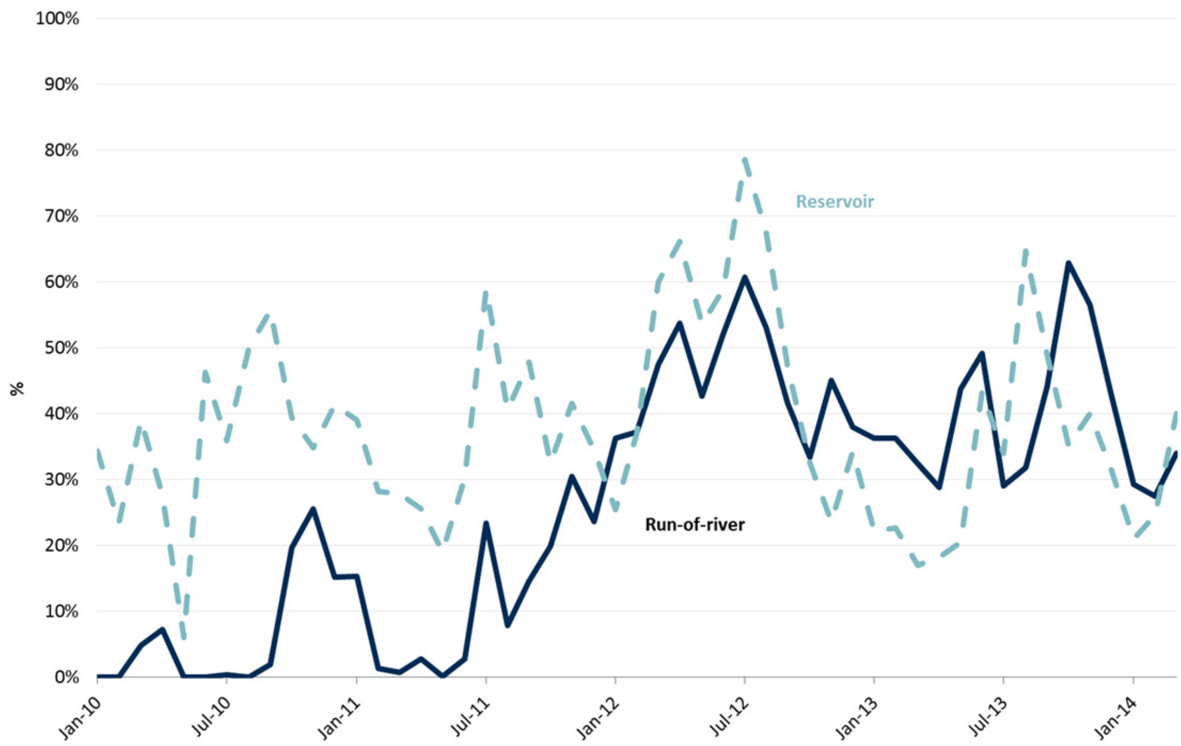
46 The comparison shown in Figure 16 only focuses in the upward spread (upward balancing energy price minus day-ahead market price) because the secondary is mainly used to provide upward regulation. The comparison with the downward spread (day-ahead market price minus downward balancing energy price) shows a similar relationship.

47 We have observed that units commonly run even if their energy marginal cost is above the energy market price, as long as they participate in the secondary reserve market and make an additional revenue that pays for the difference.

provide. However, if a unit runs predominantly to provide reserve, it may be making a loss in the energy market and need to recover that loss via the secondary reserve price.[48]

Figure 17 shows what share of the production of hydro units was produced during the hours that they were providing reserve. An increase in this share can indicate that the way in which a unit is bidding into the energy market is designed to enable it to provide reserve (rather than just reflecting its marginal energy cost) , although it can also be related to the increase in the provision of the service.

Figure 17: Share of units' generation coincident with the provision of secondary reserve



Source: The Brattle Group, from data from REN.

Finally, generation units in Portugal may have had to recover a higher share of their costs from the secondary reserve market than would have been the case if they were able to obtain higher revenues from other system services. For example, in Spain, the "technical constraints" mechanism[49] is more frequently used than in Portugal and it can be a significant revenue source for some plants. In addition, since May 2012, Spain has had an "upward reserve"

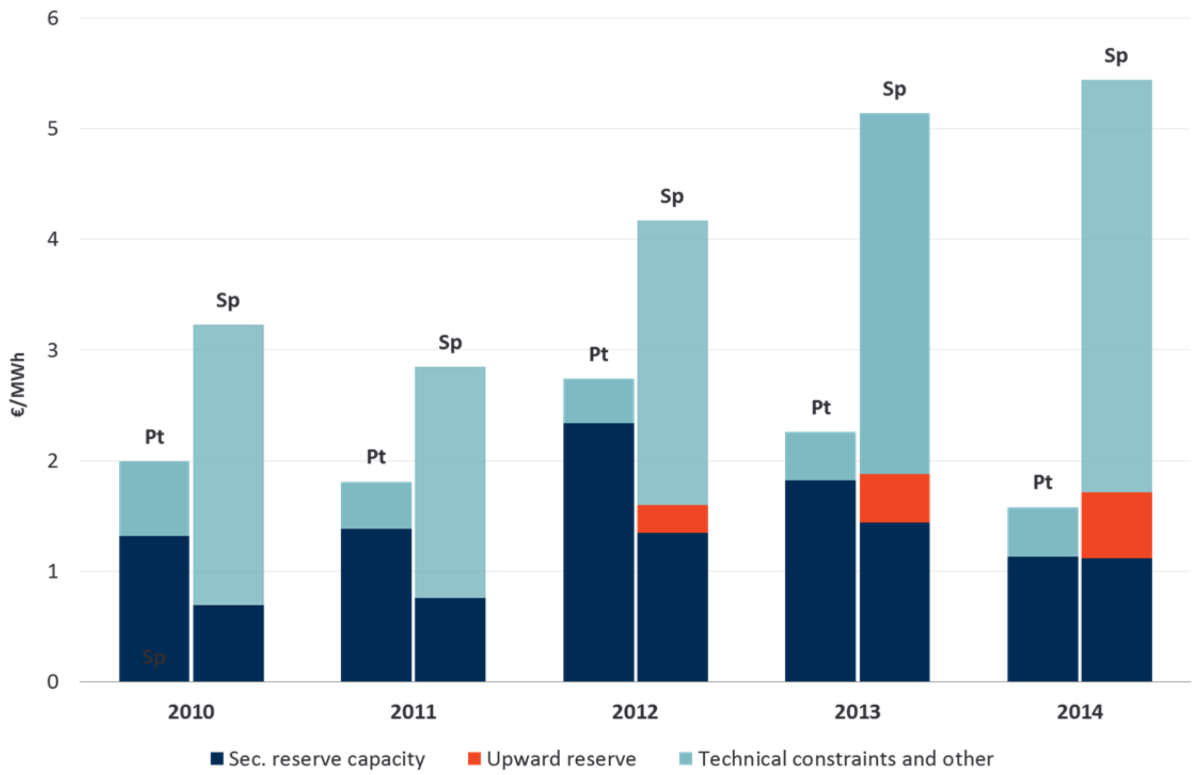
48 See the description of the opportunity cost uplift in section B.III of Appendix B.

49 The "technical constraints" mechanism is used to solve local grid constraints. It is based on a hourly €/MWh payment, but usually the amount of energy acquired is less than the unit full output.

mechanism and there is not an equivalent Portuguese market.[50] Whilst these mechanisms are not designed to substitute for the secondary reserve market, they help to cover the costs of keeping a number of units online at less than full output, thus reducing the costs of providing secondary reserve.

Although the price for secondary reserve was higher, and increased more, in Portugal than in Spain during the period under study, the cost of other system services increased more in Spain. It is likely that the increase in the cost of these other system services helped offset the cost of secondary reserve in Spain. Figure 18 compares the cost to the customers of the different system services which are procured in advance. This means that it does not include the costs of energy imbalances, which depend on the real time balance of the system.. (Table 22 in Appendix E shows the final price to customers in Portugal and Spain, including the costs of imbalances).

Figure 18: Cost to customers of some system services in Portugal and Spain (other than imbalance prices).



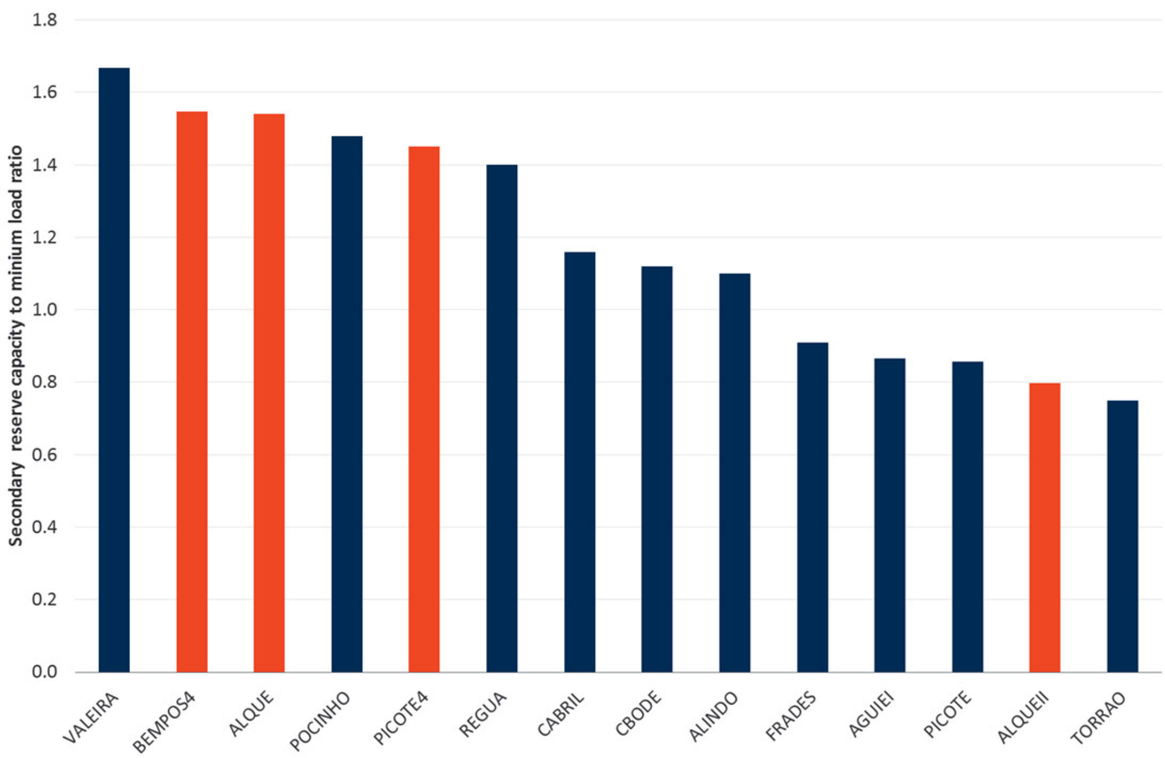
Source: The Brattle Group, from data from REN and REE.

50 The "upward reserve" mechanism rewards generators, in practice only CCGT, for starting up and staying spinning to provide upward reserve. Before the "upward reserve" mechanism was introduced, the Spanish System Operator used the "technical constraints" mechanism to start up CCGTs to provide upward reserve. REE was dispatching thermal generation under the tag "RSI" (after Reserva a Subir Insuficiente).

Notes: The cost of the balancing energy is higher in Portugal, so the final total cost paid by customers for system services is similar in both countries. The underlying data can be found in Table 22 of Appendix E, including also the cost of balancing energy.

On the other hand, the characteristics of the three new hydro units that were commissioned during the study period (Bemposta II, Picote II and Alqueva II) and Alqueva appear to have had a beneficial effect on secondary reserve costs. These units seem to be more flexible than most existing units because they have lower minimum loads. A lower minimum load increases the amount of secondary reserve a unit can provide, because the reserve capacity is roughly the difference between the maximum and minimum load. Moreover, it allows reserve to be provided at a lower cost if the unit has to start up to provide reserve.[51] To demonstrate this effect, Figure 19 shows the ratio of secondary reserve capacity to minimum load for each hydro unit.

Figure 19: Ratio of secondary reserve capacity to minimum load of hydro units



Source: The Brattle Group, from data from REN.
Note: Units with pumped storage, such as Frades, Torrao, Aguieira and Alqueva II see to have a lower ratio, regardless of how old they are.

It is also typically the case that new units are more efficient than older, existing units and have lower operating and maintenance costs. Taken together, these characteristics allowed these units to displace other units in the merit order for secondary regulation provision.

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[51] See the description of the opportunity cost uplift in section B.III of Appendix B.

IV.A. EXCHANGES OF RESERVE ALLOCATION

The participation in the secondary reserve market in Portugal is organized around the physical generation units. The bids are submitted per unit, the upward to downward reserve ratio has to be observed by every unit and it is the physical units who are connected to the System Operator's AGC and respond directly to its signal.

However, the market rules allow physical units to exchange the reserve commitment they have acquired in the market with other units, as long as the exchange unit can provide the same quantity of reserve for the same price. The possibility of exchanging reserve commitments minimizes the System Operator's need to intervene in the market to reallocate reserve if a unit subsequently becomes unavailable. It also allows market participants to avoid penalties for failing to deliver their commitments and to optimize their generation portfolio very close to real time.

The possibility of exchanging reserve commitments weakens the relationship between a unit's bids and its actual capacity and the costs it would incur in providing the service. The exchanges allow participants to prepare their bids taking into consideration the cost of their whole portfolio of units. This can make the provision of reserve cheaper, since every participant can optimize internally the provision of reserve and lower its cost bids. However, it also makes it more difficult to analyse the bids of the different units, since they will not be necessarily only related to that unit's capacity and costs. As a consequence, it may be also more difficult to ensure that lower costs are passed through customers through effective competition.

The System Operator does not disclose information on the level or pattern of reserve exchanges. However, we have studied these exchanges by combining the information that is available on bids, prices and allocations[52] and found that the exchange of secondary reserve commitments has consistently grown during the period under study, reaching 12.4% of the total reserve allocation in January 2013. Figure 20 shows the evolution of the exchanges of reserve as a percentage of the total secondary reserve allocated.

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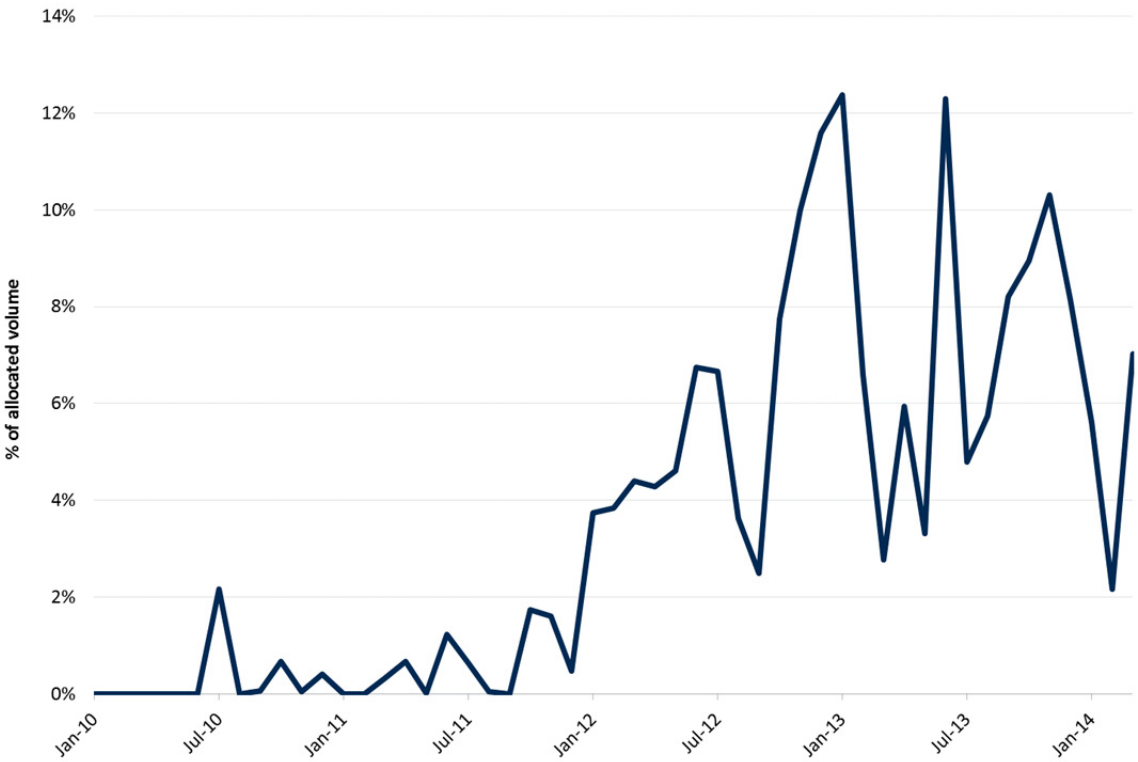
52 We have estimated the reserve exchanges comparing the final allocation with allocation that would result from the bids to the market, clearing all the bids whose economic offer was below the marginal market price and adjusting for those marginal bids not accepted in its whole.

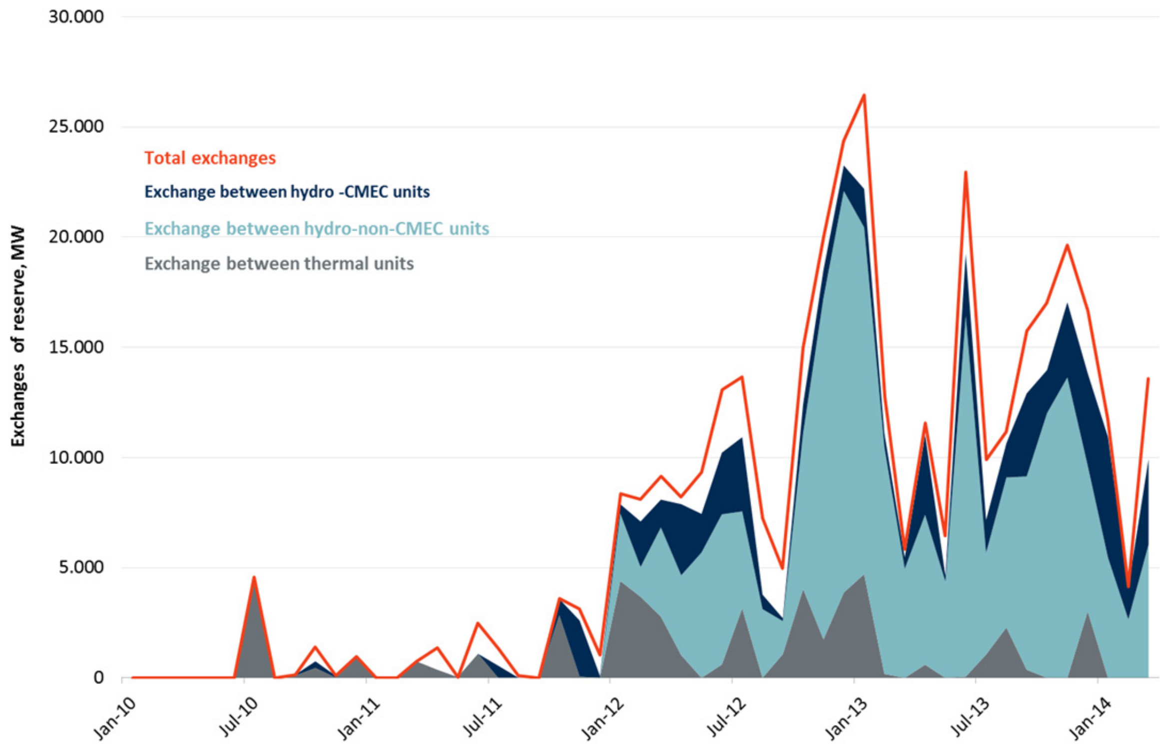
Figure 20: Exchange of secondary reserve allocations



Source: The Brattle Group, from data from REN.

For the purpose of studying these exchanges of reserve, we have grouped the units into different categories: thermal units, hydro units with CMEC and hydro units without CMEC. We have found that most of the exchanges take place between units of the same category, as can be seen from Figure 21. This figure shows the net reserve exchanges between thermal units and units with and without CMEC.

Figure 21: Net exchanges of secondary reserve within the same group of units



Source: The Brattle Group, from data from REN.

V. Assessment of the Risk of Over Compensation

AdC stated that the over-compensation risk corresponds to the possibility that EDP could obtain profits higher than those to which it was originally entitled because of an inefficient provision of secondary regulation by the units it owns that are covered by the CMEC. [53] Our assessment of this risk is based on two criteria:

- an analysis of the incentives provided by the CMEC framework and, in particular, of the annual CMEC adjustment procedures; and
- a comparison of the actual behaviour of the CMEC and non-CMEC units in the market to our estimation of what their efficient (competitive) behaviour would have been, based on a series of assumptions on the technical and economic characteristics of the units.

We use the first criteria to judge whether it would be rational to modify the operation of some units because of the impact of the CMEC. We use the second criteria to judge if there is any evidence that EDP, in practice, modified the operation of its units.

[53] See footnotes 3 and 4.

Our results suggest that units with CMEC faced an incentive not to participate in the secondary reserve market, even before the effect on affiliated units without CMEC units is considered. In addition it appears that the operation of these units may have been modified because they participated less in the reserve market than would be consistent with their capacity to provide reserve.

V.A. Analysis of CMEC Adjustments

The AdC stated that the CMEC adjustment procedure does not provide incentives to optimize the provision of secondary reserve.[54] We analysed this incentive looking at three different factors: the revenues earned by units with CMEC, the costs of these units, and the revenues of the EDP units not covered by the CMEC.[55]

We also reach the conclusion that the CMEC annual adjustment does not provide incentive to the units to provide secondary reserve. In our opinion, it can even provide incentives not to participate, even before the impact of such behaviour on other affiliated units not covered by CMEC is considered.

V.A.1. Treatment of the revenues of providing secondary reserve

The CMEC adjustment formula subtracts from EDP the entire revenue obtained by the units participating in regulation services. However, a unit's final adjustment is not independent of the regulation reserve it provides. A unit's secondary reserve provision is taken into account by the VALORAGUA model when estimating what should have been the units' optimal generation profile. This approach not only provides the units with an incentive to optimize their schedule in the market, but also implies that the estimated revenues do not necessarily coincide with the units' actual market revenues. If they always matched, there would be no incentive at all. This also means that a unit may have some ability to affect its CMEC

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54 AdC, Recomendação ao Governo, relativa ao regime de Auxílios de Estado denominado por Custos para a manutenção do Equilíbrio Contratual (CMEC)", ¶33:

> *"Assim, do facto de a EDP não ter um incentivo explícito a maximizar as receitas de serviços de sistema com centrais em regime CMEC, poderão resultar comportamentos menos eficientes do ponto de vista económico, conduzindo, tudo o resto sendo constante, a compensações suportadas pelos consumidores mais elevadas do que aquelas que poderiam ser pagas na base de comportamentos optimizadores. Deste modo, existe um risco de sobrecompensação no auxílio atribuído que importaria acautelar"*

55 The analyses in this section are based on the review of the regulations affect the CMEC annual adjustment and the annual reports prepared by REN describing how the adjustments are actually carried out.

estimation by VALORAGUA by choosing how much, and in what time periods, it provides secondary reserve.

The VALORAGUA model is adjusted differently depending on when the secondary reserve is provided.[56,57] We understand that this distinction was based on the assumption that units are available and produce more in peak load hours than in trough hours, but that it does not necessarily represent their actual behaviour.[58] The existence of different adjustments for different time periods may bias the decision of the units regarding when they provide reserve. Incentives not to provide reserve in some hours could lead to a reduction in the overall amount of reserve provided by a unit, if the reduction is not compensated in other time periods. However, we note that the Monitoring Committee is of the view that the difference in adjustments to which we refer only occurs if units provide reserve capacity without providing regulating power. The description of the adjustments made are not clear on this point and we think that it is at least possible that the adjustments can vary in circumstances other than that outlined by the Monitoring Committee. Nonetheless, given the uncertainty

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56 The adjustment differs between load steps, which are the periods into which the demand duration curve is split. The VALORAGUA version used in the CMEC adjustment uses 5 load steps per week, so it has 260 discrete load and price intervals, instead of the usual 8760 hours in a year.

57 See As explained in: REN, "Determinação do Montante de Ajustamento dos CMEC 2013, Dados e Resultados", February 2014, p.26.

> *"Os condicionamentos à exploração das centrais hidroelétricas decorrentes do fornecimento de serviços de telerregulação foram considerados na simulação com o modelo Valoragua. A forma de modelização destes condicionamentos foi a seguinte:*
>
> > *a) Nos períodos em que ocorreu telerregulação nos 1º, 2º e 3º postos horários, limitou-se a potência disponível à potência verificada; se a telerregulação ocorreu nos 4º e 5º postos horários, impõe-se uma potência correspondente à soma da base de telerregulação com a correspondente energia de regulação;*
> >
> > *b) Nos períodos em que não houve telerregulação mas o produtor ofereceu banda de regulação e caso coincida com os 1º, 2º e 3º postos horários, limita-se a potência disponível a um valor correspondente à potência máxima deduzida de metade da potência da banda;*
> >
> > *c) Em todos os outros períodos, não foi imposta qualquer restrição."*

58 There are different reasons why the production of hydro units does not follow the load steps in the VALORAGUA model. First, units are scheduled depending on the market price, rather than on the system load. Although prices are normally higher when the load is high, the integration of large amounts of intermittent generation sources, such as wind and solar energy, has weakened this relationship. The prices, and hydro production, can be very small in peak load hours if there is enough wind or solar production. Second, "fuel" constrained units, including hydro units in a dry period, do not necessarily run in all the peak hours. Finally, the production of some units in an hour is not independent from their production in other hours. So it may be misleading to model a unit capacity in different load steps as being independent from their production in other hours.

about the adjustment mechanism and the fact that we have not been able to establish how often reserve is scheduled but no regulating energy is provided, the extent to which the adjustment mechanism is anything more than a theoretical distortion remains unclear.[59]

V.A.2. Treatment of the costs of providing secondary reserve

The CMEC adjustment makes no explicit allowance for the additional costs the units may incur when providing regulation, compared to the costs of only providing energy. As a consequence, the margins CMEC units make might be lower when they participate in secondary reserve market and hence they could be incentivised not to participate in this market.

Although we have been unable to determine unambiguously whether all the costs of providing secondary reserve are appropriately accounted for in the CMEC adjustment, we think the lack of identification of these costs and clarity in the way they are compensated makes it at least possible that the CMEC adjustment may interfere with the provision of secondary reserve.

The additional costs of providing secondary regulation described in section III.B were:

- Potential increases in fuel consumption although we note that the reverse may be true for hydro plants, depending on how they are operating. [60,61] However, in the absence of detailed efficiency curves for each hydro unit, we assume that providing reserve leads to some reduction in efficiency.[62]

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59 We have observed that run-of-river hydro units with and without CMEC have a different time profile in the provision of reserve, both in terms of the load step used by the VALORAGUA model and the hour of the day. However, the evidence we have found is not robust enough to allow us to draw conclusions on a potential bias in the CMEC framework.

60 Typically, units are at their most efficient when operating at full output. Hence, operating part-loaded to provide reserve will increase their fuel consumption. However, this may not always be the case, particularly for hydro plants, which may not have monotonically increasing efficiency curves. On head-sensitive hydro power plants, such as run of river plants or plants with small reservoirs, decreasing output to provide regulation may decrease the head loss, increasing the overall efficiency. Consequently, the impact on a hydro unit's efficiency of providing reserve may depend on precisely how much reserve it provides.

61 This result is dependent on the units' actual efficiency curves and the VALORAGUA model not perfectly modelling the instantaneous efficiency of the units at different load factors and the increase in fuel (water) consumption when the units provide reserve. Since the VALORAGUA model is a medium to long term model relying on a simplified demand duration curve it does not seem likely that such adjustments are made.

62 If the opposite is in fact true i.e. a hydro unit is more efficient when it provides reserve, then the fact that the VALORAGUA model relies on average efficiencies this may be favourable for EDP,

Continued on next page

- Increased variable O&M costs, if they are not properly taken into account in the annual CMEC adjustment[63]
- Potential additional risks[64]

In order to avoid the CMEC framework distorting competition in the secondary reserve market and so adversely affecting market outcomes, units with CMEC should, in general, be allowed to include the same types of costs that a unit without CMEC would include in its bids.

However, given the purpose of the CMEC legislation is to provide units with the same revenues they would have earned with their PPA, it may not be appropriate to allow them to include a risk premium. To determine to what extent this should be allowed, it will be necessary to assess whether, and how, secondary reserve was treated under the PPAs, which lies outside the scope of this project. In any event, arguably, units covered by CMEC face fewer risks than units not covered by CMEC and, therefore, should not be allowed to retain the whole premium.[65] On the other hand, if they cannot retain an appropriate premium, they will be reluctant to participate in the market.

V.A.3. Impact on the market and on other units

ERSE and AdC have already noticed that the potentially abnormal participation of the units with CMEC affected the results of EDP because it had other units operating in the same market that were not covered by the CMEC. [66]

Continued from previous page

because it would lead to lower overall ex-post generation (for the same fuel usage) than the real generation.

63 The Monitoring Committee has informed us that all the O&M costs for hydro units are included as fixed costs and adjusted consequently. To the extent that additional O&M costs due to the provision of reserve are appropriately compensated, this cost element would not distort the provision of reserve. .

64 See footnote 39 for a description of these risks.

65 The CMEC annual adjustment corrects for potential variations in the margins made by these units in the market. Therefore, these units are less exposed to market risks. However, to the extent that there may be risk factors not included, such as the payment of penalties caused by failures to provide reserve, units with CMEC could claim that they have right to certain compensation.

66 AdC, Recomendação ao Governo, relativa ao regime de Auxílios de Estado denominado por Custos para a manutenção do Equilíbrio Contratual (CMEC)”, ¶29:

Continued on next page

A unit covered by CMEC can modify its participation in the secondary reserve market without any direct financial implication, because the money it foregoes in the secondary reserve market would, in any event, be removed or reduced by the CMEC annual adjustment. Therefore, such a unit can affect market outcomes without having to bear the cost of doing so.

This impact is possible because the CMEC units are pivotal suppliers of secondary reserve – without their reserve capacity there is not enough reserve capacity to provide the required regulation service. If the level of competition in the market were sufficient, changes in the participation of CMEC units would only marginally affect the revenues earned by non-CMEC units owned by the same company, since the impact would be spread between many units. Hence, the impact of the CMEC is dependent on the market structure of reserve supplies.

Thus, given the Portuguese market structure, the existence of the CMEC may facilitate the exercise of anti-competitive practices, since these can be undertaken without any adverse effects for the CMEC units.

V.B. Assessment of the Bids to the Market

We have estimated (on an hourly basis) the maximum secondary reserve capacity that every unit could provide and what price they should offer for that capacity. These estimations have been done following the analytical framework laid out in section III, which is described in detail in Appendix B[67] , and Appendix C.[68] Subsequently, we have estimated what the market outcomes would have been if the units had bid as estimated.

Units bid into the secondary regulation market separately for each hour of the following day, submitting up to 15 different capacity tranches for every hour. As a consequence, the complete set of bids for the study period constitutes a very extensive dataset. In order to

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> *"Assim, a gestão eficiente das centrais no mercado de telerregulação pode atuar em benefício da redução da compensação, em favor dos consumidores, mas pode também atuar em potencial prejuízo das restantes centrais operadas pelo grupo EDP em telerregulação. A presença de interesses diversos e conflituantes fundamenta por isso a existência de um conflito de interesses na gestão simultânea das centrais CMEC e das centrais em regime de mercado."*

[67] Estimation of the Costs of Providing Secondary Reserve.

[68] Estimation of Over Compensation.

analyse these data, we have calculated aggregate average monthly bids for different types of units.[69] We are then able to compare the actual and simulated data on this aggregated basis.

We have compared our estimated bids with the actual bids and outcomes of the secondary reserve market. We acknowledge that our estimations are based on a series of assumptions on the available capacity and costs of the units,[70] and therefore can only approximate the true competitive outcome. However, we use these estimations as a benchmark to assess the evolution of the actual units' behaviour, rather than to identify precise deviations from optimal outcomes.

Our analyses suggest that the units with CMEC consistently bid into the market less than the capacity they have available to provide secondary regulation and that their bids may be higher than the costs of providing reserve.

V.B.1. Assessment of the quantity offered to the market

The units covered by the CMEC seem to bid into the secondary reserve market capacities that are substantially lower than the capacity we estimate they have available to bid. While our estimated capacity bids for other types of units also deviate from the capacity they actually bid, the deviation between our estimated and the actual bids of the units with CMEC is significantly higher.

We are not aware of any constraints that limit the reserve capacity offered by the units with CMEC when they are available to produce.[71] In addition, our estimations are rather conservative, because they are based on the units' final hourly generation schedule. Therefore, they only take into account the capacity that a unit could have provided in real time, rather than the total capacity that a unit could make available.[72,73]

69 These types are: thermal units, hydro with and without CEMC.

70 The methodology, input data and assumptions we have used in order to estimate the capacity and costs of the units are described in Appendix B and Appendix C.

71 We have taken into account the availability constraints with regard to energy production included in the VALORAGUA simulations. However, there may be other constraints of which we are not aware relating specifically to the provision of secondary reserve.

72 Section C.II.1 of Appendix C discusses the impact of calculating the regulation capacity from the final generation schedule and the potential alternative. We have checked that there would be only minor changes when using the generation schedule from after the last intraday market.

73 This should imply that the simulated quantities should be below the actual quantities bid. However, since we have taken the nominal capacity of the units, which overestimates their real capacity, the net effect is unclear.

At the time the units submit their bids to the secondary reserve market, they still have the capacity to modify their generation schedule and, hence, modify their capacity to provide regulation. They can also determine their bids taking into account portfolio effects —since they have the possibility of exchanging capacity with other units.[74] Therefore, the reserve capacity the units bid into the market is not bounded by their real time capability to provide regulation, and could be expected to be higher, although these effects are likely to be small.

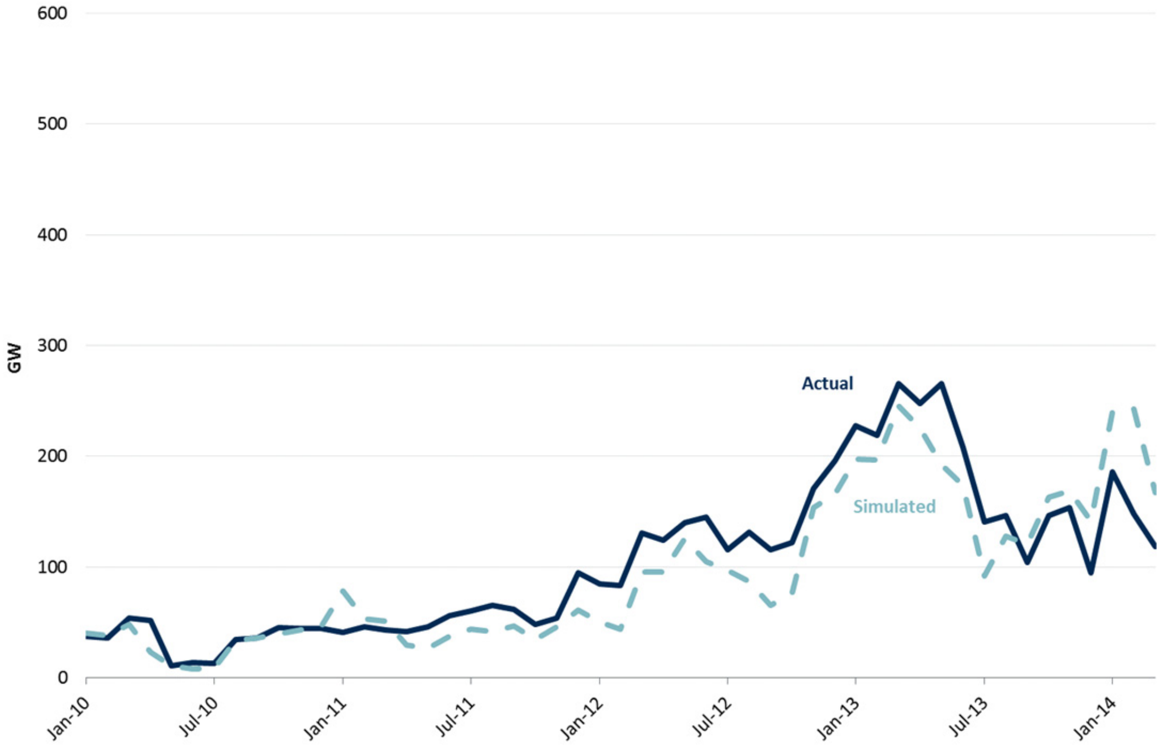
Figure 22 and Figure 23 compare the estimated and actual quantities bid by thermal units and hydro units without CMEC and show that although there are differences between the two sets of bids, these differences are not permanent and are relatively small.

Figure 22: Secondary regulation reserve offered to the market by thermal units

Source: The Brattle Group, from data from REN and own elaboration.

74 For instance, some CCGT units of the same power plant normally exchange the reserve allocations they are allocated if any of the units does not run in real time. The exchanges of reserve are described in section IV.A.

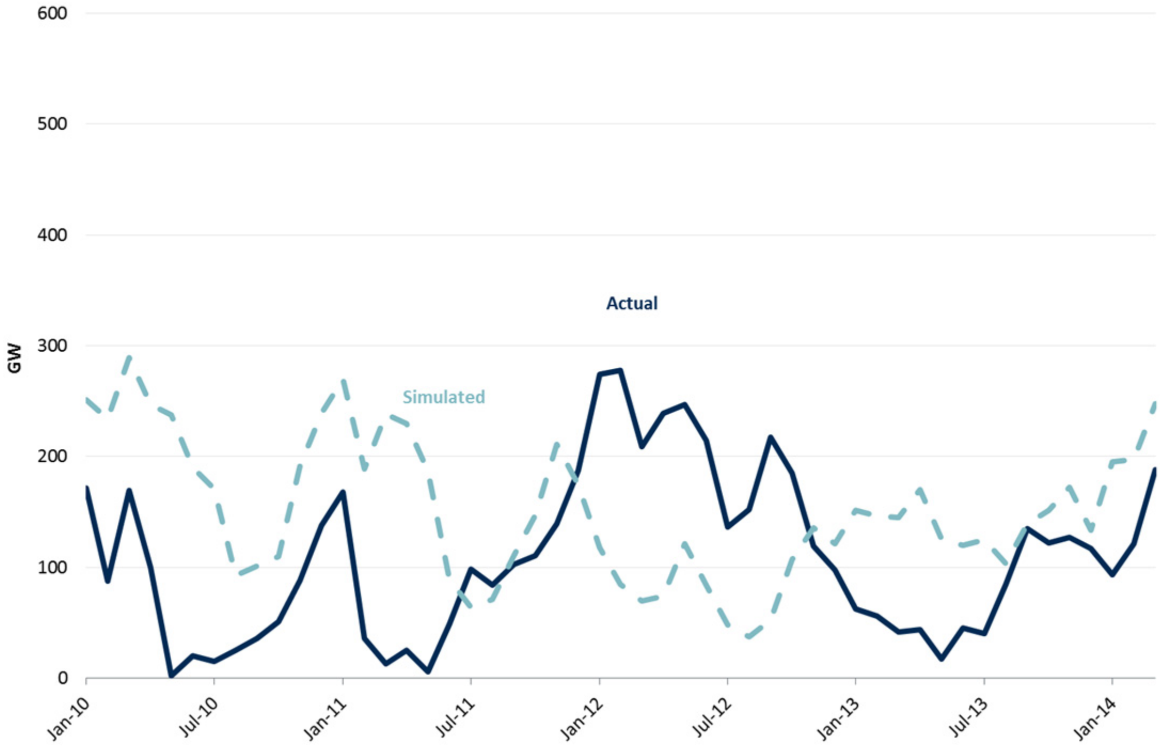
Figure 23: Secondary regulation reserve offered to the market by hydro units without CMEC



Source: The Brattle Group, from data from REN and own elaboration.

In contrast, Figure 24 shows that the actual quantity bid to the market by CMEC units has more consistently been significantly lower than our estimated of the available reserve capacity.

Figure 24: Secondary regulation reserve offered to the market by hydro units with CMEC



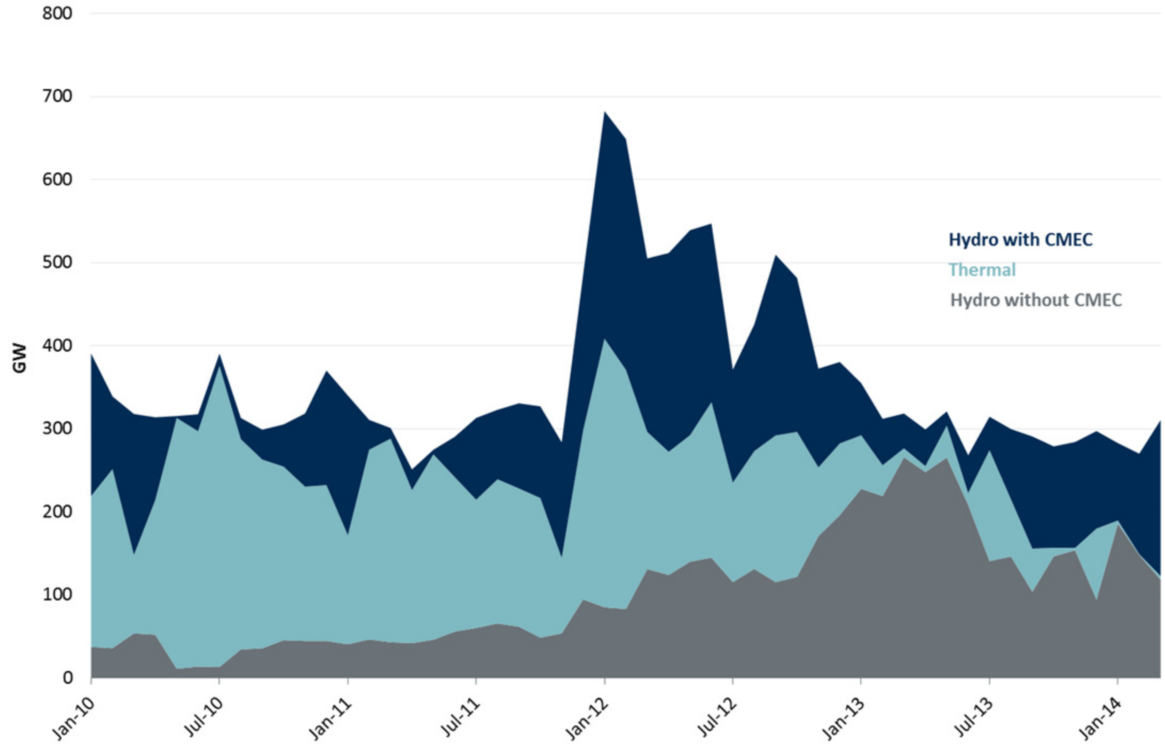
Source: The Brattle Group, from data from REN and own elaboration.

The converse is, however, true during 2012.[75] Figure 25 shows that during 2012 there was a significant increase in the total secondary reserve market offered to the market. The bids of CMEC units' were responsible for a significant part of this increase and, as we show above, it does not seem to correspond to a parallel increase in their actual ability to provide reserve.

We analysed the increase in the capacity bid in section IV.A (see Figure 14) and concluded that the increase was more notional than real because it was coincident with a significant increase in the prices in the bids, so that the additional capacity was made available at prices above the typical market clearing price.

75 We expect the estimated available secondary reserve capacity to be below the actual capacity because the estimation is conservative, since it considers only to a limited extent the possibility to modify the units' generation schedule. See explanation in section of C.II.1 of Appendix C.

Figure 25: Total secondary regulation reserve offered to the market



Source: The Brattle Group, using data from REN

V.B.2. Assessment of the price of bids

Starting from mid-2011, the units covered by the CMEC also seem to have submitted prices to the secondary reserve market that are higher than the prices we estimate they should have offered. We observe a similar deviation for hydro units without CMEC starting from around the second quarter of 2012. By contrast, our estimations for thermal plants approximate reasonably well to the actual bids throughout the study period.

We have reached these conclusions regarding above cost hydro bids after filtering out all the actual bids above 100 €/MW. While there can be reasons why reserve capacity should be offered with prices above this figure,[76] bids above 70 €/MW were seldom submitted before the end of 2011 but were extremely common in the months thereafter.[77] Figure 26 shows the monthly average of the bids submitted by different type of units, weighted by the capacity offered.

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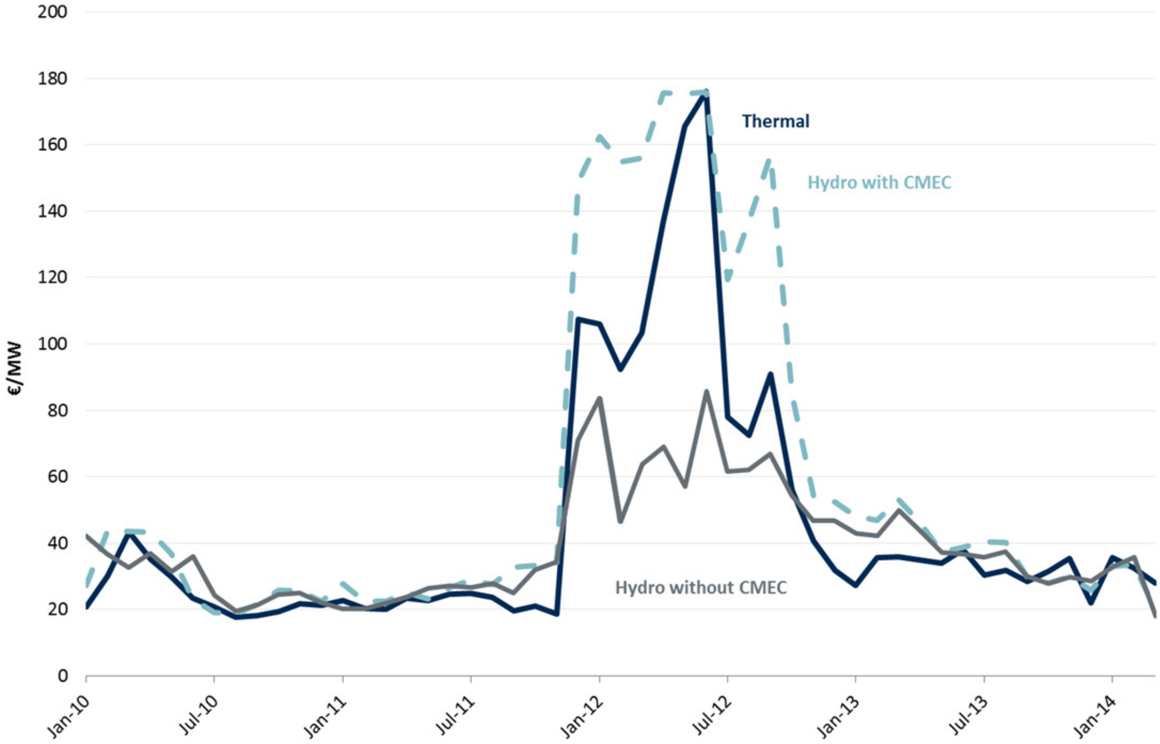
76 The threshold of 100 €/MW is not related to the potential costs borne by the units but just as a simple filter. However, our estimation of the costs of providing secondary reserve reveals than costs over 100 €/M are not uncommon.

77 As a reference, see Figure 14 and the analysis in section IV.A.

Figure 26: Average bids to the secondary reserve market

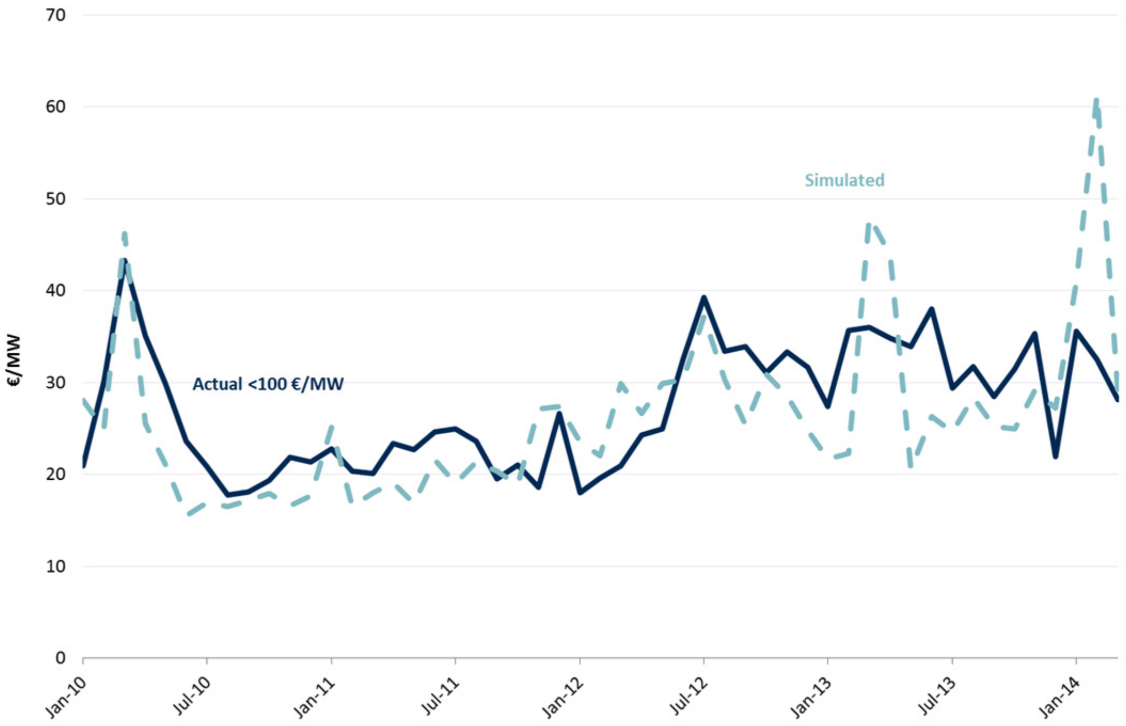


Source: The Brattle Group, from data from REN.

It seems possible that bids above 100 €/MW may relate to capacity that could only be provided by incurring costs outside the normal market range.[78] Therefore, we have excluded these bids for comparability purposes. The following figures compare the monthly averages of the actual bids with prices below 100 €/MW and our simulated bids, weighted by the capacity offered, for thermal units (Figure 27), hydro units without CMEC (Figure 28) and hydro units with CMEC (Figure 29).

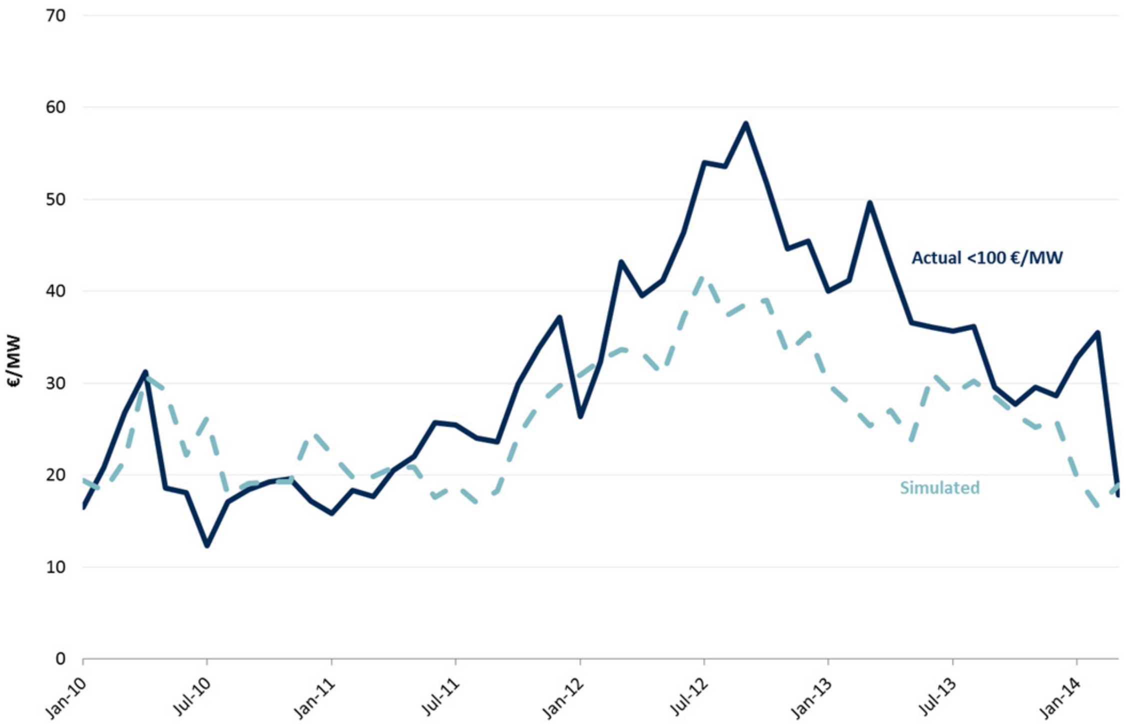
[78] REN monitors that the capacity the units bid are within the range they can provide. However, a unit with fuel constraints cannot sustain a high level of provision of reserve for long, and therefore these high levels of capacity in the market did not reflect the expectable operating conditions.

Figure 27: Average bids to the secondary reserve market by thermal units below 100 €/MW



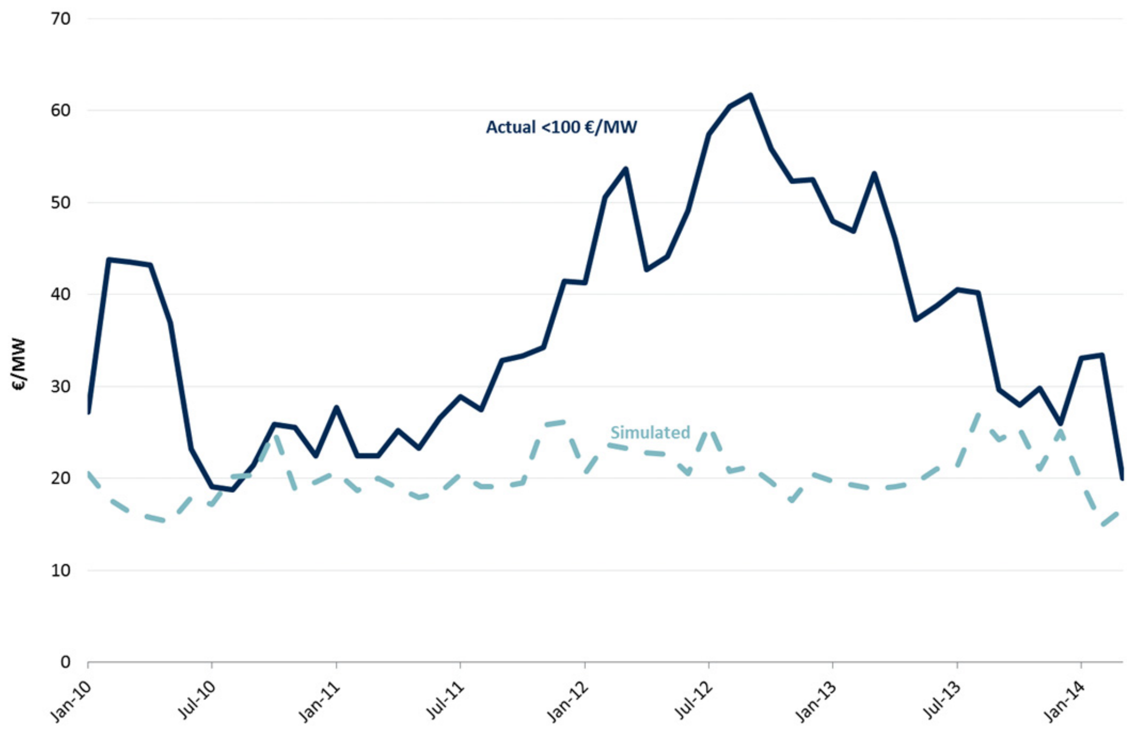
Source: The Brattle Group, from data from REN and own elaboration.

Figure 28: Average bids to the secondary reserve market by hydro units without CMEC below 100 €/MW



Source: The Brattle Group, from data from REN and own elaboration.

Figure 29: Average bids to the secondary reserve market by hydro units with CMEC below 100 €/MW



Source: The Brattle Group, from data from REN and own elaboration.

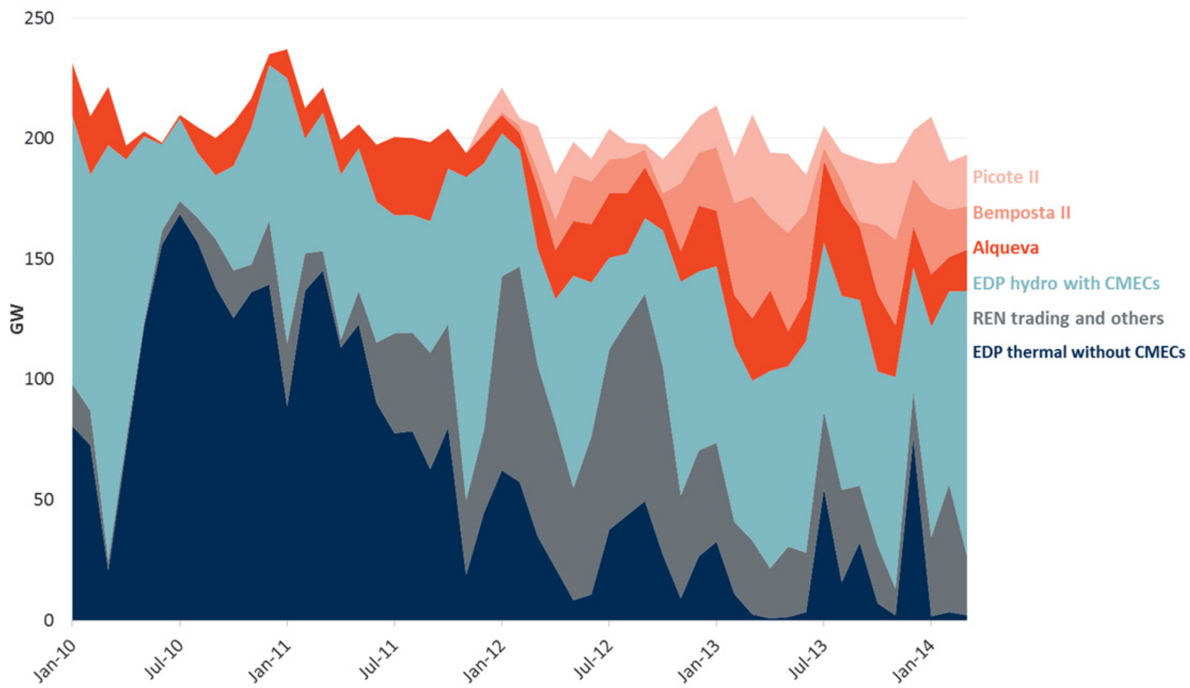
V.B.3. Assessment of the market results

We have estimated an alternative set of hourly market outcomes using our estimation of the cost-reflective level of bids. These outcomes consist of (a) an adjusted price for secondary reserve and (b) an adjusted allocation of reserve between the different units. Consistent with the findings presented in the previous sections, these results suggest that hydro units with CMEC could have provided a larger share of the regulation capacity, displacing thermal generators at the beginning of the period under study and hydro without CMEC from 2012. However, the price for secondary reserve only deviates significantly from our benchmark between 2012 and the third quarter of 2013.

As in the case of the previous comparisons, these findings depend on the assumptions we have made and should not be interpreted as a precise estimation of what the market allocations and prices should have been, but as a benchmark, which we can use to assess the units' bids.

Figure 30 shows our simulated allocation of secondary reserve, while Figure 31 shows the actual reserve allocation. Figure 32 compares the actual price for the secondary reserve with our estimation of the price.[79]

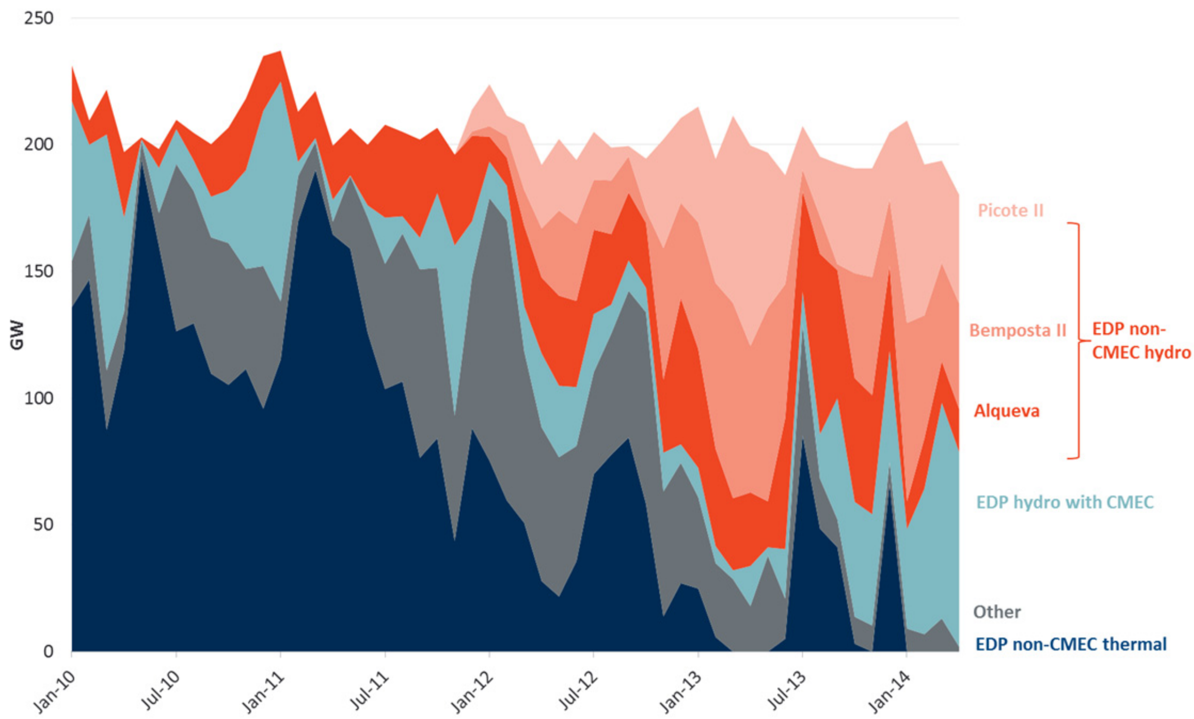
Figure 30: Simulated monthly allocation of secondary reserve



Source: The Brattle Group.

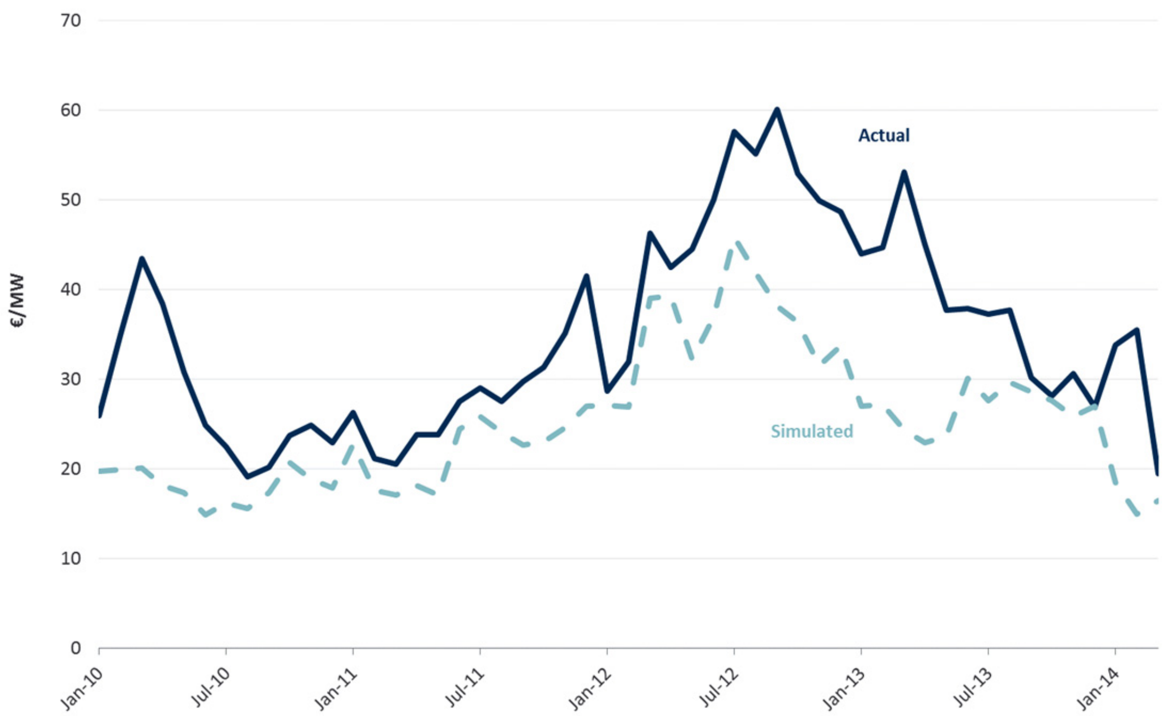
[79] Despite the similarities between our estimation of the secondary reserve price in Portugal, shown in Figure 32, and the actual secondary reserve price in Spain in Figure 4, it is not possible to compare prices in the two markets. The Spanish secondary reserve market rules differ from Portuguese ones in areas that significantly affect the prices, such as the ratio of upward to downward reserve, and the use of aggregated units to provide reserve (rather than reserve being provided by single units).

Figure 31: Actual monthly allocation of secondary reserve



Source: The Brattle Group, from data from REN.

Figure 32: Simulated and actual monthly average price of secondary reserve



Source: The Brattle Group, from data from REN and own elaboration

VI. Quantification of the Potential Over-compensation

We have used our estimation of a cost-reflective set of bids and hourly market outcomes to quantify the impact that such alternative bidding behaviour could have had on the units providing secondary reserve. Consistent with our findings in previous sections, we estimate that this impact would have been significant mainly in 2012 and 2013. It is in these years when the actual reserve allocation and prices deviate the most from our benchmarks.

We calculate the potential over-compensation for secondary reserve by determining the difference between the actual margin a unit appears to have earned in the secondary reserve market and its margin under our cost-reflective scenario. Consequently, a positive impact implies that the units made a larger margin in the actual world than we estimate they would have made with cost-reflective bids. The margin is given by the difference between the revenue and the cost of a unit.

The margin that a unit makes can vary because of:

- Changes in the extent to which its reserve bids are accepted. We refer to this impact as "the quantity effect".
- When a unit provides more reserve, all other things being equal (i.e. if the reserve price remains the same), then it will earn a higher margin. Conversely, if the reserve provided by the unit reduces, (as we have estimated that would happen to EDP's non-CMEC units under cost-reflective bidding), then the margin it can earn should fall.[80]
- The quantity effect corresponds to the scenario that the Monitoring Committee has stated that best fits the criterion used by Decree Law 240/2004 for calculating the overall CMEC compensation.[81]
- Changes in the market clearing price. We refer to this impact as "the price effect".

  If the bids offered by the marginal units are lower, then the clearing price will be lower and, even if there is no quantity effect, all units will earn a lower margin.

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80 The margin that a unit makes also varies from hour to hour depending on the unit's cost and the price of the reserve every hour. Therefore, a change in the quantity of reserve can also modify the average margin a unit makes.

81 The Monitoring Committee has stated that it thinks that the criterion to evaluate the fairness of the ex-post CMEC compensation should take into account the secondary reserve actual prices. This is the criterion used by Decree Law 240/2004 for calculating the overall CMEC compensation, which is based on actual day-ahead wholesale prices and not an ex-post estimation of the energy prices that would be observed using VALORAGUA simulations.

As agreed with the Monitoring Committee, we have made this estimation for two groups of units: the units owned by EDP and covered by the CMEC and the units owned by EDP and not covered. Since the units covered by the CMEC are subject to the annual adjustments of the CMECs, the estimated margins do not correspond to earnings that the units would actually make in the market.

The following subsections show our estimations of the potential over-compensation if we consider only the quantity effect on units' margins or the total effect. The total effect is the combination of the quantity and the price effect. Because these results rely on the assumption we have made on units' costs, we present our estimations under three different values for the margin/risk premium (0, 5 and 10 €/MW).

VI.A. Quantity Effect

The quantity effect includes only the changes in the units' margins due to changes in the amount of secondary reserve provided. Both the margin in the actual world and the margin in our alternative scenario are calculated using the actual market price for the secondary reserve.

The total margin a unit makes is the result of the different margins a unit makes every hour. Therefore, the variation in the total margin depends both on the total amount of reserve provided and on what hours our estimated allocation of secondary reserve between units differs from the actual allocation.

If we consider only the quantity effect, we estimate that, overall, the margin made by EDP's non-CMEC units would have been between €11 million lower with cost-reflective bidding in 2012 and 2013 if we do not include an allowance for a risk premium. Their margins with cost-reflective bidding would have been lower because they would have provided less secondary reserve as a result of EDP's CMEC units would have been providing more.

If we include a risk premium of 10 €/MW (close to the value used in PJM), then the margin of EDP's non-CMEC plants under cost-reflective bidding would only have been around €5 million lower in these years. Similar values would have been obtained in 2014 if the *Despacho* 4694/2014 had not have been approved. We treat the risk premium as a cost and so the margin loss from providing less secondary reserve is reduced when we include the risk premium in our calculations.

Table 2 below summarizes the results for the quantity effect under three different values for the margin/risk premium, whilst Appendix D presents a detailed set of results. A positive figure indicates that the margin would have been lower with cost-reflective bidding. If no risk premium is included, we estimate that the non-CMEC units have earned around €29.6 million more than they would have done with cost-reflective bidding. The total gain falls, in essentially a linear fashion, to around €8.8 million if we assume a risk premium of €10/MW.

Table 2: Decrease in margins from cost-reflective bidding considering only the quantity effect, € million

Unit	2010	2011	2012	2013	2014	Total
Risk premium 10 €/MW						
EDP with CMEC	-8.5	-5.6	-12.9	-12.8	-1.6	-41.5
EDP without CMEC	-3.6	-0.3	5.6	4.9	2.1	8.8
Risk premium 5 €/MW						
EDP with CMEC	-10.8	-8.6	-15.3	-16.0	-2.1	-52.9
EDP without CMEC	-2.7	2.0	8.4	8.4	3.0	19.2
Risk premium 0 €/MW						
EDP with CMEC	-13.1	-11.6	-17.7	-19.1	-2.6	-64.2
EDP without CMEC	-1.8	4.4	11.2	11.9	3.9	29.6

Source: The Brattle Group.
Notes:
Positive values indicate that the margins are higher with the actual bids than with cost-reflective bids.
Detailed additional results, including the results for other generators, can be consulted in Appendix D and in the MS Excel files accompanying this report.
Our base case assumption for the risk premium is 10 €/MW
Estimation until 31st March 2014

Table 2 also shows our estimate of the change in the margins for EDP's CMEC units before CMEC adjustments are taken into account. These should not be viewed as real margin changes because of the revenue adjustments to which CMEC units are subject. If no risk premium is included, we estimate that the CMEC units would have been around €64 million higher with cost-reflective bidding, as they would have provided more secondary reserve. The total gain falls to around €41 million if we assume a risk premium of €10/MW.

VI.B. Total Effect

The total effect includes the changes in the units' margins due to both changes in the amount and price of the secondary reserve provided, both the quantity and price effect. In this case, therefore, the margins in the actual world are calculated using the actual market price and the margins for our "cost-reflective" case are calculated using our estimation of the market price for the secondary reserve.

Because we estimate that cost-reflective secondary reserve prices would have been lower than the actual prices, the average margins in the cost-reflective scenario are lower than in the actual world. As a consequence the difference between the estimated actual margins and the cost-reflective margins are larger than if we consider only the quantity effect.

The impacts considering the total effect are also more sensitive to the risk premium assumption. The reason is that, while the margin in the actual world changes with this assumption on costs, the margin in the cost-reflective scenario is always the same because the price moves with the costs.

If we consider price effects as well as quantity effects, we estimate that, in 2012 and 2013, the margins earned by EDP's non-CMEC units would have been around €30 million per year lower with cost-reflective bidding if we do not include a risk premium and around €15 million lower when we include a risk premium of 10 €/MW. In contrast to the results for the quantity effect, it appears that EDP's non-CMEC units would also have earned lower margins in 2010 and 2011 with cost-reflective bidding. Over the entire study period, we estimate that the margins earned by EDP's non-CMEC units would have been between €46.7 million (10€/MW risk premium) and €118 million (no risk premium) lower with cost-reflective bidding.

Table 3 below summarizes the results for the quantity effect under three different values for the margin/risk premium, whilst Appendix D presents a detailed set of results.

Table 3: Decrease in margins from cost-reflective bidding considering both the price and quantity effects, € million

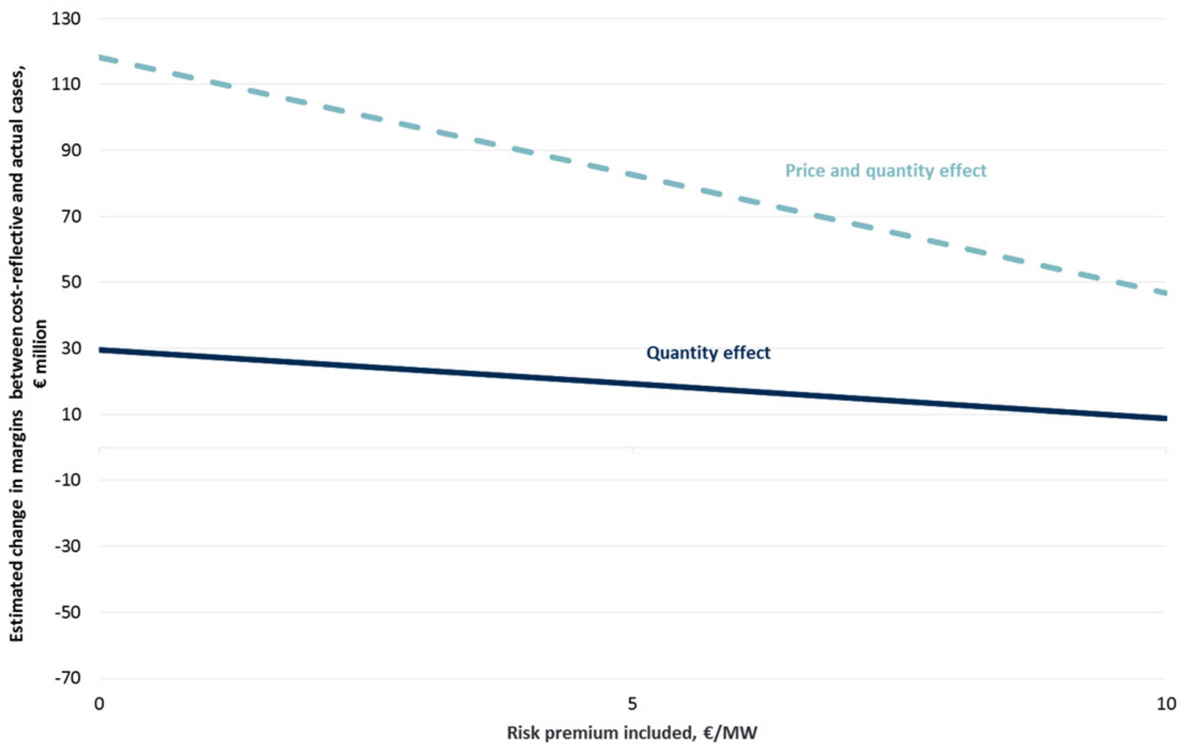
Unit	2010	2011	2012	2013	2014	Total
Risk premium 10 €/MW						
EDP with CMEC	3.0	0.7	-2.2	-0.1	1.8	3.1
EDP without CMEC	6.6	5.7	14.2	15.7	4.6	46.7
Risk premium 5 €/MW						
EDP with CMEC	5.0	2.0	-1.2	1.2	2.7	9.6
EDP without CMEC	15.1	14.4	21.5	24.9	6.5	82.5
Risk premium 0 €/MW						
EDP with CMEC	7.0	3.3	-0.2	2.5	3.6	16.1
EDP without CMEC	23.7	23.2	28.9	34.1	8.4	118.3

Source: The Brattle Group.
Note: Positive values indicate that the margins are higher with the actual bids than with cost-reflective bids.
Detailed additional results can be consulted in Appendix D and the MS Excel files accompanying this report.

Table 3 also shows what the estimated change in margins would be for EDP's CMEC units. Again, these should not be viewed as actual margin changes because of the CMEC adjustment mechanism. If no risk premium is included, we estimate that the CMEC units would have made around €16.1 million more in total with cost-reflective bidding. The total gain falls, in essentially a linear fashion, as the risk premium increases, to around €3 million for a risk premium of €10/MW. The reason that the gains are higher when we include the price effect is that the increase in the quantity of reserve that would have been provided by the CMEC units is offset by a reduction in the price they would have been paid for providing that reserve.

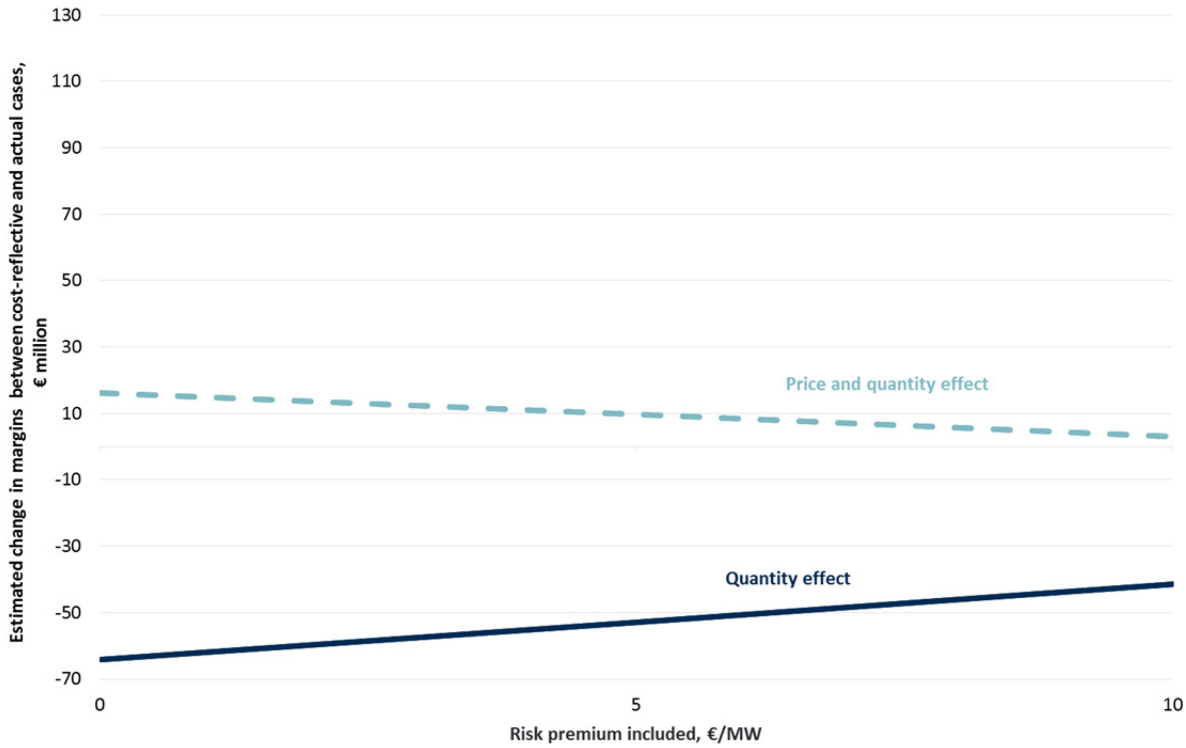
Figure 33 and Figure 34 shows the overall margin decreases over the entire study period for EDP's non-CMEC and CMEC units respectively under different assumptions on the risk margin.

Figure 33: Margin effects over the entire study period, non-CMEC units



Source: The Brattle Group

Figure 34: Margin effects over the entire study period, CMEC units



Source: The Brattle Group

VII. Recommendations on Market Design and Policy

During the elaboration of this report, we have identified several areas of the market design which influence the secondary reserve market outcomes and agents' biding strategies. This section provides some recommendations on potential changes to these areas. The recommendations are intended to reduce the information asymmetry between the regulator and the market agents and improve the monitoring of the agents' behaviour.

- Publication of guidelines on bidding behaviour for the reserve market, providing guidance with respect to both the quantity and price that agents are expected to bid. The guidelines could subsequently be used to monitor agents' bidding behaviour. The elaboration of the guidelines would benefit from a public consultation process so as to allow market agents to provide justifications for their biding behaviour.
  - Regarding costs, the guidelines should identify the different cost elements that can be included in the bids and provide rules on how the costs are expected to be calculated.
  - Regarding quantities, the guidelines should limit the agents' scope to vary the amount of capacity bid by different units.

- CMEC units should, in general, be allowed to include the same types of costs in their bids as non-CMEC units. However, analysis of the treatment of secondary reserve in the PPAs needs to be carried out to determine whether, or to what extent, they should be allowed to include a risk premium,

- Establishment of special requirements for dominant agents in the wholesale market.

  Certain agents could be subject to additional requirements regarding their participation in the market. These requirements could include the obligation to bid to the secondary reserve market (similar to the current obligation for the tertiary reserve) and to provide the regulator with additional information on how bids are elaborated.

- Assess if the current market monitoring capabilities need to be expanded.

  - A generation dispatch model could be used to monitor both the short term energy market and the provision of ancillary services, including secondary reserve. The model should be customized to reproduce the characteristics of the Portuguese market.

  - A periodic ex-post audit of the quantities and price bid by different agents would not only help check that the bidding guidelines were being respected, but would provide further insights into agents' bidding behaviour.

- Align the System Operator incentives with the reduction of the system services costs.

  Despite the difficulty of assessing the performance of the System Operator and forecasting system services costs, the System Operator should face incentives to minimize these costs. Such incentives have successfully been implemented in Great Britain.

- Encourage further harmonization of the system services market design across different countries, particularly between Spain and Portugal. The harmonization would help to:

  - Provide more options for procuring system services and so reduce the possibility that market power can be exercised.

  - Improve the amount of information available to the regulator, since it would be possible to exchange information on costs, monitoring tools or regulatory best practices.

- Consider implementing some changes to the secondary reserve market design:

  - Adapt the rules to allow purchasing units, such as pumped storage units or new non-conventional storage devices (e.g. batteries, fly-wheel storage…) to participate
  - Study the technical feasibility of an asymmetric provision of reserve by units, allowing some units to provide only downward or upward reserve, with different prices. This would reduce the cost of providing the service, since it would increase the supply of reserve capacity, and reduce the opportunity cost of some units.
  - Alternatively, consider moving to secondary reserve being provided by portfolios of units, rather than by physical units, as in Spain.[82] Sometimes the Portuguese market already behaves as if the reserve were provided by portfolios.[83]
  - Assess the 2:1 ratio of upward to downward. This ratio, that seems to be based on the lack of enough fast upwards tertiary reserve,[84] affects the secondary reserve marginal clearing price.
  - Contemplate to settle some costs after the secondary regulation service has been provided. At the moment. units need to bid on expectations of some variable costs, so the bids are both more uncertain and less transparent.
- Assess if there is need of further refinements to the CMEC annual adjustments procedures with respect to the way secondary reserve revenues and costs are accounted for.

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82 The risk of some deterioration in the response and the quality of service because of the use of serial AGCs would be compensated by an improvement in the efficiency of the provision.

83 Exchanges of reserve, especially last minute changes that require out-of-the-market modifications to the last generation schedule (PHOF) leads to results that are similar to markets in which the participation is not organized through physical units, but with portfolios of units.

84 REN's response to the first information request, question 8.

Appendix A. Units providing secondary during the period under study

Table 4: Characteristics of the units that participated in the secondary reserve market in the period under study

Unit	Code	Type	River	Current regulation capacity	CMEC
Hydro units					
Aguieira	AGUIEI	Reservoir	Mondego	156.0	Yes
Alto Lindoso	ALINDO	Reservoir	Lima	330.0	Yes
Cabril	CABRIL	Reservoir	Tejo	58.0	Yes
Castelo de Bode	CBODE	Reservoir	Tejo	84.0	Yes
Frades	FRADES	Reservoir	Cávado	91.0	Yes
Bemposta	BEMPOS	Run-of-river	Douro I.	90.0	Yes
Picote	PICOTE	Run-of-river	Douro I.	90.0	Yes
Pocinho	POCINHO	Run-of-river	Douro I.	111.0	Yes
Régua	REGUA	Run-of-river	Douro N.	105.0	Yes
Torrão	TORRAO	Run-of-river	Douro N.	60.0	Yes
Valeira	VALEIRA	Run-of-river	Douro N.	150.0	Yes
Alqueva	ALQUE	Reservoir	Guadiana	154.0	No
Alqueva II	ALQUEII	Reservoir	Guadiana	190.0	No
Bemposta II	BEMPOS4	Run-of-river	Douro I.	116.0	No
Picote II	PICOTE4	Run-of-river	Douro I.	145.0	No
Thermal units					
Lares - Group 1	LARES1	CCGT		165.0	No
Lares - Group 2	LARES2	CCGT		165.0	No
Pego C.C.- Group 3	PEGO3	CCGT		97.5	No
Pego C.C.- Group 4	PEGO4	CCGT		97.5	No
Ribatejo - Group 1	RIBATE1	CCGT		120.0	No
Ribatejo - Group 2	RIBATE2	CCGT		120.0	No
Ribatejo - Group 3	RIBATE3	CCGT		82.5	No
Pego - Group 1	RPG01	Coal		37.5	No
Pego - Group 2	RPG02	Coal		37.5	No
Total				2,852.5	

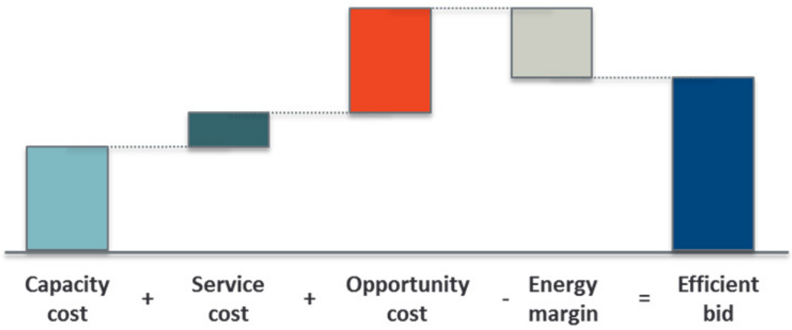
Source: The Brattle Group, from information provided by REN.
Notes:
Although the Aguieira unit is formally covered by CMEC, during the period under study it has been operated by Iberdrola and considered as a unit without CMEC.
Sines coal power plant was formally available of providing secondary reserve, but never participated in the market.

Appendix B. Estimation of the Costs of Providing Secondary Reserve

The analytical framework for the assessment of bids and costs related to the provision of secondary reserve has been developed based on the US PJM market cost development guidelines for cost-based offers to the regulation service.[85] We have adapted these guidelines to reflect the characteristics of the Portuguese electricity market and the secondary reserve service.

We have identified four different economic concepts involved in the formation of an efficient bid for the secondary reserve market. These concepts are illustrated in the Figure 35 and described in the following sections.[86]

Figure 35: Cost structure of regulation services



B.I. Estimation of Capacity Costs

The capacity costs include the costs of making the reserve capacity available, other than the opportunity costs. These costs include:

- The increase in fuel costs (including water) as a result of the reduction in the energy efficiency because the unit is operating at a lower load than the optimum.

  When a unit provides regulation it may need to reduce its production level to an inefficient point, increasing the unit's fuel or water consumption. Following the PJM guidelines, we have estimated this cost as the increase in fuel consumption

[85] In the PJM market, agents in areas that are thought to present structural market power may be subject to control over their offers to prevent any exercise of that market power. This is implemented through cost-based offers.

[86] Adapted from the PJM's cost development guidelines; Power System Economics, Designing Markets For Electricity, Chapter 3-10 (Stoft, 2002), and NYISO Industrial Load Response Opportunities: Resource and Market Assessment—Task 2 Final Report, 2009, section 4-2.

from the maximum load to the regulation set point,[87] multiplied by the cost of the fuel (or value of the water) and divided by the amount of reserve offered.[88] We have not allowed for these costs if the unit did not need to reduce its output, but increase it.

For some units, such as hydro units, the reduction in the production in order to provide reserve may lead to an increase, rather than decrease, in the unit's efficiency. However, in the absence of detailed information on their efficiency curves, we assume that hydro units are always producing at a level in which they maximize their efficiency.

- An allowance for the risks of participating in the market.

  These risks include the uncertainty in the costs of providing regulation and the potential increase risk of a unit tripping because it is operating in a non-steady-state condition.[89] The PJM market allows a cap of 12 \$/MW for this concept, under the name "margin /risk adder". We refer to this also as risk premium. Based on this value, our main results assume a value of 10 €/MW[90] and we have carried out sensitivity analyses with a value of 5 and 0 €/MW.

B.II. Estimation of Service Costs

The provision of regulation involves some costs that are not directly connected with whether a unit can provide reserve capacity. These costs are:

- The increase in variable O&M costs due to actual use of reserve capacity
- The increase in fuel consumption during non-steady-state operations[91]

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87 The PJM methodology estimates this consumption at the minimum regulation point, rather than at the regulation set point.

88 The formula is [(reg.setpoint/eff. at the reg.setpoint)-(reg.setpoint/eff. at the optimum)] x Fuel price / regul. Capacity.

89 PJM, A Review of Generation Compensation and Cost Elements in the PJM Markets, p.23. 2009.

90 In PJM, units have simultaneously submit energy and reserve bids whereas in Portugal reserve bids are submitted after the initial energy schedule is known. Consequently, the risks associated with providing reserve in Portugal are likely to be lower than those in PJM.

91 This fuel cost is related to the changes in the units' output required to provide reserve, and thus it is variable with the amount of reserve actually provided. It differs from the fuel cost included inas capacity cost in that the previous takes into account the increase in fuel cost of the actual generation level.

The increase in variable O&M costs is associated with the actual regulation provided and measured in €/MWh. Regulation is provided when the output of a unit is changed either upwards or downwards. In the US the amount of actual regulation is known as "mileage".[92]

The level of regulation provided can vary between units because not all the units can provide the same level of reserve capability, since some units are capable of ramping up and down faster and more accurately than others. In the United States, the Federal Energy Commission ruled in 2011 that the units should be paid according to the actual services provided, as measured by the "mileage".[93] Since we have no measure of the actual regulation service provided, we have included a generic cost allowance for all the units of the same technology.[94]

Regarding the second element, it is related to the increase in energy consumption for oscillating a unit output instead of holding it steady. We have not taken it into account given the small amount of the costs associated with it.[95]

B.III. Estimation of Opportunity Costs

A unit's opportunity costs are the earnings it foregoes in other markets in order to provide secondary reserve. These costs arise because when a unit makes capacity available to the System Operator it loses the possibility of using that capacity in other markets and obtain profits from them.

In electricity markets that co-optimize energy and reserve, such as the markets in the United States, the opportunity costs can be assessed and settled ex-post, once the real time price of electricity is known and the economic operation of the unit (without providing reserve) can be estimated. In the Portuguese system, where the markets are run sequentially, opportunity costs need to be assessed *ex-ante* by the agents and internalized in their bids.

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92 Mileage refers to the actual use of the regulation services, with upward and downward moves to the unit generation level.

93 The US electricity market FERC Order 755-2011 ruled that the units should be paid according to the actual services provided (the mileage).

94 This allowance is based on the assumption that the actual mileage is 1. While this value may underestimate the total O&M cost of providing the service, it does not affect the relative bids of different units and therefore it does not affect the allocation.

95 The PJM cost guidelines allows a maximum of 0.35% of fuel costs.

We estimate a unit's opportunity costs, in a simplified way, as the difference between the market price and the unit's energy marginal cost if it was optimizing its participation in that market. [96,97]

In order to estimate these costs, we consider two different situations:

- If the unit has already started-up economically (and needs to lower its production un-economically to provide regulation): we set its costs by reference to the highest foregone earnings in other markets. Thus, its opportunity cost may arise in relation to:
  - The standard energy market (day-ahead and intraday markets).
  - The real time markets, such as tertiary regulation and real time technical constraints.[98]

    The opportunity cost with respect to the tertiary reserve market may arise because, although the energy scheduled is paid the same price as for secondary regulation, the probability of being dispatched –and thus the volume of revenues received- varies between the two system services.

    The opportunity cost with respect to the real time technical constraints market may arise additionally because the prices in this market are always equal or higher than tertiary reserve market prices. [99]
- If the unit has not started-up economically we include an uplift to reflect the cost of increasing its production uneconomically.
  - The start-up costs: we have not included these costs because they are not strictly marginal costs. Start-up costs are incurred when the unit starts up and then recovered over a number of hours through the total revenues obtained in all the different markets.

96 See for instance PJM's presentation on "Basics of Regulation Lost Opportunity Cost, June 2014). http://www.pjm.com/~/media/committees-groups/committees/pc/20140610-energy/20140610-regulation-lost-opportunity-cost-overview.ashx

97 In reality, the calculation is complex because it requires knowing what would be the economic level of output, in which market the unit would participate and the unit's true marginal cost at different load levels.

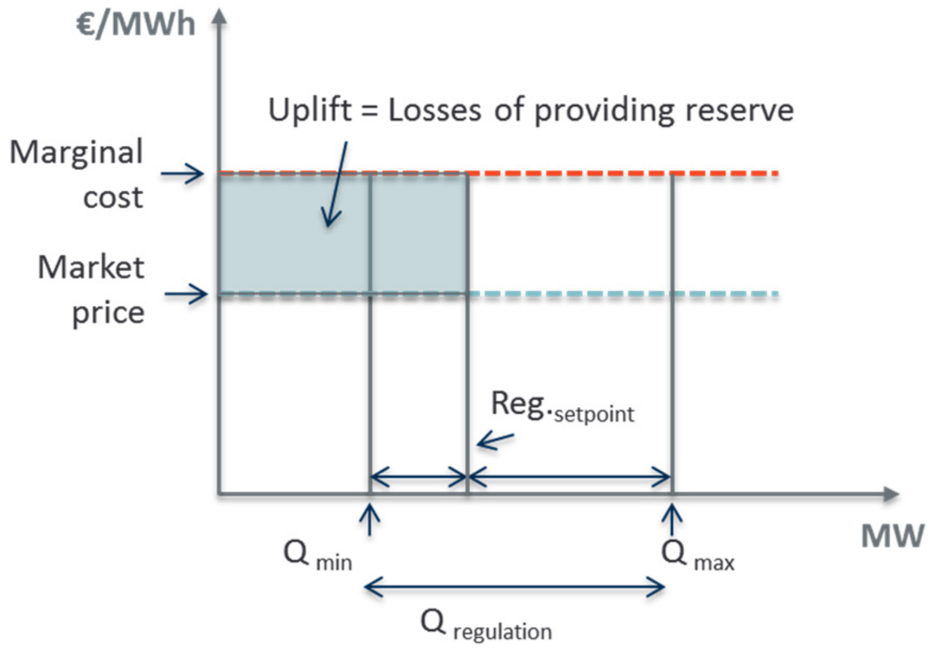
98 We have estimated this opportunity costs in a similar fashion to our estimation of energy margins, explain in section B.IV of Appendix B.

99 The technical constraints market is a pay as bid market, but if the unit's bid is lower than the tertiary reserve price, the unit receive the latter.

- The loss made on generating at the regulation set point. This is calculated as the difference between the unit's marginal cost and the energy market price. If the unit has a technical minimum load (REN data confirm that all hydro and thermal units have a minimum load), it will incur losses for all the megawatts it would produce up to the regulation set point, and it will need to recover those losses on the price paid to the reserve capacity. This implies that it is more expensive to provide reserve using units in this situation.[100]

For instance, the regulation set point of a unit with 140 MW of capacity and 80 MW of minimum load would be 100 MW, if it is to provide 60 MW of regulation capacity. If the energy market price is 60 €/MWh and the unit's marginal cost is 70 €/MWh, it would be losing 10 € for each MWh it produces. This implies an uplift cost of 16.67 €/MW ([100 $MW_{reg.setpoint}$ x 10 €/MW_{loss} / 60 $MW_{reg.}$), 67% higher than the difference between the price and the marginal cost. Figure 36 illustrates this situation.

Figure 36: Need of an uplift due to minimum load



Source: The Brattle Group.

The following figure summarises the formulae we have used in our model according to our judgement of the operational status of a unit.

100 We have assumed that when units are scheduled up to provide reserve, their optimal generation setpoint is the maximum load minus two third of their regulation capacity. This is not exactly correct for thermal units whose regulation capacity is constrained by ramping considerations. In this case, it may be also possible that the regulation setpoint is the minimum load plus a third of the regulation capacity.

Figure 37: Assumed units alternative operating states

		Day ahead market price vs energy marginal cost	
		P > C	P < C
Observed generation	Q ~ max	*Normal operation (1)* Opp.Cost = (P-C)*2/3 Uplift = 0	*Residual capacity (2)* Opp.Cost = 0 Uplift = 0
	Q ~ min	*Providing syst. Services (3)* Opp.Cost = (P-C)*2/3 Uplift = 0	*Providing syst. Services (4)* Opp.Cost = 0 Uplift = (C-P)* *(min.cap.+reg.cap/3)/reg.cap.
		Ramping (5) Opp.Cost = 0 Uplift = 0	*Avoiding cycling (6)* Opp.Cost = 0 Uplift = (C-P)/3
	Q ~ 0	*Avoiding cycling (7)* Opp.Cost = (P-C)*2/3 Uplift = start-up costs	*Normal operation (8)* Opp.Cost = 0 Uplift = (C-P)* *(min.cap.+reg.cap/3)/reg.cap.

Source: The Brattle Group.
Note: Given a 2:1 ratio of upward to downward regulation, we estimate the regulation set point at 2/3 of the total regulation capacity provided. The regulation set point is estimated as the maximum capacity minus 2/3 of the regulation capacity when the unit is running at full load or as the minimum load plus a third of the regulation capacity otherwise.

B.IV. ESTIMATION OF ENERGY MARGIN

The settlement of the secondary reserve service includes a payment to the unit for the amount of capacity made available to the System Operator and a payment or charge for the actual output increase or decrease associated with this reserve capacity, depending on whether the hourly net balance is positive (net upward regulation, what means selling more energy to the system) or negative (net downward regulation, what means buying energy back from the system). In Portugal secondary regulation is paid for at the tertiary reserve prices.

The units providing secondary reserve can have different marginal energy production costs. Therefore, some units can make a margin between the uniform settlement price for the regulation energy used and their own marginal energy costs. Because, the units are dispatched without consideration to their energy marginal costs, this may result in both positive and negative margins for a unit. If a unit is dispatched up and the price obtained is higher than its marginal cost, then the margin would be positive. Conversely, if it is dispatched up and the price is less than its marginal cost, the margin will be negative. If it is dispatched down and the energy price is lower than its marginal cost, then the margin would be again positive. Conversely, if it is dispatched down and the energy price is higher than its marginal cost, then the margin would be negative. A competitive bid should deduct this margin from the capacity costs.

A unit's expected energy margin depends, therefore, on the expected amount of energy activated, either upward and downward, the expected prices received/paid for this energy and the energy marginal costs of the unit. Because a unit knows in advance that it could make a margin from the energy activated under its contracted reserve capacity, it may internalise such a margin in its bids.[101]

Since the energy margin that units internalise in their bids is based on their expectations, estimating what margin has been included, in order to monitor the bids, is complex and may be subject to lengthy discussions with the agents. However, unlike other cost items such as the risk premium, the energy margin can be checked in hindsight.

Our model estimates the internalised energy margin as follows:

- The energy margin is estimated as the difference between the expected tertiary reserve energy prices (upward or downward) and the units' estimated marginal costs multiplied by the amount of energy that unit can expect to be dispatched.[102, 103] Since a unit provides a ratio 2:1 of upward to downward reserve, for a MW of reserve, it is providing 2/3 of upward reserve and 1/3 of downward reserve.
- We estimate the amount of activated energy a unit could expect if it provided reserve using the probability of being dispatched. We have estimated this probability as the actual monthly ratio between the energy activated and the reserve provided for every balance area. If a balance area has had very high or very low dispatched values on a given month,[104] we considered that this was due to some special circumstances and that the units did not expected these high or low values, so we changed the estimated probability to a proportion of the average. If a balance area has not provided reserve, we use the average probability.

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101 This is based on H.-P. Chao and R. Wilson, "Multi-Dimensional Procurement Auctions for Power Reserves: Robust Incentive-Compatible Scoring and Settlement Rules," in Journal of Regulatory Economics, vol. 22, no. 2, pp. 161-183, 2002. For a simplified explanation, see Power System Economics, Designing Markets For Electricity, Chapter 3-10 (Stoft, 2002).

102 The units do not know how much energy they will sell, so they should base their bids on expectations. Additionally, there are not actual values for all the units, since most units did not provide regulation, or at least, not all the hours.

103 We acknowledge that the energy marginal cost of a unit providing reserve is higher than if it was producing at full output. We have opted for using a single figure for the unit's energy marginal cost since we are already using an estimation of the marginal cost and making an assumption about the unit efficiency curve.

104 These extreme values occur when the reserve capacity provided has been very little or during only a few hours in a month. In these situations, we do not extrapolate the activation orders.

- We have estimated the tertiary energy prices that a unit may have expected when bidding to the secondary reserve market using a linear regression of the actual prices against the day-ahead price. The regression is run for every week.

Appendix C. Estimation of Over Compensation

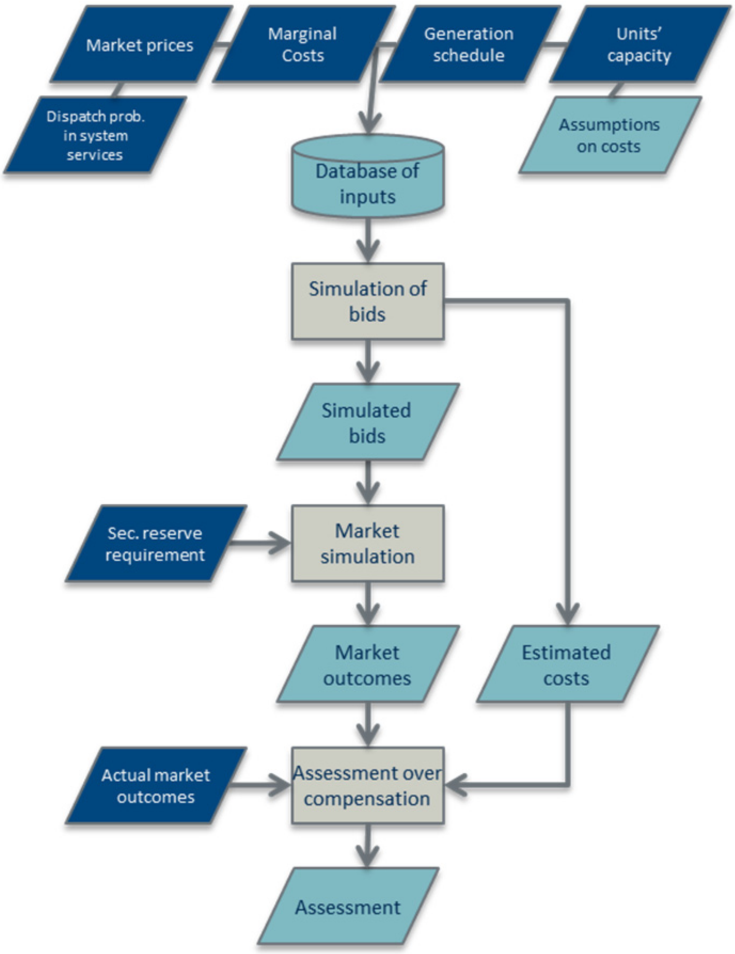
C.I. General Procedure

Our estimation of the potential over-compensation depends on determining the margins a unit actually made and the margin that it would have made under a world with cost-reflective bids. We have structured this analysis as a series of sequential steps, bearing in mind that this analysis is constraint by the following aspects:

- The analysis need to be simple, so it can be understood and replicated, while at the same time approximating as far as possible the complex economic and engineering drivers of the operation of the units.
- The cost of providing reserve depends on a series of unit specific parameters, mostly confidential, that we need to approximate.
- Some costs are based on expectations of potential outcomes in other markets, not on actual observable values.
- The quantitative assessment needs to serve a twofold purpose:
  - Providing a benchmark for assessing the bids into the secondary reserve market and, in particular, determining the relative level of CMEC and non-CMEC units with similar generation costs.
  - Determining if the actual market outcomes are compatible with the outcomes of a market not affected by the CMEC and quantifying what the difference in the compensation of CMEC units would be if they were without CMEC.

Figure 38 illustrates this process and identifies the input data and outputs of the different steps of the methodology.

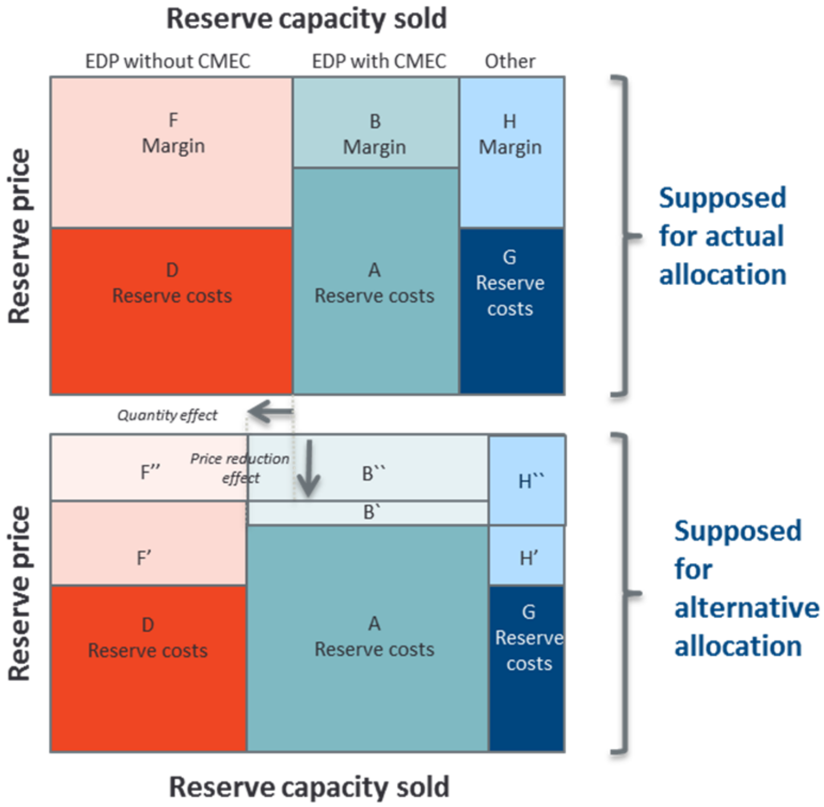
Figure 38: General methodology



Source: The Brattle Group.

The final assessment of the potential over-compensation is made by comparing the actual market outcomes with the outcomes under a competitive (cost-reflective) market scenario. Since the margin that each unit makes is the difference between the revenues it earns from the secondary reserve market and the costs of providing the service, this comparison is made in terms of the margins a unit can obtain. Figure 39 illustrates our estimate of the impact on units' margins of cost-reflective bids.

Figure 39: Estimation of the impact on units' margin of an alternative allocation



Source: The Brattle Group.

We have made this estimation considering four different metrics, as agreed with the Monitoring Committee. These metrics represent the impact on two groups of units (the units covered by the CMEC and the units owned by EDP and not covered by the CMEC) and considering two types of impacts (only the quantity effect and the combined effect).[105]

In Figure 39 these metrics are represented by the difference between different areas:

- F-F' for EDP units without CMEC i.e. considering both the price and the quantity effect
- F – (F'+F'') for EDP units without CMEC i.e. considering only the quantity effect
- B-B' for EDP units with CMEC i.e. considering both the price and the quantity effect
- B – (B'+B'') for EDP units with CMEC i.e. considering only the quantity effect

105 Although the difference in margins between the actual and the alternative scenario would include both effects, the Despacho 4694/2014 carries out the adjustment of CMEC maintaining the actual market prices and only adjusting for a different estimation of the quantity provided.

C.II. Simulation of Bids

C.II.1. Modelling of the quantity bid

The models used for the quantitative assessment assume that the units can provide different levels of secondary reserve capacity up to the nominal maximum level reported by REN. Because the cost of providing secondary reserve can vary depending on the level of reserve provided (see Appendix B), we have parameterised the reserve bids so they can be 25%, 50%, 75% or 100% of the unit's available capacity. This approach is based in the following considerations:

- A unit can vary its production level to provide varying levels of reserve capacity, unless it is fuel constrained.
- Hydro units are commonly fuel constrained, when water inflows are too high or too low.

REN provides information on the units' maximum secondary regulation capacity. We have observed that most units never bid their maximum reserve capacity to the secondary reserve market.

This fact points to that the System Operator' reported nominal reserve capacity over-estimates the reserve capacity it is reasonable to expect a unit to make available. Nonetheless, in absence of any objective criteria for adjusting this nominal capacity, we have assumed the maximum reserve capacity is equal to that indicated by REN.

We have modelled the available reserve capacity by reference to the Final Hourly Operational Programme (PHOF). We have chosen the PHOF because units often modify their schedules close to the real time in order to provide reserve.[106] Because of this, prior schedules, such as the schedule after the last intraday market, the PHF, may underestimate the final reserve capacity of the units. The choice of the PHOF has two implications. First, it may underestimate the reserve capacity of thermal units because we assume they cannot provide reserve unless they are scheduled in the PHOF (although they may have varied this schedule in a previous stage). Second, for hydro units, it may misrepresent the real reserve capacity of the units because the PHOF includes part (or all) of the energy dispatched as tertiary regulation.[107] However, we consider that it is the best option available.

[106] They modify their schedule after the last intraday market. Because there is no formal market after the last intraday, this modification seems related to the provision of reserve.

[107] If a unit is operating at full load and is providing downward tertiary regulation, it may appear that it has secondary reserve capacity when, in fact, it does not. On the other hand, if a unit is providing upward tertiary regulation, it may seem that it has less capacity to provide reserve than it really has.

Hydro units typically have "fuel" constraints relating to their water inflows, storage capacity, and environmental or social operating constraints. Therefore, their capacity to provide secondary reserve can be constrained if the unit is generating at nearly full load or at very low loads for a sustained period. Nevertheless, even in these conditions, units commonly retain some ability to move production from one hour to adjacent hours. Multi-group hydro units also have flexibility over how many turbines they operate. Therefore the same level of production can be deliver different levels of reserve capacity.

We have modelled these constraints by looking not only at the production in every hour, but also at the production in the nearby hours and the number of available generating groups. This approach makes it possible to reduce the available reserve capacity to reflect the "fuel" constraints whilst, at the same time, maintaining some reserve capacity flexibility. Consistent with this approach, we model the cost of providing reserve in each hour independently of the cost of providing reserve in other hours.

C.II.2. Input data

The quantitative assessment of the potential overcompensation is based on different input data about the units' characteristics and the different electricity markets. We have used, as far as possible, public information available from REN's Energy Market Information System, SIME.[108] However, part of the information we required is not released publicly and has been provided by REN through the Monitoring Committee. This information includes, for instance, the generation schedules on a physical unit basis,[109] and the results of the VALORAGUA model as used to calculate the CMEC annual adjustment. Finally, we have had to make assumptions for those parameters that are only known to EDP, such as the units' efficiency curves.

Below we describe the different input data we are using:

- Market prices

  These data include all the market prices that are necessary to quantify the costs and revenues of providing secondary reserve, as well as to assess the resulting costs. The source of these data is REN's SIME, or OMIE's website.

- Units' energy marginal costs

[108] SIME stands for the Portuguese for Sistema de Informação de Mercado de Energia.

[109] Information on generation schedules are released aggregating by programming unit or balance area.

A unit's energy marginal cost is the cost to the unit of changing its production level in the very short run. This cost is difficult to assess because, although it includes a variable cost element, it is mainly related to the unit's efficiency curve. Because a unit's efficiency changes as its output changes[110], its marginal cost can vary even within a single hour. Moreover, for reservoir hydro plants the energy marginal cost will reflect the value of water at that time, which will depend on the company's view on how (a) prices will develop over time and (b) what the level of future inflows is likely to be.

The energy marginal costs are used to estimate the costs of providing secondary reserve. We have estimated them using three different alternative sources, assuming that these estimates correspond to the marginal cost at full load. Figure 40 in Appendix E shows the estimated market price under the different sets of marginal costs we have used. Since both simulations are practically identical, we have used the simulations based on the marginal costs provided by the model VALORAGUA.

– The bids for the day-ahead and tertiary regulation (*reserva de regulação*) markets

  Units' bids to these markets do not necessarily represent the true marginal costs of the units.[111] However, they should be related to their marginal costs and they are the declared costs of the units. We have used the second highest bid to the day-ahead market and the lowest bid to the tertiary reserve market because we think these are the bids that best reflect the marginal costs operating at full load.[112]

  A difficulty with these data is that physical units do not always participate in the day-ahead and tertiary reserve markets directly, but rather as a part of more aggregated units. Day-ahead market participation is organised through bidding units,[113] whilst for the tertiary reserve market it is organised through balance areas. This aggregation affects especially hydro units. We have assumed that the

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110 The instantaneous capacity factor is the ratio of actual production to the maximum capacity.

111 To the extent that the competition in in the day-ahead market is higher than in the tertiary regulation market, the bids to the tertiary market may be biased upwards. Nevertheless, bids to the tertiary market take into account the actual operation status (e.g. how much the unit is producing) of the units and can be much easily monitored by the regulator than bids to other market. Therefore, we understand the risk of biasing the estimation of the marginal cost is small.

112 In the day ahead market, units normally bid the final part of the capacity at the bid cap (180 €/MWh). This is probably to reflect technical distress of the unit at such a high load. The second highest bid should then reflect the plant cost at full capacity. Regarding the tertiary bids, the lowest bid should reflect the marginal cost at the current operating conditions, which are, most of the times, full load.

113 OMIE records the units participating in its markets assigning "bidding unit" codes. These codes may be the same as the codes used to schedule the units is the code used by OMIE.

bids of the aggregated units represent the costs of all the physical units included within the aggregated group.

- Evidence from the prices for the hours in which the units are running

  We have also estimated marginal cost based on their behaviour in the market. We have taken the average between the highest priced hours in which the units are not running and the lowest priced hours in which the units are running as an indication of their marginal costs. In doing so, we have included both the price in the energy market and the price of the secondary reserve market.

- Marginal costs estimated by the VALORAGUA model

  The VALORAGUA model, as used for calculating the annual CMEC adjustments, provides an estimation of the CMEC units' marginal generation costs. The model outputs cannot be considered a perfect estimation of the units' true marginal cost, but as a useful approximation to these costs. Some of the limitations we have identified are that the model does not include: all the revenues of the units,[114] short term constraints, variations in marginal costs under different levels of load or unit specific information on O&M variable costs. As a consequence, the model only provides a marginal cost figure per week for each unit.[115]

  Because the VALORAGUA model only provides an estimation of the marginal costs for those units that are covered by the CMEC, we have used our estimations of the marginal costs for the rest of the units (the market evidence for hydro units and the median of all the other estimations for thermal units).[116]

- Units' generation schedules

These data, in combination with data on the unit's capacity and the relationship between the marginal cost and the market price, allow us to identify the unit's operating status, which in turn we use to identify the costs of the unit (see section

[114] If a unit would be running only when it can sell energy and system services simultaneously, the opportunity cost of the unit should consider both sorts of revenues, and not only the revenues from the sale of energy, as the models seems to do. This approach is, nevertheless, appropriate for the model purpose.

[115] We have been informed by the MC in the meeting held on September, 14th that ValorAgua is a long term expansion model that does not include short term modelling details such as the efficiency curves.

[116] Because these values vary from hour to hour, we have estimated the marginal cost for every hour as the median value of the market evidence and the bids to the day ahead and tertiary reserve in the following 24 hours, so it is the median of 72 values.

B.III of Appendix B for more details). The generation schedules by physical unit have been provided by REN. The schedules included as input data are.[117]

- Day ahead base operating schedule (PDBF)
- Hourly schedule after the last intraday market (PHF)
- Final hourly operative schedule, that includes all reschedules prior to 15 minutes of dispatch (PHOF)

- Units' capacity

We use these data to determine a unit's reserve capacity. In particular, we take into account data on a unit's hourly maximum and minimum output, and its unavailable capacity as well. Its reserve capacity is bounded both by the difference between its maximum and minimum capacity and by the unit's ramping capacity.[118] When a unit is totally or partially unavailable, the total and reserve capacity has been adjusted accordingly. These data have been provided by REN.

- Assumptions on costs

We have had to make our own assumptions on the following data:

- Margin / risk adder. This is a risk premium that units are assumed to include when participating in the secondary reserve market.[119]
- Variable operating and maintenance costs (O&M) for providing regulation.[120]
- Efficiency curves. The efficiency curve measures the relationship between the efficiency of the unit and its instantaneous capacity factor. The actual efficiency curves are only known by the units' owners. [121] We have made a linear approximation of the efficiency curve of different technologies, [122,123] using as

[117] REN has warned us that the original generation schedules are per balance area and that the disaggregation of these schedules in physical units is provided by the market agents and can be imprecise.

[118] The ramping capacity is the pace, measured as MW/minute, at which a unit can vary its production. This speed limits its capacity to provide reserve.

[119] See section III.B and section B.II of Appendix B for a discussion of the nature of this value.

[120] This corresponds to the specific O&M costs related to the provision of reserve. Because the provision of reserve implies a different pattern of usage of the facilities, these costs do not necessarily correspond to the standard O&M costs associated with the production of energy.

[121] We have been informed that the VALORAGUA model do not include inputs on the efficiency curve of the units at different load factors. This is reasonable since the VALORAGUA model is a mid to long term model that is not capable of reflecting short term operational conditions.

[122] Since some units' efficiency curve do not monotonically increase, the actual efficiency may increase when providing reserve. On head-sensitive hydro power plants, such as run of river plants or plants with small reservoirs, decreasing output to provide regulation may decrease the

Continued on next page

inputs the efficiencies at full load and at 50% load, based on the values for standard units.[124]

Continued from previous page

head loss, increasing the overall efficiency. Consequently, the impact on a hydro unit's efficiency of providing reserve may depend on precisely how much reserve it provides. However, in the absence of detailed efficiency curves for each hydro unit, we assume that providing reserve leads to some reduction in efficiency.

123 If the efficiency curves are concave, this approach may be underestimating the true efficiency, unless the plant is below 50% load or the maximum efficiency is reached below a 100% load.

124 See for instance the following references:

- Wärtsilä, Combustion Engine vs. Gas Turbine: Part Load Efficiency and Flexibility. http://www.wartsila.com/energy/learning-center/technical-comparisons/combustion-engine-vs-gas-turbine-part-load-efficiency-and-flexibility
- KEMA, Review of the LRMC costs of CCGT electricity generation in Singapore, for the Energy Market Authority of Singapore, updated report November 2008. https://www.ema.gov.sg/cmsmedia/Licensees/CCGT_RMC_Calcs.pdf
- IEA, Energy Technology Network, Technology Brief E02: Gas-Fired Power, April 2010. http://www.iea-etsap.org/web/e-techds/pdf/e02-gas_fired_power-gs-ad-gct.pdf
- Roaring 40s, Supplementary Submission to the AEMC Review of Frequency Operating Standards for Tasmania, August 2008. http://www.aemc.gov.au/getattachment/8cbfc028-19bc-4aba-b343-4b672c74cd73/Roaring-40s-Supplementary-Submission.aspx

Table 5: Assumptions on the costs of the units

Unit	Code	Variable O&M €/MWh [A]	Margin / risk adder €/MW [B]	Efficiency parameters At full load % [C]	 At half load % [D]
Hydro units					
Aguieira	Reservoir	1.0	10.0	87.0%	74.0%
Alto Lindoso	Reservoir	1.0	10.0	87.0%	74.0%
Cabril	Reservoir	1.0	10.0	87.0%	74.0%
Castelo de Bode	Reservoir	1.0	10.0	87.0%	74.0%
Frades	Reservoir	1.0	10.0	87.0%	74.0%
Bemposta	Run-of-river	1.0	10.0	87.0%	74.0%
Picote	Run-of-river	1.0	10.0	87.0%	74.0%
Pocinho	Run-of-river	1.0	10.0	87.0%	74.0%
Régua	Run-of-river	1.0	10.0	87.0%	74.0%
Torrão	Run-of-river	1.0	10.0	87.0%	74.0%
Valeira	Run-of-river	1.0	10.0	87.0%	74.0%
Alqueva	Reservoir	1.0	10.0	87.0%	74.0%
Alqueva II	Reservoir	1.0	10.0	87.0%	74.0%
Bemposta II	Run-of-river	1.0	10.0	87.0%	74.0%
Picote II	Run-of-river	1.0	10.0	87.0%	74.0%
Thermal units					
Lares - Group 1	CCGT	2.0	10.0	52.0%	47.0%
Lares - Group 2	CCGT	2.0	10.0	52.0%	47.0%
Pego C.C.- Group 3	CCGT	2.0	10.0	52.0%	47.0%
Pego C.C.- Group 4	CCGT	2.0	10.0	52.0%	47.0%
Ribatejo - Group 1	CCGT	2.0	10.0	52.0%	47.0%
Ribatejo - Group 2	CCGT	2.0	10.0	52.0%	47.0%
Ribatejo - Group 3	CCGT	2.0	10.0	52.0%	47.0%
Pego - Group 1	Coal	3.5	10.0	33.0%	30.0%
Pego - Group 2	Coal	3.5	10.0	33.0%	30.0%

Sources and notes:
[A]-[D]: Assumed. Assumptions explained above in the current section.
[A]: These corresponds to the specific variable O&M costs related to the provision of reserve, rather than with the normal production of energy.

- Secondary reserve requirements

The total amount of secondary reserve contracted every hour in the secondary reserve market, as provided by the REN's SIME. We are using the reserve finally allocated, instead of the initial reserve requirements, to avoid any impact on the results arising from differences in the final allocation.[125]

- Actual market outcomes

We rely on the final secondary reserve prices and reserve allocation per physical unit as provided by the REN's SIME. The data on allocation does not reflect the initial results from the market, but the final allocation after taking account of reserve exchanges by market agents.

C.III. Calculation of the Market Outcomes

Once we have estimated the costs for every unit of providing reserve and obtained a set of alternative cost-reflective bids to the secondary reserve market, we estimate what would have been the market prices and reserve allocation under that set of bids.

We insert the new bids into an MS Excel file that reproduces REN's algorithm for clearing the secondary reserve market, although with some simplifications.

- The modelled demand for reserve is the reserve allocated in reality, not the initial reserve requirement. We do this to avoid any distortion arising from taking slightly different amounts of reserve.
- The model only clears total reserve capacity and does not treat upward and downward reserve bids differently. This should not have an impact since all the bids have a ratio between the both capacities equal or almost equal to 2:1.
- If several bids have the same price, it only allocates reserve to the first three.

There are some differences between our results and the actual market outcomes that do not result from these simplifications:

- Our model allocates the reserve only taking into account the quantities bid into the market, while the reserve allocations reported by REN also take into account exchanges of reserve after the market. These exchanges of reserve can, from time to time, account for a significant share of the total allocation.

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[125] The secondary reserve market algorithm, as described in the MPGGS, allows that the final allocation deviates until 10% of the initial requirement.

- Some differences between the market price between our model and the actual outcome seemed to be due to REN algorithms filtering the reported bids.[126] Our model cannot reproduce these filtering effects since we do not know what filters are applied..

C.IV. ESTIMATION OF POTENTIAL OVERCOMPENSATION

We have estimated the potential over-compensation following the approach described in the section VI and the procedure set up in section C.I of Appendix C). This approach implies estimating the actual margin made by the units on the basis of their actual reserve allocation and activation and subtracting the estimated margin made in the alternative scenarios. In order to make this estimation, we:

- Include an estimation of the margin made from the energy activated from the secondary reserve.[127] This is necessarily an estimation given that:
  - REN reports the secondary reserve energy per balance area, not per physical unit, so we have first estimated how much energy every unit supplied based on how much reserve capacity it was providing.
  - We do not know what would be the activation of these reserves in an alternative scenario, since secondary regulation is activated by the System Operator following technical criteria.
- Estimated the costs of providing reserve for the actual reserve allocation using the same tool and options as for the alternative scenarios. The estimation of costs has been made assuming units bid 100% of their total reserve capacity.[128]

The following formula describes the estimation for a given unit "i":

$$\text{Impact on margins}_i = \sum_{h}^{N} [\text{Margin}_{\text{Actual}} - \text{Margin}_{\text{Alternative}}] =$$

[126] For instance, the 8th hour on February, 9th 2012, REN allocated 309 MW of reserve to 5 thermal units (PEGO3, PEGO4, RPG01 and RPG02 and LARES1). Although the marginal bid of the marginal unit (LARES1) was 59.95 €/MW, the market price was set at 69.73 €/MW. This situation is common throughout 2012.

[127] We have used the same estimation of the energy marginal cost as if the unit was producing at full cost (see footnote 103).

[128] We have observed the most common reserve allocation corresponds to, or close to, a 100% of the units' reserve capacity, so this is the reserve level that best reflects the units' actual costs. Although, the costs of providing reserve vary with the amount of capacity provided, the potential variation is small.

$$= \sum_{h}^{N} [\text{Revenues}_{\text{Actual}} - \text{Costs}_{\text{Actual}} + \text{Revenues}_{\text{Altern.}} - \text{Costs}_{\text{Altern.}}] \;=$$

$$= \sum_{h}^{N} \left[\text{Cap. Rev.}_{\text{Actual}} \text{-Cap. Costs}_{\text{Est. for actual}} \text{+Energy Rev.}_{\text{Est. for actual}} \text{-Energy Costs}_{\text{Est. for actual}}\right]$$

$$-\left[\text{Cap. Rev.}_{\text{Altern.}} \text{-Cap. Costs}_{\text{Altern.}} \text{+Energy Rev.}_{\text{Altern.}} \text{-Energy Costs}_{\text{Altern.}}\right]$$

Appendix D. Estimated margins and impacts

This section provides an overview of the detailed results that justify our estimation of the quantification of the potential over-compensation presented in section VI. The Excel files accompanying this report provide additional results, such as the cost structure of regulation service by unit that, due to their extension, cannot be presented in the report.

D.I. ESTIMATED OVER-COMPENSATION

Table 6: Estimated impact on units' margins.
Quantitity effect.

	Total margin						Margin on capacity						Margin on energy					
Unit	2010	2011	2012	2013	2014	Total	2010	2011	2012	2013	2014	Total	2010	2011	2012	2013	2014	Total
	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €
Alto Lindoso	-1.6	-1.1	-2.4	-3.5	-0.8	-9.5	-1.5	-0.6	-1.9	-3.0	-0.7	-7.6	-0.1	-0.6	-0.5	-0.5	-0.2	-1.9
Bemposta	0.0	0.0	0.0	0.0	-0.1	-0.1	0.0	0.0	0.0	0.0	-0.1	-0.1	0.0	0.0	0.0	0.0	0.0	0.0
Cabril	-0.3	0.7	-1.0	-0.1	-0.1	-0.7	-0.2	0.8	-0.8	-0.2	0.0	-0.4	-0.1	-0.1	-0.2	0.1	0.0	-0.3
Castelo Bode	-0.7	-0.4	-0.5	-1.4	-0.2	-3.2	-0.6	-0.3	-0.4	-1.2	-0.2	-2.7	-0.2	-0.1	-0.1	-0.2	0.0	-0.5
Picote	-0.1	-0.6	-1.0	-1.1	-0.1	-2.9	-0.1	-0.4	-0.9	-0.9	-0.1	-2.3	0.0	-0.2	-0.1	-0.2	0.0	-0.6
Pocinho	-2.2	-0.4	0.5	-0.4	-0.2	-2.8	-1.8	-0.3	0.4	-0.4	-0.2	-2.2	-0.4	-0.2	0.0	0.0	0.0	-0.6
Regua	-1.2	-1.2	-2.3	-1.7	-0.1	-6.5	-1.0	-0.9	-1.9	-1.6	-0.1	-5.5	-0.2	-0.3	-0.3	-0.1	-0.1	-1.0
Torrao	-0.4	-0.4	-1.4	-1.1	-0.1	-3.5	-0.3	-0.2	-1.1	-1.0	0.0	-2.7	-0.2	-0.2	-0.2	-0.2	-0.1	-0.9
V.Nova II(Frades)	0.2	-0.5	-1.4	-1.4	0.1	-3.0	0.0	-0.3	-1.2	-1.3	0.1	-2.6	0.1	-0.2	-0.2	-0.1	0.1	-0.3
Valeira	-2.0	-1.7	-3.5	-2.0	-0.1	-9.3	-1.7	-1.4	-3.1	-2.0	-0.1	-8.2	-0.3	-0.3	-0.4	0.0	0.0	-1.1
EDP with CMEC	**-8.5**	**-5.6**	**-12.9**	**-12.8**	**-1.6**	**-41.5**	**-7.1**	**-3.5**	**-11.0**	**-11.5**	**-1.4**	**-34.4**	**-1.4**	**-2.2**	**-2.0**	**-1.3**	**-0.3**	**-7.1**
Alqueva	-0.4	0.4	1.4	0.9	-0.1	2.2	-0.5	0.1	1.3	0.8	-0.1	1.6	0.1	0.2	0.2	0.1	0.0	0.6
Alqueva II	0.0	0.0	0.0	-0.7	-0.1	-0.9	0.0	0.0	0.0	-0.7	-0.1	-0.8	0.0	0.0	0.0	0.0	0.0	-0.1
Bemposta II	0.0	0.0	1.1	2.8	1.1	5.0	0.0	0.0	0.9	2.5	0.7	4.1	0.0	0.0	0.2	0.3	0.4	0.9
Picote II	0.0	0.0	1.0	2.2	1.1	4.3	0.0	0.0	0.9	2.3	0.8	3.9	0.0	0.0	0.1	-0.1	0.4	0.4
CC. Ribatejo 1	-1.5	-0.8	-0.2	-0.1	0.0	-2.6	-1.4	-0.9	-0.2	-0.1	0.0	-2.6	-0.1	0.1	0.0	0.0	0.0	-0.1
CC. Ribatejo 2	-0.9	-0.8	-0.1	0.0	0.0	-1.7	-0.7	-0.9	-0.1	0.0	0.0	-1.7	-0.2	0.2	0.0	0.0	0.0	0.0
CC. Ribatejo 3	-0.9	-0.2	0.0	0.0	0.0	-1.0	-0.7	-0.2	0.0	0.0	0.0	-0.9	-0.2	0.0	0.0	0.0	0.0	-0.2
CC. Lares 1	0.3	1.0	2.2	0.0	0.1	3.6	0.2	0.2	1.7	0.0	0.1	2.3	0.1	0.7	0.5	0.0	0.0	1.3
CC. Lares 2	-0.3	0.2	0.1	-0.1	0.0	-0.1	-0.3	0.0	0.0	-0.1	0.0	-0.4	0.0	0.2	0.1	0.0	0.0	0.3
EDP without CMEC	**-3.6**	**-0.3**	**5.6**	**4.9**	**2.1**	**8.8**	**-3.3**	**-1.7**	**4.5**	**4.7**	**1.4**	**5.6**	**-0.3**	**1.4**	**1.1**	**0.3**	**0.7**	**3.1**
Pego coal 1	0.0	0.4	-3.1	-0.8	0.0	-3.6	-0.2	0.1	-2.5	-0.6	0.0	-3.2	0.2	0.3	-0.7	-0.2	-0.1	-0.4
Pego coal 2	0.1	0.4	-2.6	-0.8	0.0	-2.9	-0.2	0.1	-2.1	-0.6	0.0	-2.7	0.3	0.3	-0.5	-0.2	0.0	-0.2
REN Trading	**0.1**	**0.7**	**-5.7**	**-1.6**	**-0.1**	**-6.6**	**-0.4**	**0.2**	**-4.6**	**-1.2**	**0.0**	**-6.0**	**0.5**	**0.5**	**-1.2**	**-0.4**	**-0.1**	**-0.6**
Aguieira	-0.1	-0.3	-0.4	-1.2	-1.3	-3.2	-0.3	-0.4	-0.3	-1.1	-1.0	-3.2	0.3	0.1	-0.1	-0.1	-0.3	-0.1
CC. Pego. G3	0.0	-0.2	-0.9	0.0	0.0	-1.2	0.0	-0.2	-1.3	-0.1	0.0	-1.6	0.0	0.0	0.4	0.0	0.0	0.4
CC. Pego. G4	0.0	0.0	-0.3	0.0	0.0	-0.4	0.0	0.0	-0.6	0.0	0.0	-0.7	0.0	0.0	0.3	0.0	0.0	0.3
Others	**-0.1**	**-0.6**	**-1.6**	**-1.2**	**-1.3**	**-4.8**	**-0.3**	**-0.7**	**-2.2**	**-1.2**	**-1.0**	**-5.4**	**0.3**	**0.1**	**0.6**	**0.0**	**-0.3**	**0.7**
Total	**-12.0**	**-5.8**	**-14.6**	**-10.7**	**-1.0**	**-44.1**	**-11.1**	**-5.7**	**-13.2**	**-9.2**	**-1.0**	**-40.2**	**-1.0**	**-0.1**	**-1.4**	**-1.4**	**0.0**	**-3.9**

Source: The Brattle Group
Note: assuming a risk-premium of 10€/MW

Table 7: Estimated impact on units' margins. Total effect.

	Total margin						Margin on capacity						Margin on energy					
Unit	2010 mill. €	2011 mill. €	2012 mill. €	2013 mill. €	2014 mill. €	Total mill. €	2010 mill. €	2011 mill. €	2012 mill. €	2013 mill. €	2014 mill. €	Total mill. €	2010 mill. €	2011 mill. €	2012 mill. €	2013 mill. €	2014 mill. €	Total mill. €
Alto Lindoso	2.0	0.0	-0.3	0.3	0.4	2.4	2.2	0.5	0.2	0.9	0.6	4.3	-0.1	-0.6	-0.5	-0.5	-0.2	-1.9
Bemposta	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cabril	0.0	1.2	-0.3	0.4	0.0	1.3	0.1	1.3	-0.1	0.3	0.0	1.6	-0.1	-0.1	-0.2	0.1	0.0	-0.3
Castelo Bode	-0.1	0.0	-0.1	-0.2	0.1	-0.3	0.1	0.1	0.0	0.0	0.0	0.2	-0.2	-0.1	-0.1	-0.2	0.0	-0.5
Picote	0.1	0.0	-0.3	-0.1	0.0	-0.3	0.1	0.2	-0.1	0.1	0.0	0.2	0.0	-0.2	-0.1	-0.2	0.0	-0.6
Pocinho	-0.5	-0.1	0.5	0.1	0.4	0.3	-0.1	0.1	0.4	0.1	0.4	0.8	-0.4	-0.2	0.0	0.0	0.0	-0.6
Regua	-0.2	-0.2	-0.5	-0.3	0.1	-1.1	0.0	0.1	-0.2	-0.1	0.2	-0.1	-0.2	-0.3	-0.3	-0.1	-0.1	-1.0
Torrao	0.1	-0.1	-0.4	-0.1	0.0	-0.4	0.3	0.1	-0.1	0.1	0.1	0.4	-0.2	-0.2	-0.2	-0.2	-0.1	-0.9
V.Nova II(Frades)	1.2	0.1	0.1	0.0	0.6	2.0	1.1	0.3	0.3	0.2	0.5	2.4	0.1	-0.2	-0.2	-0.1	0.1	-0.3
Valeira	0.3	-0.2	-0.9	-0.2	0.3	-0.8	0.6	0.2	-0.6	-0.2	0.3	0.3	-0.3	-0.3	-0.4	0.0	0.0	-1.1
EDP with CMEC	**3.0**	**0.7**	**-2.2**	**-0.1**	**1.8**	**3.1**	**4.4**	**2.8**	**-0.3**	**1.2**	**2.0**	**10.2**	**-1.4**	**-2.2**	**-2.0**	**-1.3**	**-0.3**	**-7.1**
Alqueva	0.9	1.3	4.0	3.7	0.1	10.1	0.8	1.1	3.8	3.6	0.2	9.4	0.1	0.2	0.2	0.1	0.0	0.6
Alqueva II	0.0	0.0	0.1	-0.2	0.0	-0.1	0.0	0.0	0.1	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.1
Bemposta II	0.0	0.0	2.1	6.6	2.1	10.9	0.0	0.0	1.9	6.3	1.7	10.0	0.0	0.0	0.2	0.3	0.4	0.9
Picote II	0.0	0.0	1.9	4.7	2.2	8.8	0.0	0.0	1.8	4.8	1.8	8.4	0.0	0.0	0.1	-0.1	0.4	0.4
CC. Ribatejo 1	-0.7	-0.4	-0.2	0.1	0.0	-1.3	-0.6	-0.5	-0.2	0.1	0.0	-1.2	-0.1	0.1	0.0	0.0	0.0	-0.1
CC. Ribatejo 2	-0.3	-0.9	-0.1	-0.1	0.0	-1.3	-0.1	-1.0	-0.1	-0.1	0.0	-1.3	-0.2	0.2	0.0	0.0	0.0	0.0
CC. Ribatejo 3	0.6	-0.1	0.0	0.0	0.0	0.5	0.8	-0.1	0.0	0.0	0.0	0.7	-0.2	0.0	0.0	0.0	0.0	-0.2
CC. Lares 1	2.0	4.2	5.1	0.4	0.2	11.8	1.9	3.4	4.6	0.4	0.2	10.5	0.1	0.7	0.5	0.0	0.0	1.3
CC. Lares 2	4.1	1.6	1.2	0.4	0.0	7.4	4.1	1.4	1.1	0.4	0.0	7.1	0.0	0.2	0.1	0.0	0.0	0.3
EDP without CMEC	**6.6**	**5.7**	**14.2**	**15.7**	**4.6**	**46.7**	**6.9**	**4.2**	**13.1**	**15.4**	**3.9**	**43.6**	**-0.3**	**1.4**	**1.1**	**0.3**	**0.7**	**3.1**
Pego coal 1	0.4	0.9	-1.1	-0.1	0.0	0.1	0.2	0.6	-0.5	0.1	0.0	0.5	0.2	0.3	-0.7	-0.2	-0.1	-0.4
Pego coal 2	0.4	0.9	-0.5	0.1	0.0	0.8	0.1	0.6	0.0	0.3	0.0	1.0	0.3	0.3	-0.5	-0.2	0.0	-0.2
REN Trading	**0.8**	**1.8**	**-1.6**	**0.0**	**-0.1**	**0.9**	**0.3**	**1.2**	**-0.5**	**0.4**	**0.0**	**1.5**	**0.5**	**0.5**	**-1.2**	**-0.4**	**-0.1**	**-0.6**
Aguieira	0.0	-0.3	0.4	-0.1	0.1	0.1	-0.2	-0.4	0.4	0.0	0.4	0.2	0.3	0.1	-0.1	-0.1	-0.3	-0.1
CC. Pego. G3	0.0	0.3	2.8	0.0	0.0	3.2	0.0	0.3	2.4	0.0	0.0	2.7	0.0	0.0	0.4	0.0	0.0	0.4
CC. Pego. G4	0.0	0.0	0.4	0.1	0.0	0.5	0.0	0.0	0.1	0.1	0.0	0.3	0.0	0.0	0.3	0.0	0.0	0.3
Others	**0.0**	**0.0**	**3.6**	**0.1**	**0.1**	**3.9**	**-0.2**	**-0.1**	**2.9**	**0.1**	**0.4**	**3.2**	**0.3**	**0.1**	**0.6**	**0.0**	**-0.3**	**0.7**
Total	**10.4**	**8.2**	**13.9**	**15.7**	**6.4**	**54.6**	**11.4**	**8.3**	**15.3**	**17.2**	**6.4**	**58.5**	**-1.0**	**-0.1**	**-1.4**	**-1.4**	**0.0**	**-3.9**

Source: The Brattle Group
Note: assuming a risk-premium of 10€/MW

D.II. SENSITIVITY OF ESTIMATED OVER-COMPENSATION TO THE RISK PREMIUM ASSUMPTION

Table 8: Estimated impact on units' margins of the market simulation for different risk premiums. Quantity effect.

	Total margin. Risk premium 10 €/MW						Total margin. Risk premium 5 €/MW						Total margin. Risk premium 0 €/MW					
Unit	2010	2011	2012	2013	2014	Total	2010	2011	2012	2013	2014	Total	2010	2011	2012	2013	2014	Total
	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €
Alto Lindoso	-1.6	-1.1	-2.4	-3.5	-0.8	-9.5	-2.0	-1.7	-2.8	-4.4	-1.2	-12.1	-2.4	-2.2	-3.3	-5.3	-1.5	-14.7
Bemposta	0.0	0.0	0.0	0.0	-0.1	-0.1	0.0	0.0	0.0	0.0	-0.2	-0.2	0.0	0.0	0.0	0.0	-0.2	-0.2
Cabril	-0.3	0.7	-1.0	-0.1	-0.1	-0.7	-0.5	0.5	-1.2	-0.3	-0.1	-1.6	-0.7	0.2	-1.4	-0.5	-0.1	-2.5
Castelo Bode	-0.7	-0.4	-0.5	-1.4	-0.2	-3.2	-1.0	-0.6	-0.6	-1.7	-0.1	-4.0	-1.2	-0.7	-0.7	-2.0	-0.1	-4.8
Picote	-0.1	-0.6	-1.0	-1.1	-0.1	-2.9	-0.1	-0.8	-1.2	-1.5	-0.1	-3.7	-0.2	-1.0	-1.4	-1.8	-0.1	-4.5
Pocinho	-2.2	-0.4	0.5	-0.4	-0.2	-2.8	-2.8	-0.6	0.6	-0.4	-0.2	-3.5	-3.3	-0.8	0.7	-0.5	-0.2	-4.1
Regua	-1.2	-1.2	-2.3	-1.7	-0.1	-6.5	-1.5	-1.6	-2.7	-2.0	-0.2	-8.0	-1.9	-2.1	-3.0	-2.3	-0.2	-9.5
Torrao	-0.4	-0.4	-1.4	-1.1	-0.1	-3.5	-0.7	-0.7	-1.7	-1.5	-0.2	-4.8	-0.9	-1.0	-2.0	-1.8	-0.3	-6.0
V.Nova II(Frades)	0.2	-0.5	-1.4	-1.4	0.1	-3.0	0.3	-0.8	-1.6	-1.7	0.2	-3.6	0.5	-1.0	-1.9	-2.1	0.2	-4.2
Valeira	-2.0	-1.7	-3.5	-2.0	-0.1	-9.3	-2.6	-2.3	-4.1	-2.4	-0.1	-11.5	-3.1	-3.0	-4.7	-2.9	-0.1	-13.8
EDP with CMEC	**-8.5**	**-5.6**	**-12.9**	**-12.8**	**-1.6**	**-41.5**	**-10.8**	**-8.6**	**-15.3**	**-16.0**	**-2.1**	**-52.9**	**-13.1**	**-11.6**	**-17.7**	**-19.1**	**-2.6**	**-64.2**
Alqueva	-0.4	0.4	1.4	0.9	-0.1	2.2	-0.1	0.9	2.0	1.6	-0.1	4.3	0.1	1.4	2.5	2.4	-0.1	6.3
Alqueva II	0.0	0.0	0.0	-0.7	-0.1	-0.9	0.0	0.0	0.1	-0.5	-0.2	-0.6	0.0	0.0	0.1	-0.4	-0.2	-0.4
Bemposta II	0.0	0.0	1.1	2.8	1.1	5.0	0.0	0.0	1.7	3.8	1.5	7.0	0.0	0.0	2.2	4.8	2.0	8.9
Picote II	0.0	0.0	1.0	2.2	1.1	4.3	0.0	0.0	1.6	3.5	1.6	6.8	0.0	0.0	2.2	4.9	2.1	9.2
CC. Ribatejo 1	-1.5	-0.8	-0.2	-0.1	0.0	-2.6	-1.4	-0.6	-0.2	-0.1	0.0	-2.3	-1.3	-0.4	-0.2	-0.2	0.0	-2.1
CC. Ribatejo 2	-0.9	-0.8	-0.1	0.0	0.0	-1.7	-0.7	-0.4	0.0	0.0	0.0	-1.2	-0.4	-0.1	0.0	-0.1	0.0	-0.6
CC. Ribatejo 3	-0.9	-0.2	0.0	0.0	0.0	-1.0	-1.0	-0.2	0.0	0.0	0.0	-1.2	-1.1	-0.2	0.0	0.0	0.0	-1.3
CC. Lares 1	0.3	1.0	2.2	0.0	0.1	3.6	0.6	1.8	3.1	0.1	0.1	5.7	0.8	2.7	4.0	0.2	0.0	7.7
CC. Lares 2	-0.3	0.2	0.1	-0.1	0.0	-0.1	-0.1	0.6	0.3	0.1	0.0	0.9	0.2	1.0	0.4	0.2	0.0	1.8
EDP without CMEC	**-3.6**	**-0.3**	**5.6**	**4.9**	**2.1**	**8.8**	**-2.7**	**2.0**	**8.4**	**8.4**	**3.0**	**19.2**	**-1.8**	**4.4**	**11.2**	**11.9**	**3.9**	**29.6**
Pego coal 1	0.0	0.4	-3.1	-0.8	0.0	-3.6	0.4	0.7	-3.5	-1.1	-0.1	-3.6	0.9	1.1	-3.9	-1.4	-0.2	-3.6
Pego coal 2	0.1	0.4	-2.6	-0.8	0.0	-2.9	0.6	0.7	-2.9	-1.1	-0.1	-2.8	1.1	1.0	-3.2	-1.3	-0.2	-2.6
REN Trading	**0.1**	**0.7**	**-5.7**	**-1.6**	**-0.1**	**-6.6**	**1.1**	**1.4**	**-6.4**	**-2.2**	**-0.2**	**-6.4**	**2.0**	**2.1**	**-7.2**	**-2.8**	**-0.4**	**-6.3**
Aguieira	-0.1	-0.3	-0.4	-1.2	-1.3	-3.2	0.4	-0.1	-0.2	-0.9	-1.6	-2.3	0.9	0.1	0.0	-0.7	-1.8	-1.5
CC. Pego. G3	0.0	-0.2	-0.9	0.0	0.0	-1.2	0.0	-0.3	-0.8	0.0	0.0	-1.1	0.0	-0.4	-0.6	0.0	0.0	-1.0
CC. Pego. G4	0.0	0.0	-0.3	0.0	0.0	-0.4	0.0	-0.1	-0.2	0.0	0.0	-0.3	0.0	-0.1	-0.1	0.0	0.0	-0.2
Others	**-0.1**	**-0.6**	**-1.6**	**-1.2**	**-1.3**	**-4.8**	**0.4**	**-0.5**	**-1.2**	**-0.9**	**-1.6**	**-3.7**	**0.9**	**-0.4**	**-0.7**	**-0.6**	**-1.8**	**-2.6**
Total	**-12.0**	**-5.8**	**-14.6**	**-10.7**	**-1.0**	**-44.1**	**-12.0**	**-5.6**	**-14.5**	**-10.6**	**-1.0**	**-43.8**	**-12.0**	**-5.5**	**-14.4**	**-10.6**	**-1.0**	**-43.5**

Source: The Brattle Group

Table 9: Estimated impact on units' margins of the market simulation for different risk premiums. Quantity effect.

	Total margin. Risk premium 10 €/MW						Total margin. Risk premium 5 €/MW						Total margin. Risk premium 0 €/MW					
Unit	2010	2011	2012	2013	2014	Total	2010	2011	2012	2013	2014	Total	2010	2011	2012	2013	2014	Total
	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €
Alto Lindoso	2.0	0.0	-0.3	0.3	0.4	2.4	2.9	0.1	-0.3	0.5	0.6	4.0	3.9	0.3	-0.2	0.8	0.8	5.6
Bemposta	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cabril	0.0	1.2	-0.3	0.4	0.0	1.3	0.0	1.2	-0.3	0.4	0.0	1.3	0.1	1.2	-0.3	0.4	0.0	1.3
Castelo Bode	-0.1	0.0	-0.1	-0.2	0.1	-0.3	-0.1	0.3	-0.1	-0.1	0.2	0.2	0.0	0.5	-0.1	0.0	0.3	0.7
Picote	0.1	0.0	-0.3	-0.1	0.0	-0.3	0.2	0.1	-0.3	-0.1	0.0	-0.1	0.3	0.3	-0.3	-0.1	0.0	0.2
Pocinho	-0.5	-0.1	0.5	0.1	0.4	0.3	-0.5	0.0	0.7	0.3	0.6	0.9	-0.5	0.1	0.8	0.5	0.8	1.6
Regua	-0.2	-0.2	-0.5	-0.3	0.1	-1.1	-0.1	0.0	-0.4	0.0	0.2	-0.3	0.0	0.2	-0.2	0.2	0.2	0.5
Torrao	0.1	-0.1	-0.4	-0.1	0.0	-0.4	0.2	-0.1	-0.4	-0.1	0.0	-0.4	0.2	-0.1	-0.4	-0.1	0.0	-0.3
V.Nova II(Frades)	1.2	0.1	0.1	0.0	0.6	2.0	1.8	0.2	0.4	0.2	0.7	3.3	2.3	0.3	0.6	0.5	0.9	4.6
Valeira	0.3	-0.2	-0.9	-0.2	0.3	-0.8	0.5	0.1	-0.6	0.1	0.4	0.6	0.8	0.5	-0.3	0.5	0.6	2.0
EDP with CMEC	**3.0**	**0.7**	**-2.2**	**-0.1**	**1.8**	**3.1**	**5.0**	**2.0**	**-1.2**	**1.2**	**2.7**	**9.6**	**7.0**	**3.3**	**-0.2**	**2.5**	**3.6**	**16.1**
Alqueva	0.9	1.3	4.0	3.7	0.1	10.1	1.9	2.9	5.7	5.8	0.3	16.5	2.8	4.5	7.3	7.9	0.5	23.0
Alqueva II	0.0	0.0	0.1	-0.2	0.0	-0.1	0.0	0.0	0.1	0.2	0.1	0.4	0.0	0.0	0.2	0.6	0.1	1.0
Bemposta II	0.0	0.0	2.1	6.6	2.1	10.9	0.0	0.0	3.4	9.2	2.9	15.5	0.0	0.0	4.7	11.8	3.7	20.2
Picote II	0.0	0.0	1.9	4.7	2.2	8.8	0.0	0.0	3.2	7.4	3.1	13.8	0.0	0.1	4.5	10.1	4.0	18.7
CC. Ribatejo 1	-0.7	-0.4	-0.2	0.1	0.0	-1.3	0.4	0.2	0.0	0.2	0.0	0.7	1.6	0.8	0.1	0.3	0.0	2.8
CC. Ribatejo 2	-0.3	-0.9	-0.1	-0.1	0.0	-1.3	0.9	-0.1	0.0	0.0	0.0	0.9	2.1	0.7	0.1	0.2	0.0	3.0
CC. Ribatejo 3	0.6	-0.1	0.0	0.0	0.0	0.5	2.2	0.0	0.0	0.0	0.0	2.2	3.7	0.0	0.0	0.0	0.0	3.8
CC. Lares 1	2.0	4.2	5.1	0.4	0.2	11.8	3.2	7.9	7.2	1.0	0.2	19.5	4.4	11.6	9.3	1.6	0.2	27.1
CC. Lares 2	4.1	1.6	1.2	0.4	0.0	7.4	6.6	3.6	1.9	1.0	0.0	13.0	9.1	5.5	2.5	1.5	0.0	18.6
EDP without CMEC	**6.6**	**5.7**	**14.2**	**15.7**	**4.6**	**46.7**	**15.1**	**14.4**	**21.5**	**24.9**	**6.5**	**82.5**	**23.7**	**23.2**	**28.9**	**34.1**	**8.4**	**118.3**
Pego coal 1	0.4	0.9	-1.1	-0.1	0.0	0.1	1.2	1.9	-0.4	0.2	0.0	2.8	1.9	2.8	0.2	0.6	0.0	5.5
Pego coal 2	0.4	0.9	-0.5	0.1	0.0	0.8	1.2	1.7	0.2	0.3	0.0	3.4	1.9	2.6	0.9	0.6	0.0	6.0
REN Trading	**0.8**	**1.8**	**-1.6**	**0.0**	**-0.1**	**0.9**	**2.3**	**3.6**	**-0.3**	**0.6**	**0.0**	**6.2**	**3.9**	**5.4**	**1.1**	**1.2**	**0.0**	**11.5**
Aguieira	0.0	-0.3	0.4	-0.1	0.1	0.1	0.6	0.1	0.9	0.5	0.3	2.4	1.2	0.5	1.4	1.1	0.4	4.6
CC. Pego. G3	0.0	0.3	2.8	0.0	0.0	3.2	0.0	0.5	4.2	0.1	0.0	4.8	0.0	0.7	5.6	0.2	0.0	6.5
CC. Pego. G4	0.0	0.0	0.4	0.1	0.0	0.5	0.0	0.1	1.0	0.2	0.0	1.3	0.0	0.1	1.5	0.4	0.0	2.0
Others	**0.0**	**0.0**	**3.6**	**0.1**	**0.1**	**3.9**	**0.6**	**0.7**	**6.0**	**0.9**	**0.3**	**8.5**	**1.2**	**1.3**	**8.5**	**1.6**	**0.4**	**13.1**
Total	**10.4**	**8.2**	**13.9**	**15.7**	**6.4**	**54.6**	**23.1**	**20.7**	**26.1**	**27.6**	**9.4**	**106.8**	**35.8**	**33.2**	**38.3**	**39.4**	**12.3**	**159.0**

Source: The Brattle Group

D.III. ESTIMATION OF ACTUAL RESULTS

Table 10: Estimated units' margins with actual market results (until 31st March 2014)

	Total margin						Margin on capacity						Margin on energy					
Unit	2010	2011	2012	2013	2014	Total	2010	2011	2012	2013	2014	Total	2010	2011	2012	2013	2014	Total
	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €
Alto Lindoso	2.3	0.3	0.2	0.5	0.2	3.4	1.5	0.1	0.1	0.3	0.0	2.1	0.8	0.1	0.0	0.1	0.2	1.3
Bemposta	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cabril	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Castelo Bode	0.0	0.4	0.1	0.2	0.1	0.7	0.0	0.1	0.1	0.1	0.0	0.3	0.0	0.2	0.0	0.0	0.1	0.4
Picote	0.0	0.0	0.0	0.0	0.0	0.1	0.0	-0.1	0.0	0.0	0.0	-0.1	0.1	0.1	0.0	0.0	0.0	0.2
Pocinho	0.0	0.2	0.9	0.2	0.4	1.7	0.0	0.1	0.8	0.2	0.3	1.4	0.0	0.1	0.1	0.0	0.1	0.3
Regua	0.1	0.4	0.8	0.4	0.1	1.8	0.0	0.2	0.7	0.4	0.1	1.3	0.1	0.2	0.1	0.1	0.0	0.5
Torrao	0.2	0.0	0.0	0.0	0.0	0.3	0.2	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.1
V.Nova II(Frades)	1.3	0.3	0.9	0.2	0.6	3.2	0.9	0.2	0.8	0.1	0.4	2.3	0.4	0.1	0.1	0.0	0.2	0.8
Valeira	1.0	0.8	1.4	0.7	0.3	4.1	0.7	0.5	1.2	0.6	0.2	3.2	0.3	0.3	0.1	0.1	0.1	0.9
EDP with CMEC	**4.9**	**2.3**	**4.2**	**2.1**	**1.7**	**15.2**	**3.3**	**1.1**	**3.7**	**1.7**	**0.9**	**10.7**	**1.7**	**1.2**	**0.5**	**0.4**	**0.8**	**4.5**
Alqueva	1.6	2.9	6.1	5.4	0.2	16.2	1.0	1.9	5.5	4.9	0.1	13.4	0.6	1.0	0.6	0.4	0.1	2.8
Alqueva II	0.0	0.0	0.1	0.1	0.1	0.3	0.0	0.0	0.1	0.1	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.1
Bemposta II	0.0	0.0	2.9	8.3	2.3	13.6	0.0	0.0	2.7	7.5	1.6	11.9	0.0	0.0	0.2	0.8	0.6	1.7
Picote II	0.0	0.0	2.4	5.5	2.4	10.4	0.0	0.0	2.3	5.4	1.7	9.4	0.0	0.0	0.1	0.1	0.7	1.0
CC. Ribatejo 1	-0.1	-0.1	0.0	0.2	0.0	0.0	-0.5	-0.5	-0.1	0.2	0.0	-0.9	0.4	0.4	0.1	0.0	0.0	0.9
CC. Ribatejo 2	0.3	-0.6	0.0	0.1	0.0	-0.3	0.1	-1.0	-0.1	0.0	0.0	-1.0	0.2	0.4	0.1	0.1	0.0	0.7
CC. Ribatejo 3	1.5	-0.1	0.0	0.0	0.0	1.4	0.9	-0.1	0.0	0.0	0.0	0.8	0.6	0.1	0.0	0.0	0.0	0.7
CC. Lares 1	2.6	7.3	7.1	0.8	0.0	17.8	2.0	4.5	6.0	0.7	0.0	13.2	0.6	2.8	1.1	0.1	0.0	4.6
CC. Lares 2	4.6	2.4	1.7	0.8	0.0	9.5	3.6	1.3	1.4	0.7	0.0	7.0	1.0	1.1	0.3	0.1	0.0	2.5
EDP without CMEC	**10.4**	**11.8**	**20.4**	**21.3**	**5.0**	**68.9**	**7.0**	**6.1**	**17.8**	**19.5**	**3.5**	**54.0**	**3.4**	**5.7**	**2.6**	**1.7**	**1.5**	**14.9**
Pego coal 1	0.6	2.0	3.3	1.5	0.0	0.0	0.2	1.2	2.6	1.2	0.0	0.0	0.4	0.8	0.7	0.3	0.0	0.0
Pego coal 2	0.6	1.9	3.5	1.2	0.0	0.0	0.2	1.1	2.8	1.0	0.0	0.0	0.4	0.8	0.7	0.2	0.0	0.0
REN Trading	**1.2**	**3.9**	**6.7**	**2.7**	**0.0**	**0.0**	**0.4**	**2.3**	**5.4**	**2.1**	**0.0**	**0.0**	**0.8**	**1.6**	**1.3**	**0.6**	**0.0**	**0.0**
Aguieira	0.1	0.0	1.0	0.3	-0.1	-0.1	-0.2	-0.3	0.8	0.2	-0.3	-0.1	0.3	0.3	0.2	0.1	0.2	-0.1
CC. Pego. G3	0.0	0.5	5.8	0.1	0.0	0.0	0.0	0.3	4.3	0.0	0.0	0.0	0.0	0.2	1.5	0.1	0.0	0.0
CC. Pego. G4	0.0	0.0	1.2	0.3	0.0	0.0	0.0	0.0	0.5	0.2	0.0	0.0	0.0	0.0	0.7	0.1	0.0	0.0
Others	**0.1**	**0.6**	**7.9**	**0.7**	**-0.1**	**-0.1**	**-0.2**	**0.0**	**5.5**	**0.4**	**-0.3**	**-0.1**	**0.3**	**0.5**	**2.4**	**0.3**	**0.2**	**-0.1**
Total	**16.7**	**18.5**	**39.2**	**26.8**	**6.7**	**6.7**	**10.5**	**9.5**	**32.4**	**23.8**	**4.2**	**6.7**	**6.2**	**8.9**	**6.8**	**3.0**	**2.5**	**6.7**

Source: The Brattle Group
Note: assuming a risk-premium of 10€/MW

Table 11: Estimated units' revenues with actual market results (until 31st March 2014)

	Total revenue						Revenue on capacity						Revenue on energy					
Unit	2010 mill. €	2011 mill. €	2012 mill. €	2013 mill. €	2014 mill. €	Total mill. €	2010 mill. €	2011 mill. €	2012 mill. €	2013 mill. €	2014 mill. €	Total mill. €	2010 mill. €	2011 mill. €	2012 mill. €	2013 mill. €	2014 mill. €	Total mill. €
Alto Lindoso	7.7	1.4	0.5	1.9	1.4	12.9	6.2	1.0	0.4	1.4	0.9	9.9	1.5	0.4	0.1	0.6	0.5	3.0
Bemposta	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Cabril	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Castelo Bode	0.1	1.9	0.3	0.7	0.6	3.6	0.1	1.4	0.2	0.5	0.5	2.8	0.0	0.5	0.1	0.1	0.1	0.8
Picote	0.7	1.2	0.1	0.0	0.0	2.1	0.6	0.9	0.1	0.0	0.0	1.6	0.1	0.3	0.0	0.0	0.0	0.5
Pocinho	0.0	0.9	2.3	1.7	1.4	6.2	0.0	0.7	1.9	1.2	1.1	5.0	0.0	0.2	0.3	0.4	0.3	1.3
Regua	0.6	1.9	2.2	2.1	0.3	7.1	0.4	1.4	1.9	1.6	0.2	5.5	0.2	0.5	0.4	0.5	0.1	1.6
Torrao	0.5	0.1	0.0	0.0	0.0	0.7	0.4	0.1	0.0	0.0	0.0	0.6	0.1	0.0	0.0	0.0	0.0	0.1
V.Nova II(Frades)	3.9	0.9	2.6	1.8	1.4	10.6	3.4	0.6	2.2	1.4	1.1	8.7	0.5	0.2	0.5	0.4	0.2	1.8
Valeira	2.2	2.9	3.6	3.0	0.9	12.5	1.8	2.1	3.0	2.3	0.7	9.8	0.4	0.8	0.6	0.7	0.2	2.7
EDP with CMEC	**15.7**	**11.2**	**11.7**	**11.2**	**6.0**	**55.9**	**12.9**	**8.3**	**9.8**	**8.5**	**4.7**	**44.1**	**2.8**	**3.0**	**1.9**	**2.7**	**1.4**	**11.8**
Alqueva	6.4	12.7	19.3	18.9	1.1	58.4	4.9	9.1	15.8	14.7	0.8	45.4	1.5	3.6	3.5	4.2	0.2	13.0
Alqueva II	0.0	0.0	0.9	3.7	0.5	5.1	0.0	0.0	0.7	2.9	0.4	4.1	0.0	0.0	0.2	0.8	0.1	1.0
Bemposta II	0.0	0.1	15.7	26.2	6.2	48.1	0.0	0.1	13.0	21.5	5.1	39.7	0.0	0.0	2.6	4.7	1.1	8.4
Picote II	0.0	0.4	15.4	26.5	7.1	49.4	0.0	0.3	12.9	22.3	5.8	41.3	0.0	0.1	2.5	4.2	1.3	8.1
CC. Ribatejo 1	7.7	4.5	2.0	0.8	0.0	15.0	5.5	3.0	1.5	0.6	0.0	10.5	2.2	1.5	0.5	0.2	0.0	4.5
CC. Ribatejo 2	9.1	6.0	0.6	1.0	0.0	16.7	7.1	4.0	0.5	0.6	0.0	12.2	2.0	2.0	0.1	0.4	0.0	4.6
CC. Ribatejo 3	11.2	0.6	0.1	0.1	0.0	12.1	8.3	0.4	0.1	0.1	0.0	8.9	2.9	0.3	0.0	0.0	0.0	3.2
CC. Lares 1	8.5	30.7	27.0	5.9	0.0	72.1	6.5	20.9	21.2	4.0	0.0	52.7	1.9	9.8	5.8	1.8	0.0	19.3
CC. Lares 2	17.4	13.2	7.7	5.1	0.0	43.3	13.4	9.2	5.9	3.6	0.0	32.0	4.0	4.0	1.8	1.5	0.0	11.4
EDP without CMEC	**60.3**	**68.2**	**88.7**	**88.1**	**14.8**	**320.1**	**45.8**	**46.9**	**71.6**	**70.2**	**12.1**	**246.7**	**14.5**	**21.2**	**17.0**	**17.9**	**2.7**	**73.4**
Pego coal 1	4.6	7.2	7.2	3.4	0.0	0.0	3.4	5.7	5.8	2.6	0.0	0.0	1.2	1.6	1.4	0.7	0.0	0.0
Pego coal 2	4.5	6.8	7.6	2.7	0.0	0.0	3.3	5.4	6.1	2.1	0.0	0.0	1.2	1.4	1.5	0.6	0.0	0.0
REN Trading	**9.1**	**14.0**	**14.9**	**6.1**	**0.1**	**0.1**	**6.7**	**11.1**	**12.0**	**4.7**	**0.1**	**0.1**	**2.4**	**3.0**	**2.9**	**1.3**	**0.0**	**0.1**
Aguieira	4.1	2.6	5.5	5.2	0.8	0.8	3.6	2.1	4.4	4.3	0.6	0.8	0.6	0.5	1.1	0.9	0.2	0.8
CC. Pego. G3	0.0	1.9	16.5	0.7	0.0	0.0	0.0	1.2	12.2	0.5	0.0	0.0	0.0	0.7	4.4	0.2	0.0	0.0
CC. Pego. G4	0.0	0.2	6.1	0.9	0.0	0.0	0.0	0.1	4.3	0.6	0.0	0.0	0.0	0.1	1.7	0.3	0.0	0.0
Others	**4.1**	**4.7**	**28.1**	**6.9**	**0.8**	**0.8**	**3.6**	**3.5**	**20.8**	**5.5**	**0.6**	**0.8**	**0.6**	**1.2**	**7.2**	**1.4**	**0.2**	**0.8**
Total	**89.3**	**98.1**	**143.3**	**112.3**	**21.8**	**21.8**	**69.0**	**69.7**	**114.2**	**88.9**	**17.4**	**21.8**	**20.3**	**28.4**	**29.1**	**23.4**	**4.4**	**21.8**

Source: The Brattle Group
Note: assuming a risk-premium of 10€/MW

Table 12: Estimated units' costs with actual market results (until 31st March 2014)

	Total costs						Costs of capacity						Costs of energy					
Unit	2010	2011	2012	2013	2014	Total	2010	2011	2012	2013	2014	Total	2010	2011	2012	2013	2014	Total
	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €
Alto Lindoso	5.4	1.1	0.4	1.5	1.2	9.5	4.7	0.9	0.3	1.0	0.9	7.9	0.7	0.3	0.1	0.4	0.2	1.7
Bemposta	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cabril	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Castelo Bode	0.1	1.6	0.2	0.5	0.5	2.9	0.1	1.3	0.2	0.4	0.5	2.5	0.0	0.2	0.0	0.1	0.0	0.5
Picote	0.7	1.2	0.1	0.0	0.0	2.1	0.6	1.0	0.1	0.0	0.0	1.7	0.1	0.2	0.0	0.0	0.0	0.3
Pocinho	0.0	0.7	1.4	1.5	0.9	4.5	0.0	0.6	1.1	1.1	0.8	3.6	0.0	0.2	0.3	0.4	0.2	1.0
Regua	0.5	1.5	1.4	1.7	0.2	5.3	0.4	1.2	1.2	1.2	0.2	4.2	0.1	0.3	0.3	0.5	0.0	1.1
Torrao	0.2	0.1	0.0	0.0	0.0	0.4	0.2	0.1	0.0	0.0	0.0	0.4	0.0	0.0	0.0	0.0	0.0	0.0
V.Nova II(Frades)	2.6	0.6	1.7	1.6	0.8	7.4	2.4	0.5	1.4	1.3	0.8	6.4	0.1	0.1	0.3	0.3	0.1	1.0
Valeira	1.2	2.1	2.2	2.3	0.6	8.4	1.1	1.6	1.8	1.7	0.5	6.6	0.1	0.5	0.4	0.6	0.1	1.8
EDP with CMEC	**10.8**	**9.0**	**7.5**	**9.1**	**4.3**	**40.7**	**9.6**	**7.2**	**6.1**	**6.7**	**3.8**	**33.4**	**1.1**	**1.8**	**1.4**	**2.4**	**0.6**	**7.3**
Alqueva	4.8	9.8	13.2	13.6	0.8	42.2	3.9	7.2	10.3	9.8	0.7	31.9	0.9	2.6	2.9	3.8	0.1	10.2
Alqueva II	0.0	0.0	0.8	3.6	0.4	4.8	0.0	0.0	0.6	2.8	0.4	3.9	0.0	0.0	0.1	0.7	0.0	0.9
Bemposta II	0.0	0.1	12.7	17.8	3.9	34.5	0.0	0.1	10.3	14.0	3.4	27.8	0.0	0.0	2.4	3.8	0.5	6.7
Picote II	0.0	0.4	13.0	21.0	4.7	39.0	0.0	0.3	10.6	16.9	4.1	31.9	0.0	0.1	2.4	4.1	0.6	7.1
CC. Ribatejo 1	7.8	4.7	2.0	0.6	0.0	15.0	6.0	3.5	1.6	0.4	0.0	11.5	1.8	1.2	0.4	0.2	0.0	3.6
CC. Ribatejo 2	8.8	6.6	0.7	1.0	0.0	17.0	7.0	5.0	0.6	0.6	0.0	13.1	1.8	1.6	0.1	0.4	0.0	3.8
CC. Ribatejo 3	9.7	0.7	0.1	0.1	0.0	10.6	7.5	0.5	0.1	0.1	0.0	8.1	2.3	0.2	0.0	0.0	0.0	2.5
CC. Lares 1	5.9	23.4	19.9	5.0	0.0	54.2	4.5	16.4	15.2	3.3	0.0	39.5	1.4	7.0	4.7	1.7	0.0	14.8
CC. Lares 2	12.8	10.8	5.9	4.3	0.0	33.8	9.8	7.9	4.4	2.9	0.0	25.0	3.0	2.9	1.5	1.4	0.0	8.8
EDP without CMEC	**49.9**	**56.4**	**68.3**	**66.9**	**9.8**	**251.2**	**38.8**	**40.8**	**53.8**	**50.7**	**8.6**	**192.7**	**11.1**	**15.6**	**14.4**	**16.2**	**1.2**	**58.5**
Pego coal 1	4.0	5.3	4.0	1.9	0.0	0.0	3.2	4.5	3.2	1.5	0.0	0.0	0.8	0.8	0.8	0.4	0.0	0.0
Pego coal 2	4.0	4.9	4.2	1.5	0.0	0.0	3.2	4.3	3.4	1.1	0.0	0.0	0.8	0.6	0.8	0.4	0.0	0.0
REN Trading	**7.9**	**10.2**	**8.2**	**3.4**	**0.0**	**0.0**	**6.3**	**8.8**	**6.6**	**2.6**	**0.0**	**0.0**	**1.6**	**1.4**	**1.6**	**0.8**	**0.0**	**0.0**
Aguieira	4.0	2.6	4.5	4.9	0.9	0.9	3.8	2.4	3.6	4.1	0.9	0.9	0.3	0.2	0.9	0.8	0.0	0.9
CC. Pego. G3	0.0	1.4	10.7	0.7	0.0	0.0	0.0	0.9	7.9	0.5	0.0	0.0	0.0	0.4	2.8	0.2	0.0	0.0
CC. Pego. G4	0.0	0.1	4.9	0.7	0.0	0.0	0.0	0.1	3.8	0.5	0.0	0.0	0.0	0.0	1.1	0.2	0.0	0.0
Others	**4.0**	**4.1**	**20.1**	**6.2**	**0.9**	**0.9**	**3.8**	**3.4**	**15.3**	**5.1**	**0.9**	**0.9**	**0.3**	**0.7**	**4.8**	**1.1**	**0.0**	**0.9**
Total	**72.6**	**79.7**	**104.1**	**85.6**	**15.1**	**15.1**	**52.2**	**51.4**	**75.2**	**62.5**	**13.2**	**15.1**	**12.5**	**18.1**	**20.7**	**19.7**	**1.8**	**15.1**

Source: The Brattle Group
Note: assuming a risk-premium of 10€/MW

Table 13: Actual capacity allocated and estimated energy allocation (until 31st March 2014)

	Secondary reserve capacity						Net secondary reserve energy					
Unit	2010 GW	2011 GW	2012 GW	2013 GW	2014 GW	Total GW	2010 GWh	2011 GWh	2012 GWh	2013 GWh	2014 GWh	Total GW
Alto Lindoso	184	37	11	43	40	314	23	6	1	8	9	47
Bemposta	0	0	0	0	2	2	0	0	0	0	0	0
Cabril	1	0	0	0	0	1	0	0	0	0	0	0
Castelo Bode	4	51	5	14	20	94	0	6	1	2	3	13
Picote	20	27	2	1	1	51	2	4	0	0	0	6
Pocinho	0	21	38	39	41	140	0	3	4	7	7	20
Regua	17	42	37	49	11	157	2	6	5	8	2	23
Torrao	10	3	1	0	0	14	1	0	0	0	0	2
V.Nova II(Frades)	111	18	48	45	35	257	5	2	6	6	5	24
Valeira	54	63	60	68	28	273	6	10	8	12	5	41
EDP with CMEC	**402**	**261**	**201**	**259**	**180**	**1,303**	**40**	**37**	**25**	**43**	**31**	**176**
Alqueva	185	318	337	421	32	1,294	24	43	43	67	4	181
Alqueva II	0	0	15	81	15	111	0	0	2	12	2	17
Bemposta II	0	2	260	519	158	937	0	0	36	84	25	145
Picote II	0	9	261	541	179	990	0	1	33	78	28	140
CC. Ribatejo 1	233	124	36	15	0	408	35	21	6	3	0	65
CC. Ribatejo 2	239	158	16	24	0	437	35	28	2	5	0	69
CC. Ribatejo 3	309	15	4	2	0	330	48	3	0	0	0	52
CC. Lares 1	236	745	420	128	0	1,529	34	131	71	25	0	261
CC. Lares 2	504	386	125	111	0	1,127	69	59	22	21	0	171
EDP without CMEC	**1,707**	**1,755**	**1,474**	**1,842**	**384**	**7,162**	**245**	**287**	**215**	**296**	**59**	**1,101**
Pego coal 1	155	188	132	63	1	1	20	17	19	12	0	1
Pego coal 2	152	175	140	51	1	1	20	14	21	10	0	1
REN Trading	**307**	**363**	**271**	**114**	**2**	**2**	**40**	**31**	**40**	**22**	**0**	**2**
Aguieira	120	82	102	118	27	27	6	4	13	14	4	27
CC. Pego. G3	0	41	271	16	0	0	0	8	54	3	0	0
CC. Pego. G4	0	4	117	21	0	0	0	1	24	3	0	0
Others	**120**	**127**	**490**	**155**	**27**	**27**	**6**	**12**	**91**	**20**	**4**	**27**
Total	**2,535**	**2,143**	**2,165**	**2,256**	**591**	**591**	**330**	**367**	**370**	**382**	**95**	**591**

Source: The Brattle Group

D.IV. ESTIMATION OF ALTERNATIVE RESULTS (QUANTITY EFFECT)

Table 14: Estimated units' margins (quantity effect, until 31st March 2014)

	Total margin						Margin on capacity						Margin on energy					
Unit	2010	2011	2012	2013	2014	Total	2010	2011	2012	2013	2014	Total	2010	2011	2012	2013	2014	Total
	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €
Alto Lindoso	3.9	1.4	2.6	4.0	1.0	12.9	3.0	0.7	2.0	3.3	0.7	9.7	1.0	0.7	0.5	0.6	0.4	3.2
Bemposta	0.0	0.0	0.0	0.0	0.2	0.2	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Cabril	0.3	-0.7	1.0	0.1	0.1	0.7	0.2	-0.8	0.8	0.2	0.0	0.4	0.1	0.1	0.2	-0.1	0.0	0.3
Miranda II	0.8	0.8	0.6	1.5	0.2	3.9	0.6	0.4	0.5	1.3	0.2	3.0	0.2	0.3	0.1	0.2	0.1	0.9
Picote	0.1	0.6	1.0	1.1	0.1	3.0	0.1	0.3	0.8	0.9	0.1	2.2	0.1	0.3	0.1	0.2	0.0	0.7
Pocinho	2.2	0.6	0.4	0.6	0.6	4.5	1.8	0.4	0.4	0.6	0.5	3.6	0.4	0.3	0.0	0.1	0.2	0.9
Regua	1.3	1.6	3.0	2.2	0.2	8.3	1.0	1.1	2.6	2.0	0.1	6.8	0.3	0.5	0.4	0.2	0.1	1.5
Torrao	0.7	0.5	1.4	1.1	0.1	3.8	0.5	0.2	1.1	1.0	0.0	2.9	0.2	0.2	0.2	0.2	0.1	0.9
V.Nova II(Frades)	1.1	0.8	2.3	1.6	0.4	6.1	0.9	0.5	1.9	1.4	0.3	4.9	0.2	0.3	0.3	0.2	0.1	1.2
Valeira	3.0	2.5	4.9	2.7	0.4	13.4	2.4	1.8	4.4	2.6	0.3	11.5	0.6	0.6	0.5	0.1	0.1	2.0
EDP with CMEC	**13.4**	**7.9**	**17.1**	**14.9**	**3.4**	**56.7**	**10.4**	**4.6**	**14.7**	**13.2**	**2.3**	**45.1**	**3.1**	**3.3**	**2.5**	**1.7**	**1.1**	**11.6**
Alqueva	2.0	2.5	4.6	4.5	0.3	14.0	1.5	1.7	4.2	4.1	0.2	11.8	0.5	0.8	0.4	0.3	0.1	2.2
Alqueva II	0.0	0.0	0.1	0.8	0.2	1.1	0.0	0.0	0.1	0.8	0.1	1.0	0.0	0.0	0.0	0.1	0.1	0.2
Bemposta II	0.0	0.0	1.8	5.5	1.2	8.6	0.0	0.0	1.8	5.0	0.9	7.7	0.0	0.0	0.0	0.5	0.3	0.8
Picote II	0.0	0.0	1.4	3.3	1.3	6.1	0.0	0.0	1.4	3.1	0.9	5.4	0.0	0.0	0.1	0.2	0.4	0.7
CC. Ribatejo 1	1.4	0.7	0.2	0.3	0.0	2.6	0.9	0.4	0.1	0.3	0.0	1.7	0.5	0.3	0.1	0.1	0.0	0.9
CC. Ribatejo 2	1.2	0.2	0.0	0.1	0.0	1.5	0.7	0.0	0.0	0.1	0.0	0.8	0.4	0.2	0.0	0.1	0.0	0.7
CC. Ribatejo 3	2.4	0.1	0.0	0.0	0.0	2.5	1.6	0.0	0.0	0.0	0.0	1.7	0.7	0.1	0.0	0.0	0.0	0.8
CC. Lares 1	2.2	6.3	4.9	0.8	-0.1	14.2	1.7	4.3	4.3	0.7	-0.1	10.9	0.5	2.0	0.6	0.1	0.0	3.3
CC. Lares 2	4.9	2.2	1.6	0.9	0.0	9.6	3.8	1.4	1.4	0.8	0.0	7.4	1.1	0.9	0.2	0.1	0.0	2.2
EDP without CMEC	**14.0**	**12.1**	**14.7**	**16.3**	**3.0**	**60.1**	**10.3**	**7.8**	**13.3**	**14.8**	**2.1**	**48.4**	**3.7**	**4.2**	**1.5**	**1.5**	**0.8**	**11.8**
Pego coal 1	0.6	1.6	6.4	2.3	0.1	0.0	0.4	1.1	5.1	1.8	0.0	0.0	0.2	0.5	1.3	0.5	0.1	0.0
Pego coal 2	0.5	1.5	6.1	2.0	0.1	0.0	0.3	1.0	4.9	1.6	0.0	0.0	0.1	0.5	1.2	0.4	0.0	0.0
REN Trading	**1.1**	**3.1**	**12.5**	**4.3**	**0.1**	**0.0**	**0.8**	**2.1**	**9.9**	**3.4**	**0.0**	**0.0**	**0.3**	**1.0**	**2.5**	**0.9**	**0.1**	**0.0**
Aguieira	0.2	0.3	1.3	1.5	1.3	-0.1	0.1	0.1	1.1	1.3	0.7	-0.1	0.1	0.1	0.2	0.2	0.5	-0.1
CC. Pego. G3	0.0	0.8	6.7	0.1	0.0	0.0	0.0	0.5	5.6	0.1	0.0	0.0	0.0	0.3	1.1	0.0	0.0	0.0
CC. Pego. G4	0.0	0.1	1.5	0.3	0.0	0.0	0.0	0.1	1.1	0.2	0.0	0.0	0.0	0.0	0.4	0.1	0.0	0.0
Others	**0.2**	**1.1**	**9.5**	**1.9**	**1.3**	**-0.1**	**0.1**	**0.7**	**7.8**	**1.6**	**0.7**	**-0.1**	**0.1**	**0.4**	**1.8**	**0.3**	**0.5**	**-0.1**
Total	**28.7**	**24.2**	**53.9**	**37.4**	**7.7**	**6.7**	**21.6**	**15.2**	**45.6**	**33.0**	**5.1**	**6.7**	**7.2**	**9.0**	**8.2**	**4.4**	**2.5**	**6.7**

Source: The Brattle Group

Note: assuming a risk-premium of 10€/MW

Table 15: Estimated units' revenues (quantity effect, until 31st March 2014)

	Total revenue						Revenue on capacity						Revenue on energy					
Unit	2010	2011	2012	2013	2014	Total	2010	2011	2012	2013	2014	Total	2010	2011	2012	2013	2014	Total
	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €
Alto Lindoso	10.5	5.7	5.7	10.9	3.8	36.6	8.4	3.8	4.2	8.5	3.0	27.8	2.1	1.9	1.5	2.4	0.8	8.7
Bemposta	0.0	0.0	0.0	0.0	0.2	0.2	0.0	0.0	0.0	0.0	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0
Cabril	1.3	2.3	2.3	2.1	0.1	8.1	1.1	1.6	1.8	1.7	0.1	6.3	0.2	0.7	0.5	0.4	0.0	1.8
Castelo Bode	2.1	3.3	1.5	3.7	0.5	11.0	1.6	2.3	1.1	2.9	0.4	8.4	0.4	1.0	0.4	0.7	0.1	2.6
Picote	1.1	3.1	2.5	3.2	0.1	10.1	0.8	2.3	2.0	2.5	0.1	7.8	0.3	0.8	0.5	0.7	0.0	2.3
Pocinho	4.5	2.4	1.1	1.8	1.5	11.4	3.8	1.8	0.9	1.5	1.2	9.2	0.7	0.7	0.2	0.3	0.3	2.2
Regua	3.2	5.5	6.7	5.1	0.7	21.2	2.6	4.1	5.4	4.1	0.6	16.7	0.6	1.5	1.4	1.0	0.2	4.6
Torrao	2.2	2.2	3.7	3.3	0.6	12.1	1.7	1.6	2.9	2.7	0.5	9.3	0.4	0.7	0.9	0.6	0.2	2.8
V.Nova II(Frades)	3.1	2.9	5.6	5.3	1.0	17.8	2.6	2.1	4.4	4.2	0.8	14.2	0.5	0.8	1.2	1.1	0.2	3.7
Valeira	6.7	8.0	10.4	7.5	1.1	33.7	5.5	5.9	8.4	6.0	0.9	26.7	1.2	2.1	2.0	1.5	0.2	7.0
EDP with CMEC	**34.7**	**35.5**	**39.5**	**42.8**	**9.7**	**162.2**	**28.2**	**25.3**	**31.1**	**34.1**	**7.8**	**126.5**	**6.5**	**10.1**	**8.4**	**8.7**	**1.9**	**35.7**
Alqueva	5.2	8.5	13.6	12.2	1.1	40.6	4.1	6.0	10.8	9.6	0.8	31.3	1.1	2.5	2.8	2.6	0.3	9.3
Alqueva II	0.0	0.0	0.2	2.0	0.7	2.9	0.0	0.0	0.2	1.7	0.6	2.4	0.0	0.0	0.1	0.3	0.2	0.6
Bemposta II	0.0	0.0	9.4	16.3	2.7	28.4	0.0	0.0	7.8	13.4	2.2	23.5	0.0	0.0	1.6	2.9	0.5	4.9
Picote II	0.0	0.3	8.5	12.5	3.0	24.4	0.0	0.3	7.1	10.3	2.4	20.0	0.0	0.1	1.4	2.3	0.6	4.4
CC. Ribatejo 1	6.6	2.9	1.7	1.0	0.0	12.3	4.8	2.0	1.3	0.7	0.0	8.7	1.9	0.9	0.5	0.3	0.0	3.6
CC. Ribatejo 2	6.0	3.1	0.4	1.1	0.0	10.5	4.3	2.1	0.2	0.6	0.0	7.2	1.7	1.0	0.1	0.4	0.0	3.3
CC. Ribatejo 3	10.4	0.5	0.1	0.1	0.0	11.1	7.6	0.3	0.1	0.0	0.0	8.1	2.8	0.2	0.0	0.0	0.0	3.0
CC. Lares 1	6.4	22.4	14.8	4.7	0.2	48.5	4.9	15.9	11.8	3.2	0.2	35.9	1.5	6.5	3.0	1.5	0.0	12.5
CC. Lares 2	15.3	10.0	5.3	3.7	0.0	34.4	11.5	7.1	4.2	2.6	0.0	25.4	3.8	3.0	1.1	1.1	0.0	8.9
EDP without CMEC	**50.0**	**47.8**	**54.1**	**53.6**	**7.8**	**213.1**	**37.2**	**33.6**	**43.5**	**42.1**	**6.2**	**162.6**	**12.8**	**14.1**	**10.6**	**11.4**	**1.6**	**50.5**
Pego coal 1	2.2	4.9	12.9	6.0	0.6	0.0	1.7	3.6	10.5	4.8	0.4	0.0	0.5	1.3	2.4	1.2	0.2	0.0
Pego coal 2	1.7	4.6	12.3	5.1	0.5	0.0	1.3	3.3	10.0	4.1	0.3	0.0	0.4	1.3	2.3	1.0	0.1	0.0
REN Trading	**3.9**	**9.5**	**25.3**	**11.1**	**1.0**	**0.1**	**3.0**	**6.9**	**20.5**	**8.8**	**0.7**	**0.1**	**0.9**	**2.6**	**4.7**	**2.2**	**0.3**	**0.1**
Aguieira	0.7	1.5	3.8	3.2	3.2	0.8	0.5	1.0	2.9	2.6	2.7	0.8	0.1	0.4	1.0	0.6	0.5	0.8
CC. Pego. G3	0.0	2.4	14.5	0.5	0.0	0.0	0.0	1.7	11.3	0.3	0.0	0.0	0.0	0.7	3.2	0.2	0.0	0.0
CC. Pego. G4	0.0	0.3	4.6	0.8	0.0	0.0	0.0	0.2	3.5	0.6	0.0	0.0	0.0	0.1	1.1	0.3	0.0	0.0
Others	**0.7**	**4.2**	**22.9**	**4.5**	**3.2**	**0.8**	**0.5**	**2.9**	**17.7**	**3.5**	**2.7**	**0.8**	**0.1**	**1.2**	**5.2**	**1.0**	**0.5**	**0.8**
Total	**89.2**	**96.9**	**141.7**	**112.0**	**21.8**	**21.8**	**68.9**	**68.8**	**112.8**	**88.6**	**17.4**	**21.8**	**20.4**	**28.1**	**28.9**	**23.4**	**4.4**	**21.8**

Source: The Brattle Group
Note: assuming a risk-premium of 10€/MW

Table 16: Estimated units' costs (quantity effect, until 31st March 2014)

	Total costs						Costs of capacity						Costs of energy					
Unit	2010 mill. €	2011 mill. €	2012 mill. €	2013 mill. €	2014 mill. €	Total mill. €	2010 mill. €	2011 mill. €	2012 mill. €	2013 mill. €	2014 mill. €	Total mill. €	2010 mill. €	2011 mill. €	2012 mill. €	2013 mill. €	2014 mill. €	Total mill. €
Alto Lindoso	6.6	4.3	3.1	7.0	2.7	23.7	5.4	3.1	2.2	5.2	2.3	18.1	1.2	1.2	0.9	1.8	0.4	5.5
Bemposta	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Cabril	1.0	3.0	1.3	2.0	0.0	7.4	0.9	2.5	1.0	1.5	0.0	5.9	0.1	0.5	0.3	0.5	0.0	1.5
Castelo Bode	1.3	2.5	0.9	2.1	0.3	7.2	1.1	1.9	0.6	1.6	0.3	5.4	0.3	0.7	0.2	0.5	0.0	1.8
Picote	1.0	2.5	1.5	2.1	0.1	7.1	0.8	2.0	1.1	1.6	0.1	5.5	0.2	0.5	0.4	0.5	0.0	1.6
Pocinho	2.3	1.8	0.7	1.2	0.9	6.9	2.0	1.4	0.5	0.9	0.8	5.6	0.3	0.4	0.2	0.2	0.1	1.3
Regua	1.9	4.0	3.7	2.9	0.5	13.0	1.6	3.0	2.7	2.2	0.4	9.9	0.3	1.0	1.0	0.8	0.0	3.1
Torrao	1.5	1.8	2.4	2.1	0.5	8.3	1.3	1.3	1.7	1.7	0.4	6.5	0.2	0.5	0.6	0.5	0.1	1.8
V.Nova II(Frades)	2.0	2.1	3.3	3.7	0.6	11.7	1.7	1.6	2.5	2.8	0.5	9.2	0.3	0.5	0.8	0.9	0.1	2.5
Valeira	3.7	5.5	5.5	4.8	0.7	20.2	3.1	4.0	4.0	3.4	0.6	15.2	0.6	1.5	1.5	1.4	0.1	5.0
EDP with CMEC	**21.3**	**27.6**	**22.3**	**27.9**	**6.4**	**105.5**	**17.8**	**20.8**	**16.4**	**20.9**	**5.5**	**81.4**	**3.4**	**6.8**	**5.9**	**7.1**	**0.9**	**24.1**
Alqueva	3.2	6.0	8.9	7.7	0.8	26.6	2.6	4.2	6.6	5.4	0.6	19.5	0.6	1.7	2.4	2.3	0.1	7.1
Alqueva II	0.0	0.0	0.1	1.2	0.5	1.8	0.0	0.0	0.1	0.9	0.4	1.4	0.0	0.0	0.0	0.3	0.1	0.4
Bemposta II	0.0	0.0	7.6	10.8	1.5	19.9	0.0	0.0	6.0	8.4	1.3	15.7	0.0	0.0	1.5	2.4	0.2	4.1
Picote II	0.0	0.3	7.1	9.2	1.7	18.3	0.0	0.2	5.7	7.2	1.4	14.5	0.0	0.1	1.4	2.0	0.3	3.8
CC. Ribatejo 1	5.3	2.2	1.6	0.6	0.0	9.7	3.9	1.6	1.2	0.4	0.0	7.1	1.4	0.7	0.4	0.2	0.0	2.7
CC. Ribatejo 2	4.8	2.9	0.4	1.0	0.0	9.0	3.5	2.1	0.2	0.6	0.0	6.5	1.3	0.8	0.1	0.4	0.0	2.6
CC. Ribatejo 3	8.1	0.4	0.1	0.0	0.0	8.6	6.0	0.3	0.1	0.0	0.0	6.4	2.1	0.1	0.0	0.0	0.0	2.2
CC. Lares 1	4.2	16.0	9.9	3.8	0.3	34.3	3.1	11.6	7.5	2.5	0.3	25.0	1.0	4.4	2.4	1.3	0.0	9.3
CC. Lares 2	10.4	7.8	3.7	2.8	0.0	24.7	7.7	5.7	2.8	1.9	0.0	18.1	2.7	2.1	0.9	1.0	0.0	6.7
EDP without CMEC	**35.9**	**35.7**	**39.3**	**37.2**	**4.8**	**153.0**	**26.9**	**25.8**	**30.2**	**27.3**	**4.0**	**114.2**	**9.1**	**9.9**	**9.1**	**9.9**	**0.8**	**38.7**
Pego coal 1	1.6	3.3	6.6	3.6	0.5	0.0	1.2	2.5	5.5	3.0	0.4	0.0	0.3	0.8	1.1	0.7	0.1	0.0
Pego coal 2	1.3	3.1	6.2	3.1	0.4	0.0	1.0	2.3	5.1	2.5	0.3	0.0	0.3	0.8	1.1	0.6	0.1	0.0
REN Trading	**2.8**	**6.4**	**12.8**	**6.8**	**0.9**	**0.0**	**2.2**	**4.8**	**10.6**	**5.5**	**0.7**	**0.0**	**0.6**	**1.6**	**2.2**	**1.3**	**0.2**	**0.0**
Aguieira	0.5	1.2	2.5	1.7	2.0	0.9	0.4	0.9	1.8	1.4	2.0	0.9	0.1	0.3	0.7	0.3	0.0	0.9
CC. Pego. G3	0.0	1.6	7.8	0.4	0.0	0.0	0.0	1.2	5.7	0.3	0.0	0.0	0.0	0.4	2.0	0.2	0.0	0.0
CC. Pego. G4	0.0	0.2	3.1	0.5	0.0	0.0	0.0	0.1	2.4	0.3	0.0	0.0	0.0	0.1	0.7	0.2	0.0	0.0
Others	**0.5**	**3.0**	**13.3**	**2.6**	**2.0**	**0.9**	**0.4**	**2.2**	**9.9**	**2.0**	**2.0**	**0.9**	**0.1**	**0.8**	**3.4**	**0.7**	**0.0**	**0.9**
Total	**60.5**	**72.7**	**87.8**	**74.5**	**14.1**	**15.1**	**47.3**	**53.6**	**67.1**	**55.6**	**12.3**	**15.1**	**13.2**	**19.1**	**20.7**	**18.9**	**1.8**	**15.1**

Source: The Brattle Group

Note: assuming a risk-premium of 10€/MW

Table 17: Estimated capacity and energy allocation (quantity effect, until 31st March 2014)

	Secondary reserve capacity						Net secondary reserve energy					
Unit	2010 GW	2011 GW	2012 GW	2013 GW	2014 GW	Total GW	2010 GWh	2011 GWh	2012 GWh	2013 GWh	2014 GWh	Total GW
Alto Lindoso	257	148	96	228	108	836	35	22	16	40	18	132
Bemposta	0	0	0	0	5	5	0	0	0	0	1	1
Cabril	39	55	40	45	2	181	4	7	6	7	0	24
Castelo Bode	54	85	26	75	15	256	7	14	5	12	3	40
Picote	31	68	44	67	4	213	4	10	7	12	1	34
Pocinho	104	62	17	41	43	268	12	9	3	5	6	36
Regua	84	133	116	104	20	456	10	19	17	16	3	66
Torrao	55	54	64	66	18	258	7	9	11	11	3	41
V.Nova II(Frades)	76	69	97	113	27	382	9	9	14	18	4	54
Valeira	164	190	177	155	33	718	20	28	25	26	5	104
EDP with CMEC	**864**	**863**	**676**	**896**	**277**	**3,575**	**108**	**126**	**104**	**149**	**44**	**532**
Alqueva	141	219	229	265	32	885	17	29	35	43	5	130
Alqueva II	0	0	4	44	21	69	0	0	1	6	3	10
Bemposta II	0	1	151	324	68	543	0	0	22	52	11	85
Picote II	0	7	142	269	76	494	0	1	20	39	14	74
CC. Ribatejo 1	214	80	37	20	1	353	27	13	5	3	0	48
CC. Ribatejo 2	197	90	10	26	0	323	26	14	2	5	0	46
CC. Ribatejo 3	333	14	3	2	0	351	44	2	0	0	0	46
CC. Lares 1	189	574	247	105	6	1,122	26	86	37	19	1	169
CC. Lares 2	455	301	92	86	0	935	63	43	13	14	0	132
EDP without CMEC	**1,529**	**1,286**	**914**	**1,142**	**205**	**5,076**	**204**	**187**	**136**	**181**	**34**	**741**
Pego coal 1	67	117	212	125	17	1	8	18	32	20	3	1
Pego coal 2	55	109	204	106	15	1	7	17	31	17	2	1
REN Trading	**122**	**226**	**415**	**231**	**33**	**2**	**15**	**35**	**63**	**38**	**5**	**2**
Aguieira	18	43	68	66	78	27	2	6	11	8	12	27
CC. Pego. G3	0	56	244	11	0	0	0	8	39	2	0	0
CC. Pego. G4	0	7	92	17	0	0	0	1	15	3	0	0
Others	**18**	**105**	**405**	**94**	**78**	**27**	**2**	**14**	**65**	**13**	**12**	**27**
Total	**2,533**	**2,480**	**2,410**	**2,363**	**593**	**591**	**329**	**363**	**367**	**381**	**95**	**591**

Source: The Brattle Group
Note: The differences between the actual and the estimated total allocation of reserve are due to hours with insufficient capacity

D.V. Estimation of Alternative Results (Total Effect)

Table 18: Estimated units' margins (total effect, until 31st March 2014)

	Total margin						Margin on capacity						Margin on energy					
Unit	2010	2011	2012	2013	2014	Total	2010	2011	2012	2013	2014	Total	2010	2011	2012	2013	2014	Total
	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €
Alto Lindoso	0.3	0.3	0.5	0.1	-0.2	1.0	-0.7	-0.4	-0.1	-0.5	-0.6	-2.2	1.0	0.7	0.5	0.6	0.4	3.2
Bemposta	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cabril	0.0	-1.2	0.3	-0.4	0.0	-1.3	-0.1	-1.3	0.1	-0.3	0.0	-1.6	0.1	0.1	0.2	-0.1	0.0	0.3
Miranda II	0.1	0.3	0.2	0.3	0.0	1.0	-0.1	0.0	0.1	0.1	-0.1	0.1	0.2	0.3	0.1	0.2	0.1	0.9
Picote	-0.1	0.0	0.3	0.1	0.0	0.4	-0.1	-0.3	0.1	-0.1	0.0	-0.3	0.1	0.3	0.1	0.2	0.0	0.7
Pocinho	0.5	0.3	0.4	0.1	0.1	1.5	0.1	0.0	0.4	0.1	-0.1	0.5	0.4	0.3	0.0	0.1	0.2	0.9
Regua	0.3	0.6	1.3	0.7	0.0	2.8	0.0	0.1	0.9	0.5	-0.1	1.4	0.3	0.5	0.4	0.2	0.1	1.5
Torrao	0.1	0.1	0.4	0.1	0.0	0.7	-0.1	-0.1	0.1	-0.1	-0.1	-0.2	0.2	0.2	0.2	0.2	0.1	0.9
V.Nova II(Frades)	0.1	0.2	0.8	0.2	0.0	1.1	-0.2	-0.1	0.4	0.0	-0.1	-0.1	0.2	0.3	0.3	0.2	0.1	1.2
Valeira	0.7	1.0	2.3	0.9	0.0	4.9	0.1	0.3	1.8	0.8	-0.1	2.9	0.6	0.6	0.5	0.1	0.1	2.0
EDP with CMEC	**1.9**	**1.6**	**6.4**	**2.2**	**-0.1**	**12.1**	**-1.1**	**-1.7**	**3.9**	**0.5**	**-1.1**	**0.5**	**3.1**	**3.3**	**2.5**	**1.7**	**1.1**	**11.6**
Alqueva	0.7	1.6	2.1	1.7	0.1	6.1	0.2	0.8	1.7	1.3	0.0	4.0	0.5	0.8	0.4	0.3	0.1	2.2
Alqueva II	0.0	0.0	0.0	0.3	0.1	0.4	0.0	0.0	0.0	0.2	0.0	0.2	0.0	0.0	0.0	0.1	0.1	0.2
Bemposta II	0.0	0.0	0.8	1.7	0.2	2.7	0.0	0.0	0.8	1.2	-0.1	1.9	0.0	0.0	0.0	0.5	0.3	0.8
Picote II	0.0	0.1	0.5	0.8	0.2	1.6	0.0	0.0	0.4	0.6	-0.1	0.9	0.0	0.0	0.1	0.2	0.4	0.7
CC. Ribatejo 1	0.6	0.3	0.2	0.1	0.0	1.3	0.1	0.0	0.1	0.1	0.0	0.3	0.5	0.3	0.1	0.1	0.0	0.9
CC. Ribatejo 2	0.6	0.3	0.0	0.2	0.0	1.1	0.2	0.1	0.0	0.1	0.0	0.4	0.4	0.2	0.0	0.1	0.0	0.7
CC. Ribatejo 3	0.9	0.1	0.0	0.0	0.0	0.9	0.1	0.0	0.0	0.0	0.0	0.1	0.7	0.1	0.0	0.0	0.0	0.8
CC. Lares 1	0.6	3.1	2.0	0.5	-0.2	6.0	0.1	1.1	1.4	0.3	-0.2	2.7	0.5	2.0	0.6	0.1	0.0	3.3
CC. Lares 2	0.5	0.7	0.5	0.4	0.0	2.1	-0.5	-0.1	0.3	0.3	0.0	-0.1	1.1	0.9	0.2	0.1	0.0	2.2
EDP without CMEC	**3.8**	**6.1**	**6.2**	**5.6**	**0.5**	**22.2**	**0.1**	**1.9**	**4.7**	**4.1**	**-0.4**	**10.4**	**3.7**	**4.2**	**1.5**	**1.5**	**0.8**	**11.8**
Pego coal 1	0.2	1.1	4.4	1.6	0.1	0.0	0.1	0.6	3.0	1.1	0.0	0.0	0.2	0.5	1.3	0.5	0.1	0.0
Pego coal 2	0.2	1.0	4.0	1.1	0.0	0.0	0.0	0.5	2.8	0.7	0.0	0.0	0.1	0.5	1.2	0.4	0.0	0.0
REN Trading	**0.4**	**2.1**	**8.4**	**2.7**	**0.1**	**0.0**	**0.1**	**1.0**	**5.8**	**1.8**	**0.0**	**0.0**	**0.3**	**1.0**	**2.5**	**0.9**	**0.1**	**0.0**
Aguieira	0.1	0.3	0.6	0.4	-0.2	-0.1	0.0	0.1	0.4	0.2	-0.7	-0.1	0.1	0.1	0.2	0.2	0.5	-0.1
CC. Pego. G3	0.0	0.2	3.0	0.0	0.0	0.0	0.0	0.0	1.8	0.0	0.0	0.0	0.0	0.3	1.1	0.0	0.0	0.0
CC. Pego. G4	0.0	0.0	0.8	0.1	0.0	0.0	0.0	0.0	0.4	0.1	0.0	0.0	0.0	0.0	0.4	0.1	0.0	0.0
Others	**0.1**	**0.5**	**4.4**	**0.6**	**-0.2**	**-0.1**	**0.0**	**0.1**	**2.6**	**0.2**	**-0.7**	**-0.1**	**0.1**	**0.4**	**1.8**	**0.3**	**0.5**	**-0.1**
Total	**6.3**	**10.3**	**25.3**	**11.1**	**0.3**	**6.7**	**-0.9**	**1.3**	**17.1**	**6.6**	**-2.3**	**6.7**	**7.2**	**9.0**	**8.2**	**4.4**	**2.5**	**6.7**

Source: The Brattle Group
Note: assuming a risk-premium of 10€/MW

Table 19: Estimated units' revenues (total effect, until 31st March 2014)

	Total revenue						Revenue on capacity						Revenue on energy					
Unit	2010	2011	2012	2013	2014	Total	2010	2011	2012	2013	2014	Total	2010	2011	2012	2013	2014	Total
	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €
Alto Lindoso	6.8	4.6	3.6	7.1	2.5	24.6	4.7	2.7	2.1	4.6	1.7	15.9	2.1	1.9	1.5	2.4	0.8	8.7
Bemposta	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Cabril	1.0	1.9	1.6	1.6	0.1	6.1	0.7	1.2	1.1	1.2	0.0	4.3	0.2	0.7	0.5	0.4	0.0	1.8
Castelo Bode	1.4	2.9	1.0	2.5	0.3	8.1	1.0	1.9	0.7	1.7	0.2	5.5	0.4	1.0	0.4	0.7	0.1	2.6
Picote	0.9	2.5	1.8	2.3	0.1	7.6	0.6	1.7	1.3	1.5	0.1	5.2	0.3	0.8	0.5	0.7	0.0	2.3
Pocinho	2.8	2.1	1.1	1.3	1.0	8.3	2.1	1.4	0.9	1.0	0.7	6.1	0.7	0.7	0.2	0.3	0.3	2.2
Regua	2.2	4.5	5.0	3.6	0.5	15.8	1.6	3.1	3.6	2.7	0.3	11.3	0.6	1.5	1.4	1.0	0.2	4.6
Torrao	1.6	1.9	2.7	2.2	0.5	9.0	1.2	1.2	1.9	1.6	0.3	6.2	0.4	0.7	0.9	0.6	0.2	2.8
V.Nova II(Frades)	2.0	2.3	4.1	3.8	0.6	12.8	1.5	1.5	2.9	2.8	0.4	9.2	0.5	0.8	1.2	1.1	0.2	3.7
Valeira	4.4	6.5	7.8	5.7	0.7	25.1	3.2	4.4	5.8	4.2	0.5	18.2	1.2	2.1	2.0	1.5	0.2	7.0
EDP with CMEC	**23.2**	**29.2**	**28.7**	**30.1**	**6.3**	**117.6**	**16.7**	**19.0**	**20.4**	**21.4**	**4.4**	**81.9**	**6.5**	**10.1**	**8.4**	**8.7**	**1.9**	**35.7**
Alqueva	3.9	7.5	11.0	9.4	0.9	32.7	2.8	5.0	8.3	6.8	0.6	23.4	1.1	2.5	2.8	2.6	0.3	9.3
Alqueva II	0.0	0.0	0.2	1.4	0.6	2.2	0.0	0.0	0.1	1.1	0.5	1.7	0.0	0.0	0.1	0.3	0.2	0.6
Bemposta II	0.0	0.0	8.4	12.5	1.6	22.6	0.0	0.0	6.8	9.6	1.2	17.6	0.0	0.0	1.6	2.9	0.5	4.9
Picote II	0.0	0.3	7.6	10.0	1.9	19.9	0.0	0.3	6.2	7.7	1.3	15.5	0.0	0.1	1.4	2.3	0.6	4.4
CC. Ribatejo 1	5.9	2.5	1.8	0.8	0.0	11.0	4.0	1.6	1.3	0.5	0.0	7.4	1.9	0.9	0.5	0.3	0.0	3.6
CC. Ribatejo 2	5.4	3.2	0.4	1.1	0.0	10.1	3.7	2.2	0.3	0.7	0.0	6.8	1.7	1.0	0.1	0.4	0.0	3.3
CC. Ribatejo 3	8.9	0.5	0.1	0.0	0.0	9.6	6.1	0.3	0.1	0.0	0.0	6.5	2.8	0.2	0.0	0.0	0.0	3.0
CC. Lares 1	4.7	19.1	11.9	4.3	0.1	40.2	3.2	12.6	8.9	2.9	0.1	27.7	1.5	6.5	3.0	1.5	0.0	12.5
CC. Lares 2	10.9	8.5	4.2	3.2	0.0	26.9	7.2	5.6	3.1	2.1	0.0	18.0	3.8	3.0	1.1	1.1	0.0	8.9
EDP without CMEC	**39.8**	**41.8**	**45.5**	**42.8**	**5.3**	**175.2**	**27.0**	**27.7**	**35.0**	**31.4**	**3.7**	**124.7**	**12.8**	**14.1**	**10.6**	**11.4**	**1.6**	**50.5**
Pego coal 1	1.8	4.4	10.9	5.2	0.5	0.0	1.3	3.0	8.5	4.0	0.4	0.0	0.5	1.3	2.4	1.2	0.2	0.0
Pego coal 2	1.5	4.1	10.2	4.2	0.5	0.0	1.0	2.8	7.9	3.2	0.3	0.0	0.4	1.3	2.3	1.0	0.1	0.0
REN Trading	**3.2**	**8.5**	**21.2**	**9.4**	**1.0**	**0.1**	**2.3**	**5.9**	**16.4**	**7.2**	**0.7**	**0.1**	**0.9**	**2.6**	**4.7**	**2.2**	**0.3**	**0.1**
Aguieira	0.6	1.5	3.1	2.1	1.8	0.8	0.4	1.0	2.1	1.5	1.3	0.8	0.1	0.4	1.0	0.6	0.5	0.8
CC. Pego. G3	0.0	1.8	10.7	0.5	0.0	0.0	0.0	1.2	7.6	0.3	0.0	0.0	0.0	0.7	3.2	0.2	0.0	0.0
CC. Pego. G4	0.0	0.2	3.9	0.6	0.0	0.0	0.0	0.1	2.8	0.4	0.0	0.0	0.0	0.1	1.1	0.3	0.0	0.0
Others	**0.6**	**3.5**	**17.7**	**3.2**	**1.8**	**0.8**	**0.4**	**2.3**	**12.5**	**2.2**	**1.3**	**0.8**	**0.1**	**1.2**	**5.2**	**1.0**	**0.5**	**0.8**
Total	**66.8**	**83.0**	**113.1**	**85.6**	**14.4**	**21.8**	**46.4**	**54.9**	**84.2**	**62.2**	**10.0**	**21.8**	**20.4**	**28.1**	**28.9**	**23.4**	**4.4**	**21.8**

Source: The Brattle Group
Note: assuming a risk-premium of 10€/MW

Table 20: Estimated units' costs (total effect, until 31st March 2014)

	Total costs						Costs of capacity						Costs of energy					
Unit	2010	2011	2012	2013	2014	Total	2010	2011	2012	2013	2014	Total	2010	2011	2012	2013	2014	Total
	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €
Alto Lindoso	6.6	4.3	3.1	7.0	2.7	23.7	5.4	3.1	2.2	5.2	2.3	18.1	1.2	1.2	0.9	1.8	0.4	5.5
Bemposta	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Cabril	1.0	3.0	1.3	2.0	0.0	7.4	0.9	2.5	1.0	1.5	0.0	5.9	0.1	0.5	0.3	0.5	0.0	1.5
Castelo Bode	1.3	2.5	0.9	2.1	0.3	7.2	1.1	1.9	0.6	1.6	0.3	5.4	0.3	0.7	0.2	0.5	0.0	1.8
Picote	1.0	2.5	1.5	2.1	0.1	7.1	0.8	2.0	1.1	1.6	0.1	5.5	0.2	0.5	0.4	0.5	0.0	1.6
Pocinho	2.3	1.8	0.7	1.2	0.9	6.9	2.0	1.4	0.5	0.9	0.8	5.6	0.3	0.4	0.2	0.2	0.1	1.3
Regua	1.9	4.0	3.7	2.9	0.5	13.0	1.6	3.0	2.7	2.2	0.4	9.9	0.3	1.0	1.0	0.8	0.0	3.1
Torrao	1.5	1.8	2.4	2.1	0.5	8.3	1.3	1.3	1.7	1.7	0.4	6.5	0.2	0.5	0.6	0.5	0.1	1.8
V.Nova II(Frades)	2.0	2.1	3.3	3.7	0.6	11.7	1.7	1.6	2.5	2.8	0.5	9.2	0.3	0.5	0.8	0.9	0.1	2.5
Valeira	3.7	5.5	5.5	4.8	0.7	20.2	3.1	4.0	4.0	3.4	0.6	15.2	0.6	1.5	1.5	1.4	0.1	5.0
EDP with CMEC	**21.3**	**27.6**	**22.3**	**27.9**	**6.4**	**105.5**	**17.8**	**20.8**	**16.4**	**20.9**	**5.5**	**81.4**	**3.4**	**6.8**	**5.9**	**7.1**	**0.9**	**24.1**
Alqueva	3.2	6.0	8.9	7.7	0.8	26.6	2.6	4.2	6.6	5.4	0.6	19.5	0.6	1.7	2.4	2.3	0.1	7.1
Alqueva II	0.0	0.0	0.1	1.2	0.5	1.8	0.0	0.0	0.1	0.9	0.4	1.4	0.0	0.0	0.0	0.3	0.1	0.4
Bemposta II	0.0	0.0	7.6	10.8	1.5	19.9	0.0	0.0	6.0	8.4	1.3	15.7	0.0	0.0	1.5	2.4	0.2	4.1
Picote II	0.0	0.3	7.1	9.2	1.7	18.3	0.0	0.2	5.7	7.2	1.4	14.5	0.0	0.1	1.4	2.0	0.3	3.8
CC. Ribatejo 1	5.3	2.2	1.6	0.6	0.0	9.7	3.9	1.6	1.2	0.4	0.0	7.1	1.4	0.7	0.4	0.2	0.0	2.7
CC. Ribatejo 2	4.8	2.9	0.4	1.0	0.0	9.0	3.5	2.1	0.2	0.6	0.0	6.5	1.3	0.8	0.1	0.4	0.0	2.6
CC. Ribatejo 3	8.1	0.4	0.1	0.0	0.0	8.6	6.0	0.3	0.1	0.0	0.0	6.4	2.1	0.1	0.0	0.0	0.0	2.2
CC. Lares 1	4.2	16.0	9.9	3.8	0.3	34.3	3.1	11.6	7.5	2.5	0.3	25.0	1.0	4.4	2.4	1.3	0.0	9.3
CC. Lares 2	10.4	7.8	3.7	2.8	0.0	24.7	7.7	5.7	2.8	1.9	0.0	18.1	2.7	2.1	0.9	1.0	0.0	6.7
EDP without CMEC	**35.9**	**35.7**	**39.3**	**37.2**	**4.8**	**153.0**	**26.9**	**25.8**	**30.2**	**27.3**	**4.0**	**114.2**	**9.1**	**9.9**	**9.1**	**9.9**	**0.8**	**38.7**
Pego coal 1	1.6	3.3	6.6	3.6	0.5	0.0	1.2	2.5	5.5	3.0	0.4	0.0	0.3	0.8	1.1	0.7	0.1	0.0
Pego coal 2	1.3	3.1	6.2	3.1	0.4	0.0	1.0	2.3	5.1	2.5	0.3	0.0	0.3	0.8	1.1	0.6	0.1	0.0
REN Trading	**2.8**	**6.4**	**12.8**	**6.8**	**0.9**	**0.0**	**2.2**	**4.8**	**10.6**	**5.5**	**0.7**	**0.0**	**0.6**	**1.6**	**2.2**	**1.3**	**0.2**	**0.0**
Aguieira	0.5	1.2	2.5	1.7	2.0	0.9	0.4	0.9	1.8	1.4	2.0	0.9	0.1	0.3	0.7	0.3	0.0	0.9
CC. Pego. G3	0.0	1.6	7.8	0.4	0.0	0.0	0.0	1.2	5.7	0.3	0.0	0.0	0.0	0.4	2.0	0.2	0.0	0.0
CC. Pego. G4	0.0	0.2	3.1	0.5	0.0	0.0	0.0	0.1	2.4	0.3	0.0	0.0	0.0	0.1	0.7	0.2	0.0	0.0
Others	**0.5**	**3.0**	**13.3**	**2.6**	**2.0**	**0.9**	**0.4**	**2.2**	**9.9**	**2.0**	**2.0**	**0.9**	**0.1**	**0.8**	**3.4**	**0.7**	**0.0**	**0.9**
Total	**60.5**	**72.7**	**87.8**	**74.5**	**14.1**	**15.1**	**47.3**	**53.6**	**67.1**	**55.6**	**12.3**	**15.1**	**13.2**	**19.1**	**20.7**	**18.9**	**1.8**	**15.1**

Source: The Brattle Group
Note: assuming a risk-premium of 10€/MW

Table 21: Estimated capacity and energy allocation (total effect, until 31st March 2014)

	Secondary reserve capacity						Net secondary reserve energy					
Unit	2010 GW	2011 GW	2012 GW	2013 GW	2014 GW	Total GW	2010 GWh	2011 GWh	2012 GWh	2013 GWh	2014 GWh	Total GW
Alto Lindoso	257	148	96	228	108	836	35	22	16	40	18	132
Bemposta	0	0	0	0	5	5	0	0	0	0	1	1
Cabril	39	55	40	45	2	181	4	7	6	7	0	24
Castelo Bode	54	85	26	75	15	256	7	14	5	12	3	40
Picote	31	68	44	67	4	213	4	10	7	12	1	34
Pocinho	104	62	17	41	43	268	12	9	3	5	6	36
Regua	84	133	116	104	20	456	10	19	17	16	3	66
Torrao	55	54	64	66	18	258	7	9	11	11	3	41
V.Nova II(Frades)	76	69	97	113	27	382	9	9	14	18	4	54
Valeira	164	190	177	155	33	718	20	28	25	26	5	104
EDP with CMEC	**864**	**863**	**676**	**896**	**277**	**3,575**	**108**	**126**	**104**	**149**	**44**	**532**
Alqueva	141	219	229	265	32	885	17	29	35	43	5	130
Alqueva II	0	0	4	44	21	69	0	0	1	6	3	10
Bemposta II	0	1	151	324	68	543	0	0	22	52	11	85
Picote II	0	7	142	269	76	494	0	1	20	39	14	74
CC. Ribatejo 1	214	80	37	20	1	353	27	13	5	3	0	48
CC. Ribatejo 2	197	90	10	26	0	323	26	14	2	5	0	46
CC. Ribatejo 3	333	14	3	2	0	351	44	2	0	0	0	46
CC. Lares 1	189	574	247	105	6	1,122	26	86	37	19	1	169
CC. Lares 2	455	301	92	86	0	935	63	43	13	14	0	132
EDP without CMEC	**1,529**	**1,286**	**914**	**1,142**	**205**	**5,076**	**204**	**187**	**136**	**181**	**34**	**741**
Pego coal 1	67	117	212	125	17	1	8	18	32	20	3	1
Pego coal 2	55	109	204	106	15	1	7	17	31	17	2	1
REN Trading	**122**	**226**	**415**	**231**	**33**	**2**	**15**	**35**	**63**	**38**	**5**	**2**
Aguieira	18	43	68	66	78	27	2	6	11	8	12	27
CC. Pego. G3	0	56	244	11	0	0	0	8	39	2	0	0
CC. Pego. G4	0	7	92	17	0	0	0	1	15	3	0	0
Others	**18**	**105**	**405**	**94**	**78**	**27**	**2**	**14**	**65**	**13**	**12**	**27**
Total	**2,533**	**2,480**	**2,410**	**2,363**	**593**	**591**	**329**	**363**	**367**	**381**	**95**	**591**

Source: The Brattle Group
Note: The differences between the actual and the estimated total allocation of reserve are due to hours with insufficient capacity

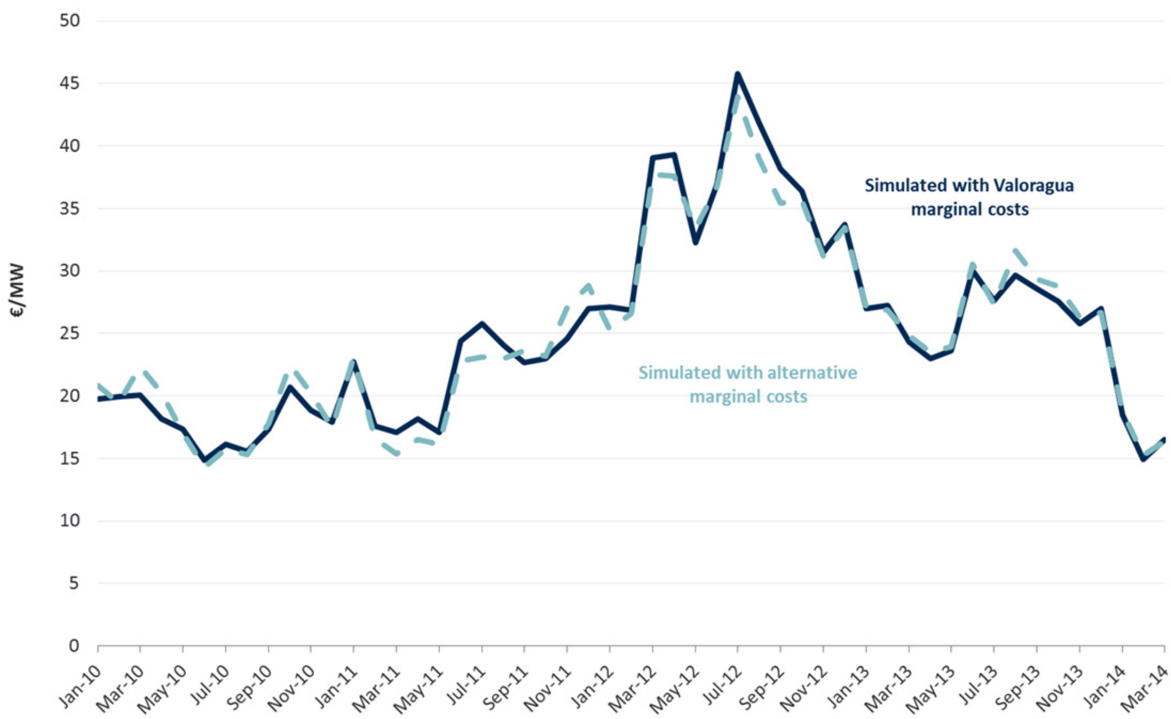
Appendix E. Other information

Table 22: Final price to customers in Portugal and Spain

	Prices in Portugal					Prices in Spain				
	2010	2011	2012	2013	2014	2010	2011	2012	2013	2014
Day ahead	40.0	51.8	49.2	44.8	42.4	38.4	50.9	48.8	46.1	43.4
Secondary reserve capacity	1.3	1.4	2.3	1.8	1.1	0.7	0.8	1.4	1.4	1.1
Tertiary reserve capacity	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.4	0.6
Technical constraints and others	0.7	0.4	0.4	0.4	0.5	2.5	2.1	2.6	3.3	3.7
Imbalances	1.2	1.7	1.6	1.0	1.0	0.5	0.4	0.4	0.4	0.3
Final price (excl. capacity payments)	43.2	55.3	53.6	48.1	45.0	42.1	54.1	53.4	51.7	49.1

Sources:
Portugal: REN, Síntese Anual 2010-2014 Mercado Electricidade
Spain: REE, Informe sobre el sistema eléctrico español, 2010, 2011, 2012, 2013 and 2014

Figure 40: Simulated monthly average price of secondary reserve: with ValorAgua marginal costs and with the alternative estimates of marginal costs



Source: The Brattle Group

Appendix F. Bibliography

Table 23: Bibliography

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