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

Final Third Report

(Report D3)

PREPARED FOR

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

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8st June, 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 third deliverable of the study and extends the analysis carried out in our First Report backwards to cover the years 2008 and 2009.[1] The objective of this analysis is to assess and quantify the impact of any potential distortions on the market for secondary reserve because of the way in which the units covered by the *Custos para a Manutenção do Equilíbrio Contratual*, CMEC, participated in this market.

This report builds on the analytical framework and methodology we developed in our First Report. However, we have added additional analysis in consideration of specific features of the market during this period and data availability limitations.[2] Particularly, we are only able to estimate cost-reflective bids and simulate the secondary reserve market in 2009.

Context for the secondary reserve market before 2010

The market for secondary reserve was created in the second half of 2007 as part of the liberalization of the Portuguese wholesale electricity market. Therefore, this study covers the first years of operation of the market during which neither the System Operator, REN, nor the agents participating in the market had any experience of how the market would operate. REN has also informed us that there was a transitional implementation period for the market that lasted until September 2009.[3]

Consequently, it is unsurprising that, during this period, the operation of the secondary reserve market appears different to that during the period after 2010 that we analysed in our previous reports. During most of 2008 and 2009 the secondary reserve capacity offered to the

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1 The Brattle Group, First Report for the project *Provision of Audit Services in compliance with the Ministerial Order no. 4694/2014*. It covered the period January 2010 to March 2014.

2 REN has confirmed that it is not possible to compile information relating to the generation and secondary reserve provided per unit before 2009. The available information for this period was recovered from the market interim system and may not be entirely consistent with the rules subsequently laid down in the manuals of procedures.

3 According to REN, this transitional period was established in order to allow the market players and REN enough time to adapt their IT platforms to the new market requirements and to train their staff.

market was insufficient to meet the REN's reserve requirements. In November 2008, for instance, only 42% of REN's secondary reserve requirements could be contracted via the market. Despite this, REN was able to cover its secondary regulation requirements by dispatching units outside of the secondary reserve market. Similarly, during the first half of 2009, at least 34% of the upward secondary regulation energy was provided by such uncommitted units.[4] We cannot estimate the secondary reserve these units provided in reality, and whether they would have provided the same reserve if they had participated in the market.[5] REN has confirmed that during the transitional period units providing reserve capacity outside of the secondary reserve market did not receive any remuneration for this capacity.[6]

The volume of reserve bids increased gradually over time and by July 2009 most of the reserve requirement could be met via the market. However, REN continued using uncommitted units to provide regulation until it increased its reserve requirements by 32% in October 2009.[7] Thus, the use of uncommitted units seems to be related to the volume of reserve required by REN, rather than to the units' low level of participation in the market.

Finally, in June 2009 the secondary reserve price nearly doubled and around the same time it decoupled from the secondary reserve price in Spain. Our assessment of the secondary reserve market takes account of all these events.

Assessment of quantity bid to the market

We have first analysed the supply of secondary reserve capacity to the market. We have compared the actual reserve bid into the market with our estimates of the reserve capacity really available. We have also checked what level of secondary regulation was actually provided as well as comparing the evolution of the units' generation profiles to their participation in the secondary reserve market.

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[4] REN has explained that this was possible because during the transitional period CMEC units capable of providing reserve remained directly under the control of the System Operator.

[5] We have verified that the generation schedules of uncommitted units were commonly modified in order to provide secondary reserve.

[6] REN claims that the CMEC arrangements meant that there was no benefit to CMEC units of being remunerated for providing secondary reserve.

[7] According to REN, it increased is secondary reserve requirements in response to complaints that it received from neighbouring System Operators regarding the quality of its frequency regulation.

We find evidence that units offered less capacity to the market than they had available to provide secondary regulation and that this behaviour was not limited to units with CMEC. Of particular note is the fact the hydro units with CMEC could clearly have bid more capacity into the secondary reserve market than they did because REN consistently used these units to provide secondary regulation, even if they had not offered reserve to the market..

Thermal units not covered by the CMEC, namely EDP's CCGTs and the REN Trading operated coal plant *Pego*, also seem to have offered less capacity to the reserve market than we estimate that they had available. They also offered less reserve capacity than in other periods where they had similar generation levels, which is relevant because the capacity of a unit to provide reserve is closely tied to whether or not it is generating.

We do not think that the low participation in the market of hydro units with CMEC was due to a wish to make room for EDP's other units to provide reserve. This is because:

(a) REN was not able to purchase all its secondary reserve requirements in the market; and

(b) EDP's other units also offered less capacity than we estimate they had available. This implies that they could have increased their revenues by offering more capacity.

Instead, we think the behaviour of the hydro units would be consistent with them having an incentive not to participate because the annual adjustment of the CMEC did not include any allowance for the potentially increased costs they might have incurred while providing secondary reserve. We acknowledge that it is not obvious whether the costs of the hydro units would be increased by providing reserve but it is at least possible that the hydro units feared this would be the case.

Assessment of the bid prices

We have analysed the reserve price bids and the costs of providing reserve by comparing the actual behaviour of the units in the market to our estimates of what their efficient (cost-reflective) behaviour would have been. We have also tried to understand the rationale for the change in the level of reserve prices since June 2009 by examining the hourly prices at different times in order to identify how the price was formed.

We find that during the first half of 2009 units' bids were aligned to our estimation of costs. The price increase in June was due to price spikes in a relatively few hours, and was caused by the bids of the *Aguieira* hydro unit alone.[8] Thereafter, EDP's units' gradually increased their bids above the level we consider would have been cost-reflective during the subsequent months. We have found no justification for the bids of *Aguieira* or of EDP units during this period. We think that these bids resulted in a reserve price that exceeded the competitive level.

Assessment of the market outcomes

We have also constructed an alternative set of hourly market outcomes using our estimates of the cost-reflective level of bids, and compared these alternative outcomes with the actual market results. Consistent with our previous findings, we find that CMEC hydro units could have provided a larger share of the regulation capacity, displacing other generation units. The displacement would have occurred mainly in the last quarter of 2009. Additionally, the units most affected would have not been other EDP units, but the units operated by REN Trading. The reserve prices under cost-reflective bidding would also have also been lower than what they actually were.

Quantification of the impact on the units providing secondary reserve

Finally, we have used our estimates of cost-reflective 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 during 2009.[9] We measure this impact based on the difference between the units' actual and estimated margins between revenues and costs. We have not included the costs of the uncommitted units providing secondary regulation, since we do not know the amount of reserve they provided.[10]

Our results suggest that the units' bidding behaviour only had an impact on their margins in the third quarter of 2009, since this is when we find that actual bids were above cost-reflective levels. Our main finding is that cost-reflective bidding would have led to lower prices mainly because we assume that more capacity would have been bid into the market. However, during most of the first three quarters of 2009, the actual prices seem to reflect the costs of those units which did participate in the market, and both the actual bids and the actual allocation of reserve capacity are similar to our cost-reflective estimates.

[8] Aguieira is a hydro unit that belongs to EDP, but was operated by the Spanish company Iberdrola between April 2009 and March 2014.

[9] We can only quantify the impact during 2009 because of the data limitations.

[10] We have verified that the generation schedules of uncommitted units were commonly modified in order to provide secondary reserve.

If we consider only the variations in the quantity provided, we estimate that EDP's non CMEC units would have been €2.9 million better off with cost-reflective bidding than in the actual world, under our base assumptions (including a risk premium of 10 €/MW). Although we estimate that the units would have provided less reserve with cost-reflective bidding, their costs would have decreased more than their revenues, and so they would have earned higher margins. Our finding does not vary greatly for different assumed values of risk premium We also estimate that, under our base case assumption on costs, the CMEC units would have been around €5.1 million better off with cost-reflective bidding, because they would have provided more secondary reserve.

If we consider price effects as well as quantity effects, we estimate that in 2009 EDP's non-CMEC units' margins would have been between €12.9 million (including a 10 €/MW risk premium) and €24.9 million (no risk premium) lower with cost-reflective bidding. This result is mostly explained by the difference between these units' price and costs in the fourth quarter. EDP's CMEC units would also have earned between €0.8 and €2.6 million less with cost-reflective bidding. The impact is small, despite the fact that we estimate they would have provided much more reserve, because the increase in the quantity of reserve provided is offset by a reduction in the price they would have been paid for providing that reserve.

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, as set out in the *Despacho* 4694/2014, of 1 April 2014, from the Office of the Portuguese Secretary of State for Energy. This is the third report of this engagement and is an optional deliverable requested by the Monitoring Committee.

The objective of this report is to extend the analysis carried out in the first deliverable to cover the period July 2007 to December 2009. These analyses are aimed at assessing and quantifying the impact of any potential distortions on the market for secondary reserve because of the way in which the units covered by the *Custos para a Manutenção do Equilíbrio Contratual*, CMEC, participated in this market.

The analysis contained in this report is based on the same principles, analytical frameworks, methodologies and assumptions developed in and for our First Report. Accordingly, we do not describe our approach in detail in this report.

Although the market for secondary reserve was created in the second half of 2007, REN only began providing public information on the market through its web platform in May 2009. REN has confirmed that the information available before then had to be recovered from the market interim systems. Consequently, the information relating to the period before May 2009 is incomplete and may not be fully consistent with the rules laid down in the manuals of procedures.[11] We have adapted our analysis in consideration of these limitations. [12]

The report is structured as follows:

- section III reviews the operation of the secondary reserve market before 2010 and highlights some features that are relevant for the subsequent analysis;

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[11] We have asked REN whether it is possible to obtain any more information for the period prior to 2009 but REN has replied that there is no possibility of compiling further information relating to this period.

[12] For instance, the *Manual De Procedimentos Do Gestor Do Sistema*, diciembre 2008, 1.7.2: Para o estabelecimento dos níveis de reserva de regulação secundária ter-se-ão em consideração os critérios e recomendações que sejam publicados para estes efeitos pela UCTE.

- section IV assesses the risk of over-compensation based on the actual bidding behaviour of market participants and a comparison between the actual behaviour of units and our estimates of their cost-reflective behaviour;
- finally, section V quantifies what this over compensation might have been based on our estimations of the quantity and cost of providing reserve.

III. The Secondary Reserve Market before 2010

In our First Report we described the secondary reserve market and discussed the concerns about the secondary reserve market between 2010 and 2013 that led to the *Despacho* 4694/2014. This section discusses the secondary reserve market between its creation and 2010 and identifies some features of the market during this period that are relevant for the rest of our analysis.

The market for secondary reserve market was created in the second half of 2007 in the context of the liberalization of the Portuguese wholesale electricity market. The rules governing the market for secondary reserve were approved in August 2007, together with other significant regulations necessary for the operation of a liberalized system.[13,14] Therefore, this study covers the first years of operation of the market. Consequently, it covers a period when both REN and the market agents participating in the market were gaining experience about how the market would operate. For this reason, it is unsurprising that the market changed over the period.

Before the opening up the market, REN operated the Portuguese Mainland electricity system centrally, dispatching the power plants as necessary in order to provide the required energy and power in real time. Most plants were covered by Power Purchase Agreements, PPA, which governed the compensation to those plants for the services provided.[15] Therefore,

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13 The market for secondary reserve was govern by the Manual of System Operator's Procedures (*Manual De Procedimentos Do Gestor Do Sistema*), approved by the *Despacho* n.º 17744-A/2007, of 10th of August.

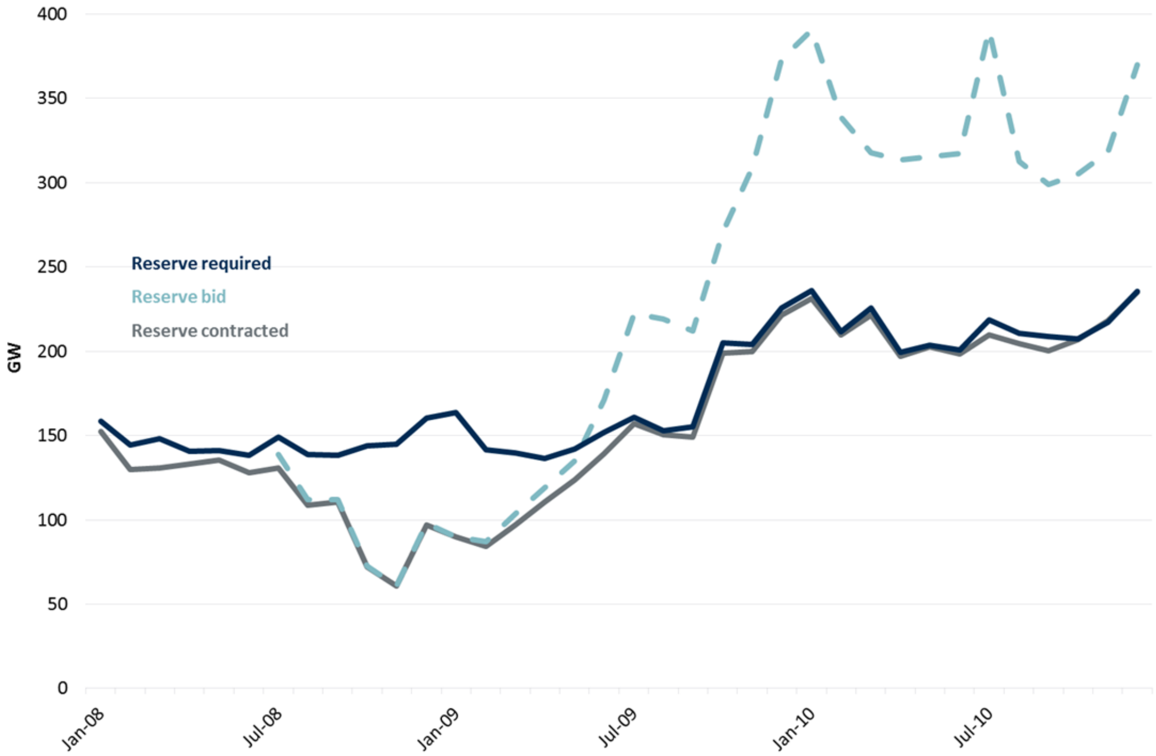
14 The *Despacho* n.º 17744-A/2007 also approved other relevant regulations, such as the System Operation Code (*Regulamento de Operação das Redes*), Manual of Settlement Procedures (*Manual de Procedimentos do Acerto de Contas*), Manual of the Commercial Agents' Procedures (*Manual de Procedimentos do Agente Comercial*), and modified, among other, the Connection and Grid Access Code (*Regulamento de Acesso às Redes e às Interligações*).

15 A smaller part of the electricity system, which was not covered by PPA, made up the so-call *Independent Electricity System*, and was not bound by public service obligations.

before 2007 there was no need for, or experience of, managing a specific market to procure secondary reserve market.

The first noteworthy feature is that until July 2009 the amount of reserve bid into the market was insufficient to meet REN's reserve requirements, as shown in Figure 1. In November 2008, for instance, REN could only contract around 42% of the secondary reserve it required.

Figure 1: Secondary reserve: requirement, bids and allocation

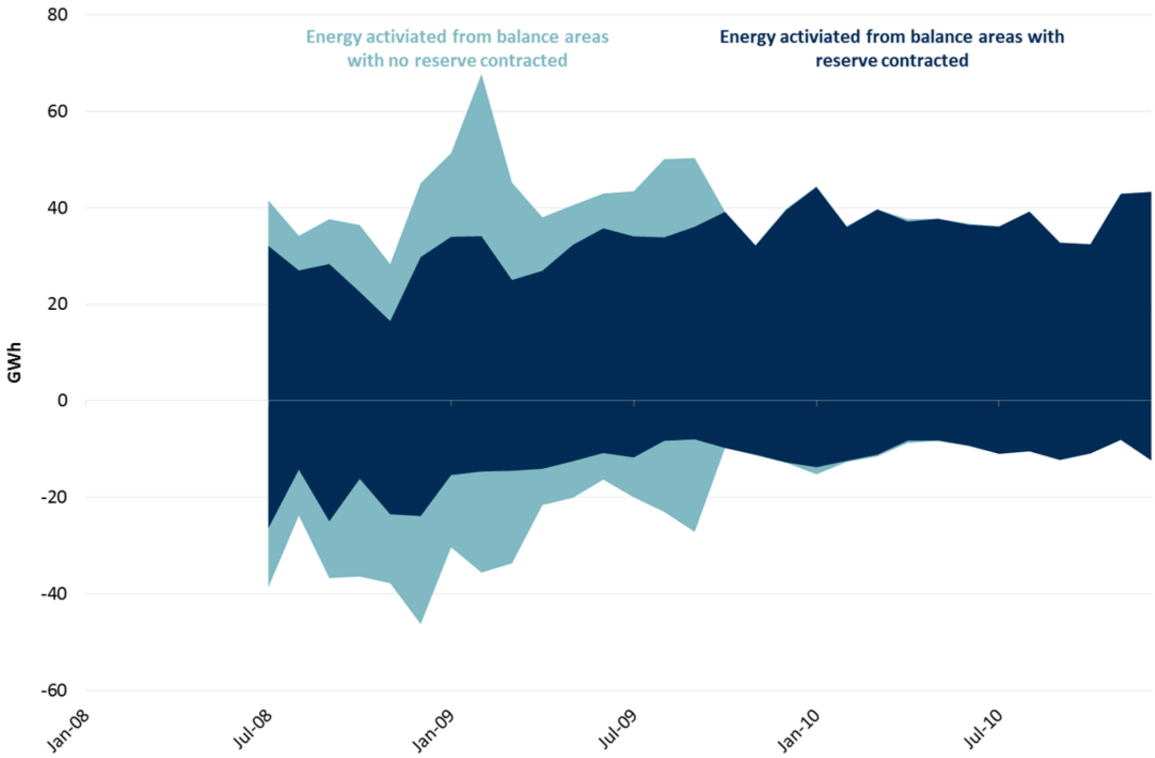


Source: The Brattle Group, from data from REN.

Three months after the level of reserve bid began to exceed the level required, in October 2009, REN increased by 32% the amount of secondary reserve it wished to procure from the market. REN has informed us that it increased its reserve requirements in response to complaints regarding the quality of its frequency regulation which it received from neighbouring TSOs. It is simply a coincidence that the increase in the reserve requirement occurred at the same time as the end of the transition period.

However, even when REN could not procure all the secondary reserve it requested in the market, it was still able to obtain the secondary regulation it required. It managed to do so by dispatching units outside of the reserve markets ("uncommitted" units). In the first half of 2009, at least 34% of the upward secondary regulation energy was provided by such uncommitted units.[16] REN continued to use uncommitted units to provide reserve until October 2009, even though it could have contracted all its requirements in the market from July 2009. Figure 2 shows the amount of secondary regulation energy provided by balance areas in which at least one unit had sold secondary reserve in the market, and by balance areas with no unit providing reserve.

Figure 2: Energy activated from secondary reserve



Source: The Brattle Group, from data from REN.

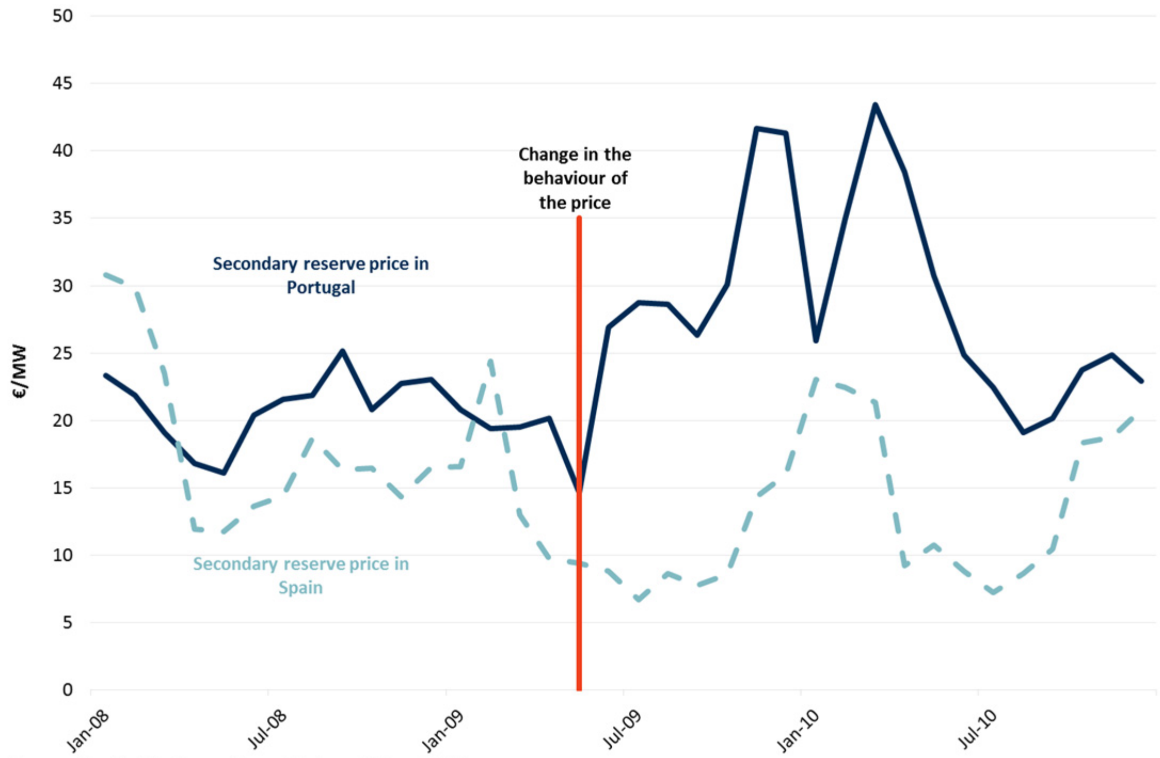
The System Operator regulations in force in 2009 allowed REN to procure reserve outside the market if the market depth was insufficient to satisfy its demand. REN has confirmed that during the transitional period the units that provided reserve without a previous reserve allocation in the market did not receive any remuneration for this capacity. These units were covered by the CMEC and REN claims that the CMEC arrangements meant that there was no benefit to CMEC units of being remunerated for providing secondary reserve.

Finally, there was also a noticeable change in the secondary reserve price from June 2009 onwards. The price increased from an average of 18.9 €/MW between January 2008 and May 2009 to 32.0 €/MW; there was no corresponding change in the secondary reserve price in

16 This figure may be higher because it does not include the regulation provided by units that did participate in the reserve market but are located in balance areas where at least one unit was committed to provide reserve.

Spain so the prices in the two markets started to deviate significantly. Figure 3 shows the secondary reserve monthly average price in Portugal and Spain between 2008 and 2010.

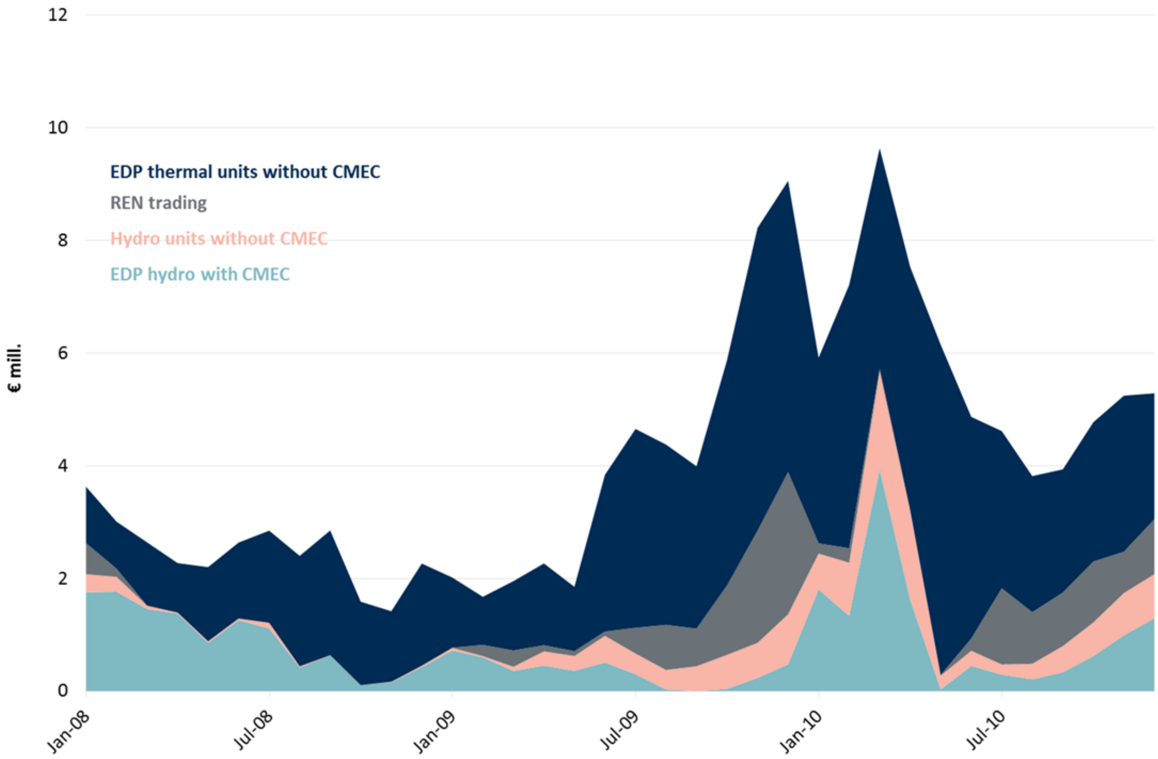
Figure 3: Secondary reserve prices in Portugal and Spain



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

As a consequence of the increase in the price and of the amount of reserve contracted in the market, the monthly cost to the electricity customers of the secondary reserve service more than doubled, as can be seen from Figure 4.

Figure 4: Revenues in the secondary reserve market



Source: The Brattle Group, from data from REN.

IV. Assessment of the Behaviour of the Market

Our assessment of the behaviour of the market and the risk of over-compensation during the period analyzed in this report is mainly based on a comparison between the actual behaviour of the generating units in the market and our estimates of what their efficient (competitive) behaviour would have been, based on a series of assumptions on the technical and economic characteristics of the units. Because of the particularity of the secondary reserve market before 2010, we have also carried out additional analysis to support our assessment. We use these analyses to judge if there is any evidence that EDP, in practice, modified the operation of its units.

Our results suggest that both units with and without CMEC participated less in the reserve market than would be consistent with their capacity to provide reserve during 2009. Market participation did, however, increase significantly from the point at which the reserve market price increased in June 2009.[17] Although this increase was initially caused by the bids of a single unit, it was followed by an increase in the bids of most units.

[17] Market participation had begun increasing somewhat earlier in 2009 but to a much lesser extent.

The low level of participation in the market of hydro units with CMEC cannot be explained by a wish to make room for EDP's other units to provide reserve for two reasons.[18] First, because REN was unable to contract for all the reserve it wanted in the market, and so EDP could have increased the amount bid by its CMEC units without affecting the extent to which its other units would have been contracted. Second, because EDP's non-CMEC thermal units also offered less capacity to the market than the capacity we estimate they had available, thereby limiting the revenues that they could have earned from providing reserve. Instead, this behaviour would be consistent with the suggestion in our First Report that CMEC units could be incentivised not to participate in the secondary reserve market if the annual adjustment of the CMEC did not include any allowance for the potentially increased costs they might have incurred while providing secondary reserve. We acknowledge that it is not obvious whether the costs of the hydro units would have been increased by providing reserve but it is at least possible that the hydro units feared this would be the case.

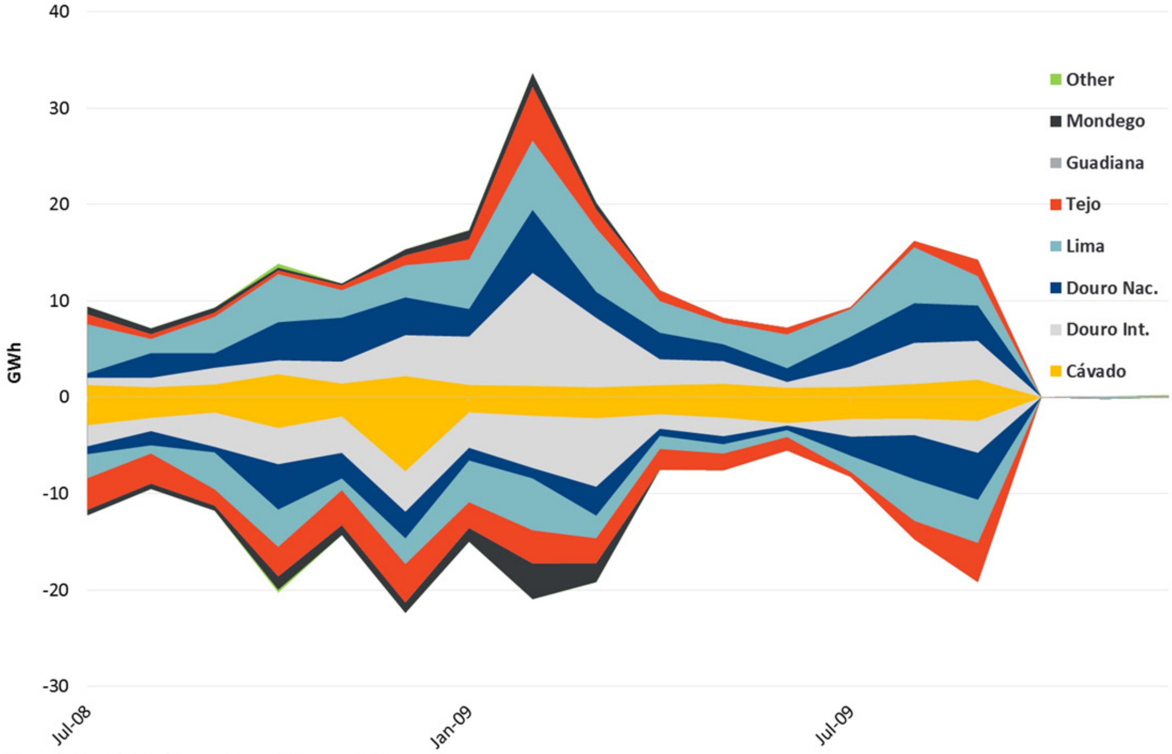
IV.A. Assessment of the Quantity Offered to the Market

In section III, we identified that, until July 2009, REN was unable to procure all its secondary reserve requirements in the market. Since REN made up the shortfall from capacity that had not been offered to the market, there can be no doubt that the units offered less reserve capacity than they had available.

In order to identify which units were not participating fully in the market, we analyse first the secondary regulation energy provided outside the market. We find that the capacity dispatched to provide secondary regulation belonged almost exclusively to hydro units with CMEC. Hydro units have lower operating constraints, since they have shorter start-up times and faster ramp-up rates, and therefore may be a valuable resource of upward regulation in emergency situations. On the other hand, thermal units can provide emergency downward regulation as efficiently as hydro units and upward regulation given sufficient warning. Consequently, the fact that REN only relied on hydro units does not seem justified. This is particularly the case since the need for uncommitted plants to provide regulation was known. Figure 5 shows the breakdown of secondary regulation energy from uncommitted balance areas.

18 As noted in our First Report, CMEC units are pivotal suppliers of secondary reserve – without their reserve capacity there is not enough reserve capacity to provide the required regulation service – and therefore any increase in supply does not imply a reduction in the price.

Figure 5: Secondary reserve Energy from un-contracted capacity, per balance area



Source: The Brattle Group, from data from REN.

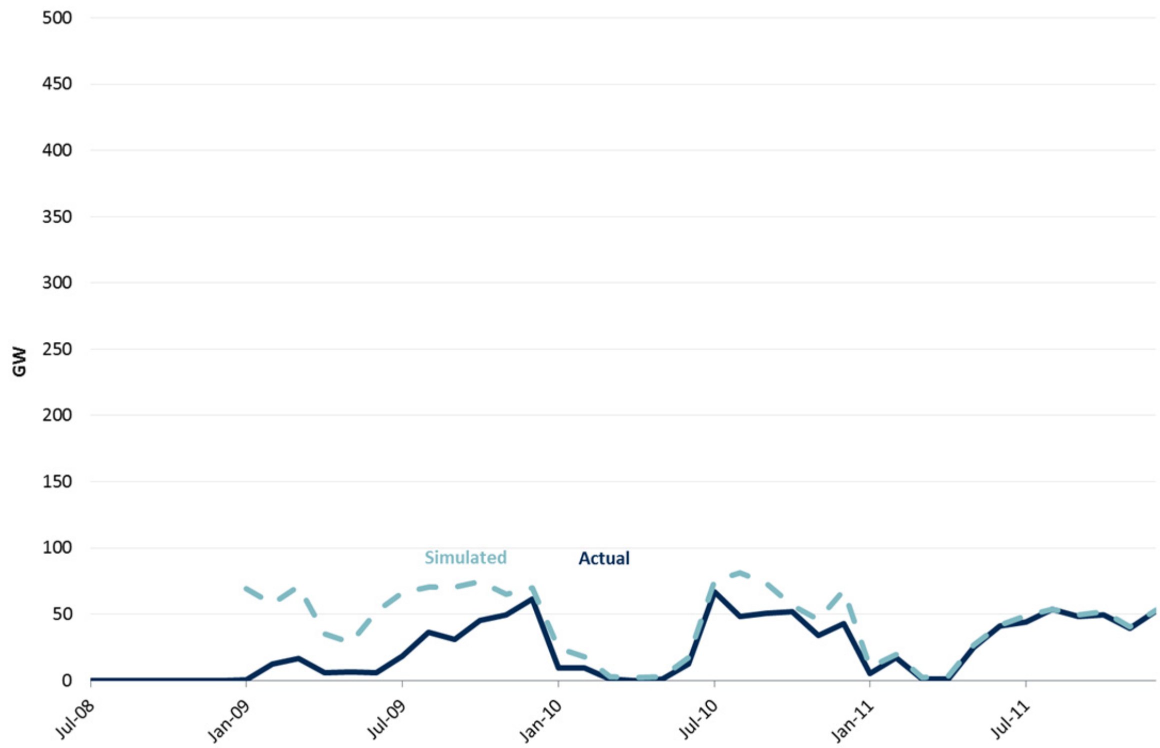
We have also analysed the supply of secondary reserve capacity to the market. We have compared the actual reserve bid into the market with our estimate of the reserve capacity really available. We find that all units, not just those covered by the CMEC, seem to have offered less capacity than they had available to provide secondary regulation – as can be seen for - CCGTs (Figure 6), coal units (Figure 7) and hydro units (Figure 8 and Figure 9).[19] We have included data to the end of 2011 to demonstrate that during the period after 2009, our estimates for most plant types are broadly comparable to the capacity actually bid into the market.

19 The coal units correspond to the two groups of the Pego power plant.

Figure 6: Secondary regulation reserve offered to the market by CCGT units

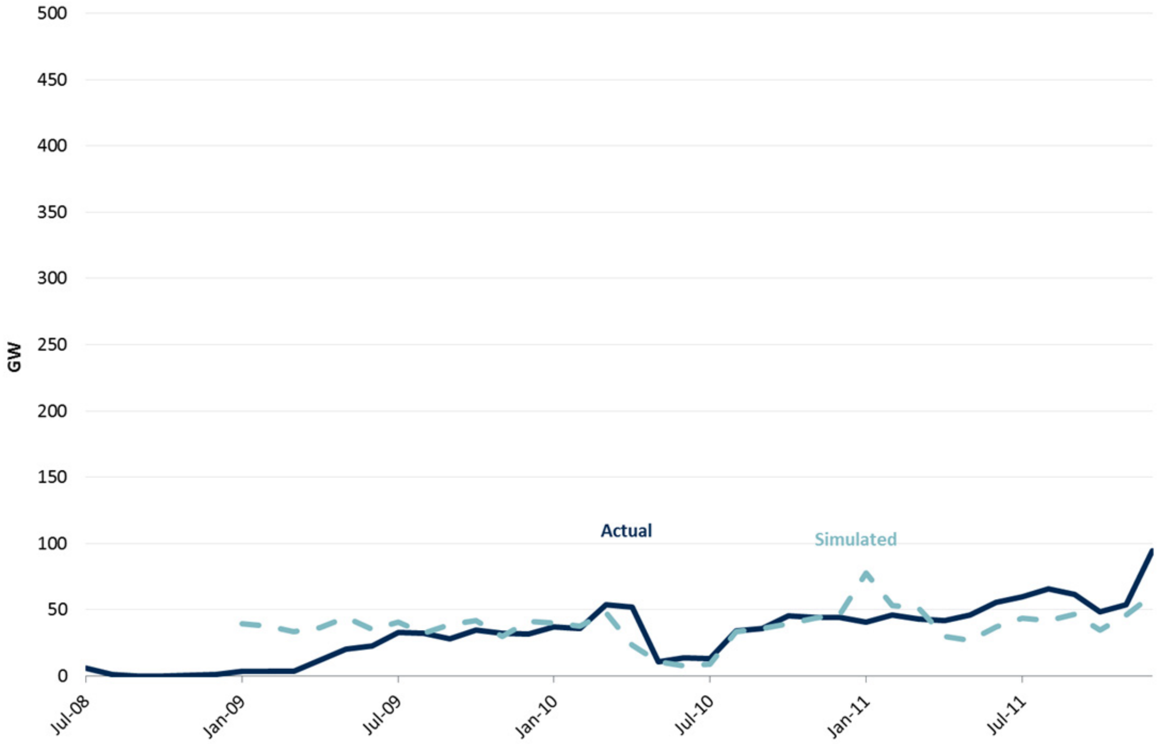
Source: The Brattle Group, from data from REN and own elaboration.

Figure 7: Secondary regulation reserve offered to the market by coal units



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

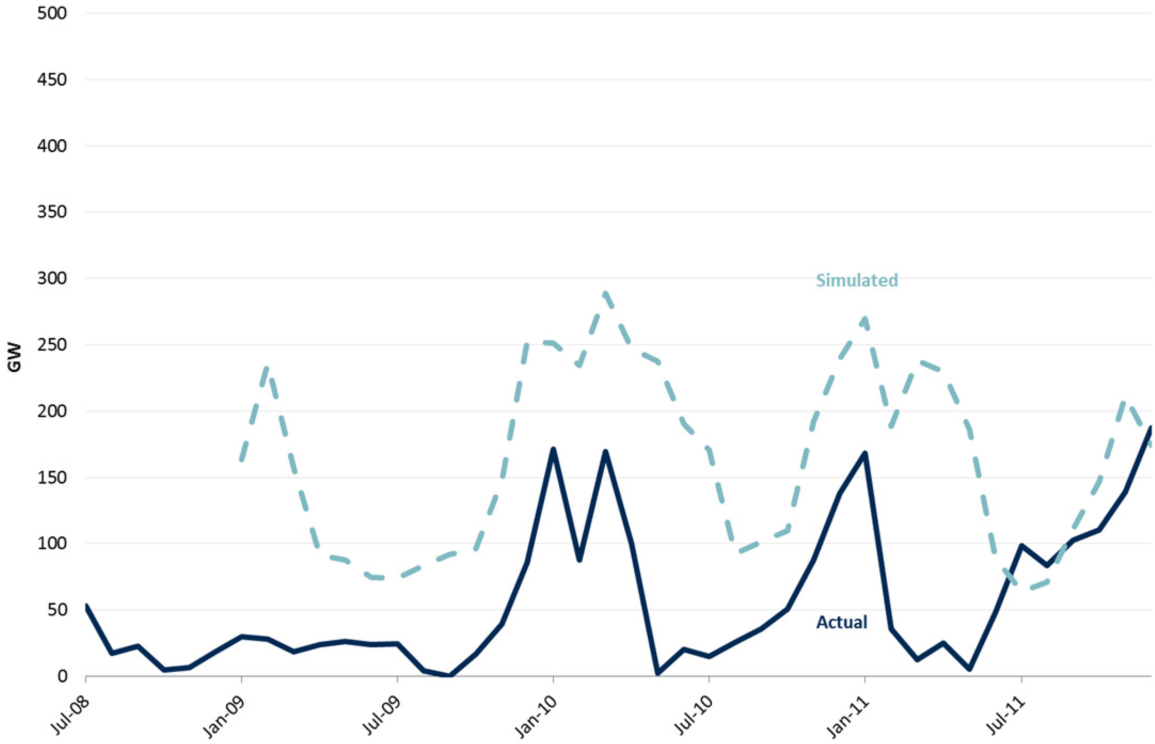
Figure 8: Secondary regulation reserve offered to the market by hydro units without CMEC



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

However, while for non-CMEC units the gap between the reserve actually offered to the market and our estimation of available reserve narrows by 2010, as discussed in our First Report, hydro units with CMEC continued to offer less capacity that we estimate they had available (Figure 9 below).

Figure 9: Secondary regulation reserve offered to the market by hydro units with CMEC

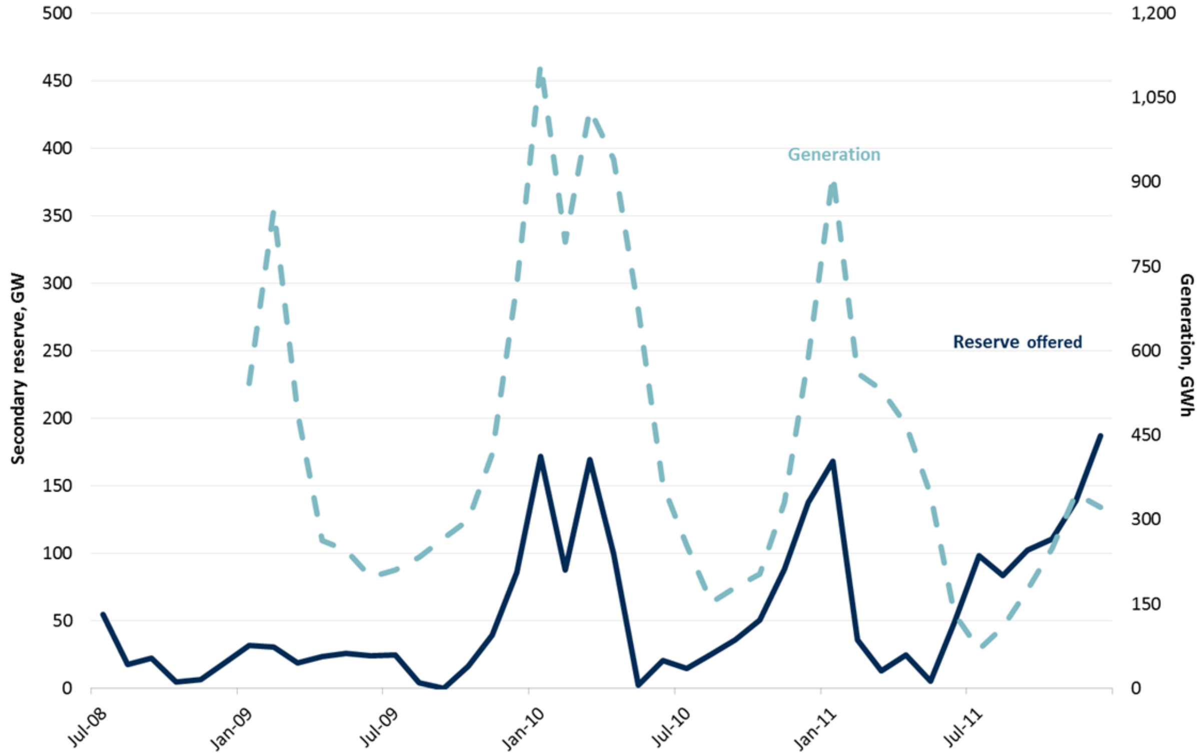


Source: The Brattle Group, from data from REN and own elaboration.

Finally, we have developed an additional way of determining whether the actual capacity offered to the market was consistent with the capacity that should have been available. We compare the actual reserve offered to the market by a unit to its output. If a unit is generating the same amount of electricity at two points of time, it should, in theory, have roughly the same capacity to provide secondary reserve. We find that prior to 2010, with the exception of the hydro units without CMEC (Alqueva and, from April 2009, *Aguieira*), all the other types of units seems to have offered less secondary reserve to the market than their level of generation would suggest.

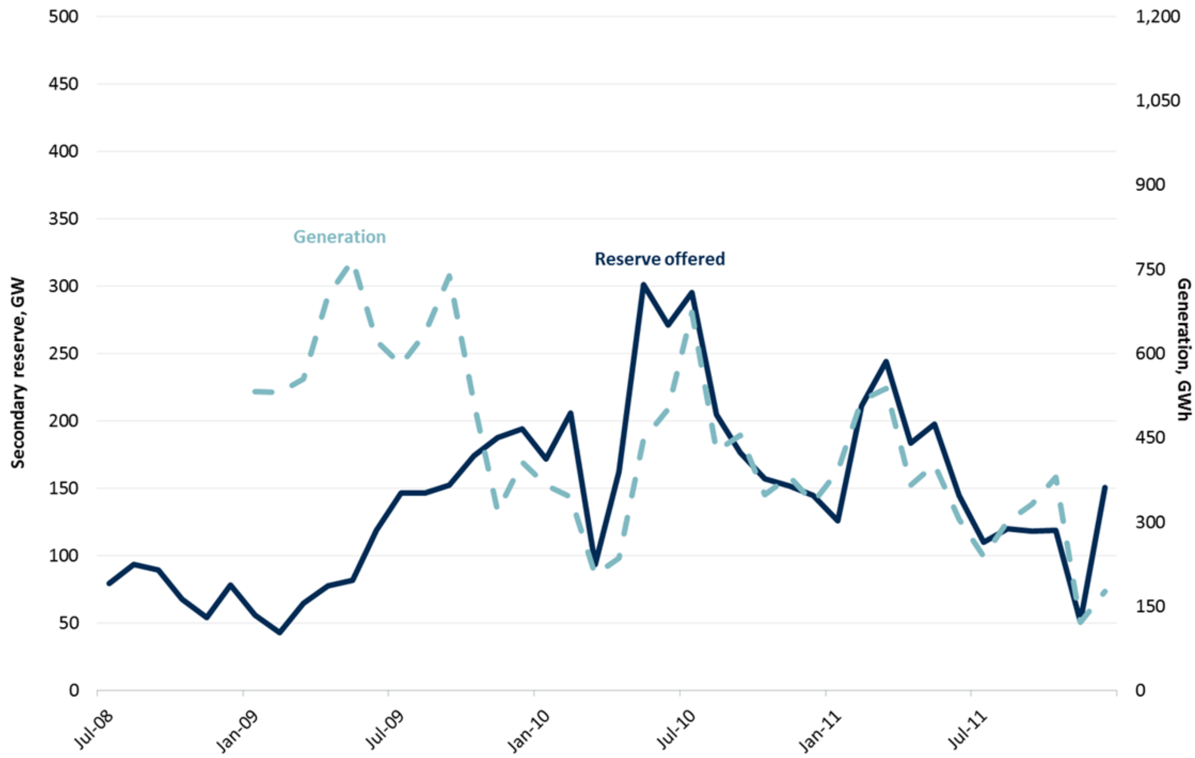
The following figures shows the evolution of the reserve capacity bid and the units' output, for hydro units with CMEC (Figure 10), CCGT units (Figure 11), coal units (Figure 12), and hydro units without CMEC (Figure 13). The coal units correspond to the two groups of the *Pego* power plant.

Figure 10: Generation and secondary reserve offered by hydro units with CMEC



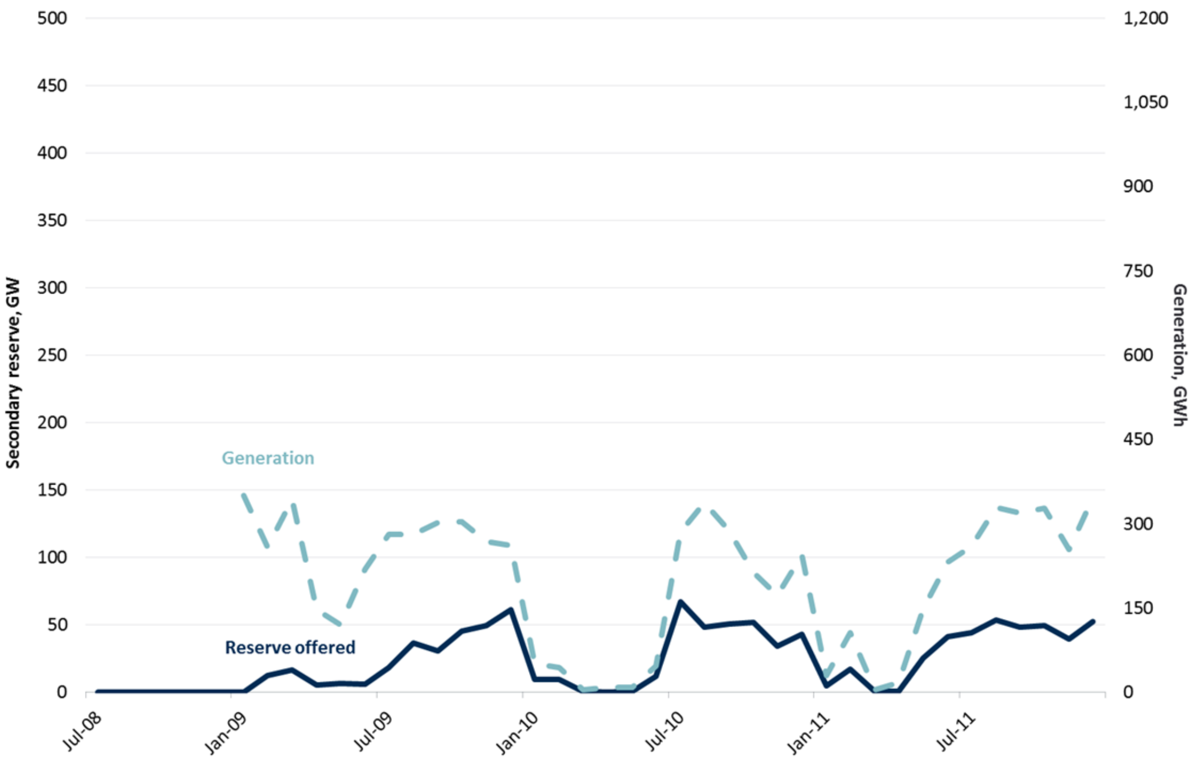
Source: The Brattle Group, from data from REN.

Figure 11: Generation and secondary reserve offered and provided by CCGT units



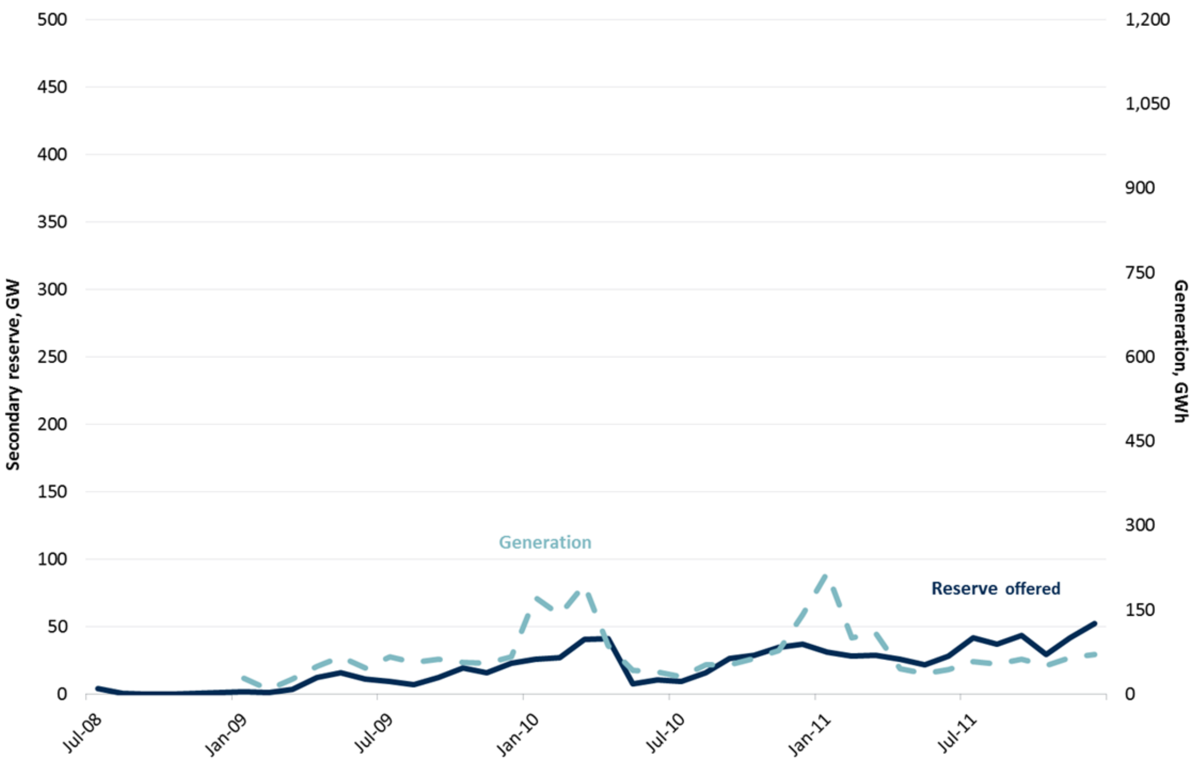
Source: The Brattle Group, from data from REN.

Figure 12: Generation and secondary reserve offered and provided by coal units



Source: The Brattle Group, from data from REN.

Figure 13: Generation and secondary reserve offered by hydro units with CMEC



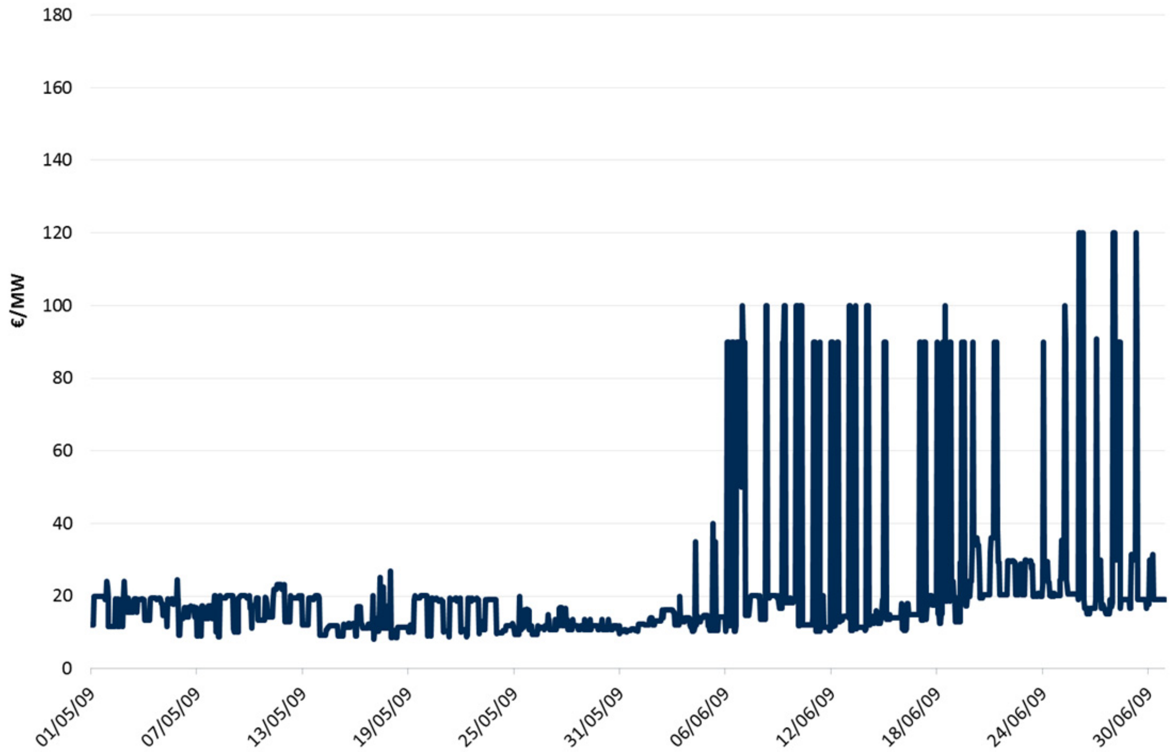
Source: The Brattle Group, from data from REN.

IV.B. ASSESSMENT OF BID PRICES

In section III, we identified that the secondary reserve market price underwent a structural change in June 2009. In order to investigate this effect, we have first examined the hourly secondary reserve market prices and bids at different times before and after June 2009. We have also estimated (on an hourly basis) the price that every unit should have offered for the secondary reserve capacity they had available. These estimates rely on the analytical framework laid out in our First Report. We have calculated aggregate average monthly bids for different types of units in order to compare the actual and simulated data on this aggregated basis.

As shown in Figure 14, the increase in the reserve price in June 2009 is due to a number of price spikes, with most hours in June 2009 still having price levels comparable to those in May 2009.

Figure 14: Secondary reserve price, May and June 2009



Source: The Brattle Group, from data from REN.

We have found that all the price spikes were due to the bids of *Aguieira*, a hydro unit that belongs to EDP but was operated by the Spanish company Iberdrola between April 2009 and March 2014. As shown in Figure 15, we can find no cost justification for the increase in *Aguieira's* bids during June 2009. We note that the bids of EDP's other units did not change substantially in June 2009 compared to their levels in previous months.

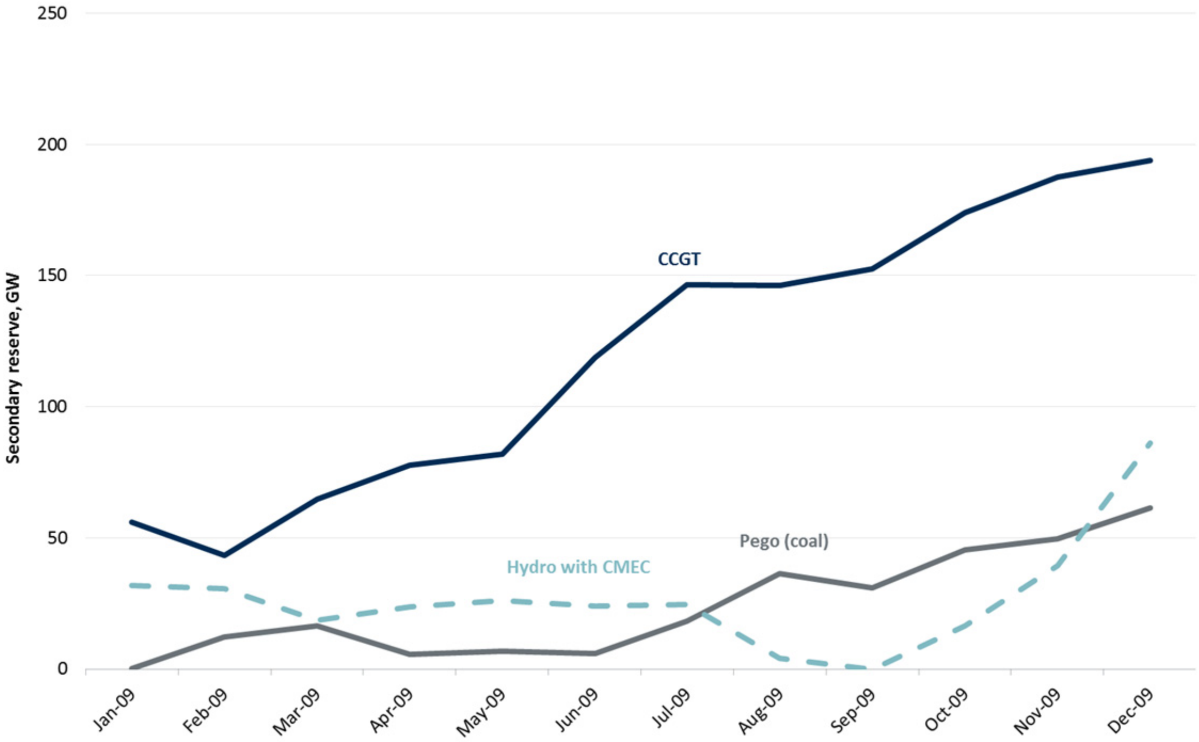
Figure 15: Average bids to the secondary reserve market by *Aguieira*, below 100 €/MW

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

Aguieira became the marginal unit in the market and set such a high marginal prices because of the lack of alternative bidders. Despite some growth in the overall secondary reserve capacity offered to the market (see Figure 16), REN could still not procure enough reserve in the market for 32% of the hours in June 2009.[20]

[20] The reserve allocated was lower than the reserve requirement in 230 out of 720 hours in June 2009.

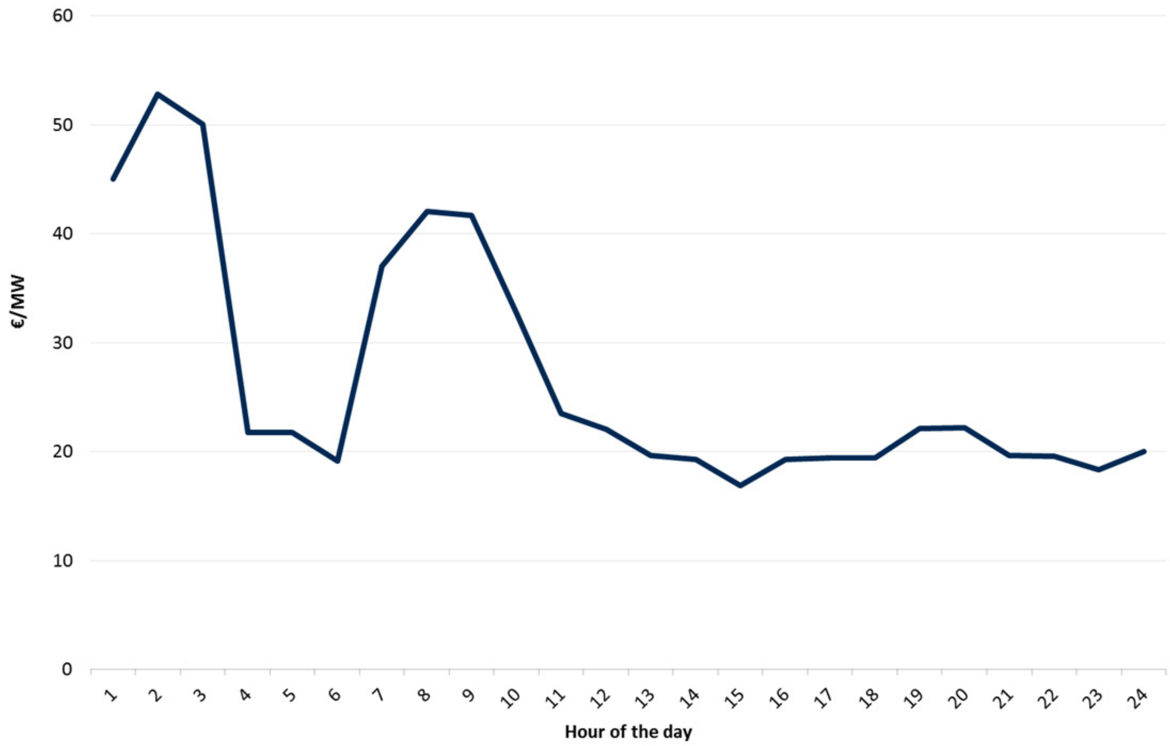
Figure 16: Secondary reserve capacity bid to the market



Source: The Brattle Group, from data from REN.

However, the amount of reserve bid into the market, and therefore the hours when *Aguieira* bids had an impact on the market price, was not evenly distributed across the day. Figure 17 shows the average price in June 2009 for each hour in the day, and demonstrates that the price spikes mainly occurred between 00:00 and 02:00 and 06:00 and 08:00.

Figure 17: Hourly average secondary reserve price in June 2009



Source: The Brattle Group, from data from REN.

These hours coincide with the transition from higher to lower demand hours. During these periods units are increasing or decreasing their generation level, which might affect their capacity to provide secondary reserve, at least for thermal units.[21] The cost of providing reserve at these hours would be also different from other hours, since the provision of reserve when a unit's output is changing might affect its ability to meet its generation schedule in adjacent hours.[22] Figure 19 shows the hourly generation of those CCGT and CMEC hydro units owned by EDP that were capable of providing secondary reserve during the last fortnight in June. It shows how these units ramp up and down in the hours when *Aguieira* was able to set the marginal price.

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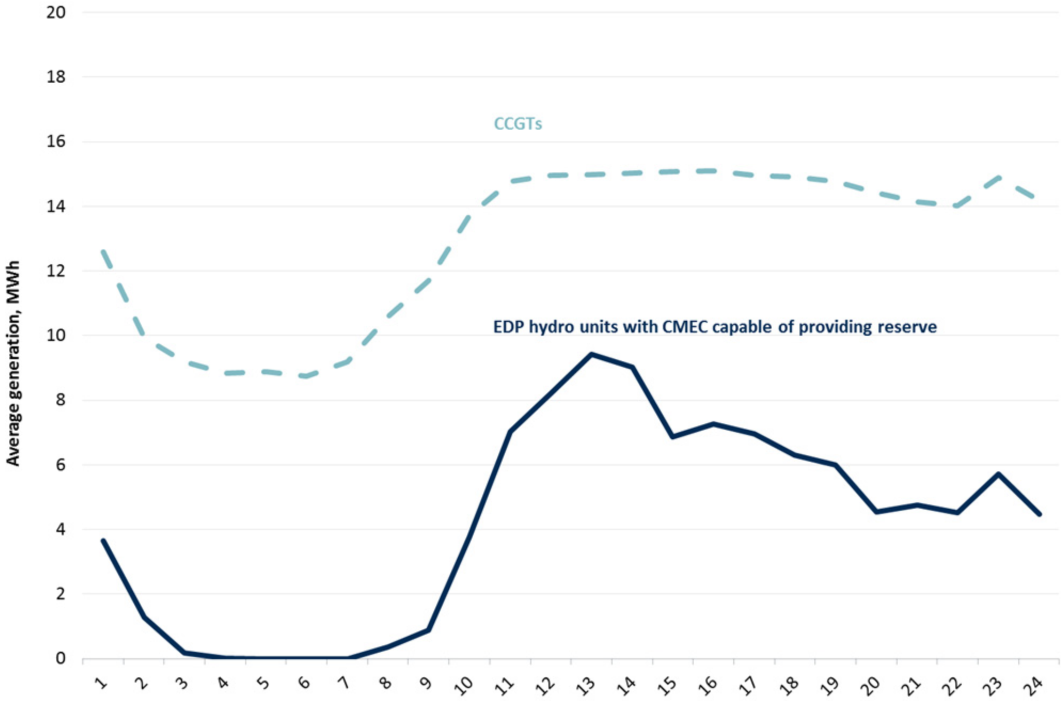
21 Secondary regulation is provided by increasing or reducing a unit's active power in response to a signal from the System Operator. If a unit is already increasing or decreasing its output, there is less remaining capacity to provide regulation.

22 This may imply some additional costs, such as the cost of imbalances or an additional opportunity cost the subsequent hours.

Figure 18: Average electricity generation of some unit in the second half of June 2009

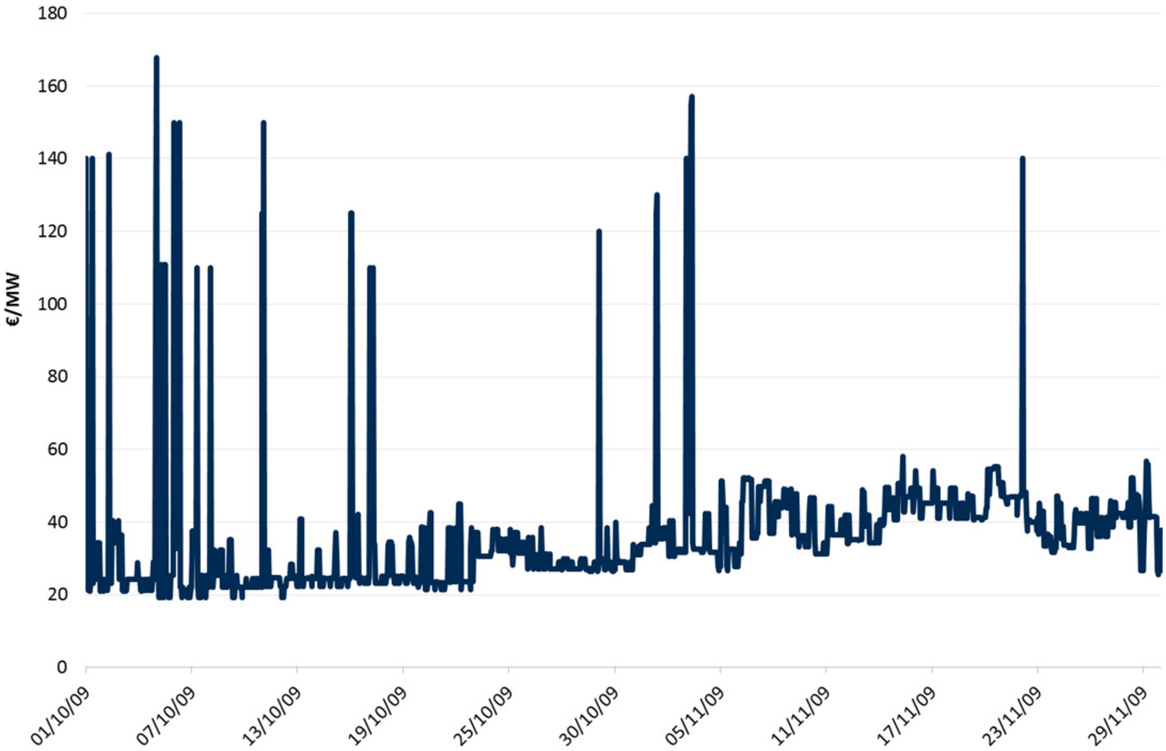


Source: The Brattle Group, from data from REN.

However, 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. We would expect competitive participants to respond swiftly to high market prices, increasing the supply to the market and hence ensuring that spikes did not keep on occurring. However, EDP did not increase its supply promptly when these price spikes occurred and its delay in responding to the price signals would be consistent with the hypothesis that it was obtaining rents from *Aguieira's* behaviour.

The number of price spikes decreased over the following months. However, the average price stayed at about the same level because the prices in the remaining hours increased, as shown in Figure 19.

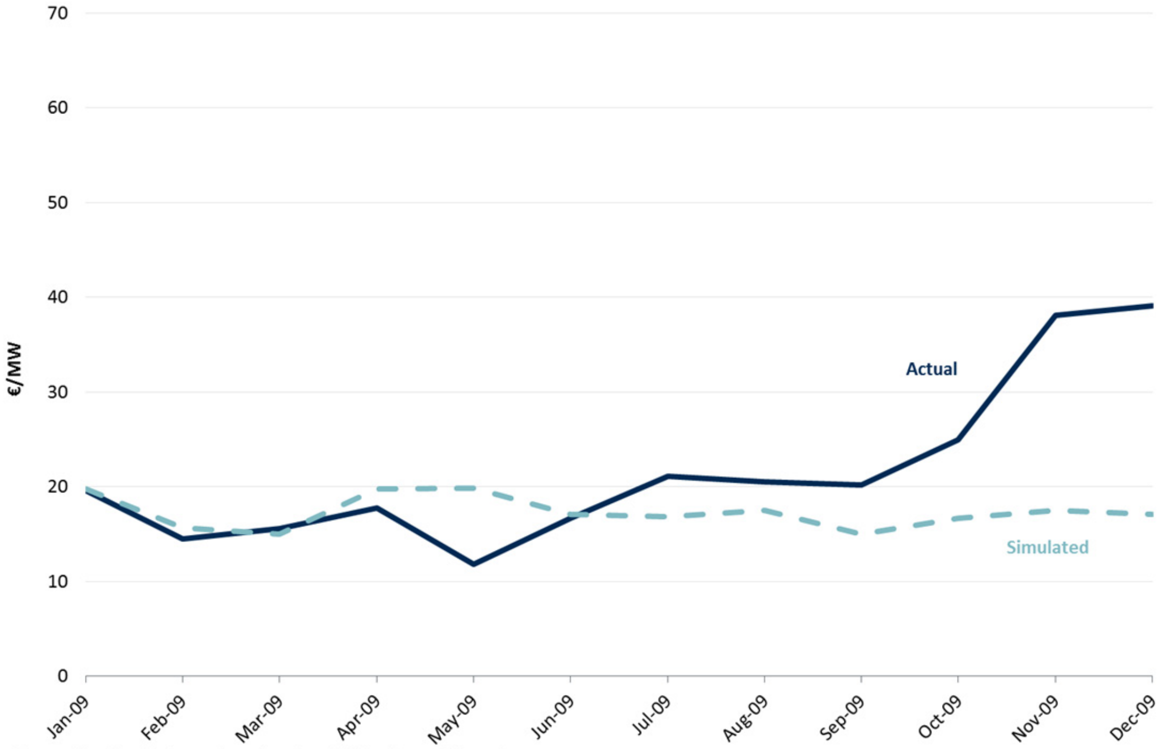
Figure 19: Secondary reserve price, October and November 2009



Source: The Brattle Group, from data from REN.

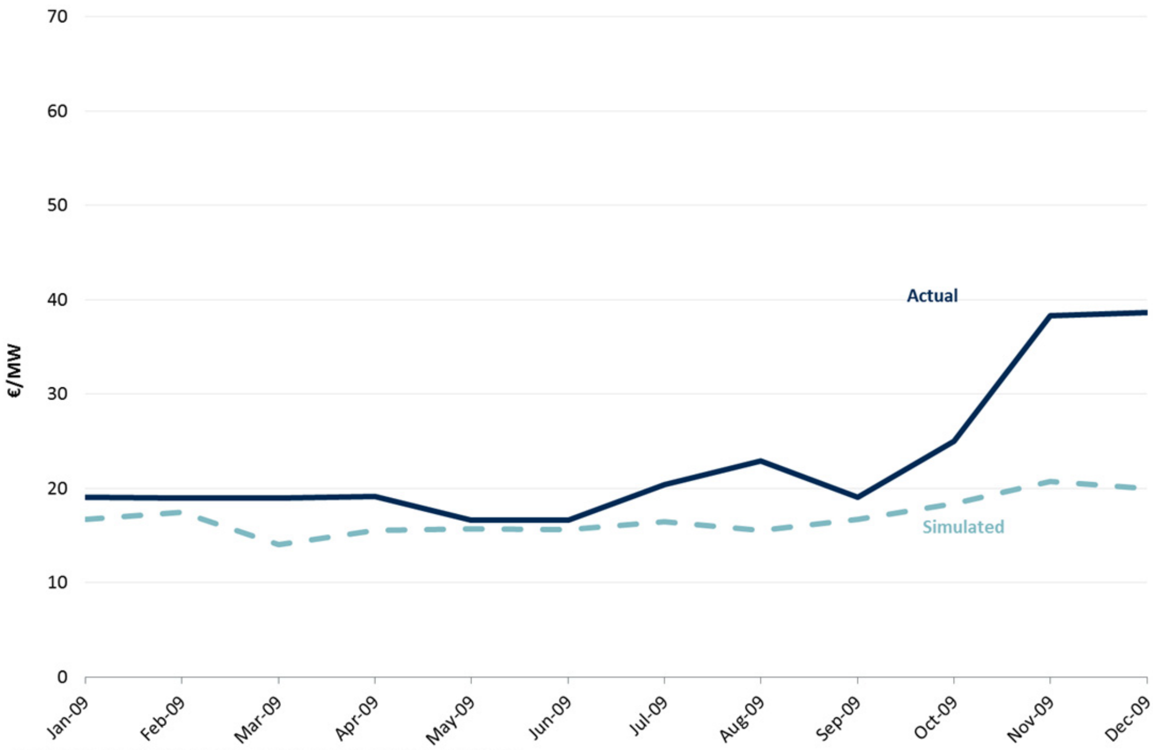
The increase in hourly prices from the end of October was due to increases in the bids of all other units, except for the *Pego* coal unit operated by REN Trading. We have found no cost justification for the increase in the bids. The following figures compare the monthly averages of the actual bids with prices below 100 €/MW and our simulated bids, weighted by the capacity offered, for CCGT units (Figure 20), hydro units without CMEC (Figure 21) and hydro units with CMEC (Figure 22).

Figure 20: Average bids to the secondary reserve market by CCGT units, below 100 €/MW



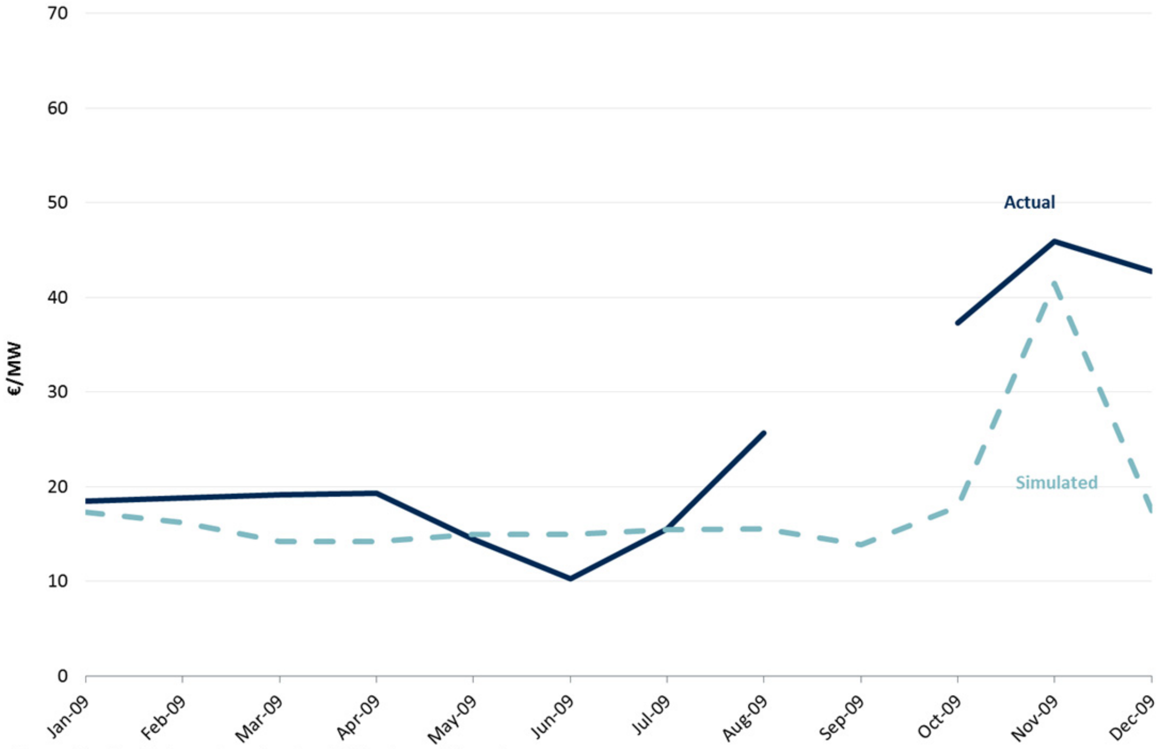
Source: The Brattle Group, from data from REN and own elaboration.

Figure 21: Average bids to the secondary reserve market by Alqueva unit, below 100 €/MW



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

Figure 22: Average bids to the secondary reserve market by CMEC units, below 100 €/MW



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

IV.C. Assessment of the market outcomes

We have estimated an alternative set of hourly market outcomes using our estimates 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.

We first simulated the cost-reflective market outcome assuming that the overall amount of secondary reserve allocated in the market would have been as that actually provided, rather than the reserve requirements posted by REN. We have also simulated what would have been the price and the reserve allocation assuming that REN reserve demand was fully met and found the results do not vary significantly.

As in the case of the previous comparisons, our 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 that can be used to assess the units' bids.

Consistent with the findings presented in the previous sections, our results suggest that hydro units with CMEC could have provided a larger share of the regulation capacity than they actually did and, if they had done so, they would have displaced other generation units.

According to our estimates, the units most affected would have been the two units of the *Pego* coal power plant. EDP's units without CMEC would only have been affected significantly in the second quarter of 2009. During this quarter, however, there was a significant amount of unmet demand for reserve capacity, so even if the hydro units had provided more reserve they could have sold their reserve capacity if they had wished to do so. Table 6 shows the difference between our estimates of reserve allocation and the actual allocation.

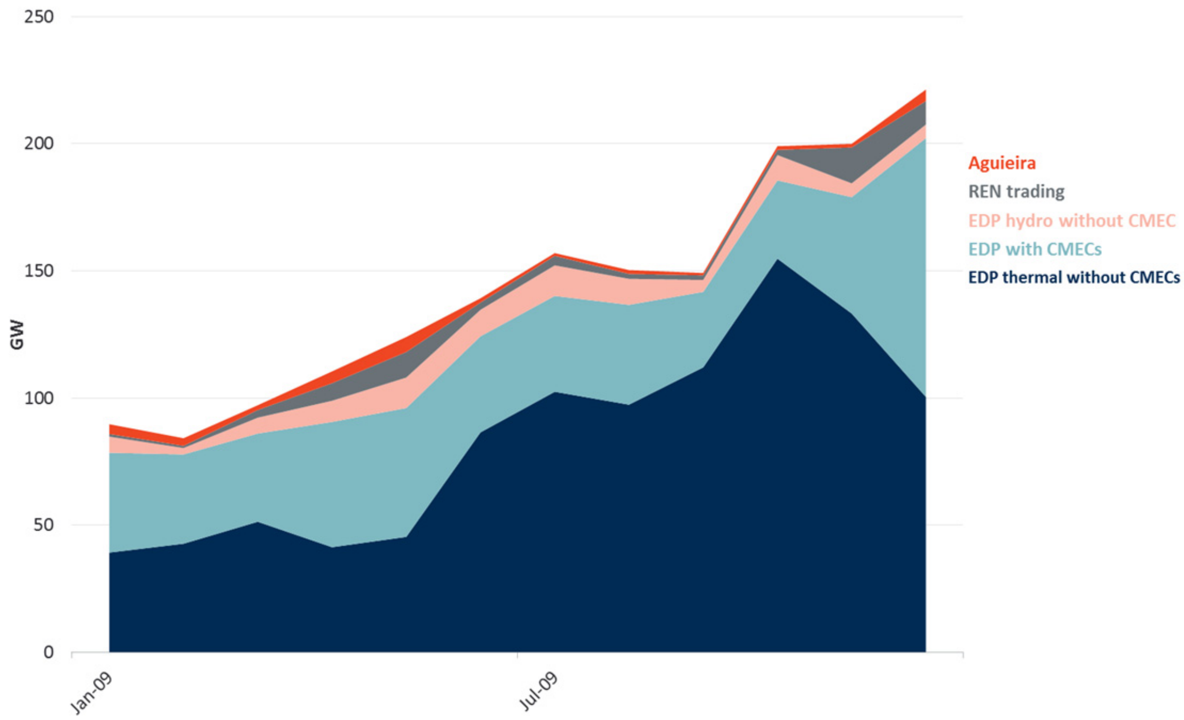
Table 1: Estimated minus actual secondary reserve allocated in 2009

Unit	Q1 GW	Q2 GW	Q3 GW	Q4 GW	Total GW
EDP with CMEC	40	70	91	161	363
EDP without CMEC	-18	-66	-4	-11	-99
REN Trading	-22	5	-73	-129	-220
Others	0	-9	-15	-21	-45
Total	0	0	0	0	0

Source: The Brattle Group.

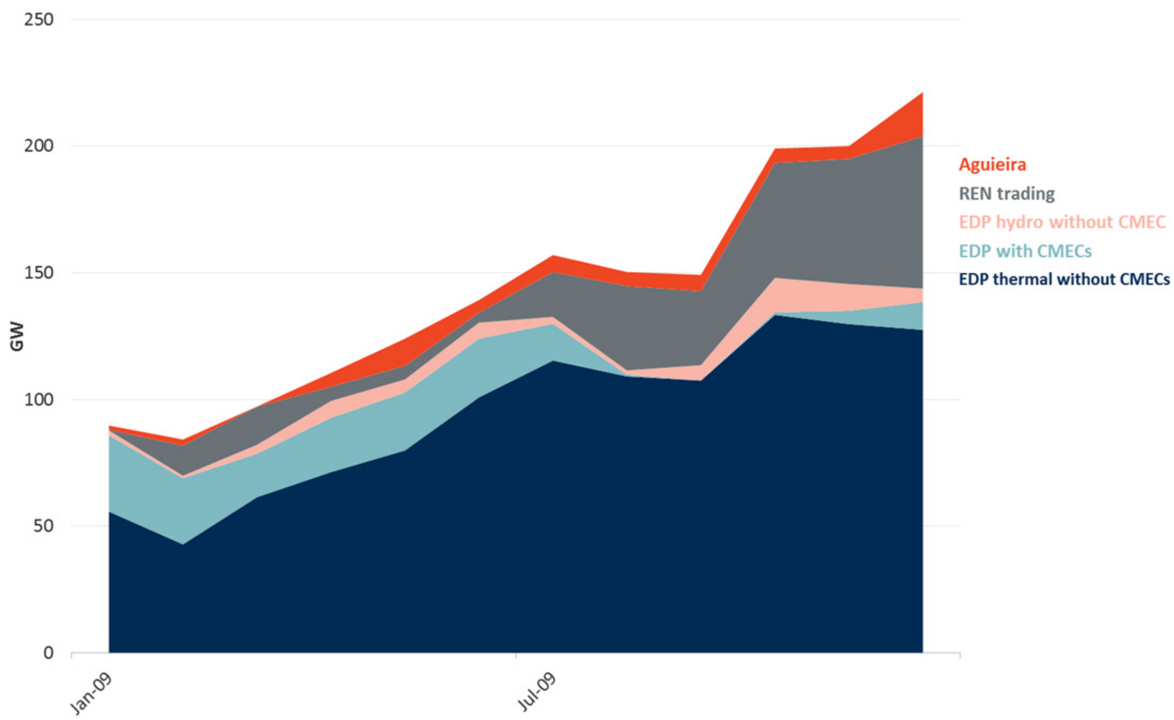
Figure 23 shows our simulated allocation of secondary reserve, while Figure 24 shows the actual reserve allocation.

Figure 23: Simulated monthly allocation of secondary reserve



Source: The Brattle Group.

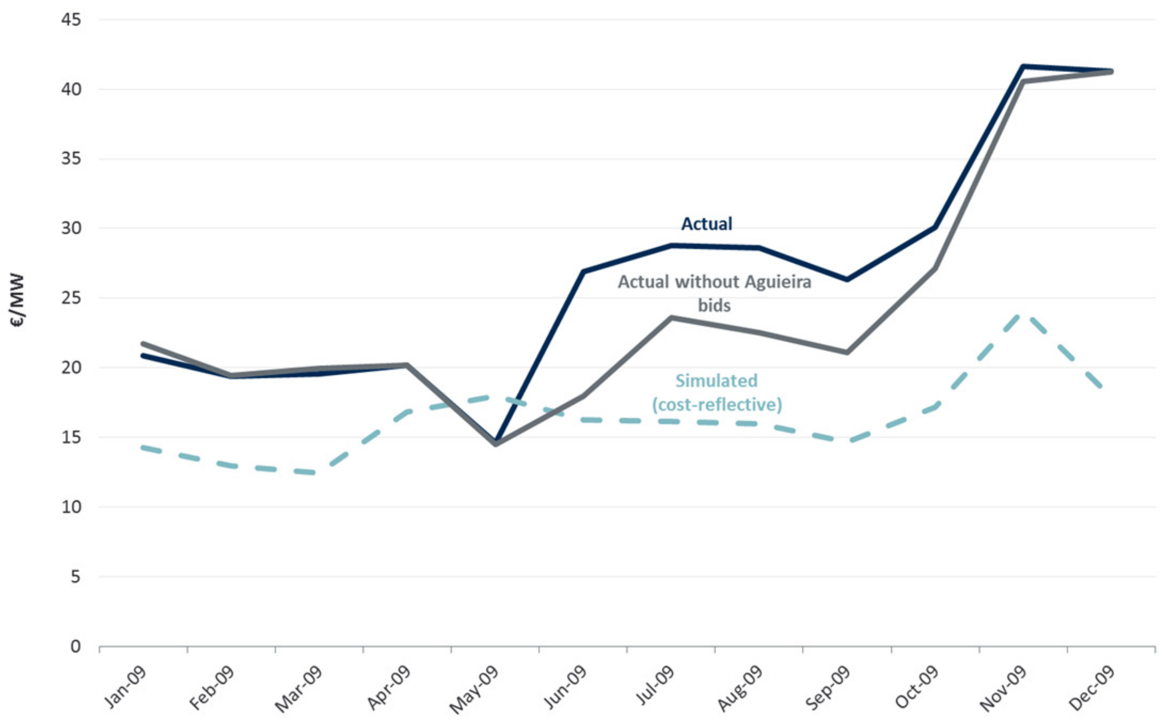
Figure 24: Actual monthly allocation of secondary reserve



Source: The Brattle Group, using data from REN.

Our simulation of a cost-reflective outcome also shows a significant reduction in market prices, see Figure 25. In this figure, we have also included our estimate of what the price would have been without the high *Aguieira* bids.

Figure 25: Simulated and actual monthly average price of secondary reserve



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

V. Quantification of the Potential Over-Compensation

We have used our estimates 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 providing secondary reserve. Note that we can only quantify the impact during 2009 because of the data limitations described in section II. Consistent with our findings in previous sections, we estimate that this impact would only have been significant in the second and third quarter of 2009.

In making these calculations, we have not included the costs of the units that provided reserve outside the market, since we do not know the amount of reserve they provided and we have focused on the case where the overall amount of secondary reserve allocated in the market is the same the actual allocation.

The estimated impacts combine the effect on the secondary reserve prices and the allocation of reserve of three different factors: *i*) the impact of the low level of participation in the secondary reserve market by most units; *ii*) the impact on prices of *Aguieira's* bidding behaviour; and *iii*) the impact on prices of EDP's non-CMEC units' bidding behaviour. Therefore, these impacts are not entirely attributable to the bidding behaviour of EDP units with CMEC.

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. A positive impact implies that the units made a larger margin in the actual world than we estimate they could have made with cost-reflective bids. The margin is given by the difference between the revenue and the cost of a unit.[23]

V.A. Quantity effect

The quantity effect includes only takes account of changes in the units' margins due to changes in the amount of secondary reserve we assume they would have provided under a cost-reflective scenario. We use the actual market prices for secondary reserve to calculate both the actual and alternative margins.

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

If we consider only the quantity effect, we estimate that, with our base case assumption of a 10 €/MW risk premium, the margin made by EDP's non-CMEC units would have been €2.9 million higher with cost-reflective bidding than they were in reality.[24]. Although these units would have provided 8% less secondary reserve, we find that the reduction in their costs would have been higher than the reduction in the revenues they would have obtained. This result does depend significantly on our risk premium assumptions because the secondary

23 The impact is given by the following expression:

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

24 These are the results under the assumption of a risk premium of 10 €/M, close to the value used in PJM. If we consider

reserve provided by these units in reality and under our cost-reflective scenario is very similar.

Table 2 below summarizes the results for the quantity effect, whilst Appendix A presents a detailed set of results. A negative figure indicates that the margin would have been higher with cost-reflective bidding.

Table 2: Estimated impacts on units of cost-reflective outcomes. Quantity effect

Unit	Q1	Q2	Q3	Q4	Total
Risk premium 10 €/MW					
EDP with CMEC	-0.2	-0.3	-0.7	-3.9	-5.1
EDP without CMEC	-0.6	-0.8	-0.9	-0.5	-2.9
Risk premium 5 €/MW					
EDP with CMEC	-0.4	-0.6	-1.2	-4.7	-6.9
EDP without CMEC	-0.5	-0.5	-0.9	-0.4	-2.4
Risk premium 0 €/MW					
EDP with CMEC	-0.6	-1.0	-1.7	-5.5	-8.7
EDP without CMEC	-0.4	-0.2	-0.9	-0.4	-1.9

Source: The Brattle Group

Table 2 also shows our estimate of the change in the margins for EDP's CMEC units before CMEC adjustments are taken into account. Hence, these margin changes should not be viewed as real margin changes because of the revenue adjustments to which CMEC units are subject. Under our base case assumption on costs, we estimate that the CMEC units' margins would have been around €5.1 million higher with cost-reflective capacity bidding, as they would have provided more secondary reserve.

V.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, i.e. including both a 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 estimated market prices 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.

We estimate that in 2009 the margins earned by EDP's non-CMEC units would have been around €12.9 million lower with cost-reflective bidding when we include a risk premium of 10 €/MW. The estimated cost-reflective margins are €24.9 million lower if we do not include any risk premium. This result is mostly explained by the difference between these units' price and costs in the third quarter of 2009. EDP's CMEC units would have earned €0.8 million more with cost-reflective bidding. Despite these units providing significantly more reserve under the cost-reflective scenario, we estimate that they would have made only a small margin on that additional reserve, since the increase in the quantity of reserve they provide is offset by a reduction in the price they would have been paid for providing that reserve.

Table 3 below summarizes the results for the total effect under, whilst Appendix A presents a detailed set of results. Again, a positive figure indicates that the margin would have been lower with cost-reflective bidding

Table 3: Estimated impacts on units of cost-reflective outcomes. Total effect

Unit	Q1	Q2	Q3	Q4	Total
Risk premium 10 €/MW					
EDP with CMEC	0.7	0.2	0.0	0.0	0.8
EDP without CMEC	0.4	0.5	4.3	7.7	12.9
Risk premium 5 €/MW					
EDP with CMEC	1.1	0.5	0.1	0.0	1.7
EDP without CMEC	1.3	1.9	6.0	9.8	18.9
Risk premium 0 €/MW					
EDP with CMEC	1.4	0.9	0.2	0.1	2.6
EDP without CMEC	2.1	3.2	7.7	11.9	24.9

Source: The Brattle Group

Appendix A. 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 V.

A.I. ESTIMATED OVER-COMPENSATION

Table 4: Estimated impact on units' margins.
Quantity effect

	Total margin					Margin on capacity					Margin on energy				
Unit	Q1 mill. €	Q2 mill. €	Q3 mill. €	Q4 mill. €	2009 mill. €	Q1 mill. €	Q2 mill. €	Q3 mill. €	Q4 mill. €	2009 mill. €	Q1 mill. €	Q2 mill. €	Q3 mill. €	Q4 mill. €	2009 mill. €
Aguieira	-0.1				-0.1	0.0				0.0	0.0				0.0
Alto Lindoso	-0.1	-0.1	-0.2	-1.5	-1.9	-0.1	-0.1	-0.2	-1.4	-1.7	0.0	0.0	-0.1	-0.1	-0.2
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
Cabril	0.0	0.0	0.0	-0.3	-0.3	0.0	0.0	0.0	-0.2	-0.3	0.0	0.0	0.0	0.0	-0.1
Castelo Bode	0.0	0.0	0.0	-0.2	-0.2	0.0	0.0	0.0	-0.2	-0.3	0.1	0.0	0.0	0.0	0.0
Picote	0.0	0.1	0.0	-0.2	-0.2	0.0	0.0	0.0	-0.2	-0.3	0.0	0.1	0.0	0.0	0.1
Pocinho	-0.1	-0.1	-0.1	-0.1	-0.4	-0.1	0.0	0.0	-0.1	-0.3	-0.1	0.0	0.0	0.0	-0.1
Regua	0.4	0.1	-0.1	-0.4	0.0	-0.1	0.0	-0.1	-0.4	-0.5	0.4	0.1	0.0	0.0	0.5
Torrao	0.0	0.0	0.0	-0.1	-0.2	0.0	0.0	0.0	-0.1	-0.2	0.0	0.0	0.0	0.0	-0.1
V.Nova II(Frades)	0.0	0.0	-0.1	-0.1	-0.2	0.0	0.0	-0.1	-0.1	-0.2	0.0	0.0	0.0	0.0	-0.1
Valeira	-0.3	-0.2	-0.2	-0.9	-1.5	-0.2	-0.1	-0.1	-0.8	-1.2	-0.1	-0.1	0.0	-0.1	-0.3
EDP with CMEC	**-0.2**	**-0.3**	**-0.7**	**-3.9**	**-5.1**	**-0.5**	**-0.2**	**-0.6**	**-3.6**	**-4.9**	**0.3**	**-0.1**	**-0.1**	**-0.3**	**-0.2**
Alqueva	-0.2	-0.1	-0.2	0.0	-0.5	-0.1	-0.1	-0.2	0.0	-0.3	-0.1	-0.1	0.0	0.0	-0.2
Alqueva II	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
Bemposta II	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
Picote II	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
CC. Ribatejo 1	-0.1	0.0	0.1	-0.1	-0.2	-0.1	-0.2	-0.1	-0.2	-0.6	0.0	0.1	0.2	0.1	0.4
CC. Ribatejo 2	-0.2	-0.3	-0.1	-0.2	-0.7	-0.1	-0.4	-0.2	-0.2	-1.0	-0.1	0.1	0.1	0.0	0.2
CC. Ribatejo 3	-0.2	-0.4	-0.1	0.5	-0.1	-0.3	-0.5	-0.3	0.4	-0.7	0.1	0.1	0.2	0.1	0.5
CC. Lares 1	0.0	0.0	-0.4	0.0	-0.5	0.0	0.0	-0.3	-0.1	-0.4	0.0	0.0	-0.1	0.0	-0.1
CC. Lares 2	0.0	0.0	-0.2	-0.7	-0.8	0.0	0.0	-0.1	-0.6	-0.8	0.0	0.0	0.0	0.0	-0.1
EDP without CMEC	**-0.6**	**-0.8**	**-0.9**	**-0.5**	**-2.9**	**-0.5**	**-1.1**	**-1.3**	**-0.7**	**-3.7**	**-0.1**	**0.3**	**0.4**	**0.2**	**0.8**
Pego coal 1	-0.1	-0.1	0.0	0.9	0.9	-0.1	0.0	-0.1	0.7	0.5	0.0	0.0	0.2	0.2	0.4
Pego coal 2	-0.1	0.0	0.1	1.0	1.0	-0.1	0.0	0.0	0.7	0.6	0.0	0.0	0.2	0.2	0.4
REN Trading	**-0.1**	**-0.1**	**0.2**	**1.9**	**1.8**	**-0.2**	**-0.1**	**-0.2**	**1.5**	**1.1**	**0.1**	**0.0**	**0.3**	**0.4**	**0.8**
Aguieira		0.1	0.4	0.2	0.7		0.1	0.3	0.2	0.5		0.0	0.1	0.1	0.1
CC. Pego. G3	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
CC. Pego. G4	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
Others	**0.0**	**0.1**	**0.4**	**0.2**	**0.7**	**0.0**	**0.1**	**0.3**	**0.2**	**0.5**	**0.0**	**0.0**	**0.1**	**0.1**	**0.1**
Total	**-0.9**	**-1.1**	**-1.1**	**-2.3**	**-5.4**	**-1.2**	**-1.4**	**-1.7**	**-2.6**	**-6.9**	**0.3**	**0.3**	**0.6**	**0.3**	**1.5**

Source: The Brattle Group.

Table 5: Estimated impact on units' margins. Total effect

Unit	Total margin					Margin on capacity					Margin on energy				
	Q1	Q2	Q3	Q4	2009	Q1	Q2	Q3	Q4	2009	Q1	Q2	Q3	Q4	2009
	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €
Aguieira	0.0				0.0	0.0				0.0	0.0				0.0
Alto Lindoso	0.1	0.0	0.0	-0.1	0.0	0.1	0.0	0.1	0.1	0.2	0.0	0.0	-0.1	-0.1	-0.2
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
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	-0.1
Castelo Bode	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0
Picote	0.1	0.2	0.0	0.0	0.2	0.0	0.1	0.0	0.0	0.1	0.0	0.1	0.0	0.0	0.1
Pocinho	0.0	0.0	0.0	0.0	-0.1	0.0	0.0	0.0	0.0	0.0	-0.1	0.0	0.0	0.0	-0.1
Regua	0.5	0.2	0.0	0.0	0.8	0.1	0.1	0.0	0.0	0.2	0.4	0.1	0.0	0.0	0.5
Torrao	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	-0.1
V.Nova II(Frades)	0.0	0.0	0.0	0.2	0.2	0.0	0.0	0.0	0.2	0.3	0.0	0.0	0.0	0.0	-0.1
Valeira	0.0	-0.1	0.0	-0.1	-0.2	0.1	0.0	0.0	0.0	0.1	-0.1	-0.1	0.0	-0.1	-0.3
EDP with CMEC	**0.7**	**0.2**	**0.0**	**0.0**	**0.8**	**0.4**	**0.3**	**0.2**	**0.3**	**1.1**	**0.3**	**-0.1**	**-0.1**	**-0.3**	**-0.2**
Alqueva	0.0	0.0	0.0	0.4	0.3	0.1	0.0	0.1	0.3	0.5	-0.1	-0.1	0.0	0.0	-0.2
Alqueva II	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
Bemposta II	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
Picote II	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
CC. Ribatejo 1	0.2	0.1	1.3	1.4	2.9	0.2	0.0	1.0	1.3	2.5	0.0	0.1	0.2	0.1	0.4
CC. Ribatejo 2	0.2	0.3	1.5	1.1	3.2	0.3	0.2	1.4	1.1	3.0	-0.1	0.1	0.1	0.0	0.2
CC. Ribatejo 3	0.1	0.1	1.4	2.0	3.5	0.0	-0.1	1.2	1.9	3.0	0.1	0.1	0.2	0.1	0.5
CC. Lares 1	0.0	0.0	0.0	1.5	1.5	0.0	0.0	0.1	1.4	1.5	0.0	0.0	-0.1	0.0	-0.1
CC. Lares 2	0.0	0.0	0.0	1.4	1.4	0.0	0.0	0.0	1.5	1.5	0.0	0.0	0.0	0.0	-0.1
EDP without CMEC	**0.4**	**0.5**	**4.3**	**7.7**	**12.9**	**0.5**	**0.2**	**3.9**	**7.5**	**12.1**	**-0.1**	**0.3**	**0.4**	**0.2**	**0.8**
Pego coal 1	-0.1	0.0	0.1	1.3	1.3	-0.1	0.0	0.0	1.1	0.9	0.0	0.0	0.2	0.2	0.4
Pego coal 2	0.0	0.0	0.2	1.3	1.5	-0.1	0.0	0.1	1.1	1.1	0.0	0.0	0.2	0.2	0.4
REN Trading	**-0.1**	**0.0**	**0.4**	**2.5**	**2.8**	**-0.2**	**0.0**	**0.0**	**2.1**	**2.0**	**0.1**	**0.0**	**0.3**	**0.4**	**0.8**
Aguieira		0.2	0.4	0.3	0.9		0.1	0.4	0.3	0.8		0.0	0.1	0.1	0.1
CC. Pego. G3	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
CC. Pego. G4	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
Others	**0.0**	**0.2**	**0.4**	**0.3**	**0.9**	**0.0**	**0.1**	**0.4**	**0.3**	**0.8**	**0.0**	**0.0**	**0.1**	**0.1**	**0.1**
Total	**1.0**	**0.8**	**5.1**	**10.5**	**17.4**	**0.7**	**0.6**	**4.5**	**10.2**	**15.9**	**0.3**	**0.3**	**0.6**	**0.3**	**1.5**

Source: The Brattle Group.

A.II. ESTIMATION OF ACTUAL RESULTS

Table 6: Estimated units' margins with actual market results

Unit	Total margin				Margin on capacity				Margin on energy			
	Q1 mill. €	Q2 mill. €	Q3 mill. €	Q4 mill. €	Q1 mill. €	Q2 mill. €	Q3 mill. €	Q4 mill. €	Q1 mill. €	Q2 mill. €	Q3 mill. €	Q4 mill. €
Aguieira	0.0				0.0				0.0			
Alto Lindoso	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0
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
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
Castelo Bode	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0
Picote	0.1	0.3	0.1	0.0	0.0	0.1	0.0	0.0	0.1	0.2	0.0	0.0
Pocinho	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Regua	0.6	0.3	0.1	0.0	0.1	0.1	0.0	0.0	0.5	0.2	0.0	0.0
Torrao	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
V.Nova II(Frades)	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0
Valeira	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EDP with CMEC	**1.0**	**0.6**	**0.2**	**0.2**	**0.1**	**0.2**	**0.1**	**0.2**	**0.9**	**0.4**	**0.1**	**0.0**
Alqueva	0.0	0.1	0.1	0.4	0.0	0.0	0.1	0.4	0.0	0.1	0.0	0.0
Alqueva II	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bemposta II	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Picote II	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC. Ribatejo 1	0.2	0.2	1.3	1.5	0.1	-0.1	1.0	1.3	0.1	0.3	0.3	0.3
CC. Ribatejo 2	0.3	0.5	1.6	1.2	0.1	0.2	1.3	1.1	0.2	0.3	0.3	0.2
CC. Ribatejo 3	0.1	0.2	1.5	2.1	-0.1	-0.1	1.1	1.9	0.3	0.3	0.4	0.2
CC. Lares 1	0.0	0.0	0.0	1.5	0.0	0.0	0.0	1.3	0.0	0.0	0.0	0.2
CC. Lares 2	0.0	0.0	0.0	1.7	0.0	0.0	0.0	1.5	0.0	0.0	0.0	0.2
EDP without CMEC	**0.7**	**0.9**	**4.6**	**8.4**	**0.1**	**0.0**	**3.5**	**7.4**	**0.6**	**1.0**	**1.1**	**1.0**
Pego coal 1	-0.1	0.0	0.1	1.3	-0.1	0.0	0.0	1.1	0.1	0.0	0.2	0.2
Pego coal 2	0.0	0.0	0.2	1.3	-0.1	0.0	0.0	1.1	0.1	0.0	0.2	0.2
REN Trading	**-0.1**	**0.0**	**0.4**	**2.6**	**-0.2**	**0.0**	**0.0**	**2.2**	**0.1**	**0.0**	**0.3**	**0.4**
Aguieira		0.2	0.4	0.4		0.1	0.4	0.3		0.1	0.1	0.1
CC. Pego. G3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC. Pego. G4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Others	**0.0**	**0.2**	**0.4**	**0.4**	**0.0**	**0.1**	**0.4**	**0.3**	**0.0**	**0.1**	**0.1**	**0.1**
Total	**1.6**	**1.8**	**5.5**	**11.7**	**0.0**	**0.3**	**4.0**	**10.1**	**1.6**	**1.5**	**1.6**	**1.6**

Source: The Brattle Group.

Table 7: Estimated units' revenues with actual market results

Unit	Total revenue				Revenue on capacity				Revenue on energy			
	Q1 mill. €	Q2 mill. €	Q3 mill. €	Q4 mill. €	Q1 mill. €	Q2 mill. €	Q3 mill. €	Q4 mill. €	Q1 mill. €	Q2 mill. €	Q3 mill. €	Q4 mill. €
Aguieira	0.1				0.1				0.0			
Alto Lindoso	0.5	0.0	0.0	0.3	0.2	0.0	0.0	0.3	0.3	0.0	0.0	0.0
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
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
Castelo Bode	0.5	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.2	0.0	0.0	0.0
Picote	0.3	1.1	0.2	0.0	0.2	0.7	0.2	0.0	0.1	0.4	0.0	0.0
Pocinho	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Regua	1.9	1.2	0.2	0.0	0.7	0.6	0.1	0.0	1.2	0.7	0.1	0.0
Torrao	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
V.Nova II(Frades)	0.0	0.0	0.0	0.5	0.0	0.0	0.0	0.4	0.0	0.0	0.0	0.0
Valeira	0.1	0.2	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.1	0.0	0.0
EDP with CMEC	**3.5**	**2.5**	**0.5**	**0.8**	**1.7**	**1.3**	**0.3**	**0.7**	**1.9**	**1.2**	**0.1**	**0.1**
Alqueva	0.2	0.5	0.3	1.1	0.1	0.4	0.3	1.0	0.0	0.1	0.1	0.1
Alqueva II	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bemposta II	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Picote II	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC. Ribatejo 1	1.2	2.4	3.9	3.9	0.9	1.7	3.0	3.2	0.3	0.6	0.8	0.7
CC. Ribatejo 2	1.6	2.7	4.2	3.2	1.1	2.0	3.2	2.7	0.5	0.7	1.0	0.5
CC. Ribatejo 3	1.9	2.3	4.4	4.4	1.3	1.7	3.4	3.7	0.5	0.6	1.0	0.7
CC. Lares 1	0.0	0.0	0.0	2.7	0.0	0.0	0.0	2.3	0.0	0.0	0.0	0.4
CC. Lares 2	0.0	0.0	0.0	3.0	0.0	0.0	0.0	2.7	0.0	0.0	0.0	0.3
EDP without CMEC	**4.9**	**7.8**	**12.7**	**18.4**	**3.5**	**5.7**	**9.9**	**15.5**	**1.4**	**2.0**	**2.8**	**2.8**
Pego coal 1	0.3	0.3	1.2	3.3	0.3	0.2	0.9	2.9	0.1	0.1	0.3	0.4
Pego coal 2	0.3	0.1	1.4	3.3	0.2	0.1	1.0	2.9	0.1	0.0	0.3	0.4
REN Trading	**0.7**	**0.4**	**2.6**	**6.6**	**0.5**	**0.3**	**1.9**	**5.7**	**0.2**	**0.1**	**0.6**	**0.8**
Aguieira		0.7	0.9	1.2		0.6	0.9	1.1		0.0	0.0	0.1
CC. Pego. G3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC. Pego. G4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Others	**0.0**	**0.7**	**0.9**	**1.2**	**0.0**	**0.6**	**0.9**	**1.1**	**0.0**	**0.0**	**0.0**	**0.1**
Total	**9.1**	**11.3**	**16.7**	**26.9**	**5.6**	**8.0**	**13.0**	**23.2**	**3.5**	**3.4**	**3.6**	**3.8**

Source: The Brattle Group.

Table 8: Estimated units' costs with actual market results

Unit	Total costs				Costs of capacity				Costs of energy			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €
Aguieira	0.1				0.1				0.0			
Alto Lindoso	0.4	0.0	0.0	0.4	0.2	0.0	0.0	0.3	0.2	0.0	0.0	0.0
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
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
Castelo Bode	0.4	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.1	0.0	0.0	0.0
Picote	0.2	0.8	0.1	0.0	0.2	0.6	0.1	0.0	0.0	0.2	0.0	0.0
Pocinho	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Regua	1.3	0.9	0.1	0.0	0.6	0.5	0.1	0.0	0.7	0.4	0.1	0.0
Torrao	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
V.Nova II(Frades)	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0
Valeira	0.1	0.2	0.0	0.0	0.1	0.1	0.0	0.0	-0.1	0.1	0.0	0.0
EDP with CMEC	**2.5**	**1.9**	**0.3**	**0.6**	**1.6**	**1.1**	**0.2**	**0.6**	**0.9**	**0.7**	**0.1**	**0.0**
Alqueva	0.1	0.4	0.2	0.7	0.1	0.3	0.2	0.6	0.0	0.1	0.0	0.1
Alqueva II	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bemposta II	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Picote II	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC. Ribatejo 1	1.0	2.1	2.5	2.3	0.8	1.8	2.0	1.9	0.2	0.3	0.5	0.4
CC. Ribatejo 2	1.3	2.2	2.5	2.0	1.0	1.8	1.9	1.6	0.3	0.4	0.6	0.4
CC. Ribatejo 3	1.7	2.1	2.9	2.4	1.4	1.8	2.3	1.8	0.3	0.3	0.6	0.5
CC. Lares 1	0.0	0.0	0.0	1.2	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.2
CC. Lares 2	0.0	0.0	0.0	1.3	0.0	0.0	0.0	1.1	0.0	0.0	0.0	0.2
EDP without CMEC	**4.2**	**6.8**	**8.1**	**9.9**	**3.4**	**5.8**	**6.4**	**8.1**	**0.8**	**1.1**	**1.7**	**1.8**
Pego coal 1	0.4	0.3	1.1	2.0	0.4	0.2	0.9	1.8	0.0	0.1	0.1	0.2
Pego coal 2	0.4	0.1	1.1	2.0	0.3	0.1	1.0	1.8	0.0	0.0	0.2	0.2
REN Trading	**0.8**	**0.4**	**2.2**	**4.0**	**0.7**	**0.3**	**1.9**	**3.6**	**0.1**	**0.1**	**0.3**	**0.4**
Aguieira		0.5	0.5	0.8	0.1	0.5	0.5	0.8		0.0	0.0	0.0
CC. Pego. G3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC. Pego. G4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Others	**0.0**	**0.5**	**0.5**	**0.8**	**0.1**	**0.5**	**0.5**	**0.8**	**0.0**	**0.0**	**0.0**	**0.0**
Total	**7.5**	**9.5**	**11.1**	**15.3**	**5.7**	**7.7**	**9.1**	**13.1**	**1.8**	**1.9**	**2.1**	**2.2**

Source: The Brattle Group.

Table 9: Estimated capacity and energy allocation with actual market results

Unit	Secondary reserve capacity				Net secondary reserve energy			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
	GW	GW	GW	GW	GWh	GWh	GWh	GWh
Aguieira	4				-1			
Alto Lindoso	7	0	0	7	5	0	0	0
Bemposta	0	0	0	0	0	0	0	0
Cabril	2	0	0	0	-1	0	0	0
Castelo Bode	13	0	0	0	4	0	0	0
Picote	11	33	7	0	1	5	0	0
Pocinho	2	0	0	0	-1	0	0	0
Regua	33	28	6	0	18	10	1	0
Torrao	0	0	0	0	0	0	0	0
V.Nova II(Frades)	0	0	1	10	0	0	0	0
Valeira	6	6	1	0	-2	2	0	0
EDP with CMEC	**77**	**67**	**15**	**17**	**23**	**17**	**2**	**1**
Alqueva	6	18	11	29	0	1	1	2
Alqueva II	0	0	0	0	0	0	0	0
Bemposta II	0	0	0	0	0	0	0	0
Picote II	0	0	0	0	0	0	0	0
CC. Ribatejo 1	42	84	106	92	5	12	17	16
CC. Ribatejo 2	55	88	111	80	8	13	21	12
CC. Ribatejo 3	63	81	115	97	9	12	21	17
CC. Lares 1	0	0	0	57	0	0	0	7
CC. Lares 2	0	0	0	64	0	0	0	6
EDP without CMEC	**167**	**270**	**342**	**420**	**22**	**38**	**60**	**59**
Pego coal 1	14	10	39	77	2	2	7	8
Pego coal 2	13	5	41	78	2	1	8	9
REN Trading	**27**	**15**	**80**	**155**	**4**	**3**	**15**	**17**
Aguieira		21	19	28	-1	-1	0	1
CC. Pego. G3	0	0	0	0	0	0	0	0
CC. Pego. G4	0	0	0	0	0	0	0	0
Others	**0**	**21**	**19**	**28**	**-1**	**-1**	**0**	**1**
Total	**271**	**374**	**457**	**620**	**48**	**58**	**76**	**77**

Source: The Brattle Group.

A.III. ESTIMATION OF ALTERNATIVE RESULTS (QUANTITY EFFECT)

Table 10: Estimated units' margins (quantity effect)

	Total margin				Margin on capacity				Margin on energy			
Unit	Q1 mill. €	Q2 mill. €	Q3 mill. €	Q4 mill. €	Q1 mill. €	Q2 mill. €	Q3 mill. €	Q4 mill. €	Q1 mill. €	Q2 mill. €	Q3 mill. €	Q4 mill. €
Aguieira	0.1				0.0				0.1			
Alto Lindoso	0.2	0.1	0.2	1.4	0.1	0.1	0.2	1.3	0.1	0.0	0.1	0.1
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
Cabril	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0
Castelo Bode	0.1	0.0	0.0	0.2	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0
Picote	0.1	0.2	0.1	0.2	0.0	0.1	0.1	0.2	0.0	0.1	0.0	0.0
Pocinho	0.2	0.1	0.1	0.1	0.1	0.0	0.0	0.1	0.1	0.0	0.0	0.0
Regua	0.2	0.2	0.1	0.4	0.1	0.1	0.1	0.4	0.1	0.1	0.0	0.0
Torrao	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0
V.Nova II(Frades)	0.0	0.0	0.1	0.3	0.0	0.0	0.1	0.3	0.0	0.0	0.0	0.0
Valeira	0.3	0.2	0.2	0.9	0.2	0.1	0.1	0.8	0.1	0.1	0.0	0.1
EDP with CMEC	**1.2**	**0.9**	**0.9**	**4.1**	**0.6**	**0.4**	**0.7**	**3.7**	**0.6**	**0.5**	**0.2**	**0.3**
Alqueva	0.2	0.2	0.3	0.4	0.1	0.1	0.3	0.4	0.1	0.1	0.1	0.0
Alqueva II	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bemposta II	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Picote II	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC. Ribatejo 1	0.4	0.3	1.2	1.7	0.2	0.1	1.1	1.5	0.2	0.2	0.1	0.2
CC. Ribatejo 2	0.5	0.8	1.7	1.4	0.2	0.6	1.5	1.3	0.2	0.2	0.2	0.1
CC. Ribatejo 3	0.3	0.5	1.6	1.6	0.1	0.4	1.4	1.5	0.1	0.1	0.2	0.1
CC. Lares 1	0.0	0.0	0.4	1.6	0.0	0.0	0.3	1.4	0.0	0.0	0.1	0.2
CC. Lares 2	0.0	0.0	0.2	2.3	0.0	0.0	0.1	2.1	0.0	0.0	0.0	0.2
EDP without CMEC	**1.3**	**1.8**	**5.5**	**8.9**	**0.6**	**1.1**	**4.8**	**8.1**	**0.7**	**0.6**	**0.7**	**0.8**
Pego coal 1	0.0	0.0	0.1	0.4	0.0	0.0	0.1	0.4	0.0	0.0	0.0	0.0
Pego coal 2	0.0	0.0	0.1	0.4	0.0	0.0	0.1	0.3	0.0	0.0	0.0	0.0
REN Trading	**0.0**	**0.1**	**0.2**	**0.8**	**0.0**	**0.0**	**0.2**	**0.7**	**0.0**	**0.1**	**0.0**	**0.1**
Aguieira		0.1	0.0	0.2		0.1	0.0	0.2		0.0	0.0	0.0
CC. Pego. G3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC. Pego. G4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Others	**0.0**	**0.1**	**0.0**	**0.2**	**0.0**	**0.1**	**0.0**	**0.2**	**0.0**	**0.0**	**0.0**	**0.0**
Total	**2.6**	**2.9**	**6.6**	**13.9**	**1.2**	**1.7**	**5.7**	**12.7**	**1.4**	**1.2**	**1.0**	**1.2**

Source: The Brattle Group.

Table 11: Estimated units' revenues (quantity effect)

	Total revenue				Revenue on capacity				Revenue on energy			
Unit	Q1 mill. €	Q2 mill. €	Q3 mill. €	Q4 mill. €	Q1 mill. €	Q2 mill. €	Q3 mill. €	Q4 mill. €	Q1 mill. €	Q2 mill. €	Q3 mill. €	Q4 mill. €
Aguieira	0.3				0.2				0.2			
Alto Lindoso	0.6	0.3	0.9	2.7	0.3	0.2	0.5	2.3	0.3	0.1	0.3	0.4
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
Cabril	0.1	0.1	0.2	0.5	0.1	0.1	0.1	0.4	0.1	0.0	0.0	0.1
Castelo Bode	0.2	0.1	0.1	0.4	0.1	0.1	0.1	0.4	0.1	0.0	0.0	0.1
Picote	0.3	1.0	0.4	0.4	0.2	0.7	0.3	0.4	0.1	0.3	0.1	0.1
Pocinho	0.6	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.1	0.1	0.0
Regua	0.7	0.8	0.5	0.8	0.4	0.5	0.3	0.7	0.2	0.3	0.2	0.1
Torrao	0.1	0.1	0.1	0.3	0.1	0.1	0.1	0.2	0.1	0.0	0.0	0.0
V.Nova II(Frades)	0.1	0.2	0.3	0.6	0.1	0.2	0.3	0.5	0.1	0.1	0.1	0.1
Valeira	0.9	0.8	0.7	1.8	0.6	0.6	0.5	1.5	0.3	0.3	0.2	0.2
EDP with CMEC	**4.0**	**3.9**	**3.4**	**7.8**	**2.5**	**2.6**	**2.3**	**6.7**	**1.5**	**1.3**	**1.1**	**1.1**
Alqueva	0.5	0.9	0.9	0.8	0.3	0.6	0.7	0.7	0.2	0.3	0.2	0.1
Alqueva II	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bemposta II	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Picote II	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC. Ribatejo 1	1.4	1.6	2.8	3.4	0.9	1.2	2.3	2.8	0.5	0.5	0.5	0.5
CC. Ribatejo 2	1.8	2.2	3.8	2.8	1.2	1.6	3.1	2.4	0.7	0.6	0.7	0.4
CC. Ribatejo 3	1.1	1.7	3.4	3.2	0.7	1.3	2.9	2.7	0.5	0.4	0.6	0.5
CC. Lares 1	0.0	0.0	1.3	2.8	0.0	0.0	0.9	2.4	0.0	0.0	0.4	0.4
CC. Lares 2	0.0	0.0	0.5	4.5	0.0	0.0	0.4	3.9	0.0	0.0	0.1	0.5
EDP without CMEC	**4.9**	**6.4**	**12.8**	**17.5**	**3.1**	**4.6**	**10.3**	**15.0**	**1.8**	**1.7**	**2.5**	**2.5**
Pego coal 1	0.1	0.4	0.2	0.7	0.0	0.2	0.2	0.6	0.0	0.1	0.0	0.1
Pego coal 2	0.1	0.2	0.2	0.6	0.1	0.1	0.2	0.6	0.0	0.1	0.0	0.1
REN Trading	**0.2**	**0.6**	**0.4**	**1.3**	**0.1**	**0.4**	**0.3**	**1.1**	**0.1**	**0.2**	**0.0**	**0.1**
Aguieira		0.4	0.1	0.4		0.3	0.1	0.3		0.2	0.0	0.1
CC. Pego. G3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC. Pego. G4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Others	**0.0**	**0.4**	**0.1**	**0.4**	**0.0**	**0.3**	**0.1**	**0.3**	**0.0**	**0.2**	**0.0**	**0.1**
Total	**9.1**	**11.3**	**16.7**	**26.9**	**5.6**	**8.0**	**13.0**	**23.2**	**3.5**	**3.4**	**3.6**	**3.8**

Source: The Brattle Group.

Table 12: Estimated units' costs (quantity effect)

	Total costs				Costs of capacity				Costs of energy			
Unit	Q1 mill. €	Q2 mill. €	Q3 mill. €	Q4 mill. €	Q1 mill. €	Q2 mill. €	Q3 mill. €	Q4 mill. €	Q1 mill. €	Q2 mill. €	Q3 mill. €	Q4 mill. €
Aguieira	0.3				0.2				0.1			
Alto Lindoso	0.4	0.2	0.7	1.3	0.3	0.1	0.4	1.0	0.2	0.1	0.3	0.3
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
Cabril	0.1	0.1	0.1	0.2	0.1	0.1	0.1	0.2	0.0	0.0	0.0	0.0
Castelo Bode	0.1	0.1	0.1	0.2	0.1	0.1	0.1	0.2	0.0	0.0	0.0	0.0
Picote	0.2	0.8	0.3	0.2	0.2	0.6	0.2	0.2	0.1	0.2	0.1	0.0
Pocinho	0.4	0.3	0.2	0.1	0.3	0.2	0.1	0.1	0.1	0.1	0.1	0.0
Regua	0.5	0.6	0.4	0.4	0.3	0.5	0.2	0.3	0.2	0.2	0.1	0.1
Torrao	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0
V.Nova II(Frades)	0.1	0.2	0.2	0.3	0.1	0.1	0.2	0.2	0.0	0.0	0.1	0.1
Valeira	0.6	0.6	0.5	0.9	0.5	0.5	0.3	0.7	0.1	0.2	0.2	0.2
EDP with CMEC	**2.8**	**3.0**	**2.5**	**3.8**	**1.9**	**2.2**	**1.7**	**3.0**	**0.9**	**0.8**	**0.9**	**0.8**
Alqueva	0.3	0.6	0.6	0.4	0.3	0.5	0.4	0.3	0.1	0.2	0.2	0.1
Alqueva II	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bemposta II	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Picote II	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC. Ribatejo 1	1.0	1.4	1.6	1.7	0.7	1.1	1.2	1.3	0.3	0.3	0.4	0.3
CC. Ribatejo 2	1.3	1.4	2.0	1.4	0.9	1.1	1.6	1.1	0.4	0.4	0.5	0.3
CC. Ribatejo 3	0.9	1.1	1.8	1.6	0.5	0.9	1.4	1.2	0.3	0.3	0.4	0.4
CC. Lares 1	0.0	0.0	0.9	1.3	0.0	0.0	0.6	1.0	0.0	0.0	0.3	0.2
CC. Lares 2	0.0	0.0	0.4	2.2	0.0	0.0	0.2	1.8	0.0	0.0	0.1	0.4
EDP without CMEC	**3.6**	**4.6**	**7.3**	**8.5**	**2.4**	**3.5**	**5.5**	**6.9**	**1.2**	**1.1**	**1.8**	**1.7**
Pego coal 1	0.1	0.3	0.1	0.3	0.0	0.2	0.1	0.2	0.0	0.1	0.0	0.0
Pego coal 2	0.1	0.2	0.1	0.2	0.1	0.1	0.1	0.2	0.0	0.0	0.0	0.0
REN Trading	**0.1**	**0.5**	**0.2**	**0.5**	**0.1**	**0.4**	**0.1**	**0.4**	**0.0**	**0.1**	**0.0**	**0.1**
Aguieira		0.3	0.1	0.2		0.2	0.1	0.1		0.1	0.0	0.1
CC. Pego. G3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC. Pego. G4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Others	**0.0**	**0.3**	**0.1**	**0.2**	**0.0**	**0.2**	**0.1**	**0.1**	**0.0**	**0.1**	**0.0**	**0.1**
Total	**6.5**	**8.4**	**10.0**	**13.0**	**4.4**	**6.3**	**7.4**	**10.4**	**2.1**	**2.1**	**2.7**	**2.6**

Source: The Brattle Group.

Table 13: Estimated capacity and energy allocation (quantity and total effect)

	Secondary reserve capacity				Net secondary reserve energy			
Unit	Q1 GW	Q2 GW	Q3 GW	Q4 GW	Q1 GWh	Q2 GWh	Q3 GWh	Q4 GWh
Aguieira	9				0			
Alto Lindoso	15	9	25	59	0	0	0	0
Bemposta	0	0	0	0	1	1	1	0
Cabril	3	5	5	11	0	0	0	0
Castelo Bode	5	4	3	10	0	0	0	0
Picote	10	37	13	11	0	0	0	0
Pocinho	15	13	9	7	0	0	0	0
Regua	22	29	16	20	0	0	0	0
Torrao	3	5	4	6	0	0	0	0
V.Nova II(Frades)	4	8	10	14	0	0	0	0
Valeira	31	29	22	42	0	0	0	0
EDP with CMEC	**118**	**138**	**107**	**178**	**1**	**1**	**1**	**1**
Alqueva	15	31	27	21	0	0	0	0
Alqueva II	0	0	0	0	0	0	0	0
Bemposta II	0	0	0	0	0	0	1	1
Picote II	0	0	0	0	0	0	0	0
CC. Ribatejo 1	44	61	76	78	93	95	104	111
CC. Ribatejo 2	56	61	95	65	-45	-37	-28	-34
CC. Ribatejo 3	34	50	86	75	0	0	0	0
CC. Lares 1	0	0	39	61	3	3	4	4
CC. Lares 2	0	0	16	110	0	0	0	0
EDP without CMEC	**148**	**204**	**339**	**409**	**53**	**62**	**80**	**82**
Pego coal 1	2	14	4	13	104	90	82	80
Pego coal 2	3	6	4	12	63	56	50	40
REN Trading	**5**	**20**	**7**	**25**	**167**	**147**	**132**	**120**
Aguieira		12	4	7		0	0	0
CC. Pego. G3	0	0	0	0	0	0	0	0
CC. Pego. G4	0	0	0	0	0	0	0	0
Others	**0**	**12**	**4**	**7**	**0**	**1**	**0**	**0**
Total	**271**	**374**	**457**	**620**	**222**	**210**	**213**	**202**

Source: The Brattle Group.

A.IV. ESTIMATION OF ALTERNATIVE RESULTS (TOTAL EFFECT)

Table 14: Estimated units' margins (total effect)

	Total margin				Margin on capacity				Margin on energy			
Unit	Q1 mill. €	Q2 mill. €	Q3 mill. €	Q4 mill. €	Q1 mill. €	Q2 mill. €	Q3 mill. €	Q4 mill. €	Q1 mill. €	Q2 mill. €	Q3 mill. €	Q4 mill. €
Aguieira	0.0				0.0				0.1			
Alto Lindoso	0.1	0.0	0.0	0.0	-0.1	0.0	-0.1	-0.1	0.1	0.0	0.1	0.1
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
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
Castelo Bode	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Picote	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0
Pocinho	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0
Regua	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0
Torrao	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
V.Nova II(Frades)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Valeira	0.1	0.1	0.0	0.1	-0.1	0.0	0.0	0.0	0.1	0.1	0.0	0.1
EDP with CMEC	**0.3**	**0.4**	**0.1**	**0.3**	**-0.3**	**-0.1**	**-0.1**	**-0.1**	**0.6**	**0.5**	**0.2**	**0.3**
Alqueva	0.1	0.1	0.1	0.1	-0.1	0.0	0.0	0.0	0.1	0.1	0.1	0.0
Alqueva II	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bemposta II	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Picote II	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC. Ribatejo 1	0.1	0.1	0.1	0.2	-0.1	-0.1	-0.1	0.0	0.2	0.2	0.1	0.2
CC. Ribatejo 2	0.1	0.1	0.1	0.1	-0.2	-0.1	-0.1	0.0	0.2	0.2	0.2	0.1
CC. Ribatejo 3	0.0	0.1	0.1	0.1	-0.1	-0.1	-0.1	0.0	0.1	0.1	0.2	0.1
CC. Lares 1	0.0	0.0	0.0	0.1	0.0	0.0	-0.1	-0.1	0.0	0.0	0.1	0.2
CC. Lares 2	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.2
EDP without CMEC	**0.3**	**0.4**	**0.3**	**0.7**	**-0.4**	**-0.2**	**-0.4**	**-0.1**	**0.7**	**0.6**	**0.7**	**0.8**
Pego coal 1	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pego coal 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
REN Trading	**0.0**	**0.0**	**0.0**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.1**	**0.0**	**0.1**
Aguieira		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0
CC. Pego. G3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC. Pego. G4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Others	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Total	**0.6**	**0.9**	**0.5**	**1.1**	**-0.7**	**-0.3**	**-0.5**	**-0.1**	**1.4**	**1.2**	**1.0**	**1.2**

Source: The Brattle Group.

Table 15: Estimated units' revenues (total effect)

	Total revenue				Revenue on capacity				Revenue on energy			
Unit	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €	mill. €
Aguieira	0.3				0.1				0.2			
Alto Lindoso	0.5	0.2	0.7	1.3	0.2	0.1	0.3	0.9	0.3	0.1	0.3	0.4
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
Cabril	0.1	0.1	0.1	0.3	0.1	0.1	0.1	0.2	0.1	0.0	0.0	0.1
Castelo Bode	0.1	0.1	0.1	0.2	0.1	0.1	0.0	0.2	0.1	0.0	0.0	0.1
Picote	0.3	0.9	0.3	0.2	0.1	0.6	0.2	0.2	0.1	0.3	0.1	0.1
Pocinho	0.4	0.3	0.2	0.2	0.2	0.2	0.1	0.1	0.2	0.1	0.1	0.0
Regua	0.5	0.7	0.4	0.4	0.3	0.5	0.2	0.3	0.2	0.3	0.2	0.1
Torrao	0.1	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.0
V.Nova II(Frades)	0.1	0.2	0.2	0.3	0.1	0.1	0.2	0.2	0.1	0.1	0.1	0.1
Valeira	0.7	0.7	0.5	0.9	0.4	0.4	0.3	0.7	0.3	0.3	0.2	0.2
EDP with CMEC	**3.2**	**3.5**	**2.7**	**4.0**	**1.6**	**2.2**	**1.6**	**2.9**	**1.5**	**1.3**	**1.1**	**1.1**
Alqueva	0.4	0.8	0.7	0.5	0.2	0.5	0.4	0.4	0.2	0.3	0.2	0.1
Alqueva II	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bemposta II	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Picote II	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC. Ribatejo 1	1.1	1.5	1.7	1.9	0.6	1.0	1.2	1.4	0.5	0.5	0.5	0.5
CC. Ribatejo 2	1.4	1.6	2.1	1.5	0.7	1.0	1.5	1.1	0.7	0.6	0.7	0.4
CC. Ribatejo 3	0.9	1.2	1.9	1.7	0.4	0.8	1.3	1.2	0.5	0.4	0.6	0.5
CC. Lares 1	0.0	0.0	0.9	1.3	0.0	0.0	0.5	0.9	0.0	0.0	0.4	0.4
CC. Lares 2	0.0	0.0	0.3	2.4	0.0	0.0	0.2	1.8	0.0	0.0	0.1	0.5
EDP without CMEC	**3.8**	**5.0**	**7.6**	**9.3**	**2.0**	**3.3**	**5.1**	**6.8**	**1.8**	**1.7**	**2.5**	**2.5**
Pego coal 1	0.1	0.4	0.1	0.3	0.0	0.2	0.1	0.3	0.0	0.1	0.0	0.1
Pego coal 2	0.1	0.2	0.1	0.3	0.0	0.1	0.1	0.2	0.0	0.1	0.0	0.1
REN Trading	**0.2**	**0.5**	**0.2**	**0.6**	**0.1**	**0.3**	**0.1**	**0.5**	**0.1**	**0.2**	**0.0**	**0.1**
Aguieira		0.4	0.1	0.2		0.2	0.1	0.2		0.2	0.0	0.1
CC. Pego. G3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC. Pego. G4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Others	**0.0**	**0.4**	**0.1**	**0.2**	**0.0**	**0.2**	**0.1**	**0.2**	**0.0**	**0.2**	**0.0**	**0.1**
Total	**7.1**	**9.4**	**10.5**	**14.1**	**3.7**	**6.0**	**6.9**	**10.3**	**3.5**	**3.4**	**3.6**	**3.8**

Source: The Brattle Group.

Table 16: Estimated units' costs (total effect)

	Total costs				Costs of capacity				Costs of energy			
Unit	Q1 mill. €	Q2 mill. €	Q3 mill. €	Q4 mill. €	Q1 mill. €	Q2 mill. €	Q3 mill. €	Q4 mill. €	Q1 mill. €	Q2 mill. €	Q3 mill. €	Q4 mill. €
Aguieira	0.3				0.2				0.1			
Alto Lindoso	0.4	0.2	0.7	1.3	0.3	0.1	0.4	1.0	0.2	0.1	0.3	0.3
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
Cabril	0.1	0.1	0.1	0.2	0.1	0.1	0.1	0.2	0.0	0.0	0.0	0.0
Castelo Bode	0.1	0.1	0.1	0.2	0.1	0.1	0.1	0.2	0.0	0.0	0.0	0.0
Picote	0.2	0.8	0.3	0.2	0.2	0.6	0.2	0.2	0.1	0.2	0.1	0.0
Pocinho	0.4	0.3	0.2	0.1	0.3	0.2	0.1	0.1	0.1	0.1	0.1	0.0
Regua	0.5	0.6	0.4	0.4	0.3	0.5	0.2	0.3	0.2	0.2	0.1	0.1
Torrao	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0
V.Nova II(Frades)	0.1	0.2	0.2	0.3	0.1	0.1	0.2	0.2	0.0	0.0	0.1	0.1
Valeira	0.6	0.6	0.5	0.9	0.5	0.5	0.3	0.7	0.1	0.2	0.2	0.2
EDP with CMEC	**2.8**	**3.0**	**2.5**	**3.8**	**1.9**	**2.2**	**1.7**	**3.0**	**0.9**	**0.8**	**0.9**	**0.8**
Alqueva	0.3	0.6	0.6	0.4	0.3	0.5	0.4	0.3	0.1	0.2	0.2	0.1
Alqueva II	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bemposta II	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Picote II	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC. Ribatejo 1	1.0	1.4	1.6	1.7	0.7	1.1	1.2	1.3	0.3	0.3	0.4	0.3
CC. Ribatejo 2	1.3	1.4	2.0	1.4	0.9	1.1	1.6	1.1	0.4	0.4	0.5	0.3
CC. Ribatejo 3	0.9	1.1	1.8	1.6	0.5	0.9	1.4	1.2	0.3	0.3	0.4	0.4
CC. Lares 1	0.0	0.0	0.9	1.3	0.0	0.0	0.6	1.0	0.0	0.0	0.3	0.2
CC. Lares 2	0.0	0.0	0.4	2.2	0.0	0.0	0.2	1.8	0.0	0.0	0.1	0.4
EDP without CMEC	**3.6**	**4.6**	**7.3**	**8.5**	**2.4**	**3.5**	**5.5**	**6.9**	**1.2**	**1.1**	**1.8**	**1.7**
Pego coal 1	0.1	0.3	0.1	0.3	0.0	0.2	0.1	0.2	0.0	0.1	0.0	0.0
Pego coal 2	0.1	0.2	0.1	0.2	0.1	0.1	0.1	0.2	0.0	0.0	0.0	0.0
REN Trading	**0.1**	**0.5**	**0.2**	**0.5**	**0.1**	**0.4**	**0.1**	**0.4**	**0.0**	**0.1**	**0.0**	**0.1**
Aguieira		0.3	0.1	0.2		0.2	0.1	0.1		0.1	0.0	0.1
CC. Pego. G3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CC. Pego. G4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Others	**0.0**	**0.3**	**0.1**	**0.2**	**0.0**	**0.2**	**0.1**	**0.1**	**0.0**	**0.1**	**0.0**	**0.1**
Total	**6.5**	**8.4**	**10.0**	**13.0**	**4.4**	**6.3**	**7.4**	**10.4**	**2.1**	**2.1**	**2.7**	**2.6**

Source: The Brattle Group.

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