Integration of electricity balancing markets and regional procurement of balancing reserves

Final Report
October 2016

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EUROPEAN COMMISSION

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European Commission
B-1049 Brussels

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Directorate-General for Energy
Internal Energy Market

2016

EUR 2016.3807 EN

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Luxembourg: Publications Office of the European Union, 2014
ISBN 978-92-79-54559-7
doi:10.2832/463464

Printed in [Country]

PRINTED ON ELEMENTAL CHLORINE-FREE BLEACHED PAPER (ECF)

PRINTED ON TOTALLY CHLORINE-FREE BLEACHED PAPER (TCF)

PRINTED ON RECYCLED PAPER

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1. ABBREVIATIONS AND DEFINITIONS

1.1. ABBREVIATIONS

Abbreviation	Definition
ACER	Agency of Co-operation of Energy Regulators
BSP	Balancing Service Provider
BRP	Balance Responsible Party
DR	Demand Response
CMOL	Common Merit Order List
FCR	Frequency Containment Reserves
FRR	Frequency Restoration Reserves (aFRR and mFRR)
IA	Impact Assessment
KPI	Key Performance Indicator
MDI	Market Design Initiative
NRA	National Regulatory Authority
NTC	Net Transfer Capacity
RES	Renewable Energy System
RR	Replacement Reserves
TSO	Transmission System Operator

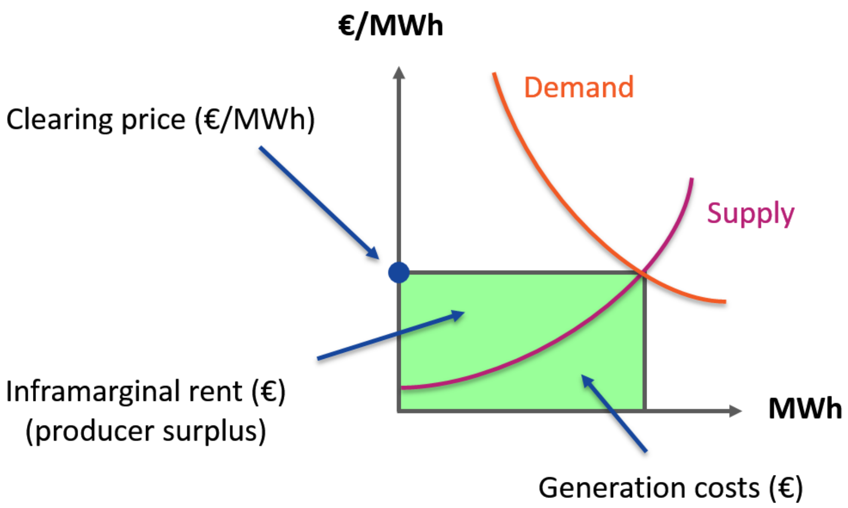
1.2. DEFINITIONS

Concept	Definition
Active Power Reserves	Balancing reserves available for maintaining the frequency. This term is to be understood as the sum of FCR reserves and aFRR reserves.
Balancing	All actions and processes, on all timelines, through which TSOs ensure, in a continuous way, the maintenance of system frequency within a predefined stability range and compliance with the amount of reserves needed with respect to the required quality. Imbalances can occur due to a number of reasons (see Imbalances).
Balancing Capacity	TSOs may hedge against the risk of not having enough Balancing Energy bids by BSPs in real-time by procuring Balancing Capacity ahead of real-time. Providers of Balancing Capacity have to inject or withdraw Balancing Energy at the TSO's request for the duration of the contract period.
Balancing Energy	Energy, either injected in or withdrawn from the electricity grid in real-time, used by TSOs to compensate for unforeseen imbalances and to guarantee the stability of the power system.
Balancing Services	Either or both balancing capacity and balancing energy.

Balance Responsible Party (BRP)	Market participant or its chosen representative responsible for its imbalances.
Balancing Service Provider (BSP)	Market participant with reserve-providing units or reserve-providing groups able to provide balancing services to TSOs.
Common merit order list	List of Balancing Energy Bids sorted in order of their bid prices used for the activation of balancing energy bids
Downwards regulation	Action required when the electricity system is long (i.e. the frequency is higher than its nominal value)
Frequency Containment Reserves (FCR)	Active power reserves available to contain system frequency after the occurrence of an imbalance
Frequency Restoration Reserves (FRR)	Active power reserves available to restore system frequency to the nominal frequency and, for a synchronous area consisting of more than one LFC area, to restore power balance to the scheduled value
Imbalances	Energy volume calculated for a Balance Responsible Party and representing the difference between the allocated volume attributed to that Balance Responsible Party and the final position of that Balance Responsible Party, including any imbalance adjustment applied to that Balance Responsible Party, within a given imbalance settlement period. At intraday gate closure time the generation planning is balanced. Imbalances can be caused by noise, 5-minute gradient, forecast errors, and outages that happen between the intraday gate closure time and real-time.
Imbalance Settlement Period (ISP)	Time unit over which Balance Responsible Parties' imbalance is calculated.
Load payment	The load payment is the total payment made by the public for the provision of electricity. It is computed as the product of the marginal cost of electricity and the demand time series. Note that this computation assumes a pay-as-clear market clearing process. **Figure 1** illustrates this definition in a simple case. Load payment in this case is given by the sum of the production cost and the inframarginal rent (producer surplus).
Pay-as-clear	Market clearing practice in which all selected offers receive the amount offered by the highest selected offer
Reserve Capacity	Amount of FCR, FRR or RR that needs to be available to the TSO
Reserve Providing Unit	Single or aggregation of power generating modules and/or demand units connected to a common connection point fulfilling the requirements to provide FCR, FRR or RR
Reserve Providing Group	Aggregation of power generating modules, demand units and/or reserve providing units connected to more than one connection point fulfilling the requirements to provide FCR, FRR or RR

Replacement Reserves (RR)	Active power reserves available to restore or support the required level of FRR to be prepared for additional system imbalances, including operating reserves
Standard Product	Harmonised balancing product defined by all TSOs for the exchange of balancing services.
Upwards regulation	Action required when the electricity system is short (i.e. the frequency is lower than its nominal value)

Figure 1 - Load payment – Illustration



The figure above illustrates the definition of load payment (shown in light green) when using pay-as-clear practices. Load payment is defined as the payment made by the public for the provision of electricity. It consists of two parts (congestion rents are disregarded in this discussion): the generation costs and the inframarginal rent (or producer surplus). When using pay-as-clear practices, each generator receives the clearing price for each MWh of electricity it produces. The total cost to the public therefore not only covers the generation costs, but also provides a surplus to those generators which have generation costs that are lower than the market clearing price (i.e. to all generators but the marginal unit).

In practice, the load payment is computed as the sum over time-steps (8760 hourly time-steps per year) of the product of the electricity clearing price and the electricity demand.

2. EXECUTIVE SUMMARY

Context

Solidarity is at the heart of the Energy Union strategy, which aims at providing Europe with a secure, sustainable and competitive energy. As the penetration of variable renewable sources of energy increases, the European Commission actively encourages Member States (MSs) to cooperate so as to ensure Europe designs its energy system cost-efficiently and progresses towards reaching its energy and climate targets.

In this context, transmission system operators (TSOs) need to increase their coordination. In some cases this could include transferring some of their competencies to regional entities. This study explores the costs and benefits of several models aiming at further integrating electricity balancing markets and at procuring balancing reserves at a regional level.

Currently, the dimensioning of balancing reserves, their procurement and activation are mainly dealt with at national level. After the intraday markets close, national TSOs are responsible for maintaining the balance between demand and supply. To that aim, TSOs estimate their reserve needs so as to be able to face their national risks independently, procure the required reserves nationally, and finally activate the reserves they have secured when their system faces imbalances.

A number of ongoing initiatives and pilot projects are already exploiting the benefits emerging from a tighter collaboration between TSOs, but no EU legislation currently binds TSOs to enter such collaborations.

The predominantly fragmented approach to reserve dimensioning, procurement and activation can lead to inefficiencies. This study examines whether savings can be generated by introducing policy measures in two areas, which are covered by the following documents:

- **Guideline on Electricity Balancing**
  The Guideline on Electricity Balancing explores several models of cross-zonal exchange of balancing energy. It is expected that savings can be generated by allowing TSOs to exchange balancing energy across zones (even in the case where the reserves are dimensioned at the national level).

- **Market Design Initiative**
  The Market Design Initiative introduces a number of legislative proposals to ensure all technologies compete on a level playing field, to pull all distributed resources into the market and to better interconnect short-term markets. In particular, it is expected that dimensioning reserves at the regional level can generate savings thanks to the statistical cancellation of imbalances and to the fact that large imbalances tend to happen at different times in different zones. As a result, fewer reserves would need to be procured when adopting a regional approach to reserve dimensioning.

In order to enable further collaboration between TSOs, one may need to transfer some of their responsibilities to regional entities, to run reserve need computations at regional level, to organise a regional reserve procurement market, and to set up a platform gathering balancing energy bids.

Objectives of the study

This study was commissioned by the European Commission to examine the costs and benefits of various models for the cross-zonal exchange of balancing energy and the regional dimensioning and procurement of reserves. The aim of this report is to present the costs and benefits associated with each of these models. The cost estimates are based on publications from pilot projects and a literature survey, while the benefits have been assessed by using the METIS model, which is developed by Artelys and its partners on behalf of the European Commission.

The main characteristics of the options investigated in this report are shown below:

Guideline on Electricity Balancing	
Option A	Imbalance netting
Option B	Cross-zonal exchange of balancing energy
Option C	Cross-zonal exchange of balancing energy with enhanced collaboration amongst TSOs

The counter-activation of frequency restoration reserves (FRR) is avoided in option A, subject to available transmission capacity. In option B, one assumes that TSOs can also activate balancing energy provided by balancing service providers (BSPs) located abroad. Finally in option C, one assumes that the tighter collaboration between TSOs would result in a higher capacity being available to net imbalances and exchange balancing energy.

Option C is disregarded from a legal point of view, but is included in this report to illustrate the effects a tighter coordination between TSOs could have.

Market Design Initiative	
Option 1ab	Removal of current sub-optimal reserve procurement practices such as fixed allocation to large thermal units. Independent procurement of upwards and downwards reserves. Hourly dimensioning of reserves.
Option 1b	Regional dimensioning of balancing reserves
Option 2	EU-level dimensioning of balancing reserves, further distributed resources pulled into the market (DSR, RES).

Option 1ab assumes that the current sub-optimal reserve procurement practices are removed. In particular, upwards and downwards reserves are procured independently under this option. This allows cheap generation technologies to increase their participation in electricity production by reducing the amount of upwards reserves they procure. Options 1b and 2 assume a regional or EU-level dimensioning of reserves, and therefore introduce a mutual assistance between MSs which necessitates the introduction of option B of the Guideline on Electricity Balancing. Both options are characterised by lower reserve needs than in option 1ab, but involve the reservation of interconnection capacity to exchange balancing energy. The savings are computed with respect to MDI option 1a, which foresees, among other policy measures, the removal of priority dispatch.

Approach

The costs associated with the introduction of the policy measures discussed above have been evaluated by conducting a review of the literature with the aim of identifying data points relevant to each of the costs arising from the Guideline on Electricity Balancing and Market Design Initiative options. The costs have been scaled and adjusted so as to provide costs estimates for each of the options shown in the above tables.

The benefits associated with the options identified above have been estimated by running simulations of the European power system with the METIS model, which is developed by Artelys. The impacts of the Guideline on Electricity Balancing models have been assessed by simulating how a given portfolio of FRR capacities would be exploited to maintain the demand-supply equilibrium. When running this simulation, the METIS model uses a 5-minute time resolution over the whole year and a MS-level spatial granularity.

After having dimensioned the reserve needs for each of the Market Design Initiative options, their benefits have been evaluated by running METIS to jointly procure balancing reserve capacity and to dispatch electricity. In this case, METIS uses an hourly time resolution (8760 consecutive time-steps per year), and a MS-level spatial granularity.

In all simulations, we adopt the installed capacities, transmission capacities (NTCs), fuel costs, and CO_2 cost from the 2030 METIS EuCo27 scenario, which is itself based on the 2030 PRIMES EuCo27 scenario. In some of the options, the transmission capacities available for certain market timeframes are increased compared to the PRIMES EuCo27 scenario to reflect the impact of policy measures.

Findings

Guideline on Electricity Balancing

The costs of implementing the different models considered in the Guideline on Electricity Balancing have been estimated by looking at the different constitutive elements of the options. The costs of the options are then obtained by summing all the identified cost components (imbalance netting, TSO-BSP or TSO-TSO trading, Europe-wide common merit order list, etc.). Option A is found to have one-off costs of the order of 18-21 M€ and ongoing annual costs of around 0.7-1.3 M€. Options B and C both involve the creation and the management of a Europe-wide common merit order list. Option B is estimated to have one-off costs of the order of 76-96 M€ and ongoing costs of around 1.8-4.6 M€. Option C further requires the creation of additional bodies to perform some of the Europe-wide coordination tasks. Since these bodies cannot be created by the Guideline on Electricity Balancing, their costs are not included.

The benefits of introducing the policy measures discussed above have been assessed by comparing the operational costs of the European power system of all the options with a baseline. The baseline assumes no imbalance netting, and no cross-zonal exchange of balancing energy. In option A, thanks to imbalance netting, counter activations of FRR are avoided. As a result, based on our assumptions, the activated volumes are reduced by around 50%. While activations are reduced by almost 19 TWh, cost savings remain limited (around 210 M€), as imbalance netting reduces upwards activation costs but also removes opportunities to save fuel costs via downwards activations. In option B, TSOs take advantage of cross-zonal exchanges of balancing energy to better exploit the reserve portfolio. The cheapest technologies are exploited to generate upwards regulation, while the most expensive ones are used to provide downwards regulation, subject to the availability of the interconnection capacities. Again, based on our assumptions, Option B results in savings of the order of 480 M€. Finally, option C assumes that the interconnection capacity available during the balancing timeframe is increased by 15% to reflect the tighter coordination between TSOs. It results in savings of the order of 820 M€ thanks to further counter-activations being avoided and a better exploitation of the balancing portfolio.

As can be read from the following table, the benefits of all the options for the Guideline on Electricity Balancing are found to outweigh the costs. Imbalance netting has a 10-year NPV of 1.7 B€, while the introduction of an EU-wide possibility to exchange balancing energy has a 10-year NPV of 3.8 B€.

Options for the Guideline on Electricity Balancing	Option A		Option B		Option C	
	One-off	Ongoing	One-off	Ongoing	One-off	Ongoing
Costs	18.1–20.7 M€	660 k€–1.3 M€	76.1–96.4 M€	1.8–4.6 M€	76.1–96.4 M€	1.8–4.6 M€
Benefits	-	212 M€	-	479 M€	-	817 M€
NPV[1]	1.7 B€		3.8 B€		6.5 B€	

Market Design Initiative

The estimation of the costs of the different models for the dimensioning and the procurement of balancing reserves is obtained by summing the costs of the various identified cost components (role for supranational entities, Europe-wide common merit order list). No extra costs are associated with the implementation of the policy measures of option 1ab, which mainly concern the removal of sub-optimal procurement practices and the hourly dimensioning of reserve needs. The regional dimensioning and procurement of reserves in option 1b would imply a transfer of some responsibilities from national TSOs to regional bodies. The one-off costs are estimated to be of the order of 59-219 M€, while the ongoing costs are of the order of 23-42 M€. Finally, in option 2, a lower number of such entities would be created since reserves would be dimensioned and procured at an EU-level instead of at a regional level. The one-off costs of option 2 are estimated to be of the order of 24-125 M€, while its ongoing costs are of the order to 7-12 M€.

The benefits associated with option 1ab mainly originate from the possibilities offered by the removal of sub-optimal reserve procurement practices and the independent procurement of upwards and downwards reserves. The latter policy measure allows cheap generation technologies to concentrate on electricity production and to lower their participation in the procurement of upwards reserves. Option 1ab results in savings of the order of 1.8 B€. The regional cooperation introduced in option 1b further lowers the costs of the European power system by around 1.6 B€. In this option, less reserve capacity is to be procured thanks to the introduction of a mutual assistance scheme between Member States. This results in further cheap generation technologies being available for power production. Finally in option 2, a number of distributed resources are pulled into the market: demand-side response and renewable energy systems participate in the reserve procurement exercise. Moreover, the reserve needs are dimensioned at an EU-level, freeing additional capacity and allowing it to participate in the electricity markets. As a result, option 2 generates extra savings of around 1.1 B€.

As can be read from the following table, the benefits of all the options for the Market Design Initiative are found to significantly outweigh the costs. Option 1ab has a 10-year NPV of around 15 B€, option 1b of around 27 B€, and finally option 2, with around 36 B€, has the highest NPV of all the considered options.

[1] The Net Present Value (NPV) is computed using a 4% discount rate on an indicative 10 year duration. This should not be interpreted as the benefits over a 10-year period (the capacity mix and demand would be different).

Options for the Market Design Initiative	Option 1ab		Option 1b		Option 2	
	One-off	Ongoing	One-off	Ongoing	One-off	Ongoing
Costs	-	-	58.8-218.5 M€	23.0-42.2 M€	23.9-125.1 M€	7.3-12.3 M€
Benefits	-	1.8 B€	-	3.4 B€	-	4.5 B€
NPV[1]	15 B€		27 B€		36 B€	

Summary

Overall, all the measures investigated in this report appear significantly beneficial in terms of system costs: based on our estimates, the benefits clearly outweigh the costs for both the options for the Guideline on Electricity Balancing and the MDI options. Assuming our modelling is representative, their adoption, by increasing the flexibility of the power system, strengthening regional cooperation and pulling additional resources into the market, would lessen the overall cost of the power system to the ultimate benefit of EU citizens and businesses.

Limitations

Scope

Our estimates are based on a number of assumptions. The costs reported in this study are mainly based on costs published by pilot projects. One can expect that, as lessons are drawn for these pilot projects, the implementation costs presented herein could be overestimated. Equally, however, it may prove that implementation of live projects across large regions in Europe result in costs which were not foreseen in the pilots.

In a similar way, the benefits analysis is based on modelling which relies on a number of assumptions in terms of inputs. Changes to the input dataset may materially change the outputs. Our benefits calculations may be overestimated since they do not take into account the fact that pilot projects are already partly implementing some of the policy measures that are foreseen in the options discussed above.

However, we do not expect the conclusion drawn above to be significantly impacted by these limitations.

Model

The dimensioning of reserves is based on a probabilistic approach. The results may differ if one were to consider the deterministic approach currently used by many Member States. METIS also assumes that the 2030 balancing markets will be perfectly liquid, which is not what is currently observed in many Member States. Finally, the analysis is based on an NTC description of the network, which does not capture costs related to congestion within Member States.

One should note that the analysis presented in this report aims at quantifying the impacts of different models of regional cooperation on the procurement and activation of frequency restoration reserves. Additional savings could be generated if one were to include replacement reserves in the analysis.

3. INTRODUCTION AND BACKGROUND

The present document has been prepared by Artelys and its subcontractors under the existing COWI Service Framework Contract with DG ENER covering Impact Assessments and Evaluations (ex-ante, intermediate and ex-post) in the field of Energy (Ref. ENER/A4/2014-516) and in response to the Terms of Reference included under Work Order ENER/B2/556-2016.

Readers should note that the report presents the views of the Consultant, which do not necessarily coincide with those of the Commission.

3.1. INTRODUCTION AND STRUCTURE OF THE REPORT

This report sets out an assessment of the costs and benefits associated with options to integrate national electricity balancing markets across the EU. The integration of electricity balancing markets is essential to the creation of a well-functioning Internal Electricity Market, and therefore an important step towards realising a common market for electricity. By presenting analysis on the nature and scale of the costs and benefits realised under alternative options for integration, it is hoped that this report will help inform EU policy on market integration to the ultimate benefits of its citizens.

In the remainder of this section, we set out in further detail the scope and objectives of the report (Section 3.2), and provide some brief background on both the importance of balancing integration and the relevance of this work to current EU regulatory and legislative efforts.

Section 4 provides a detailed description of the options. Importantly, we distinguish between options that are being considered in the context of the Guideline on Electricity Balancing, and those being considered under the Market Design Initiative. The Guideline, as an implementing act of the Regulation 714/2009 on conditions for access to the network for cross-border exchanges in electricity, will define EU-wide rules related to the operation of electricity balancing markets and is currently under consideration by the European Commission. By contrast, the Market Design Initiative intends to revise the primary legislation and focuses on longer-term integration not covered by the Guideline, with a view to identifying areas where further legislative action may be required.

Section 5 provides a qualitative assessment of the costs and benefits associated with both sets of options. It develops a framework for thinking about and assessing these costs and benefits and specifies which costs and benefits are relevant to each option.

Section 6 attempts to quantify the costs and benefits identified in Section 4, explaining the methodology used and highlighting gaps in the quantitation. It also summarises the implications of our analysis for the relative performance of the options.

Section 7 provides a brief summary of the analysis presented, drawing out the key conclusions for both the Guideline on Electricity Balancing and the Market Design Initiative.

3.2. SCOPE AND OBJECTIVES OF THE ANALYSIS

This report aims to enable an accurate comparison of the costs and benefits of different options to integrate national electricity balancing markets across the EU. Specifically, it sets out the nature of the likely costs and benefits that result from these options and, where possible, seeks to value the relevant effects. Benefits have been quantified using a model of the European power sector, METIS, which is described further in Appendix A. Costs have been extrapolated from pre-existing estimates, drawn largely from a review of the related literature. These estimates are made at a European level and reflect an annual impact unless otherwise stated. Whereas the benefits are likely to be realised on an ongoing basis, many of the costs associated with integration are one-off and this distinction is highlighted in the results.

Two distinct sets of options have been considered and these are described in greater detail in Section 4. One set relates explicitly to the policy choices available as part of the creation of a Guideline on Electricity Balancing. As described in the next section, this Guideline, which is currently under consideration, is likely to establish a series of rules for the operation of EU balancing markets. The second set relates to DG ENER's Market Design Initiative (MDI), which is considering the appropriate, long-term design of an integrated European electricity market. The context to these two initiatives is discussed in further detail in the next section.

Because the options under consideration have been designed to support these two distinct processes, their scope differs. Specifically, the Guideline options consider the integration of markets for Balancing Energy, as well as some of the associated System Operator functions, but do not consider integration related to Balancing Capacity, as this is not yet mandatory under the Guideline. Conversely, the MDI options have been designed to explore Balancing Capacity integration, including both the supranational assessment of Reserve Capacity requirements and multi-national Balancing Capacity procurement processes.

3.3. BRIEF BACKGROUND TO WORK

The integration of electricity balancing markets is a necessary step towards the creation of a well-functioning Internal Electricity Market across the EU. Electricity is consumed and produced continuously in real-time and, as a result, the electricity market actually consists of a series of discrete but interlinked markets for the future consumption and generation of electricity. Balancing markets represent the final link in this chain of forward markets, being as close to real-time delivery as technical constraints allow. Because electricity for the same point in time is traded in the future, day-ahead, intraday and ultimately balancing markets, all of these markets are inherently interlinked. Prices in the balancing market affect both the imbalance price used in ex post settlement and the intraday price. Inconsistencies and inefficiencies in the operation of balancing markets across Member States therefore lead to corresponding inconsistencies and inefficiencies in the wider elements of the electricity market and act as an important constraint on the integration of the electricity market as a whole.

To date, and despite the fundamental position of balancing markets within the wider electricity market, significant variation in the operation of balancing markets has persisted among Member States. This reflects both underlying differences in the types of balancing resources available to the national markets, and the fact that purchases in the balancing market are generally limited to the relevant national system operator.

The potential benefits of integrating electricity balancing markets, which are considered more fully in Sections 5 and 6, are widely acknowledged, and in some cases already being realised through specific examples of regional cooperation (e.g.: Nordic balancing market, IGCC). They include the possibility of netting imbalances across borders, reducing both countries' balancing energy activation and thereby reducing their costs of balancing. Integration of electricity balancing markets can also facilitate a reduction in balancing costs where countries with relatively expensive balancing resources are able to substitute these for cheaper, unused balancing assets in neighbouring countries.

Given the importance of balancing market integration in supporting the efficiency of an Internal Electricity Market, the Commission is actively considering the options for balancing market integration.

As noted in Section 3.2 above, this report considers options relevant to both the creation of a Guideline on Electricity Balancing and longer-term considerations of the structure of the market under the Market Design Initiative.

The Guideline on Electricity Balancing is intended to establish an EU-wide set of technical, operational and market rules to govern the functioning of electricity balancing markets. Like Network Codes and other Guidelines, it is explicitly intended to drive collectively-beneficial energy market harmonisation through a process established under the 2009 Third Energy Package.[2] In accordance with this process, a draft Guideline on Electricity Balancing has been developed by TSOs, through ENTSO-E, and this has subsequently been recommended to the Commission by ACER in July 2015. The Commission is now considering whether to propose the Guideline to Member States for adoption, and this report is intended to inform the Commission's own Impact Assessment, as part of these considerations.

The Market Design Initiative is a review of the legislative instruments needed to facilitate the creation of an integrated European energy market, with the aim of recommending a package of new legislative measures by the end of this year.[3] This package would effectively update and extend the 2009 Third Energy Package in order to address new or evolving challenges to energy market integration. Although the integration of electricity balancing markets represents only a part of the MDI's scope, the Commission's recommendation will ultimately need to be informed by an understanding of where further integration is desirable and what form it should take. This is especially true of potential integration that is beyond the scope of the draft Guideline currently under consideration, such as supranational assessments of the Reserve Capacity requirements and multi-national Balancing Capacity procurement processes. These issues are therefore addressed separately within this report.

[2] The Third Energy Package is a set of European legislation, consisting of three European Regulations and two European Directives that, among other things, establishes bodies and processes to facilitate the integration of the EU energy market.

[3] Further information on the MDI's objectives can be found in the Commission Communication COM(2015) 80 final.

4. DESCRIPTION OF THE OPTIONS

4.1. INTRODUCTION

This section is devoted to presenting the different models for

- **Cross-zonal exchange of balancing energy**
  Cross-zonal exchange of balancing energy is a process that allows TSOs facing imbalances to activate balancing energy abroad if there is sufficient remaining capacity on interconnectors. Cross-zonal exchanges of balancing energy are expected to give rise to savings since TSOs would not be limited to domestic reserve providing units, and would therefore be able to lower their costs if cheaper units are available abroad. All models of cross-zonal exchange of balancing energy are compatible with national, regional and EU-wide dimensioning and procurement of balancing capacity: the exchange of balancing energy can occur even in situations in which MSs dimension and procure their balancing capacity nationally.

- **Regional dimensioning and procurement of balancing capacity**
  The second set of models whose impacts are assessed in the following are related to the dimensioning and procurement of balancing capacity. When using a national approach, MSs dimension their balancing capacity so as to be able to face their imbalances independently. From a cost efficiency point of view, it would be preferable to reserve balancing capacity at a regional level. Regional dimensioning allows MSs to face the same level of risk with less capacity since imbalances tend to statistically cancel out. The models of regional dimensioning and procurement of balancing capacity assume that TSOs are able to exchange balancing energy in order to be able to manage their national risks.

The two sets of options are investigated independently, but, as mentioned previously, the implementation of the Guideline on Electricity Balancing is a necessary first step before envisaging regional dimensioning and procurement of balancing capacity.

4.2. GUIDELINE ON ELECTRICITY BALANCING

The objective for the Guideline on Electricity Balancing is to define a model for cross-zonal exchange of balancing energy. The options considered below differ in terms of the standardisation of balancing energy products and exchanges of balancing products between TSOs. The analysis focuses on the netting and cross-zonal exchange of aFRR and mFRR (FCR and RR[4] are excluded from the analysis).

In order to concentrate on the impacts of the different models of cross-zonal exchange of balancing energy, we have used a common day-ahead simulation for all options. This simulation results in the day-ahead dispatch of electricity and national portfolios of balancing capacity. The day-ahead simulation, performed with the METIS model (see Appendix A), assumes:

- **Scenario**
  The 2030 METIS EuCo27 scenario is used throughout this study[5]. The installed capacities, fuel costs, CO_2 cost, and interconnection net transfer capacities are based on the 2030 PRIMES EuCo27 scenario.

[4] https://consultations.entsoe.eu/markets/terre/supporting_documents/20160307_TERRE_Consultation_FV.pdf

[5] See the following supporting document for more details "Integration of PRIMES scenarios into METIS – Description of the Methodology", Artelys (2016)

- **Energy**
  - No priority dispatch for RES producers[6].
  - RES producers are balance responsible. As a consequence, it is assumed that RES producers use good quality forecasting methods (h-1 forecast for demand, PV and outages; h-30' for wind), thereby resulting in fewer imbalances compared to the current situation.

- **Reserves**
  - FRR reserves are assumed to be dimensioned at the national level. This mostly corresponds to current practices (FRR should be dimensioned at LFC Block level according to ENTSO-E System Operation Guideline), the exceptions being the Nordics, the Baltic countries[7], Spain and Portugal, and the SHB LFC Block (Slovenia, Croatia, Bosnia & Herzegovina). This assumption therefore tends to overestimate the need for balancing capacity.
  - FCR and FRR reserves needs remain constant over the year.
  - Current sub-optimal practices in FCR and aFRR reserve procurement are assumed to be removed[8].
  - Upwards and downwards aFRR reserves are assumed to be procured independently[9].
  - RES is assumed to be able to participate in reserves procurement.
  - Demand-response is assumed not to participate in reserves.

It should moreover be noted that METIS jointly optimises the day-ahead provision of electricity and the procurement of balancing capacity. Although this differs from current practices, it mimics the fact that electricity producers take both markets into account (energy and reserves) when determining their bidding strategies.

4.2.1. *POLICY DESCRIPTION*

<u>Baseline</u>

The baseline assumes no further EU action on cross-border exchanges of balancing energy (other actions are assumed to be taken in other sectors, see discussion above). It assumes that imbalances are not netted, and that there are no cross-zonal exchanges of balancing energy.

The assumptions likely result in an overestimation of the costs of the baseline since it disregards the possible implementation of regional initiatives, which could emerge even if the EU takes no further action. This option does not take into account current initiatives

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[6] Priority dispatch is a policy measure giving priority to generators using renewable energy resources. The removal of priority dispatch practices is foreseen in MDI option 1a, which aims at ensuring all generators compete on a level playing field. In practice, the absence of priority dispatch mainly impacts biomass units, since they may be "out of the money" due to their high variable costs (i.e. their bids would not be selected when the market is cleared).

[7] The Baltic countries are synchronously interconnected with the IPS/UPS synchronous grid. It is therefore assumed they will not be impacted by the Guideline on Electricity Balancing. However, in order to be consistent with other Impact Assessments, they are included when analysing the MDI options.

[8] The following countries currently adopt suboptimal FCR procurement practices: BE, EE, ES, FR, HR, IT, LT, LV, PT, SI, SK, UK. The following countries currently adopt suboptimal aFRR procurement practices: EE, FR, LT, LV, UK. Source: "Electricity Market Functioning: Current Distortions, and How to Model Their Removal", COWI (2016).

[9] The following countries currently jointly procure upwards and downwards aFRR reserves: BE, DK, EE, ES, FR, HR, IT, LT, LV, PL, PT, RO, SI, SK, UK. Source: "Electricity Market Functioning: Current Distortions, and How to Model Their Removal", COWI (2016).

such as the IGCC[10] imbalance netting initiative and pilots of cross-zonal exchanges of balancing energy such as RPM[11]. IGCC reports that the value of netted imbalances in 2013 is around 50 M€[12]. RPM reports annual consumer surplus gains of the order of 200 M€ for 2013[13]. The overestimation of the costs of the baseline is not straightforward to evaluate since the previous two figures are not directly comparable with the results presented in this report.

Option A – Binding regulation on cross-border exchanges

This option would introduce binding regulation on imbalance netting and cross-zonal exchanges for selected balancing resources (cross-zonal exchanges are only allowed if they result in the avoidance of loss of load. The stochastic nature of imbalances can result in situations where a country is short while one of its neighbours is long at the same moment. In such situations, without cooperation between TSOs, positive and negative FRR would be activated simultaneously: positive in the short country and negative in the long one.

Imbalance netting would ensure that simultaneous activations of positive and negative aFRR and mFRR are avoided. This option assumes EU-wide imbalance netting, assuming that netting can also be applied between separate synchronous zones linked via DC interconnectors, subject to available transmission capacity. The activation of balancing energy can therefore be decreased compared to the baseline thanks to imbalance netting.

The assumptions likely result in an overestimation of the costs of option A since this option does not take into account existing pilots of cross-zonal exchanges of balancing energy such as RPM.

Implementing option A would mean introducing a technical system for imbalance netting and a settlement process. Option A would also require an infrastructure for TSO-TSO or BSP-TSO trading and settlement arrangements.

Option B – Binding regulation on cross-zonal and national exchanges

This option would introduce a binding regulation on imbalance netting and cross-zonal exchanges of all balancing resources. Further to option A's imbalance netting, TSOs would also be able to exchange standard balancing products at an EU level. All bids that are available in each control area would be gathered in a single Common Merit Order List (CMOL), leading to resources being activated according to a merit order approach subject to available transmission capacity. As a result, cheaper balancing resources would displace the more expensive ones.

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[10] The International Grid Control Cooperation (IGCC) initiative is a cooperation between TSOs which deals exclusively with Imbalance Netting for aFRR reserves under residual transmission constraints at the borders. IGCC is composed, from 2016, of 10 TSOs from 7 countries: 50Hertz, Amprion, APG, CEPS, Elia, Energinet.dk, Swissgrid, TenneT B.V., TenneT G and TransnetBW.

[11] The "Regulating Power Market" (RPM) initiative is a cooperation between the Nordics which deals with the exchange of mFRR products.

[12] See e.g. https://www.entsoe.eu/Documents/Network%20codes%20documents/Implementation/Pilot_Projects/140514_CBB_pilot_projects_1-9.pdf. Note that the IGCC figure is obtained using a different methodology, and thus is not directly comparable to the figures quoted in this report.

[13] See e.g. https://www.entsoe.eu/Documents/Network%20codes%20documents/Implementation/Pilot_Projects/140911_CBB_pilot_project_5_RPM.pdf. Note that the RPM benefits quantify the consumer surplus gains, and should not be compared with the cost savings presented in this report. The subdivision of the 200 M€ between imbalance netting, cross-zonal exchange of balancing energy, and benefits related to the regional dimensioning and procurement of balancing capacity is not provided.

Two key aspects are needed to implement option B: an imbalance netting system (as in option A) and an EU-wide exchange and settlement system, including provisions for clearing process and algorithm, hosting, maintenance and support.

Option C – Binding regulation enforcing one or several regulated entities to perform the tasks of supranational balancing operators[14]

This option would involve the introduction of one or several supranational operators that would be responsible for balancing (imbalance netting and cross-zonal exchange of balancing energy) and cooperating with national TSOs. All balancing products would be gathered in a single CMOL. Thanks to the increased level of interaction amongst TSOs that is foreseen in this option, one can expect that TSOs will be able to better manage the transmission grid by sharing precise information on the state of the network. As a consequence, one can expect a reduction of the security margins on cross-zonal transmission lines, thus offering more transmission capacity for imbalance netting and cross-zonal exchanges of balancing energy.

Three key aspects are needed to implement option C: an imbalance netting system (as in option A), an EU-wide exchange and settlement system, including provisions for clearing process and algorithm, hosting, maintenance and support (as in option B), and the establishment of one or several regulated entities to coordinate with national TSOs.

The three options considered for the Guideline on Electricity Balancing are compatible with either national or regional dimensioning and procurement of balancing reserve capacity[15]. The bodies that would be introduced under option C would therefore not necessarily correspond to those whose introduction is discussed in the MDI options.

4.2.2. Implementation in METIS

A brief introduction to the METIS model is presented in Appendix A. In order to evaluate the benefits of each of the options for the Guideline on Electricity Balancing, a common day-ahead situation is used.

The portfolio of available technologies for balancing energy (capacity) and the state of the system (incl. utilisation of cross-zonal transmission capacity) is determined by the common day-ahead simulation. The different models of cross-zonal exchange of balancing energy differ in the way they exploit the balancing resources and the remaining transmission capacity.

The following table describes the main differences between the options for the Guideline on Electricity Balancing:

[14] Note that option C lacks legislative and juridical support, and, as a result, might be disregarded. Even though the precise implications of option C on the modelling assumptions might be difficult to identify, it is interesting to assess the impacts of a tighter collaboration between TSOs.

[15] Strictly speaking a regional dimensioning and procurement of reserves only requires regional exchanges of balancing energy.

Concept	Baseline	Option A	Option B	Option C
Imbalance netting	No[16]	EU-wide	EU-wide	EU-wide
Exchange of balancing energy	No[17]	No	EU-wide	EU-wide
Cross-zonal transmission available for balancing	-	NTC	NTC	NTC+15%

4.3. MARKET DESIGN INITIATIVE

The objective of the MDI options considered in this study is to introduce measures to better interconnect short-term markets and to pull all flexible distributed resources into the market. These measures impact the dimensioning of reserve capacity and the procurement of balancing capacity by defining areas wider than national borders over which these operations should be performed.

Larger balancing zones (or Load-Frequency Control areas) and more frequent recalculation of balancing capacity needs will result in lower amounts of required reserve capacity while at the same time giving TSOs access to more balancing resources such as demand-response and renewable energy sources.

The impacts of the different models of regional dimensioning and procurement of balancing reserves have been assessed by simulating the operations of the European power system. This simulation results in a day-ahead dispatch of electricity and national portfolios of balancing capacity. The day-ahead simulation, performed with the METIS model (see Appendix A), assumes:

- **Scenario**
  The 2030 METIS EuCo27 scenario is used throughout this study. The installed capacities, fuel costs, CO_2 cost, and interconnection net transfer capacities are based on the 2030 PRIMES EuCo27 scenario.

- **Energy**
  - No priority dispatch for RES producers.
  - RES producers are balance responsible. As a consequence, it is assumed that RES producers use good quality forecasting methods (h-1 forecast for demand, PV and outages; h-30’ for wind), thereby resulting in fewer imbalances compared to the current situation.

Finally, it should be noted that METIS jointly optimises the day-ahead provision of electricity and the procurement of balancing capacity. This procedure mimics the fact that electricity producers take both markets into account (energy and reserves) when determining their bidding strategies. All MDI options assume that option B of the Guideline on Electricity Balancing is implemented, so as to allow the exchange of balancing energy, which is a prerequisite for MDI options 1b and 2.

[16] As noted in Section 4.2.1, the baseline does not take current initiatives into account (e.g. IGCC).

[17] As noted in Section 4.2.1, the baseline does not take current initiatives into account (e.g. RPM).

4.3.1. POLICY DESCRIPTION

Baseline

The baseline assumes no further EU action on the dimensioning and procurement of balancing capacity (other actions are assumed to be taken in other sectors, see discussion above). In particular, it assumes the national dimensioning of balancing reserves and the national procurement of balancing capacity.

These assumptions likely result in an overestimation of the costs of the baseline since the baseline disregards the possible implementation of regional initiatives, which could emerge even if the EU takes no further action. Furthermore, this option does not take into account current initiatives such as the common dimensioning of FRR reserves in the Nordic system (RPM initiative). As noted in Section 4.2.1, the RPM quotes annual consumer surplus gains of the order of 200 M€. It is however not straightforward to estimate what proportion of this figure should be associated with the Guideline on Electricity Balancing policy measures, and what should be with the MDI policy measures.

Option 1ab: Binding regulation on cross-zonal exchanges

This option would consist in removing a number of inefficiencies in the national reserve procurement processes.

This option foresees the removal of current sub-optimal practices in FCR and aFRR reserve procurement (such as annual allocation to thermal power plants)[18]. Upwards and downwards aFRR reserves are assumed to be procured independently[19]. The reserves requirements are assumed to depend on the hour of the day and on the share of intermittent RES. Finally, the balancing products are assumed to be auctioned daily in the form of hourly products.

Option 1b: Binding regulation on cross-zonal and national exchanges

This option involves the setup of European binding regulation allowing TSOs to share balancing capacity. Regional entities would be responsible for the dimensioning of reserve capacity and the organisation of the procurement of balancing capacity by national TSOs. A strong cooperation of TSOs would be required in order to determine the amount of reserve capacity necessary in their control areas, taking into account the consequences of cross-zonal transmission capacity reservation. For example, this could be achieved by enhancing the capabilities of the Regional Security Coordinators (RSCs)[20]. Thanks to the increased level of interaction amongst TSOs that is foreseen in this option, one can expect that TSOs will be able to better manage the transmission grid by sharing precise information on the state of the network. As a consequence, one can expect a reduction of the security margins on cross-zonal transmission lines, thus offering more transmission capacity for day-ahead and balancing markets. The cross-zonal transmission capacities in this case are assumed to be about 5% larger than in the two previous options.

[18] The following countries currently adopt suboptimal FCR procurement practices: BE, EE, ES, FR, HR, IT, LT, LV, PT, SI, SK, UK. The following countries currently adopt suboptimal aFRR procurement practices (source: COWI): EE, FR, LT, LV, UK. Source: “Electricity Market Functioning: Current Distortions, and How to Model Their Removal”, COWI (2016).

[19] The following countries currently jointly procure upwards and downwards aFRR reserves: BE, DK, EE, ES, FR, HR, IT, LT, LV, PL, PT, RO, SI, SK, UK. Source: “Electricity Market Functioning: Current Distortions, and How to Model Their Removal”, COWI (2016).

[20] Regional Security Coordinators are entities owned or controlled by TSOs, in one or more capacity calculation regions performing tasks related to TSO regional coordination (source: ENTSO-E System Operation Guideline)

Option 2: Binding regulation enforcing regional TSOs

This option would result in a significant evolution of the current design of European electricity systems operation. A supranational entity would be responsible for the dimensioning of reserve capacity and the procurement of balancing capacity at an EU level. TSOs would still be responsible for real-time activation; however, they would only have access to a single EU platform for the procurement of balancing capacity. The further strengthening of cooperation between TSOs that is foreseen in option 1b is reflected by an additional increase of the cross-zonal transmission capacity by 5%.

4.3.2. Implementation in METIS

A brief introduction to the METIS model is presented in Appendix A. The following table describes the main differences between the MDI options:

Concept	Baseline	Option 1ab	Option 1b	Option 2
Reserve Capacity dimensioning	Fixed over the year	Variable	Variable	Variable
Reserve Capacity dimensioning	National	National	Regional	EU
Balancing Capacity procurement	Suboptimal	Optimal	Optimal	Optimal
Cross-zonal transmission capacity	NTC – 5%	NTC – 5%	NTC	NTC + 5%
Cross-zonal transmission capacity reservation	No	No	Yes	Yes
Upwards and downwards bids	Joint[21]	Separate	Separate	Separate
RES participation to Balancing Capacity procurement	No	No	No	Yes

The following paragraphs succinctly describe some of the concepts appearing in the previous table. More details can be found in *METIS Technical Note T3 - Focus on day-ahead, intra-day and balancing markets.*

- **Dimensioning of reserve capacity**
  In the baseline, reserve capacity requirements are assumed to be constant over the whole year. In option 1ab, 1b and 2, aFRR capacity requirements depend on the state of the system (mainly impacted by demand and wind production), which results in lower reserve capacity requirements. FCR and mFRR needs are assumed to remain constant over the whole year.

  In the baseline and option 1ab, the reserve capacity requirements are computed at the national level, thereby allowing each of the countries to cover their own imbalances independently. In option 1b, the reserve capacity requirements are

[21] Note that the Guideline on Electricity Balancing already require the separation of upwards and downwards bids for FRR.

computed at regional level, which results in lower needs thanks to the risk pooling effect: the probability that imbalances cancel each other increases as one increases the area on which they are observed. Finally, in option 2, the reserve capacity requirements are computed at an EU level.

- **Procurement of balancing capacity**
  In the baseline, one assumes that the countries which currently follow suboptimal procurement practices (see footnote 18) do not modify their practices. In option 1ab, 1b and 2, suboptimal procurement practices are phased out, meaning that balancing capacities are procured as hourly products during the day-ahead market, and that all plants that meet the technical requirements can participate in the procurement.

- **Reservation of cross-zonal transmission capacity**
  The cross-zonal transmission capacity available to trade energy and balancing capacity is assumed to reflect the tighter collaboration between TSOs in options 1b and 2. Moreover, since options 1b and 2 assume regional or EU-wide dimensioning of reserve capacity requirements, it is necessary that cross-zonal transmission capacities be reserved, so as to ensure balancing energy can be exchanged by MSs.

- **Separation of upward and downward balancing capacity**
  In the baseline, one assumes that upwards and downwards balancing capacities are jointly procured, except in countries which already follow separate procurement practices (see footnote 19). In a country using such practices, units providing balancing capacity have to simultaneously provide upwards and downwards capacity. Options 1ab, 1b and 2 assume that these practices are phased out in all countries and that upwards and downwards balancing capacities are procured independently.

5. QUALITATIVE ASSESSMENT OF COSTS AND BENEFITS

5.1. STRUCTURE AND DESCRIPTION OF DIFFERENT COSTS AND BENEFITS

This section sets out a framework for the consideration of each of the option's cost and benefits, with the aim of ensuring that all impacts are considered and that the categories used are mutually exclusive, readily understandable, and directly applicable to the options considered. We begin by describing all of the cost and benefit categories and the factors that are likely to influence them. Where relevant, distinctions are drawn between those impacts which relate to the integration of markets for Balancing Energy and those that relate to the integration of markets for Balancing Capacity. Section 4.2 then maps these costs onto the options, detailing the categories relevant to each option under consideration. Attempts to quantify these impacts are reserved for Section 5.

5.1.1. COSTS

Figure 2 sets out the various cost categories relevant to one or more options. Each of these is discussed in more detail below[22].

Figure 2 – Costs of electricity balancing market integration

<table>
<tr><th></th><th>Balancing energy</th><th>Balancing reserves</th></tr>
<tr><td>Imbalance netting</td><td>Common technical controller
Settlement and process system</td><td></td></tr>
<tr><td>TSO-TSO trading and settlement</td><td>Limited standard product design cost
Regional trade and settlement processes</td><td></td></tr>
<tr><td>Europe-wide or regional exchange</td><td colspan="2">Exchange platform
Settlement system
Clearing algorithm & process
Hosting, maintenance, support, etc.</td></tr>
<tr><td>Europe-wide or regional system operator(s)</td><td colspan="2">Administrative costs
Control block redesign
Technical investment to centralise SCADAs
Regional agreement on funding & responsibilities</td></tr>
<tr><td>Product standardisation</td><td colspan="2">Standard product development
TSO & BSP process adaptation
Extent of standardisation depends on option</td></tr>
<tr><td>Gate closure harmonisation</td><td>TSO & BSP process adaptation</td><td></td></tr>
<tr><td>Security of supply risk</td><td colspan="2">Operational risk due to process change</td></tr>
<tr><td>Opportunity cost of transmission capacity</td><td></td><td>Reduced energy market arbitrage</td></tr>
</table>

[22] The efficiency of cross-zonal exchanges of balancing energy would be supported by the harmonisation of imbalance pricing and of imbalance settlement periods. These changes would themselves entail costs not included below. Further consideration of the costs of ISP harmonisation can be found as part of ENTSO-E's Cost Benefit Analysis for the Imbalance Settlement Period, available at: https://www.entsoe.eu/major-projects/network-code-implementation/cba-imbalance-settlement-period/Pages/default.aspx

Imbalance netting

The implementation of imbalance netting across balancing zones requires the integration of the related technical systems and processes responsible for preserving real-time energy balance, and the creation of a system of settlement to account for the value of energy traded between areas as part of the netting process.

The first of these costs essentially requires that a central controller be created to sit between and interface with the respective balancing control systems already in place in each zone. The central controller takes information on the imbalance prevailing in each zone and identifies a series of netting actions, in which excess energy in one zone can be transferred to a zone with insufficient energy. It then sends a revised estimate of the imbalances that will exist post-netting to the pre-existing (national) balancing control systems, which undertake any necessary residual balancing actions without the risk of them overcorrecting. The additional costs associated with this are largely the one-off costs of establishing the central common technical controller. Because the control interfaces with existing (national) control systems, as opposed to directly with balancing parties, these costs are typically fairly limited.

Since this netting process may result in systematic flows of balancing energy from one zone to another, netting will also require a form of settlement between the respective TSOs. Were this not the case, a balancing zone that tended to export power under the netting process could find itself financially worse off, since it loses out on potential revenues from the activation of downward balancing actions. A simple process to value the exchanges of energy between TSOs is therefore also required. This is likely to entail a relatively small, one-off setup cost.

There are likely to be fixed costs associated with creation of both systems. Total costs are expected to increase with the number of parties involved, as more TSOs need to adapt their existing processes to interface with the central controller and settlement process.

TSO-TSO or TSO-BSP trading and settlement

Some of the options envisage exchanges of Balancing Energy through TSO-BSP or TSO-TSO arrangements, as opposed to the creation of a centralised exchange.

The creation of a system like this involves the identification or creation of a cross-border product or products to be bilaterally traded and the establishment of the trading and settlement processes needed to effect trades in a timely manner.

The costs of creating the cross-border product(s) are likely to be one-off and fairly minimal. Essentially the TSOs must agree among themselves a specification that is both useful and deliverable given the underlying balancing energy products available to them. The costs of establishing a trading system are likely to be more material, since this system will need to interface with the TSO's own systems and processes in such a way that each TSO can compare the national and cross-zonal balancing actions available to it and ensure that cross-zonal flows are consistent with any trades agreed. In practice, this is likely to entail some one-off transition costs to build the relevant IT infrastructure and integrate this within existing systems. Thereafter, the on-going costs of the system are likely to be fairly minimal.

Europe-wide or regional exchange

Some options envisage the use of Common Merit Order lists to facilitate trade in Balancing Energy or Balancing Capacity. In these cases, there will be costs associated with establishing and maintaining the relevant exchange(s). The principal costs of the system are likely to include the design and creation of an IT platform, where bids and offers can be posted and trades effected, and an associated settlement process to ensure that payments are made in accordance with these trades.

Ideally, the exchange would automatically account for technical constraints, e.g. the availability of cross-zonal transmission capacity, even if the ultimate responsibility for managing power flows was left elsewhere. This would entail the creation of a potentially complicated clearing process, automated through the design of an appropriate algorithm. The complexity of this process could significantly add to the costs of establishing the exchange, but would reduce the transaction costs involved in each trade. In particular, technical constraints not accounted for by the platform will otherwise need to be checked independently by trading parties, who would need to confirm the technical validity, by other means, of the offers shown.

An exchange of this type would also have material on-going costs associated with hosting and maintaining the exchange, as well as providing support to its users. There would be substantial fixed costs associated with creating the central or regional platform(s). Absolute costs can also be expected to increase with the number of TSOs participating, both as a result of an increasingly complicated clearing process and because more parties will need to be supported in using the exchange.

Europe-wide or regional regulated entities performing the tasks of supranational balancing operator(s)

Where some system operator functions are transferred to a regional body, there will be costs associated with the creation or expansion of the relevant institution in order to enable it to undertake these tasks. These costs could include accommodation and staffing costs, as well as the technical costs associated, for example, with the development of the business systems needed to fulfil its responsibilities. In addition to these setup costs, the relevant organisation will have on-going costs, for example staffing costs.

In theory, some of these administrative costs may be offset by cost reductions in those national organisations whose responsibilities are reduced. However, there may be a degree of duplication, in which previous system operators retain their functionality, in order to assure the performance of the regional system operator. In such cases, the scope for cost reductions will be limited.

The associated technical costs will depend on exactly what functions are transferred to the regulated entities. Where these functions can't be effectively performed without changing the SCADA systems previously in use, it may be necessary to not only develop an appropriate system for use by the new system operator, but also to mandate that various Balancing Services Providers incur costs in order to transition to the new system. Given the number of potential actors involved, we'd expect these costs to be comparatively large in aggregate.

The creation of Europe-wide or regional regulated entities performing the tasks of a supranational balancing operator(s) would also necessitate the creation of associated multilateral funding and regulatory processes. These will have a fixed cost to establish, and may imply some additional on-going costs related to the need for persistent regulatory oversight.

Product standardisation

The standardisation of Balancing Energy and Balancing Capacity products would make it easier for system operators to compare offers from different markets. It would also make the relevant markets more liquid, thereby providing greater price certainty to all parties. However, the process of standardising products will likely entail a variety of costs.

The bulk of these will be one-off transitional costs as new product specifications are designed and various business and control system are amended to accommodate the revised product specifications. Since these changes are likely to impact a large number of actors, including Balancing Service Providers, the aggregate costs of standardisation may be quite large, even if the costs to any individual party are small.

In addition to these one-off costs, product standardisation may result in on-going efficiency losses if the final set of standardised products fails to reflect the technical characteristics of some balancing resources. For example, if a Balancing Service Providers is capable of providing Balancing Energy more rapidly than required by the standard product definition, and this faster service could technically be used to reduce overall system costs, it may nevertheless be the case that it is not used, and the potential efficiency forgone, because its technical superiority is hidden under the standard product definition.

Standardisation can clearly be carried out to various degrees, with greater standardisation likely to increase both costs and the associated benefits, e.g. comparability and product liquidity. As noted above, costs are expected to increase rapidly where standards necessitate investments on the part of Balancing Service Providers.

Gate closure harmonisation

The harmonisation of gate closure times is not a prerequisite for trade in balancing services and is not envisioned as part of the implementation costs of these options. However, it is important to note that, under a TSO-BSP trading model, asymmetry in gate closure times would mean that BSPs in the market with an earlier closure time will effectively have to exit the relevant cross-zonal market early. This may give rise to a distortion in competition and asymmetric gains from trade. This issue is not present under a TSO-TSO model of trade.

Gate closure harmonisation is likely to be a feature of any move to regional regulated entities with responsibility for balancing. The costs of harmonisation relate primarily to the need to update business systems and processes in order to adapt to the change in gate closure. These changes would affect a far wider group than Balancing Service Providers alone, including generators and suppliers. Again, the aggregate costs of harmonisation could be significant in aggregate, given the large number of parties affected, even if the costs to an individual party are small.

The costs of gate closure harmonisation would be expected to be entirely transitory, with no on-going cost associated with the change. Indeed, businesses operating internationally may even realise some small efficiency gains associated with the standardisation of gate closures across their business.

Security of supply risk

Many of the options considered entail some procedural or technical changes to the balancing system. Inevitably, there is an operational risk associated with this transformation process and, because balancing activity is so critical to the operation of the power system, these failures have the potential to negatively impact on security of supply. For example, where balancing services are not provided as anticipated because of a process change, the stability of system frequency could suffer as a result.

Given the obvious link to system security, it is likely that the risks arising from any change will be carefully considered and appropriate actions taken to deal with them.

We note this cost therefore not because we expect that any of the options will give rise to a significant likelihood of a security of supply problem, but rather because the cost impact of such an event could be very large and so even very small increases in this risk may be material as part of a comprehensive consideration of the options.

Opportunity cost of cross-zonal transmission capacity

Unlike Balancing Energy, which can be traded close to real-time and after gate closure, Balancing Capacities are necessarily traded before gate closure, before the availability of cross-zonal transmission capacity is known. One important implication of this is that, in order for cross-zonal trades in balancing capacity to be firm and reliable, they need to be accompanied by the reservation of cross-zonal transmission capacity. In effect, this transmission capacity must itself be kept in reserve, in case it is required to transfer Balancing Energy from one zone to another.

Holding this cross-zonal transmission capacity in reserve prevents its use in other energy markets, and entails an opportunity cost equal to the foregone value of the electricity transmission that might otherwise have occurred. Most straightforwardly, if the reservation of cross-zonal transmission capacity means that less power can be flowed from low- to high-price electricity markets, then the value of this potential arbitrage, which is equal to the price spread that could have been realised, is lost.

The materiality of this opportunity cost will depend on the specific context. In particular, where cross-zonal transmission capacity is almost always expected to flow in one direction, the opportunity cost of reserving cross-zonal transmission capacity to flow in the opposite direction is likely to be very small. The energy market will tend to use up the full technical cross-zonal transmission capacity of the interconnector to flow in the predominant direction (A->B), but, in the event that balancing energy is required to flow in the opposite direction (B->A), this can be easily achieved by reducing the net flows from A to B. Conversely, where the reservation of cross-zonal transmission capacity is likely to routinely restrict desired energy market flows, it would have a large associated opportunity cost.

Although the opportunity costs of reserving cross-zonal transmission capacity are important to bear in mind when considering the various options, and are accounted for in the quantification of costs and benefits considered in Section 5, these costs are not split out. This is because the benefits modelling exercise undertaken to inform Section 5 works to minimise all system costs collectively, selecting the quantity of cross-zonal transmission capacity to be reserved in order to minimise overall costs. The inherent trade-off between using this cross-zonal transmission capacity for the energy market, or to support sharing of balancing capacity is therefore accounted for, but no impacts are notionally allocated to this constraint alone. Instead, the constraint acts to limit the net benefits that can potentially be realised as a result of cross-zonal trading of balancing capacity. As a result, the opportunity cost of cross-zonal transmission capacity reservation is simply noted here in order to facilitate a better understanding of the cost impacts at work.

5.1.2. BENEFITS

Figure 3 sets out the framework of benefits that arise under one or more of the options. Each of these benefits is discussed in more detail below.

Figure 3 – Benefits of electricity balancing market integration

	Balancing energy	Balancing reserves
Lower required volumes	Netting of imbalances	Netting of imbalances AND Risk pooling (dimensioning)
Greater allocative efficiency	Cheaper resource displaces more expensive resource (procurement)	
Enhanced competition	Larger number of providers increases competitive pressure	
Greater accessibility for RES and DR	Product definitions and procurement processes are amended (alongside product and procurement standardisation) to facilitate the participation of RES and DR	

Lower required volumes

Balancing activity is costly, for example because fuel must be consumed to generate additional power at short notice, or because assets must be built and maintained to cover extreme imbalances. If less of this activity is required, this represents a reduction in the costs of operating the power system. Lowering the volume of balancing actions and reserve capacity required is therefore one of the major benefits arising from the options under consideration.

The netting of positive and negative imbalances across balancing areas reduces the need for downward and upward regulation respectively in these areas, thereby reducing the total volume of balancing actions that need to be taken. This reduction in the volume of balancing actions required can also have a knock-on effect on the volume of reserve capacity required, since if TSOs can effectively rely on there being some degree of netting; they can also plan their reserve capacity requirements on the basis of a lower level of (net) imbalances.

Lower capacity reserve requirements may also result from improvements in the process for calculating capacity reserve requirements ('dimensioning'). 'Variable dimensioning' assumes more sophisticated and frequent dimensioning based on underlying system requirements. Improvements may also be possible by taking advantage of other forms of risk pooling across balancing areas. For example, a system operator with relatively few reserve providers may need to account for the possibility that part of its reserve plant becomes unexpectedly unavailable, and therefore need to build in a substantial safety margin, effectively over-procuring balancing capacity relative to the level that it would need if could be absolutely certain of its reserve capacity requirements. Were several system operators in this position able instead to assess their reserve capacity requirements collectively, they could maintain the same level of security with a smaller safety margin, because the likelihood of multiple reserve plants all being unavailable at the same time is smaller.

The reduction in reserve capacity requirements due to netting and risk pooling stems from the fact that reserve capacity requirements are being assessed over a larger system (or 'load-frequency block'). The increase in scale leads to diversification benefits. In effect, system operators can rely on the fact that problems are unlikely to occur simultaneously in all regions to maintain the same security of supply with a lower level of reserve capacity requirements.

All of the effects described above ultimately imply lower volumes of either balancing actions or reserve capacity requirements and so we consider them collectively under this category of benefits.

Greater allocative efficiency

Separate from the volume of Balancing Energy and Balancing Capacity required, is the underlying cost of providing these services. Where the cost of providing balancing services differs between balancing areas, integrating markets for these services across areas makes it possible for comparatively low-cost providers in one area to displace comparatively high-cost services elsewhere. For example, countries with relatively low-cost assets may be able to provide upwards regulation more cheaply than the fossil fuel generators used elsewhere. Were these cheaper resources used instead, the same absolute level of balancing energy could be provided at lower cost. This is an efficiency gain that results from allocating the balancing services required more cost-effectively across the pool of potential Balancing Service Providers, thereby reducing total costs.

Enhanced competition

ACER market monitoring reports[23] have previously expressed concerns that high levels of concentration in many national markets for balancing services could indicate a lack of competition. Where this is the case, consumers may be paying more than is necessary for the operation of the power system, and the efficiency of the system itself could also be harmed.

The distributional impacts of a lack of competition, although arguably not a societal cost, are clearly of interest to consumers, since, where the prices of balancing services are in excess of Balancing Service Providers' costs, consumer bills will be higher than necessary. More generally, these excessive prices may result in inefficient decisions about system operation. For example, where balancing capacity prices are excessive, as a result of insufficient competition, the system operator may opt to reduce the quantity of balancing capacity procured, effectively sacrificing system security to reduce the costs of system operation.

By merging small national markets, Balancing Service Providers in these markets can be exposed to a competitive threat from Balancing Service Providers in neighbouring markets. The larger number of providers increases the competitive pressure to maintain low prices, thereby minimising consumer costs and encouraging efficient decisions on system operation.

Assessing the size of these benefits would require an assessment of competitive dynamics in these markets, which is beyond the scope of this report. However, the potential opportunity for consumer benefits as a result of market integration is noted here for completeness, in particular given the previous competition concerns raised in some markets.

Greater accessibility for RES and Demand Response

One of the objectives of efforts to integrate European balancing markets is to open up these markets to both renewable generators and providers of demand response. Doing so could act to extend some of the benefits already discussed, for example by offering up lower cost balancing services and thereby enhancing both allocative efficiency and/or competition. It is also likely to support the EU's climate objectives, by increasing the region's balancing capabilities, while also potentially lowering the cost of balancing.

The key mechanisms by which balancing market integration is likely to facilitate RES and Demand Response participation are the standardisation of balancing products and any move to the daily procurement of balancing capacity. Standardisation, though entailing costs, provides an opportunity to define products in a way that is technology-neutral, or else to create new products that match the types of services that RES and Demand Response can provide. Daily procurement implies that RES and Demand Response will be able to offer balancing capacity far closer to real-time than is currently possible. This is critically important because RES and Demand Response often only know their capability with the required level of certainty fairly close to real-time. Consequently, while month-ahead procurement of balancing capacity might by notionally technology-neutral, in practice, it excludes the participation of these resources.

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[23] See for example ACER Market Monitoring Report 2015

5.2. MAPPING OF COSTS AND BENEFITS TO SPECIFIC OPTIONS

This section describes which costs and benefits are relevant to each of the various options considered in the report.

5.2.1. Options for the Guideline on Electricity Balancing

Figure 4 – Costs by option for the Guideline on Electricity Balancing

Baseline	• None
Option A	• Imbalance netting • TSO-TSO or TSO-BSP trading & settlement arrangements
Option B	• Imbalance netting • Europe-wide exchange • Product standardisation • Security of supply risk (relatively low)
Option C	• Imbalance netting • Europe-wide exchange • Product standardisation • Security of supply risk (relatively high) • Europe-wide or regional regulated entities performing the tasks of supranational balancing operator(s) • Gate closure harmonisation?

It is envisaged that all options (other than the baseline) will entail imbalance netting across balancing zones. Therefore the costs of setting up a central controller for this process and of establishing a fair settlement system will be incurred in each of the options.

In option A, exchanges of balancing energy will be carried out through TSO-TSO or TSO-BSP trading; so in addition to costs from imbalance netting, option A will also include the costs of creating a product and trading system to facilitate this process. In options B and C, a Common Merit Order List will be set up instead of specific TSO-TSO trading arrangements. Therefore in both options, there is the cost of creating the IT platform able to process bids and offers and perform the clearing process, as well as the non-negligible costs of operating this exchange.

The move towards centralised trading entailed in options B and C also entails the transitional costs of product standardisation and any associated efficiency losses. Given the significant changes to the current market design in both options, there may also be some security of supply risk. This is likely to be a greater risk in the initial stages of the project - when most of the adaptation will occur. It is also likely to be a greater risk in option C, as this option is further removed from the *status quo*.

The difference between options B and C relates to responsibility for system operator functions. In option B this remains with national system operators, but in option C some of these functions are transferred to regional bodies. Therefore the total cost of option C also includes the creation or expansion of the relevant institutions, as well as any associated on-going costs.

Figure 5 – Benefits by option for the Guideline on Electricity Balancing

Baseline	• None
Option A	• Lower volumes due to netting of imbalances
Option B	• Lower volumes due to netting of imbalances • Greater allocative efficiency • Greater competition (Enhanced by CMOL*) • Greater accessibility for RES and DR (as part of product and procurement standardisation)
Option C	• As Option B but enhanced by reductions in cross-zonal transmission capacity reliability margins

* There are likely to be operational limits on the extent to which a simple, centralised CMOL can be followed in practice.

In terms of benefits, option A will only realise benefits in the form of lower volumes of real-time balancing energy activated due to the cross-zonal netting of imbalances. This benefit will also occur in options B and C and the magnitude of this benefit is likely to be around similar in all cases.

Since options B and C both entail a Europe-wide exchange for balancing energy, there are additional benefits in the form of greater allocative efficiency and competition. The exchange will facilitate the displacement of more expensive balancing energy sources by cheaper foreign alternatives. It may also increase competition since more Balancing Service Providers will become available to each participating country. The likely impact of this is a fall in prices – benefiting consumers of these products. The development of a Common Merit Order List will further increase both of these benefits over and above what can be expected from an exchange alone.

In option C, the move to regional-level system operation may also facilitate the more efficient management of cross-zonal flows. This could enable some trades that would otherwise have been technically infeasible, potentially increasing the scale of the benefits already described.

5.2.1. MDI OPTIONS

Figure 6 – Costs by MDI option

Baseline	• None
Option 1ab	• Limited product standardisation through creation of new products • TSO-TSO reserve trading & settlement platform
Option 1b	• Extensive product standardisation through replacement of national systems • Europe-wide daily trading and settlement platform with some optimisation • Cross-zonal transmission capacity reservation
Option 2	• Extensive product standardisation through replacement of national systems • Europe-wide daily trading and settlement platform with some optimisation • Cross-zonal transmission capacity reservation • Control block redesign and regional regulated entities

A significant degree of standardisation is assumed for Balancing Energy products in the MDI baseline case as option B for the Guideline on Electricity Balancing is assumed to be implemented in all of the MDI options.

Comparing the baseline to option 1ab, the latter also entails limited product standardisation for capacity products through the creation of new balancing capacity products to be traded multilaterally between TSOs. It therefore includes the costs of creating these products. As for balancing energy, one-off and (relatively minor) ongoing costs will need to be incurred to create a TSO-TSO or TSO-BSP balancing capacity trading platform and related settlement system.

In option 1b, we expect more extensive balancing capacity product standardisation, as national systems make way for several regional, daily trading and settlement platforms for balancing capacity. The creation of these systems will incur material one-off and operational costs. This will include the costs of creating an IT platform with an algorithm able to clear the market in an efficient manner. Option 1b also entails the creation of several regional regulated entities to coordinate and monitor transmission in each region. Again this will involve material one-off costs as well as the ongoing costs of running these organisations.

In option 2, centralisation will occur at the European level, rather than at the regional level. This, of course, avoids the duplication incurred in option 1b, but it is fair to expect that the IT system in a Europe-wide entity will be more sophisticated and complex than the regional equivalents. See Section 6 for further detail on how we dealt with this issue in the quantification.

In options 1b and 2, we would generally expect there to be some opportunity cost from cross-zonal transmission capacity reservation. This cost may be outweighed by the benefits of cross-zonal trade in balancing capacity. The modelling work conducted in this report assumes that cross-zonal transmission capacity reservation only takes place if it is net beneficial.

Figure 7 – Benefits by MDI option

Baseline	• None
Option 1ab	• Greater allocative efficiency due to the removal of suboptimal balancing capacity procurement practices and separation between upwards and downwards bids • Lower volumes due to the variable dimensioning of reserve capacity requirements
Option 1b	• Lower volumes to procure due to the regional dimensioning of reserve capacity requirements • More technically feasible trades due to better cross-zonal flow management
Option 2	• Lower volumes to procure due to the EU-wide dimensioning of reserve capacity requirements • More technically feasible trades due to better cross-zonal flow management (incremental benefit compared to Option 1b) • RES and further DSR can participate in procurement of balancing capacity

In option 1ab, there will be a benefit from the replacement of suboptimal balancing capacity procurement processes and the separation of upwards and downwards bids (also the case in option 1b and 2). This will result in a more efficient allocation of balancing capacities across Balancing Service Providers. There will also be some reduction in the total volume of balancing capacity required in the market through the variable dimensioning of reserve capacity requirements, since this now takes better account of the underlying reserve capacity requirements. These volume decreases will be larger in option 1b, since dimensioning will then be regional and further again in option 2 as dimensioning will be Europe-wide.

Common Merit Order Lists in option 1b and 2 will lead to benefits through increased competition and increased allocative efficiency.

Greater regional or Europe-wide system operator coordination may make more trades technically feasible, extending the other benefits described. This extension of feasible trades and of the associated benefits is expected to be greater, the greater the degree of system operator integration.

Finally the participation of RES and of residential and storage Demand Response in option 2 further increases the level of benefits one can expect from this option.

6. QUANTITATIVE ASSESSMENT OF COSTS AND BENEFITS

6.1. COSTS

In this section we discuss our cost methodology for each of the Guideline on Electricity Balancing and MDI options. We also discuss the limitations present in our approach. For each of the cost categories for which data is available, we set out the figures and sources used. After discussing the source data, we proceed to construct cost estimates for each option, using the data available. In addition to providing a summary and breakdown of the option costs, we also discuss the non-quantified costs and how these are likely to vary among the options.

6.1.1. DESCRIPTION OF METHODOLOGY AND LIMITATIONS

In order to develop cost estimates we conducted a review of the literature with the aim of identifying data points relevant to each of the costs arising from the Guideline on Electricity Balancing and MDI options. We drew on cost estimates for electricity balancing markets in both Europe and the US. Unfortunately we were not able to find plausible estimates for all cost categories, meaning that the total quantified costs are likely underestimates of the true total cost. Nonetheless, we feel that the estimates give a good idea of the orders of magnitude of the costs and can be used to compare the options. We were unable to find cost estimates for the following cost categories:

- Product standardisation;
- Gate closure harmonisation;
- Security of supply risk; and
- Opportunity cost of cross-zonal transmission capacity

In some instances we directly use the number from the literature[24] and in others we adjust the figure to tailor it to the details and scale of the relevant option. In many cases costs were scaled to reflect the fact that the proposed integration covers all European countries; but the data points themselves cover a far smaller number of countries or states. To achieve this we developed a scaling methodology based on disaggregating data points into fixed and per country components and scaling up the per country components. Many of the original cost estimates were not disaggregated into fixed and per country components and therefore cannot be directly scaled by the number of countries involved. In these cases we have assumed that a share of total costs reflects fixed common costs, that should not be scaled, and that the remaining costs scale with the number of countries involved. Specifically, we have established a general ratio between single country and common fixed costs based on the costs of the Trans-European Replacement Reserve Exchange (TERRE) pilot project[25]. On the basis of this project's cost structure we calculated a general ratio between single country and common fixed costs. We have then used this ratio to split total cost estimates from the literature into estimates of the per country and common costs. The per country cost estimates are subsequently scaled by the relevant number of countries when we generate the option cost estimates. One of the limitations of this analysis is the reliance on this unavoidable but somewhat crude assumption.

The fact that scaling is required is a further limitation. We make the assumption that our per country cost estimates scale linearly with the number of participating countries; however it is certainly possible that there may be economies of scale, such that costs scale

[24] Where necessary costs were inflated to 2015 prices and converted to Euros.

[25] The TERRE project refers to the creation of a Common Merit Order list for Balancing Energy and Balancing Capacity between several European countries. 8 countries were included in the pilot.

less than linearly, or even that the increased complexity from implementing a policy Europe-wide pushes costs above the assumed level.

6.1.2. *Description of key sources*

In the remainder of this section, we discuss the data points identified that underpin our cost estimates.

Imbalance netting

The data points identified to quantify the cost of cross-zonal imbalance netting come from the International Grid Control Cooperation (IGCC) initiative; a cooperative initiative between TSOs in Germany, France, the Netherlands, Belgium, Denmark, Austria, Switzerland and the Czech Republic to net imbalances and thereby reduce FRR activation.

The costs identified are from when IGCC had only two participating countries – Germany and the Netherlands. The lower of the two estimates is from a 2013 Mott McDonald impact assessment of IGCC. The other estimate provides the procurement costs of the IGCC system mentioned in a CBA for the TERRE project. As discussed above, the TERRE ratio is used to disaggregate these two data points into fixed and per country components. The costs for the TERRE pilot are stated as €5-10m in fixed costs and an average of €2.65 million per participating country. Given that the IGCC estimates include two countries, this implies that 58% of total costs were fixed costs and 21% were the per country cost for both the Netherlands and Germany (42% overall). This per country cost is multiplied by the number of countries relevant to the option.

Table 1 – Imbalance netting cost estimates (€)

Cost category	Cost estimate (€)	Year	Fixed, per country or total?	One-off or ongoing?	Source	Description
Imbalance netting	610k	2013	Total	One-off	Mott MacDonald	One-off cost of IGCC imbalance netting
	1.0m	2016	Total	One-off	ENTSO-E	One-off cost of IGCC imbalance netting

TSO-TSO or TSO-BSP trading and settlement

The estimates for TSO-TSO or TSO-BSP trading and settlement costs (shown in **Table 2**) come from the same Mott MacDonald report mentioned above. The costs here are those from the implementation of a BALIT style mechanism, as currently seen between Great Britain and France, where TSOs separately calculate the total amount of reserve capacity required in a national merit order and make any surplus bids/offers available to the neighbouring TSO through a bespoke product.

The report mentions both a one-off cost of implementation and an annual operational cost. As done for the IGCC estimate, both data points are disaggregated into fixed and per country components using the TERRE ratio. Since BALIT also includes two countries, this implies that 58% of total costs are fixed costs and 21% of the original costs are attributed to each country joining the mechanism.

Table 2 – TSO-TSO or TSO-BSP trading and settlement cost estimates (€)

Cost category	Cost estimate (€)	Year	One-off or ongoing?	Source	Description
TSO-TSO or TSO-BSP trading and settlement	2.0m	2013	One-off	Mott MacDonald	One-off cost of BALIT style mechanism
	100 – 200k	2013	Ongoing	Mott MacDonald	Operational cost of BALIT style mechanism

Europe-wide or regional exchange

Table 3 – Europe-wide or regional exchange cost estimates (€)

Cost category	Cost estimate (€)	Year	Fixed, per country or total?	One-off or ongoing?	Source	Description
Europe-wide or regional exchange	5–10m	2016	Fixed	One-off	TERRE	Fixed cost of CMOI
	2.65m	2016	Per country	One-off	TERRE	Per country cost of CMOI
	2.8-5.5m	2004	Fixed	One-off	PacifiCorp-CAISO	Fixed cost of Energy Imbalance Market (EIM) implementation
	2.3m	2004	Per country	One-off	PacifiCorp-CAISO	Per country cost of EIM implementation
	1.8-4.6m	2004	Total	Ongoing	PacifiCorp-CAISO	Ongoing cost of EIM

The cost estimates for the setting up and operation of an exchange come from two sources: the TERRE project and the PacifiCorp-CAISO Energy Imbalance Market (EIM). These are shown in **Table 3**. When we apply these costs later, they are taken to include all of the costs associated with setting up and operating a commercial exchange, including, for example, the creation and hosting of the commercial platform, the development and maintenance of the clearing algorithm, and the provision of support to the exchanges' users.

The TERRE project is the setting up of a Common Merit Order list for Balancing Energy and Balancing Capacity between several European countries (8 in the pilot) with a standardised product. Ongoing costs are stated as negligible for the project. We use the TERRE data points as cost estimates for both the Europe-wide exchange of balances entailed in the options B and C for the Guideline on Electricity Balancing as well as the Europe-wide or regional sharing of balancing capacity present in options 1b and 2 of the MDI.

The other data point refers to the implementation of a centralised Energy Imbalance Market (EIM) between PacifiCorp and the California Independent System Operator (ISO). We use the PacifiCorp-CAISO estimate for estimating the cost of creating a Europe-wide Common Merit Order list – part of option B and C for the Guideline on Electricity Balancing. It should be noted that this is an older cost estimate and from the USA, however we still deem to it be a useful additional data point, since it relates directly to previous attempts to integrate discrete balancing systems.

Table 4 – Europe-wide or regional regulated entities performing the tasks of supranational balancing operator(s) cost estimates (€)

Cost category	Cost estimate (€)	Year	Fixed, per country or total?	One-off or ongoing?	Source	Description
TSO-TSO trading and settlement	18.9m	2006	Per organisation	One-off	Eirgrid	Physical assets transferred under Eirgrid capitalisation process
	9.9–35.6m	2004	Per organisation	One-off	FERC	Cost of creating a Regional Transmission Organisation (RTO)
	5.5–7.7m	2004	Per organisation	Ongoing	FERC	Operational costs of a RTO

Table 4 displays the cost estimates found for the setting up of a regional or Europe-wide regulated entity performing the tasks of supranational balancing operator. There are three data points identified for this purpose: one from Eirgrid and two from the Federal Energy Regulatory Commission (FERC).

It should be noted that these estimates relate to the creation of entities with functions beyond balancing operation alone. Consequently, these estimates are likely to systematically overestimate the costs of a body that was minimally designed to just undertake balancing operation. The cost estimates derived from these source costs should be viewed with this in mind. Unfortunately, better cost proxies for a balancing-only body are not available, forcing us to develop cost estimates using this conservative approach.

The Eirgrid estimate reflects the total physical assets transferred under the Eirgrid capitalisation process upon its creation as the new electricity transmission operator in Ireland. We view this figure as an appropriate proxy for the cost of setting up the regulated entity from scratch.

The FERC estimates are the one-off and ongoing costs of creating a day-one Regional Transmission Organisation (RTO) in the USA from scratch. These estimates are a range based on figures for the PJM Interconnection, Midwest Independent Transmission System Operator, the Electric Reliability Council of Texas and the Southwest Power Pool. We removed or scaled certain cost categories in an attempt to exclude costs pertaining to transmission services[26]. The rationale for this adjustment is that under the options

[26] The sources state that the total costs of setting up a day-one RTO are made up of: transmission service provision and support, a reliability authority, management, building costs and sunk costs. In order to exclude irrelevant costs, we first remove costs directly resulting from transmission services. We then take the remaining

considered, these services will remain under TSOs control, rather than the regional regulated entity.

Both estimates are used as estimates for the cost of system operators. The same cost is used in option C for the Guideline on Electricity Balancing and MDI option 1b for the Europe-wide regulated entity established in MDI option 2. The mapping of these data points to each option is discussed in more detail below.

6.1.3. COST RESULTS BY COST CATEGORY AND SPECIFIC OPTION

In this section we set out quantitative cost estimates for the cost categories where data was available and determine total costs per option. We also discuss missing cost elements and how these are likely to vary in magnitude across the different options. It is important to note at the outset that many of the sources identified with cost data relate either to pilot projects, or to entities with functions additional to those required by the option description. The costs of these projects and entities are expected to be greater than those implied by the business-as-usual operation of a minimally-functional design. In short, we expect that the option costs provided, which are based on these costs, are an overestimate. However, they are useful to establish the order of magnitude for the options' costs.

Table 5 sets out the cost categories which we have been able to quantify for the Guideline on Electricity Balancing. These are split out into fixed and per country figures, with the total cost also presented. For imbalance netting, TSO-TSO or TSO-BSP trading and the Europe-wide Common Merit Order list, fixed one-off and ongoing costs are incurred only once. For the regional regulated entities performing the tasks of supranational balancing Operators, the fixed cost is incurred five times to reflect the creation of five distinct entities. All per country cost components are incurred 30 times - once for each participating country. Adding these fixed and per country totals together gives the overall cost estimate for both one-off and ongoing costs.

As made clear by the data points identified in our literature review, the costs incurred from implementing option A are relatively minor. Imbalance netting will incur a minimal implementation cost with ongoing costs expected to be negligible. TSO-TSO or TSO-BSP trading involves a slightly larger upfront cost, with ongoing costs close to negligible.

Options B and C entail more significant shifts from the *status quo* and therefore higher cost impacts. The creation and transfer of power to five regional regulated entities performing the tasks of supranational balancing operators is expected to result in significant one-off costs and operational costs (e.g. staffing). The Common Merit Order list, on the other hand, is expected to mostly involve upfront costs from designing and implementing the IT system. Some ongoing costs are envisaged, but these will be a fraction of one-off costs.

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cost categories and multiply each by the percentage of total costs not attributed to transmission. We make this adjustment based on an assumption that, even in these cost categories, a proportion of the total cost will still pertain to transmission services. For example, some of the required management will be management of transmission services.

Table 5 – Cost estimates by measure for the Guideline on Electricity Balancing (€)

Cost category	Fixed		Per country		Total	
	One-off	Ongoing	One-off	Ongoing	One-off	Ongoing
Imbalance netting	360–590k		130–210k		4.3–6.9m	
TSO-TSO or TSO-BSP trading	1.2m	60–120k	420k	20–40k	13.8m	660k–1.3m
Europe-wide Common Merit Order List	2.8–10m	1.8–4.6m	2.3-2.65m		71.8–89.5m	1.8–4.6m
Regional regulated entities performing the tasks of supranational balancing operators*	9.9–35.6m	5.5–7.7m			49.4–177.8m	25.4–35.3m

***The Guideline on Electricity Balancing cannot create or oblige the creation of these entities. These estimates are provided for information only and are not attributed to the Guideline on Electricity Balancing.

Table 6 sets out the total costs for each option for the Guideline on Electricity Balancing by noting the category costs only when they are present. The table also shows the costs for which estimates are missing. For these, ticks are used give a rough idea of how the cost's magnitude might vary across options. The more ticks (between 1 and 3), the greater the expected cost. Note that these ticks provide an indication of how the cost category varies across options. We do not make any assertions about the magnitudes of the different missing costs relative to one another, as - given the lack of available data - we are unable to make a judgement on this.

The table shows that, for the cost estimates available, total costs are highest in option C and lowest in option A. The ordering is the same for the missing costs.

The significant shift in processes and the transfer of control in option C means that we would expect the operational risk in security of supply to be highest in this option. In option A, where there is no change in control and cross-zonal activity is limited to imbalance netting and exchange of surpluses, we would expect security of supply risk to be the lowest out of the three options. Option B falls somewhere in the middle, since transmission remains nationally controlled, but there is a shift to the centrally determined allocation of balancing energy.

If gate closures are harmonised, we would expect the associated costs to be the same regardless of the option and to be purely transitory. As discussed above, there is no requirement for gate closure harmonisation under the TSO-TSO or TSO-BSP agreements in option A. Therefore this cost is only likely to be relevant in options B and C.

Product standardisation will occur to some degree in all options, with the level of standardisation expected to be greater in option B than A and greater in option C than B. The associated costs reflect this. Again these will be predominantly one-off costs. We assume any ongoing efficiency costs from standardisation are negligible.

Table 6 – Cost categories mapped across to options for the Guideline on Electricity Balancing, and total cost estimates (€)

Cost category	Option A		Option B		Option C	
	One-off	Ongoing	One-off	Ongoing	One-off	Ongoing
Imbalance netting	4.3–6.9m		4.3-6.9m	neg	4.3–6.9m	
TSO-TSO or TSO-BSP trading	13.8m	660k–1.3m				
Europe-wide Common Merit Order List			71.8-89.5m	1.8–4.6m	71.8-89.5m	1.8–4.6m
Regional regulated entities performing the tasks of supranational balancing operators					(49.4-177.8m)*	(25.4–35.3m)*
Product standardisation	✓		✓✓✓		✓✓✓	
Gate closure harmonisation			✓✓✓		✓✓✓	
Security of supply risk	✓		✓✓		✓✓✓	
Total	**18.1–20.7m**	**660k–1.3m**	**76.1–96.4m**	**1.8–4.6m**	**76.1–96.4m***	**1.8-4.6m***

***Note that although we have estimated the potential costs associated with the creation of supranational balancing operators, the Guideline on Electricity Balancing cannot create or oblige the creation of these entities. As such, the costs of these operators are not included within the total option cost estimates.

Identified cost estimates for MDI cost categories are shown in **Table 7**. These include the costs of a Europe-wide or regional commercial platform to enable the exchange of balancing capacity and, depending on the option, either the enhancement of regional cooperation among TSOs or the creation of an Europe-wide regulated entity performing the tasks of supranational balancing operator.

Option 1b entails an extension to existing regional cooperation between TSOs. Regional Security Coordinators (RSCs) will become mandatory with the adoption of the System Operation Guideline[27] and are expected, in the future, to undertake day-ahead system analysis on cross-zonal transmission capacity. Under this option, the functions and capabilities of these existing organisations would be expanded to enable efficient cross-zonal exchanges of balancing capacity. These functions might include, for example, calculating the maximum cross-zonal transmission capacity that could efficiently be reserved for the purpose of facilitating cross-zonal exchanges of balancing capacity. Ultimate responsibility for system security would remain with national system operators

27 https://ec.europa.eu/energy/sites/ener/files/documents/SystemOperationGuideline%20final%28provisional%2904052016.pdf

and consequently, the functions of these expanded RSCs would likely be less extensive than their national members.

The quantitative estimates we have in relation to the costs of system operation, shown in **Table 4**, relate to the creation of an entirely new system operator and are therefore likely to be significantly greater than the costs of expanding an existing RSC to take on functions that, even in aggregate, are likely to be smaller than those of a fully-fledged system operator. However, we have no basis on which to assess the proportion of the costs of establishing a full system operator that are likely to be expended when enhancing an existing RSC.

In the interests of providing a conservative upper bound on these costs, we have assumed that five RSCs[28] would need to be enhanced, and that the costs of these enhancements will be no more than half of the costs of creating a new system operator, as implied by the data points in **Table 4**. It is not expected that there will be any material economies from duplication, since each region will require its own distinct oversight and the costs incurred will reflect this.

In option 2, we assume that the full cost of creating a system operator, as implied by the data points shown in **Table 4**, is borne once at the European level. This reflects the need to create a single new body. The actual costs will depend on the exact nature of this body's functions and the scale of any offsetting savings made at a national level.

Regarding the creation and operation of Common Merit Order Lists, a key issue is the level of increased sophistication and complexity required of an IT system for a Europe-wide exchange above that of the regional equivalents. Since the clearing algorithm in the former must efficiently allocate balancing capacity from a far greater number of countries, we expect at least a degree of increased complexity. However the cost of this complexity compared to the duplication of the fixed cost in option 1b is crucial to determining which will be more expensive. As seen in the table, the ranges given for this cost element allow for the possibility of either option 1b or 2 being more expensive; we feel that this is appropriate given this uncertainty.

[28] The number of RSCs that need to be enhanced is an assumption. This number could be different in practice. The use of the number five is consistent with the requirements to appoint an RSC as set out in the current text of the System Operation Guideline, and was deemed to be a reasonable assumption given the current structure of system operation.

Table 7 – Cost estimates by MDI category (€)

Measure	Fixed		Per country		Total	
	One-off	Ongoing	One-off	Ongoing	One-off	Ongoing
Regional regulated entities – option 1b	5.0m-17.8m*	2.8-3.9m*			24.8-89.0m*	13.8-19.3m*
Europe-wide regulated entity – option 2	9.9m-35.6m	5.5-7.7m			9.9m-35.6m	5.5-7.7m
Common Merit Order – option 1b	5-10m	1.8-4.6m	300k-2.65m		34.0-129.5m	9.2-22.9m
Common Merit Order – option 2	5-10m	1.8-4.6m	300k-2.65m		14.0m-89.5m	1.8-4.6m

*As discussed above, we have halved the base cost data related to the cost of creating new system operators in order to generate these estimates. This is a crude but necessary step to account for the fact that the cost proxies used are likely to significantly overestimate the costs of a minimalist balancing agency. A similar adjustment is not made to option 2 estimates because the geographic scope of an all-Europe body would be significantly larger than the scope of the system operators informing the base cost data.

Table 8 sets out the cost estimates for the categories which we were able to quantify. As for the options for the Guideline on Electricity Balancing, we also present missing cost elements with an indication as to how these might vary in size across options.

We factor the implementation of an exchange for balancing energy under option B for the Guideline on Electricity Balancing into our per country cost range for the creation of exchange(s) for reserves in MDI options 1b and 2, by reducing the per country cost for the MDI options. Effectively, we assume that there is some learning or a group of common costs associated with the creation of the balancing energy exchanges that lowers the incremental cost of then setting up an exchange for the sharing of balancing capacity. Specifically, we use a range for the per country cost of these exchanges which takes as its lower bound the lowest per country cost estimate developed for the TERRE project pilot and, as its upper bound, the average per country cost from TERRE (as used in the option B cost estimation for the Guideline on Electricity Balancing).

When looking at the system operation costs implied by options 1b and 2, it should be noted that the costs shown for option 1b represent an expected upper bound in the absence of data on the likely costs of enhancing the capabilities of existing RSCs. This upper bound is increased by the presence of regional duplication, but may still be a significant overestimate.

It should also be noted that the numbers provided are, at best, a picture of costs in terms of their orders of magnitude. They may well overestimate total costs, given that the underlying cost data is drawn from pilot projects and from organisations with more extensive responsibilities than are directly implied by the option description. These estimates should therefore form only a part of a more comprehensive decision-making process about the appropriateness of various market designs.

Looking at the non-quantified cost elements, any non-negligible product standardisation costs are likely to be one-off only, as was the case with the options for the Guideline on Electricity Balancing. These standardisation costs are likely to be fairly small in all cases, since a significant amount of energy balancing product standardisation is already entailed under option B for the Guideline on Electricity Balancing and is therefore already accounted for. Any remaining standardisation costs are likely to be at their lowest in option 1ab, higher in option 1b, and higher again in option 2. The same cost ordering and one-off nature is envisaged for the security of supply risk, and matches the size of the implied process changes.

There is unlikely to be any opportunity cost associated with reduced transmission capacity in option 1ab, since balancing capacities are procured nationally. However, when balancing capacities are procured supra-nationally, we envisage the possibility of some cross-zonal transmission capacity reservation in order to allow for cross-zonal exchanges or sharing of balancing capacity. Again, these costs are likely to be at their greatest under option 2, reflecting greater volumes of cross-zonal transmission capacity being reserved for balancing purposes. However, these higher volumes would also be expected to reap additional benefits from additional cross-zonal trading of balancing capacity.

Table 8 – Cost categories mapped across to MDI options, and total cost estimates (€)

Cost category	Baseline		Option 1ab		Option 1b		Option 2	
	One -off	On- going	One -off	On- going	One-off	On- going	One-off	On- going
Europe-wide or regional Common Merit Order List(s)					34.0-129.5m	9.2-22.9m	14.0-89.5m*	1.8–4.6m
Europe-wide or regional regulated entities performing the tasks of supranational balancing operator(s)					24.8-89.0m **	13.8-19.3m **	9.9-35.6m	5.5-7.7m
Product standard-isation			✓		✓✓✓		✓✓✓	
Security of supply risk			✓		✓✓		✓✓✓	
Opportunity cost of reduced cross-zonal transmission capacity						✓✓		✓✓✓
Total					**58.8-218.5m**	**23.0-42.2m**	**23.9-125.1m**	**7.3-12.3m**

***Given that we are not able to account for the additional complexity of a Europe-wide exchange in the quantification, this lower bound is likely to be artificially low.**
****These costs represent an expected upper bound. They reflect half of the expected costs of creating five regional regulated entities performing the tasks of supranational balancing operators.

6.2. BENEFITS

This section begins with a presentation of the benefits of options for the Guideline on Electricity Balancing compared to the baseline. The main source of savings in option A is the introduction of imbalance netting. Option B further allows cross-zonal exchange of balancing energy via a Common Merit Order List (CMOL). The cheaper resources are shown to displace the more expensive ones. Finally, the introduction of a supranational balancing operator (which results in lower security margins during balancing) allows for further imbalance netting and exchanges of balancing energy.

The second part of this section is devoted to presenting the benefits of the MDI options compared to the baseline. The option 1ab savings are shown to originate from the removal of sub-optimal balancing capacity procurement practices (fixed allocation to thermal plants and symmetric bids). Regional cooperation (option 1b) results in less reserve capacity needs but requires a proportion of the cross-zonal transmission capacity to be reserved to share balancing capacity. Finally, option 2 introduces further policy measures such as an EU-level dimensioning of reserve capacity requirements, and further resources for reserve capacity (RES and further DSR).

6.2.1. Options for the Guideline Electricity Balancing

<u>Baseline</u>

In the baseline, each country balances its own power system independently. The total demand for upwards FRR is 19.1 TWh, while the demand for downwards FRR is 17.9 TWh. The demand for FRR is constant across all options (since the imbalances the system has to face are identical), but the level of activation will be shown to decrease in all further options thanks to the introduction of imbalance netting.

Table 9 - Baseline for the Guideline on Electricity Balancing

Baseline	aFRR	mFRR
Upwards activation	14.2 TWh	4.8 TWh
Downwards activation	12.3 TWh	5.5 TWh
Upwards activation cost	1 088 M€	438 M€
Downwards activation cost	- 523 M€	- 341 M€
Total activation cost	565 M€	97 M€
Total	**662 M€**	

It is worthwhile noting that the cost of downwards regulation is negative. This is due to that fact that the activation of downwards balancing energy saves fuel costs[29]. The average upwards activation cost is found to be 77 €/MWh for aFRR and 92 €/MWh for mFRR. The average downwards costs are -43 €/MWh for aFRR and -62 €/MWh for mFRR.

[29] The value of downwards balancing energy activation for hydro is captured by using the value of water: it is computed as the value that the water that has been saved thanks to the activation can bring to the system at later times.

In the baseline, TSOs can only exploit the nationally procured balancing capacities, and can neither exchange balancing energy with neighbouring zones nor net imbalances. The cost of balancing activation is therefore heavily dependent on the composition of the national power generation mixes.

The dispersion of aFRR prices amongst Member States is important. MSs such as Slovenia or Hungary have limited mid-merit unit capacities (hard coal and CCGT) according to the EuCo27 scenario, and provide a significant part of their active power upwards reserve with cheap resources such as RES, nuclear, lignite and hydropower (in countries with abundant water resources). This induces high reserve procurement prices (because of the high opportunity cost), but low activation costs (less than 20 €/MWh).

On the other extreme, MSs such as the Czech Republic, Germany, Luxembourg, Poland or Slovakia use pumped-storage to provide a significant part (>20%) of their upwards reserve supply. As their hydro resources are limited (<10% of the power demand), the water value can reach values above 200 €/MWh, which leads to high upwards aFRR costs (around 100 €/MWh).

The dispersion amongst MS of mFRR costs is lower than for aFRR. The highest costs per MWh are reached by two kinds of systems: those relying on pumped-storage in countries with high values of water (Czech Republic and Poland) and those relying on oil-fired power plants and OCGTs (Romania, Sweden). In all these countries the upwards mFRR costs is of the order of 110 €/MWh.

The following table shows the set of technologies participating in balancing the power system in the baseline.

Table 10 - Baseline for the Guideline on Electricity Balancing - Activations

Baseline (GWh)	aFRR		mFRR	
	Upwards	Downwards	Upwards	Downwards
Wind	600	700	20	180
Solar	-	160	-	-
Hydro	7 300	2 230	3 350	2 840
Biomass	480	190	480	250
Nuclear	820	1 420	50	260
Coal	2 280	660	50	640
Lignite	180	1 220	20	70
CCGT	2 340	5 450	50	1 150
OCGT	180	270	620	100
Oil	10	-	150	10

Although the avoided utilisation of thermal power plants due to downwards activation decreases CO_2 emissions, the upwards activation of coal cancels out this effect. Overall, the activation of balancing energy has almost no effect on CO_2 emissions (930 fewer kilotons of CO_2 are emitted compared to the day-ahead programme, which represent less than 0.2% reduction of CO_2 emissions).

Option A

As the result of the introduction of imbalance netting at an EU-wide level, less balancing energy is activated in option A (18.4 TWh instead of 36.8 TWh in the baseline). The lower activation volumes translate into savings of 212 M€. The following table provides a summary of the activations of upwards and downwards reserves and the corresponding costs, and their comparison with the baseline figures.

Table 11 - Option A for the Guideline on Electricity Balancing (and comparison with baseline)

Option A	aFRR		mFRR	
Upwards activation	6.6 TWh	(-54%)	3.2 TWh	(-33%)
Downwards activation	4.7 TWh	(-62%)	3.9 TWh	(-29%)
Upwards activation cost	554 M€	(-49%)	310 M€	(-29%)
Downwards activation cost	- 182 M€	(+65%)	- 232 M€	(+32%)
Total activation cost	372 M€		78 M€	
Total	**450 M€**			
Cost reduction (savings)	**212 M€**			
Savings per MWh[30]	**5.8 €/MWh**			

While activations are reduced by almost 19 TWh, cost savings remain limited (212 M€), as imbalance netting reduces upwards activation costs but also removes the opportunities to save fuel costs via downwards activations. As an example, let us consider aFRR activations: upwards and downwards activations are both reduced by the same amount due to the nature of netting (around 7.6 TWh). The need for upwards activations being reduced, their costs decrease by 534 M€. At the same time, fewer downwards activations are needed. This results in losses from a systems perspective: downwards activations save fuel costs, or, in the case of hydropower, allow the system to save water in reservoirs and to use it at later times. The benefits of downwards activations decrease by 341 M€ compared to the baseline, which combined with the savings from the avoided upwards regulation result in overall savings of 193 M€. The same reasoning can be applied to mFRR activations.

The distribution of savings per country is given in Appendix C. Unsurprisingly, option A results in savings for almost all countries. However, in countries characterised by cheap upwards regulation costs (e.g. Hungary where nuclear power is the main provider of upwards aFRR), the fuel cost savings are found to be less important than the opportunity cost related to the avoided downwards activations. For these countries, imbalance netting results in additional costs.

The following table shows which technologies participate in balancing the power system in option A, along with a comparison with the baseline figures.

[30] This indicator is computed by dividing the savings of the considered options compared with the baseline costs by the activated balancing energy in the baseline.

Table 12 - Option A for the Guideline on Electricity Balancing - Activations (and comparison with baseline)

Option A (GWh)	aFRR				mFRR			
	Upwards		Downwards		Upwards		Downwards	
Wind	300	(-50%)	270	(-61%)	10	(-50%)	170	(-6%)
Solar	0		80	(-50%)	0		0	
Hydro	3 330	(-54%)	980	(-56%)	2 230	(-33%)	2 020	(-29%)
Biomass	270	(-44%)	50	(-74%)	330	(-31%)	140	(-44%)
Nuclear	350	(-57%)	680	(-52%)	30	(-40%)	240	(-8%)
Coal	1 030	(-55%)	230	(-65%)	30	(-40%)	440	(-31%)
Lignite	70	(-61%)	400	(-67%)	10	(-50%)	50	(-29%)
CCGT	1 060	(-55%)	1 900	(-65%)	30	(-40%)	780	(-32%)
OCGT	130	(-28%)	60	(-78%)	460	(-26%)	60	(-40%)
Oil	0	(-100%)	0		100	(-33%)	0	(-100%)

Overall, the share of balancing energy provided by each technology is very close to the baseline situation. This is explained by the fact that, in both the baseline and option A, TSOs have the exact same portfolio at their disposal to balance their systems. Imbalance netting mostly results in a lower demand for balancing energy activation, but the remaining activations still have to be provided by national balancing service providers[31]. The situation will be shown to be different in options B and C, in which TSOs can take advantage of cross-zonal exchanges of balancing energy to lower the cost of balancing.

In this option too, the activation of balancing energy has almost no effect on CO_2 emissions (170 more kilotons of CO_2 are emitted compared to the day-ahead programme).

Option A takes advantage of the cross-zonal transmission capacities that are remaining after the day-ahead simulation. In the day-ahead simulation, around 580 TWh are exchanged on cross-zonal interconnectors. Due to imbalance netting, some interconnections see their utilisation increase (5.2 TWh for aFRR, 0.8 for mFRR), while others see theirs decrease (5.3 TWh for aFRR, 0.7 for mFRR).

[31] The balancing capacities provided by balancing service providers are fixed by the day-ahead simulation. Note that cross-zonal exchanges are allowed when such exchanges can contribute to avoiding loss of load situations.

Option B

In option B, TSOs are allowed to exchange balancing energy. The demand for upwards and downwards regulation is the same as in option A, but thanks to the competition introduced amongst balancing service providers, the model favours the utilisation of cheaper resources for upwards regulation while the most expensive ones are used for downwards regulation in order to save their fuel costs. The cross-zonal exchanges of balancing energy translate into savings of the order of 267 M€ compared to option A, which only allowed imbalance netting. Compared to the baseline, the measures introduced in option B result in savings of 479 M€ per year. The following table provides a summary of the activations of upwards and downwards reserves and the corresponding costs, and their comparison with the baseline figures.

Table 13 - Option B for the Guideline on Electricity Balancing (and comparison with baseline)

Option B	aFRR		mFRR	
Upwards activation	6.6 TWh	(-54%)	3.2 TWh	(-33%)
Downwards activation	4.7 TWh	(-62%)	3.9 TWh	(-29%)
Upwards activation cost	419 M€	(-61%)	255 M€	(-42%)
Downwards activation cost	- 226 M€	(+57%)	- 265 M€	(+22%)
Total activation cost	193 M€		- 10 M€	
Total	**183 M€**			
Cost reduction (savings)	**479 M€**			
Savings per MWh[32]	**13.0 €/MWh**			

The activation volumes are the same as in option A, but thanks to the competition between balancing service providers, the total cost of balancing the power system decreases as cheaper resources displace more expensive ones.

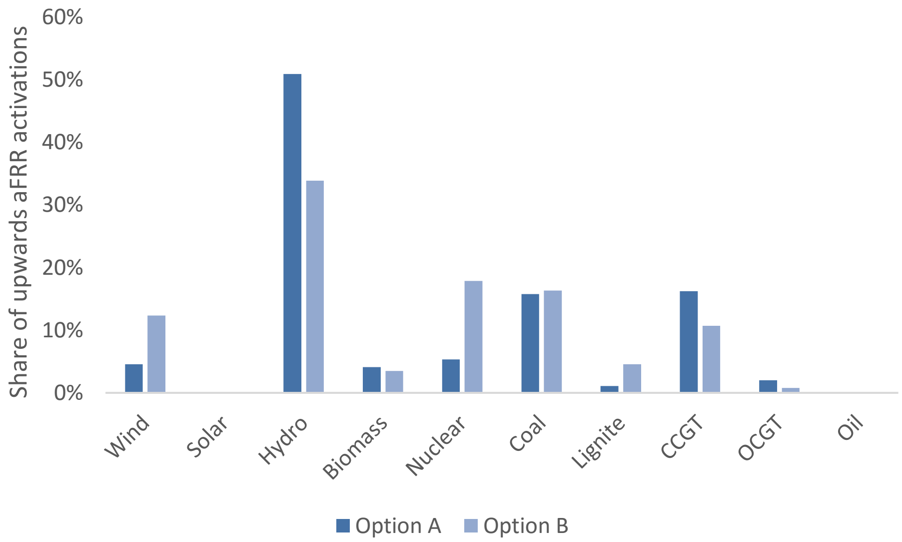
More precisely, TSOs can access cheaper resources for upwards regulation and save more fuel costs by decreasing the output of expensive power plants to provide downwards regulation, as long as the cross-zonal exchange capacities are available. The following table shows the impacts of the measures introduced in option B by comparing the results between options A (shown in parenthesis) and B.

[32] This indicator is computed by dividing the savings of the considered options compared with the baseline costs by the activated balancing energy in the baseline.

Table 14 - Option B for the Guideline on Electricity Balancing - Activations (and comparison with option A)

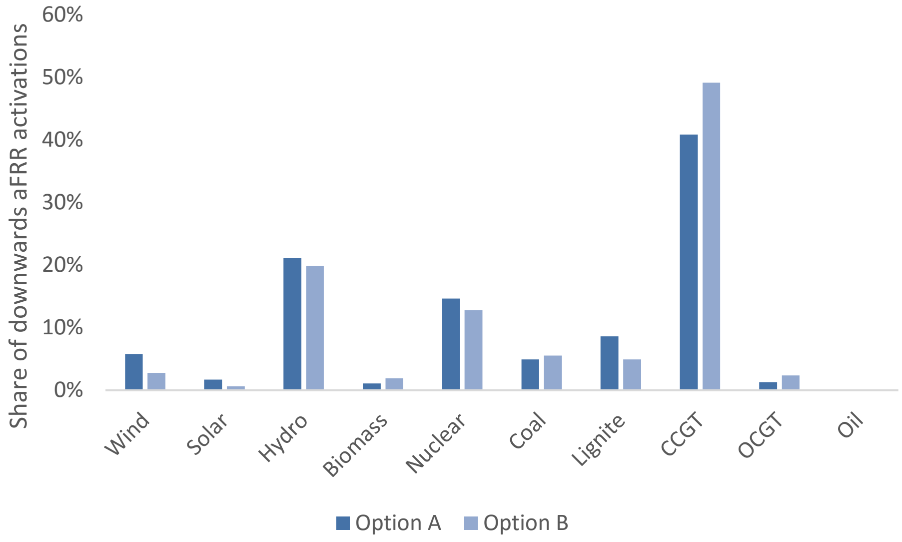
Option B (GWh)	aFRR				mFRR			
	Upwards		Downwards		Upwards		Downwards	
Wind	810	(300)	130	(270)	10	(10)	140	(170)
Solar	0	(0)	30	(80)	0	(0)	0	(0)
Hydro	2 220	(3 330)	930	(980)	1 860	(2 230)	2 820	(2 020)
Biomass	230	(270)	90	(50)	550	(330)	20	(140)
Nuclear	1 170	(350)	600	(680)	20	(30)	190	(240)
Coal	1 070	(1 030)	260	(230)	90	(30)	90	(440)
Lignite	300	(70)	230	(400)	210	(10)	20	(50)
CCGT	700	(1 060)	2 300	(1 900)	390	(30)	200	(780)
OCGT	50	(130)	110	(60)	90	(460)	430	(60)
Oil	0	(0)	0	(0)	10	(100)	10	(0)

The competition between Balancing Service Providers introduced in this option results in a displacement towards cheaper resources for upwards regulation. The following figure presents the share of the upwards aFRR activations by technology for options A and B.



We can clearly see that cheap resources such as wind and nuclear power are better exploited in option B than in option A. In option A, these resources could only be used by the TSO of the country where they are located. In option B, other TSOs gain access to these resources, subject to the availability of a sufficient transmission capacity. As a consequence, expensive resources such as hydropower and CCGTs can lower their participation in upwards aFRR activations and be replaced by cheaper ones.

The opposite behaviour can be witnessed in the case of downwards regulation. The following figure illustrates the downwards aFRR activations in options A and B.



CCGTs are found to increase their participation in downwards aFRR activations, thereby saving further fuel costs. One can also note that wind and solar reduce their curtailment in this option thanks to the availability of cross-zonal resources.

The extra 267 M€ savings of option B compared to option A are due to the ability for TSOs to exchange energy across zones. The countries which were characterised by high balancing costs per MWh for upwards products will reduce their activations and the countries with lower balancing costs will not only produce balancing energy to face their domestic imbalances, but also help neighbouring countries balance their own systems.

The average share of balancing energy activated cross-zonal is 53%, which means that less than half of balancing requirements are activated nationally. Hungary and Slovenia, which use cheap resources such as RES, hydro, or nuclear power as their main providers of upwards aFRR balancing capacities, are good illustrations of this phenomenon. The significant additional activations of upwards aFRR in these countries is compensated by a decrease of activations of the most expensive resources (in countries such as Luxembourg and Germany). For example, the producer surplus of Hungary's nuclear power increases tenfold when the possibility of cross-zonal exchanges of balancing energy is introduced in option B. Appendix C presents the savings per country. It should be noted that the savings are computed by subtracting the cost of the options from the baseline costs, and therefore do not take into account the settlement between TSOs for the cross-zonal activation of balancing services.

In option B too, the activation of balancing energy has almost no effect on CO_2 emissions (360 fewer kilotons of CO_2 are emitted compared to the day-ahead programme).

Option B takes further advantage of the cross-zonal transmission capacities that are remaining after the day-ahead simulation. In the day-ahead simulation, around 580 TWh are exchanged on cross-zonal interconnectors. Due to imbalance netting and cross-zonal exchange of balancing energy, some interconnections see their utilisation increase (10.8 TWh for aFRR, 4.5 for mFRR), while others see theirs decrease (9.5 TWh for aFRR, 2.7 for mFRR).

Option C

Finally, in option C, the cross-zonal transmission capacities available for balancing are increased (the EuCo27 NTCs available for balancing are increased by 15%). This leads to a greater level of imbalance netting (4.6 TWh more than in options A and B) and opportunities to balance the system more cost-efficiently, resulting in further savings compared to option B worth 340 M€.

Table 15 - Option C for the Guideline on Electricity Balancing (and comparison with baseline)

Option C	aFRR		mFRR	
Upwards activation	4.9 TWh	(-65%)	2.6 TWh	(-46%)
Downwards activation	3.0 TWh	(-76%)	3.2 TWh	(-42%)
Upwards activation cost	192 M€	(-82%)	156 M€	(-64%)
Downwards activation cost	- 197 M€	(+62%)	- 306 M€	(+10%)
Total activation cost	- 5 M€		- 150 M€	
Total	**- 155 M€**			
Cost reduction (savings)	**817 M€**			
Savings per MWh[33]	**22.2 €/MWh**			

In option C, the extra cross-zonal transmission capacity allows TSOs to net more than 60% of their imbalances. The remaining upwards imbalances are faced with cheap resources, while downwards imbalances save additional fuel costs, as is indicated in the table below:

Table 16 – Average balancing costs – Option C versus baseline

Average balancing costs (€/MWh)	Baseline	Option C
Upwards aFRR	77 €/MWh	39 €/MWh
Downwards aFRR	- 43 €/MWh	- 66 €/MWh
Upwards mFRR	92 €/MWh	60 €/MWh
Downwards mFRR	- 62 €/MWh	- 96 €/MWh

The activation of balancing energy has almost no effect on CO_2 emissions (80 fewer kilotons of CO_2 are emitted compared to the day-ahead programme). The following table

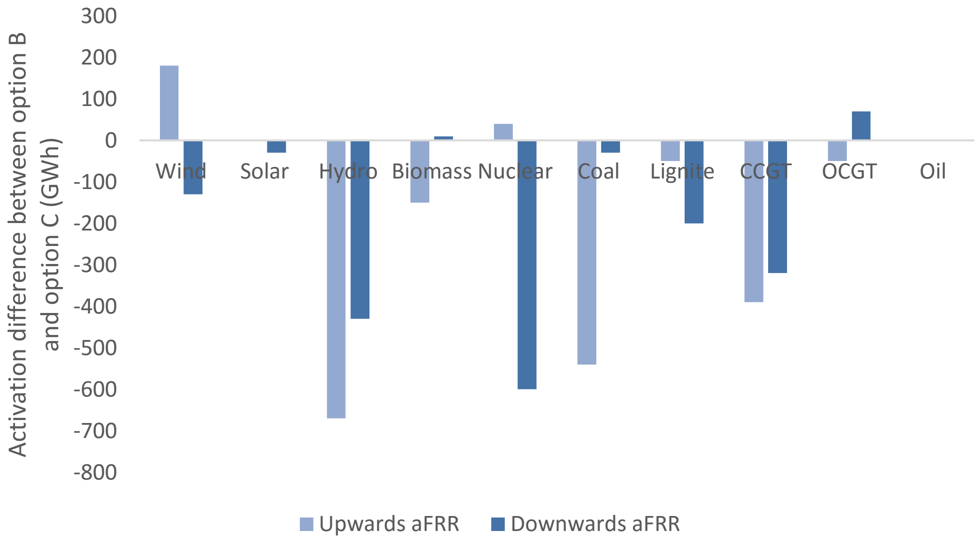
[33] This indicator is computed by dividing the savings of the considered options compared with the baseline costs by the activated balancing energy in the baseline.

shows the impacts of the further cross-zonal transmission capacity available for balancing introduced in option C, and compares them with the option B figures, which are shown in parenthesis.

Table 17 - Option C for the Guideline on Electricity Balancing – Activations (and comparison with option B)

Option C (GWh)	aFRR				mFRR			
	Upwards		Downwards		Upwards		Downwards	
Wind	990	(810)	0	(130)	60	(10)	30	(140)
Solar	0	(0)	0	(30)	0	(0)	0	(0)
Hydro	1 550	(2 220)	500	(930)	1 710	(1 860)	2 420	(2 820)
Biomass	80	(230)	100	(90)	190	(550)	10	(20)
Nuclear	1 210	(1 170)	0	(600)	80	(20)	0	(190)
Coal	530	(1 070)	230	(260)	130	(90)	20	(90)
Lignite	250	(300)	30	(230)	180	(210)	0	(20)
CCGT	310	(700)	1 980	(2 300)	220	(390)	10	(200)
OCGT	0	(50)	180	(110)	0	(90)	720	(430)
Oil	0	(0)	0	(0)	0	(10)	10	(10)

The differences between the aFRR activations in options B and C are shown below. Due to the additional imbalance netting between option B and option C, almost all technologies decrease their activations. One can note that cheap upwards resources such as wind and nuclear power are exploited more intensely than in option B, while hydropower, coal-fired power plants and CCGTs significantly see their activations reduced. Furthermore, nuclear power ceases to provide downwards aFRR regulation: it is more cost-effective to use more expensive resources such as CCGTs, hydropower, coal-fired power plants and OCGTs to provide this service.



Option C takes further advantage of the cross-zonal transmission capacities that are remaining after the day-ahead simulation. In the day-ahead simulation, around 580 TWh are exchanged on cross-zonal interconnectors. Due to imbalance netting and cross-zonal exchange of balancing energy, some interconnections see their utilisation increase (14.5 TWh for aFRR, 5.4 for mFRR), while others see theirs decrease (8.2 TWh for aFRR, 2.3 for mFRR).

Table 18 presents an estimate of how much of the transmission capacity still available after the day-ahead market clearing is used by imbalance netting and the cross-border exchange of balancing energy. The indicator is obtained by computing the ratio between the balancing flow in the prevailing direction (i.e. the energy that flows in the same direction as the day-ahead flow) and the remaining transmission capacity in the prevailing direction (i.e. the difference between the transmission capacity in the day-ahead direction and the day-ahead flow).

Table 18 - Utilisation of the remaining transmission capacity

	Option A	Option B	Option C
FRR flow in the prevailing direction	6.0 TWh	15.3 TWh	19.9 TWh
Available capacity in the prevailing direction	461 TWh	461 TWh	617 TWh
Average utilisation rate	1.3 %	3.3 %	3.2 %

Summary

In this section, we have estimated the savings that would result from three different models for imbalance netting and cross-zonal exchanges of balancing energy. To do so, a common portfolio of balancing capacities has been used for all options. The options thus only differ in the way they exploit the reserve capacities[34].

The following table provides a comparison between the most relevant indicators for all the considered models of imbalance netting and cross-border exchange of balancing energy.

Table 19 - Guideline on Electricity Balancing - Summary

Summary	Baseline	Option A	Option B	Option C
Day-ahead demand	3490 TWh	3490 TWh	3490 TWh	3490 TWh
Total balancing demand	37.0 TWh	37.0 TWh	37.0 TWh	37.0 TWh
Total activation	37.0 TWh	18.4 TWh	18.4 TWh	13.7 TWh
Imbalance netting	-	18.6 TWh	18.6 TWh	23.3 TWh
Share of cross-zonal activation[35]	-	-	53%	70%
Total cost	662 M€	450 M€	183 M€	- 155 M€
Saving vs baseline	**-**	**212 M€**	**479 M€**	**817 M€**

The 212 M€ savings in option A are mainly due to imbalance netting[36]. The share of imbalances faced by each technology evolves only very moderately between the baseline and option A: in both cases the TSOs only have their local resources to face their domestic imbalances. This limits the possibilities of changing the way technologies are used to balance the system.

Option B introduces the possibility for TSOs to use cross-zonal resources to balance their systems, provided enough cross-zonal transmission capacity is available. In this option, more than half the balancing energy is provided by balancing service providers located in a different TSO responsibility area. The competition between balancing service providers results in additional savings of 267 M€ compared to option A.

Finally, in option C, which assumes a 15% increase of the cross-zonal transmission capacities available for balancing purposes, both imbalance netting and cross-zonal activations increase. The share of upwards imbalances met by inexpensive technologies such as hydro and nuclear power increases, while the downwards demand is met by expensive technologies, including CCGTs and OCGTs. This results in total savings of 817 M€ compared to the baseline.

[34] Note that the NTCs available for balancing are increased by 15% in option C.

[35] This indicator does not take imbalance netting into account.

[36] Cross-zonal exchanges of balancing energy were only allowed if they could avoid loss of load situations.

Table 20 - Guideline on Electricity Balancing - Results (1/2)

Summary	Baseline	Option A	Option B	Option C
Day-ahead demand	3490 TWh	3490 TWh	3490 TWh	3490 TWh
Total balancing demand	37.0 TWh	37.0 TWh	37.0 TWh	37.0 TWh
Imbalance netting	-	18.6 TWh	18.6 TWh	23.3 TWh
Share of cross-zonal activation[37]	-	-	53%	70%
Total activation	**36.8 TWh**	**18.4 TWh**	**18.4 TWh**	**13.7 TWh**
of which upwards aFRR	14.2	6.6	6.6	4.9
of which downwards aFRR	12.3	4.7	4.7	3.0
of which upwards mFRR	4.8	3.2	3.2	2.6
of which downwards mFRR	5.5	3.9	3.9	3.2
Total cost	**662 M€**	**450 M€**	**183 M€**	**- 155 M€**
of which upwards aFRR	1088	554	419	192
of which downwards aFRR	- 523	- 182	- 226	- 197
of which upwards mFRR	438	310	255	156
of which downwards mFRR	- 341	- 232	- 265	- 306
Saving vs baseline	**-**	**212 M€**	**479 M€**	**817 M€**

[37] This indicator does not take imbalance netting into account.

Table 21 - Guideline on Electricity Balancing - Results (2/2)

Activations	Baseline	Option A	Option B	Option C
Upwards aFRR activation	**14.2 TWh**	**6.6 TWh**	**6.6 TWh**	**4.9 TWh**
of which wind	0.6	0.3	0.8	1.0
of which solar	< 0.1	< 0.1	< 0.1	< 0.1
of which hydro	7.3	3.3	2.2	1.6
of which biomass	0.5	0.3	0.2	< 0.1
of which nuclear	0.8	0.4	1.2	1.2
of which coal	2.3	1.0	1.1	0.5
of which lignite	0.2	< 0.1	0.3	0.3
of which CCGT	2.3	1.1	0.7	0.3
of which OCGT	0.2	0.1	< 0.1	< 0.1
of which oil	< 0.1	< 0.1	< 0.1	< 0.1
Downwards aFRR activation	**12.3 TWh**	**4.7 TWh**	**4.7 TWh**	**3.0 TWh**
of which wind	0.7	0.3	0.1	< 0.1
of which solar	0.2	< 0.1	< 0.1	< 0.1
of which hydro	2.2	1.0	0.9	0.5
of which biomass	0.2	< 0.1	< 0.1	0.1
of which nuclear	1.4	0.7	0.6	< 0.1
of which coal	0.7	0.2	0.3	0.2
of which lignite	1.2	0.4	0.2	< 0.1
of which CCGT	5.4	1.9	2.3	2.0
of which OCGT	0.3	< 0.1	0.1	0.2
of which oil	< 0.1	< 0.1	< 0.1	< 0.1
Upwards mFRR activation	**4.8 TWh**	**3.2 TWh**	**3.2 TWh**	**2.6 TWh**
of which wind	< 0.1	< 0.1	< 0.1	< 0.1
of which solar	< 0.1	< 0.1	< 0.1	< 0.1
of which hydro	3.4	2.2	1.9	1.7
of which biomass	0.5	0.3	0.6	0.2
of which nuclear	< 0.1	< 0.1	< 0.1	< 0.1
of which coal	< 0.1	< 0.1	< 0.1	0.1
of which lignite	< 0.1	< 0.1	0.2	0.2
of which CCGT	< 0.1	< 0.1	0.4	0.2
of which OCGT	0.6	0.5	< 0.1	< 0.1
of which oil	0.2	0.1	< 0.1	< 0.1
Downwards mFRR activation	**5.5 TWh**	**3.9 TWh**	**3.9 TWh**	**3.2 TWh**
of which wind	0.2	0.2	0.1	< 0.1
of which solar	< 0.1	< 0.1	< 0.1	< 0.1
of which hydro	2.8	2.0	2.8	2.4
of which biomass	0.3	0.1	< 0.1	< 0.1
of which nuclear	0.3	0.2	0.2	< 0.1
of which coal	0.6	0.4	< 0.1	< 0.1
of which lignite	< 0.1	< 0.1	< 0.1	< 0.1
of which CCGT	1.2	0.8	0.2	< 0.1
of which OCGT	0.1	< 0.1	0.4	0.7
of which oil	< 0.1	< 0.1	< 0.1	< 0.1

6.2.2. MDI OPTIONS

In this section we examine the impacts of the introduction of a number of policy measures aimed at improving the functioning of the electricity markets. In particular, the different models differ in terms of reserve dimensioning and procurement, and are a subset of the options considered in the MDI IA. For each option, we present the impacts on balancing reserve dimensioning, their procurement and the corresponding costs.

Baseline

Dimensioning

In the baseline, reserve capacity requirements are dimensioned so that each country can face its national imbalances independently. As a number of countries jointly procure their upwards and downwards reserves[38], the reserve dimensioning is taking these specificities into account. As a result, the reserve capacity needs in the baseline is the largest of all the studied options.

The following table presents the reserve capacities. Active power stands for the sum of FCR and aFRR reserves.

Table 22 - MDI Baseline - Dimensioning

Baseline	Active power		mFRR	
	Upwards	Downwards	Upwards	Downwards
Reserve needs	16.7 GW	16.1 GW	17.4 GW	15.6 GW

Since no regional cooperation is assumed in the baseline, the reserves are dimensioned at country level. The automatic FRR is mainly used for small demand or RES generation variations, or, in case of larger imbalances, to limit frequency deviation before mFRR is triggered. The aFRR is dimensioned so as to compensate for the variation of imbalances during a 5mn interval[39] excluding outages, while the mFRR is dimensioned to cope with total imbalances, including forecast errors and outages[40]. The main drivers of the reserve capacity needs are therefore the dynamics of the load curve, as well as those of RES production profiles, and the importance of RES in the generation mix (fixed by the EuCo27 scenario).

Procurement

The procurement of reserves is simulated with METIS, which jointly optimises the energy dispatch and the reserve capacity procurement. The following table summarises the results of the procurement exercise.

[38] The following countries currently jointly procure upwards and downwards aFRR reserves: BE, DK, EE, ES, FR, HR, IT, LT, LV, PL, PT, RO, SI, SK, UK. Source: "Electricity Market Functioning: Current Distortions, and How to Model Their Removal", COWI (2016).

[39] The 0.1 and 99.9 percentiles of imbalance variations distributions are used to compute the downwards and upwards aFRR needs.

[40] The 0.1 and 99.9 percentiles of total imbalance variations distributions are used to compute downwards and upwards FRR needs. mFRR needs are then computed by subtracting aFRR to FRR sizes

Table 23 - MDI Baseline - Procurement

Baseline	Energy (TWh)	Active power		mFRR	
		Upwards (MW)	Downwards (MW)	Upwards (MW)	Downwards (MW)
Wind	730	-	-	-	-
Solar	300	-	-	-	-
Hydro	620	6 370	4 200	12 780	2 190
Biomass	80	1 030	460	1 380	10
Nuclear	770	1 730	2 220	130	1 400
Coal	270	1 950	1 520	100	730
Lignite	270	530	1 990	160	1 850
CCGT	530	4 290	5 570	360	8 750
OCGT	10	700	130	1 680	690
Oil	-	10	10	560	20
Other RES	10	-	-	-	-
DSR	-	-	-	10	-

The baseline scenario assumes that the procurement of reserves is performed at the national level. Therefore, the METIS model determines which of the local capacities to reserve for balancing purposes, and which to use to meet the demand for electricity (the EU day-ahead markets are assumed to be fully coupled). The portfolios of balancing capacities are therefore constrained by the local installed capacities, which are inputs of the model (EuCo27 scenario).

Countries such as Estonia, Hungary, Slovenia and Slovakia which have generation mixes with limited access to mid-merit capacities, use lignite and nuclear power for an important share of their active power reserve needs (>50%)[41]. Although the activation of the balancing services provided by nuclear power is very inexpensive (<20 €/MWh), there is a high opportunity cost associated with the provision of reserves by cheap technologies. From a systems point of view, using these resources to produce electricity rather than upwards reserves would be more cost-efficient. Regional cooperation, introduced in options 1b and 2, will be shown to reduce the occurrence of these situations (e.g. nuclear power's contribution to upwards reserves will decrease, allowing it to produce more electricity).

[41] France also uses nuclear power for a large share of its upwards active power reserves. However this is not due to the lack of mid-merit capacities, but rather to the sub-optimal procurement practices assumed in the baseline.

Costs

The following table provides key indicators for the baseline and the associated costs.

Table 24 - MDI Baseline - Costs

Baseline	Total
Electricity production	3610 TWh
CO_2 emissions	614 $MtCO_2$
Electricity load payment	293.4 B€
Total cost	76.9 B€

The following table shows the breakdown of the cost and load payment figures by region.

Table 25 - MDI Baseline - Regional impacts

Baseline	Region 1	Region 2	Region 3	Region 4	Region 5
Electricity production (TWh)	1 810	450	400	370	520
Electricity load payment (B€)	161.2	40.0	30.9	18.3	37.0
Generation costs (B€)	40.3	5.5	10.7	5.3	14.9

One can note that even if a region is characterised by relatively low costs (e.g. the Nordic and the Baltic countries), its load payment per MWh, which is the mean wholesale price of electricity paid by consumers, can still be important. This is due to the fact that although generation costs are very low (mainly from hydro or base-load units), the marginal price of electricity is fixed by the dynamics of the European market. This can lead to high producer surplus.

Option 1ab

Dimensioning

In option 1ab, reserve capacity needs are also dimensioned so that each country can face its national imbalances independently. However, in contrast with the baseline, in option 1ab each country is assumed to procure its balancing capacities asymmetrically. In addition, the active power reserves can vary depending on the hour of the day (according to wind generation and demand profile), so that the procured balancing capacities can be lower during the hours with less imbalance risk.

Table 26 - MDI Option 1ab – Dimensioning (and comparison with baseline)

Option 1ab	Active power				mFRR			
	Upwards		Downwards		Upwards		Downwards	
Reserve needs (GW)	16.4	(-0.3)	15.1	(-1.0)	17.4	(-)	15.6	(-)

These two effects (independent procurement of active power and mFRR reserves, and hourly dimensioning) reduce the reserve capacity needs by around 1.3 GW.

Procurement

There are essentially two ways the procurement in option 1ab differs from that of the baseline: first, there is less active power reserve to procure thanks to the independent procurement of upwards and downwards balancing capacities, as discussed above. Second, option 1ab assumes that all suboptimal procurement practices are removed.

Table 27 - MDI Option 1ab – Procurement (and comparison with baseline)

Option 1ab	Energy (TWh)		Active power				mFRR			
			Upwards (MW)		Downwards (MW)		Upwards (MW)		Downwards (MW)	
Wind	730	(-)	-	(-)	-	(-)	-	(-)	-	(-)
Solar	300	(-)	-	(-)	-	(-)	-	(-)	-	(-)
Hydro	630	(+10)	8 600	(+2230)	2 320	(-1880)	12 390	(-390)	2 210	(+20)
Biomass	80	(-)	1 260	(+230)	270	(-190)	1 490	(+110)	10	(-)
Nuclear	790	(+20)	800	(-930)	2 640	(+420)	130	(-)	1 430	(+30)
Coal	280	(+10)	1 570	(+380)	1 200	(-320)	60	(-40)	980	(+250)
Lignite	270	(-)	470	(-60)	2 410	(+420)	160	(-)	1 550	(-300)
CCGT	510	(-20)	2 900	(-1390)	6 060	(+490)	370	(+10)	8 830	(+80)
OCGT	10	(-)	680	(-20)	180	(+50)	1 900	(+220)	620	(-70)
Oil	-	(-)	10	(-)	-	(-10)	660	(+100)	20	(-)
Other RES	10	(-)	-	(-)	-	(-)	-	(-)	-	(-)
DSR	-	(-)	-	(-)	-	(-)	10	(-)	-	(-)

The following two figures illustrate the impact of the removal of suboptimal procurement practices on a three-day period. In the baseline, the fact that some countries allocate their reserves to selected thermal power plants (**Figure 8**) can deteriorate the merit order. In option 1ab, the reserves are allocated to the marginal units for upwards reserves and to sub-marginal ones for downwards ones (**Figure 9**).

Figure 8 – Active power upwards reserve procurement with suboptimal practices

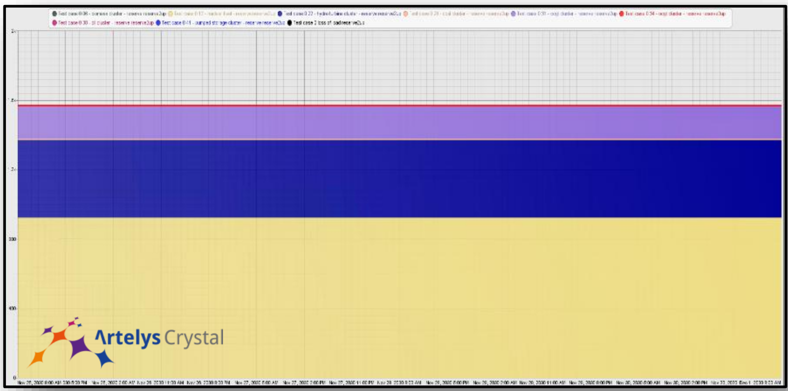
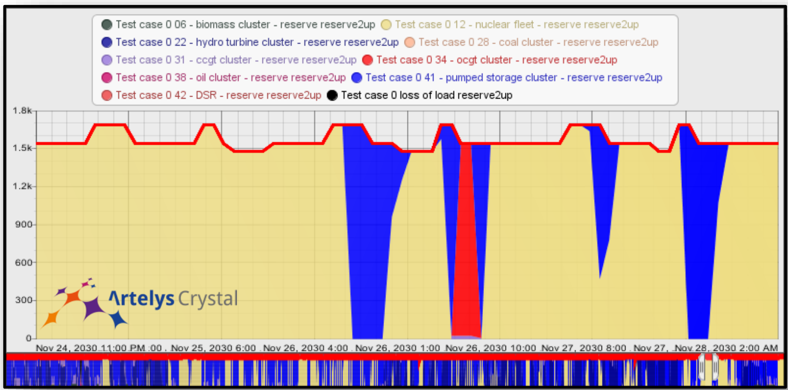


Figure 9 - Optimal active power upwards reserve procurement



As a result, cheap resources like nuclear power see their electricity production increase, and their participation in the provision of balancing capacity (which has a high opportunity cost) decrease. By diminishing its participation in upwards active power reserve capacity, nuclear power can generate more electricity. This improves the management of the power system from a systems cost point of view.

Moreover, the fact that upwards and downwards reserves are procured independently in option 1ab results in a more cost-efficient allocation of reserve capacity. The provision of downwards active power reserve capacity by hydropower decreases with respect to the baseline, which results in an increased system flexibility. The asymmetric provision of reserves also saves opportunity costs: in the baseline, if a country using sub-optimal procurement practices wanted to use nuclear power for downwards reserve capacity, it also had to use it for upwards reserve capacity, which has a high opportunity costs. Option 1ab relaxes this constraint. As a result, nuclear power provides more downwards reserves, and reduces its participation in upwards reserves capacity procurement.

Costs

The following table provides general characteristics of the option and its costs, and compares them with the baseline.

Table 28 - MDI Option 1ab – Costs (and comparison with baseline)

Option 1ab	Total	
Electricity production	3610 TWh	(-)
CO_2 emissions	609 $MtCO_2$	(-5)
Electricity load payment	289.8 B€	(-3.6)
Total cost	**75.1 B€**	
Cost savings vs baseline	**1.8 B€**	

The measures introduced in option 1ab have a limited impact on CO_2 emissions and electricity load payment (less than 1€ per MWh). Option 1ab results in savings of the order of 1.8 B€ compared with the baseline. MS-level saving are shown in Appendix E.

The following table shows the breakdown of the cost and load payment figures by region, and their comparison with the baseline.

Table 29 - MDI Option 1ab - Regional impacts (and comparison with baseline)

Option 1ab	Region 1		Region 2		Region 3		Region 4		Region 5	
Electricity production (TWh)	1 820	(+10)	450	(-)	400	(-)	370	(-)	520	(-)
Electricity load payment (B€)	157.3	(-3.9)	39.3	(-0.7)	31.5	(+0.6)	18.9	(+0.6)	37.0	(-)
Generation costs (B€)	40.0	(-0.3)	5.3	(-0.2)	9.8	(-0.9)	5.1	(-0.2)	14.7	(-0.2)

Option 1b

Dimensioning

In option 1ab, all the national inefficiencies in reserve dimensioning have been removed. The reserve needs have been shown to decrease by around 1.3 GW. In order to further increase the level of competition in the internal market, option 1b introduces measures to enhance regional cooperation and make better use of interconnection capacities.

In particular, instead of being computed at national level, FRR reserves are dimensioned at a regional level. The statistical cancellation of imbalances of opposite directions results in a reduction of 34% of the reserve needs compared to option 1ab. The following table presents the reserve needs and compares them with the needs in option 1ab.

Table 30 - MDI Option 1b – Dimensioning (and comparison with option 1ab)

Option 1b	Active power				mFRR			
	Upwards		Downwards		Upwards		Downwards	
Reserve needs	11.5	(-30%)	11.0	(-27%)	10.2	(-41%)	9.6	(-38%)

The lower relative decrease of active power reserve requirements compared to those of mFRR is explained by the fact that active power reserves include both FCR and aFRR, and that the regional dimensioning of reserves is assumed only to impact FRR needs (FCR dimensioning is performed at the synchronous area level, and thus already assumes a certain level of collaboration between TSOs). The following table shows how FRR needs evolve at a regional level between option 1ab and option 1b:

Table 31 - MDI Option 1b – Decrease of FRR regional needs between option 1b and option 1ab

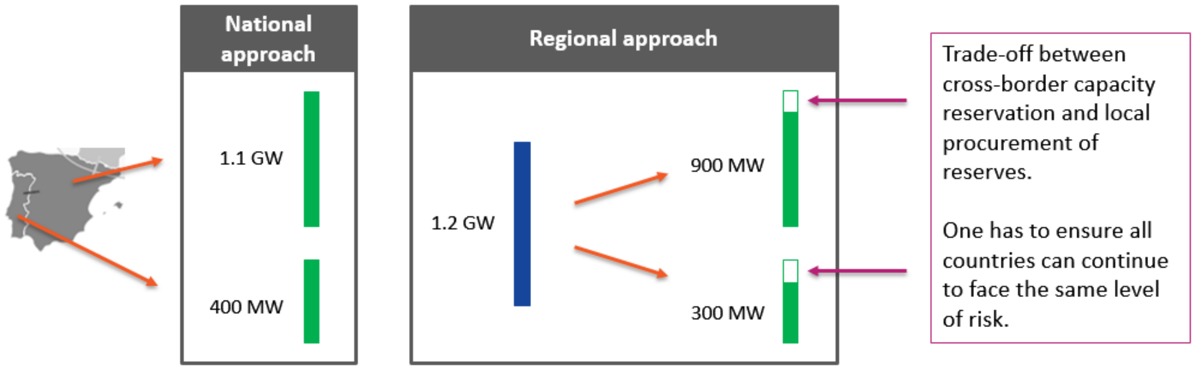
Option 1b	Region 1	Region 2	Region 3	Region 4	Region 5
FRR needs reduction	-54%	-48%	-18%	-17%	-44%

As expected, the most marked decreases of FRR needs are found in the largest regions, as the probability of occurrence of imbalances of opposite directions increases with the size of the considered region. One should note that the above figures heavily depend on the definition of the regions.

Although the reserve needs are lower than in option 1ab, the imbalance risks faced by a given TSO do not change. In order to continue to be able to face the same risk level, TSOs can either reserve the same amount of capacity as in option 1ab, or can reserve less capacity (the minimum being given by **Table 30**) and reserve capacity on interconnectors so as to be able to import balancing services from neighbouring countries. This trade-off between domestic reserves (and their associated costs) and interconnectors' reservation (and the associated opportunity costs) is central to understanding the results of option 1b.

Figure 10 illustrates how the regional balancing needs are allocated to countries, and the trade-off between a local provision of balancing capacity and interconnectors' reservation.

Figure 10 - Trade-off between local provision of reserves and interconnectors' reservation



In this fictitious example, we illustrate the impact of a regional dimensioning of upwards active power reserves in Spain and Portugal. The nationally-determined reserve needs allow both countries to independently face their respective risks. In this situation, Spain has to procure 1.1 GW of upwards active power reserves, and Portugal 400 MW. When the dimensioning is performed at the regional level, the statistical cancellation of imbalances results in a regional requirement of 1.2 GW, which is lower than the sum of the nationally-determined reserve needs (1.2 GW *vs* 1.5 GW). Each of the countries is assumed to procure a share of the regional reserve needs, according to their annual electricity demands. In our fictitious example, Spain has to procure at least 900 MW and Portugal at least 300 MW.

In order to face their imbalance risks (due to forecasting errors, outages, etc.), both Spain and Portugal have to secure access to the amount of reserve computed using a national approach. This reserve might either be procured locally, or be provided by another country:

- Spain therefore has to choose how to secure the 200 MW between its national needs (1.1 GW) and the local share of the regional needs (900 MW). Spain can for example choose to procure 100 additional MW and to reserve 100 MW on interconnectors. Spain would then have 1.0 GW of local reserves, and 100 MW reserved on interconnectors. The total would allow Spain to face its imbalance risks (1.1 GW).

- Portugal faces the same choice, only for 100 MW. Portugal could for example choose to procure the entire local needs (400 MW) locally, so as to maximise the import capacity from Spain.

This example illustrates the trade-offs between a local procurement of reserves, and the reservation of cross-zonal transmission capacity.

Procurement

The strengthened collaboration amongst TSOs introduced in option 1b is assumed to result in a higher interconnection capacity available to market participants (+ 5% compared to option 1ab). The following table shows the impacts of the policy measures introduced in option 1b, and compares them with option 1ab.

Table 32 - MDI Option 1b – Procurement (and comparison with option 1ab)

Option 1b	Energy (TWh)		Active power Upwards (MW)		Active power Downwards (MW)		mFRR Upwards (MW)		mFRR Downwards (MW)	
Wind	730	(-)	-	(-)	-	(-)	-	(-)	-	(-)
Solar	300	(-)	-	(-)	-	(-)	-	(-)	-	(-)
Hydro	620	(+10)	6 560	(-24%)	2 190	(-6%)	8 600	(-31%)	2 090	(-5%)
Biomass	70	(-)	1 030	(-18%)	170	(-37%)	740	(-50%)	10	(-)
Nuclear	800	(+20)	490	(-39%)	2 420	(-8%)	-	(-100%)	1 440	(+1%)
Coal	270	(+10)	840	(-46%)	1 140	(-5%)	10	(-83%)	1 000	(+2%)
Lignite	280	(-)	240	(-49%)	2 430	(+1%)	-	(-100%)	1 540	(-1%)
CCGT	510	(-20)	2 270	(-22%)	6 000	(-1%)	60	(-84%)	9 000	(+2%)
OCGT	10	(-)	300	(-56%)	170	(-6%)	900	(-53%)	380	(-39%)
Oil	-	(-)	-	(-100%)	-	(-)	250	(-62%)	10	(-50%)
Other RES	10	(-)	-	(-)	-	(-)	-	(-)	-	(-)
DSR	-	(-)	-	(-)	-	(-)	-	(-100%)	-	(-)

As in option 1ab, the lower requirements for balancing capacities translate into more cheap generation capacity being available to generate electricity. As a consequence, nuclear power, coal-fired power plants, and hydropower displace CCGTs in the merit order.

It is interesting to note the behaviour of the reduction of balancing capacities for upwards and downwards reserves. While the reduction for upwards reserves is broadly in line with the reduction of balancing requirements (see **Table 30**), the reduction of downwards reserves is not as important as the corresponding demand. This phenomenon is the result of a trade-off between providing balancing reserves locally, and procuring less reserves but reserving interconnectors to be able to balance the system at any time. Since downwards reserve capacities have a very low cost, the model favours a local provision of these reserves so that interconnectors can be used to exchange energy.

The average reservation of interconnectors in option 1b is found to be 5.8%. This figure is found by averaging interconnectors' reservations over the year. Note that since the portfolio of reserves changes from hour to hour, the need for interconnection reservation does too. Moreover, some countries are better interconnected than others, leading to various interconnection reservation rates, which in some cases could reach double-digit figures.

Costs

The following table provides general characteristics of the option and its costs, and compares it with the baseline.

Table 33 - MDI Option 1b – Costs (and comparison with baseline)

Option 1b	Total	
Electricity production	3600 TWh	(-10)
CO2 emissions	605 $MtCO_2$	(-9)
Electricity load payment	261.0 B€	(-31.4)
Total cost	**73.5 B€**	
Cost savings vs baseline	**3.4 B€**	

Option 1b has a sizable impact on electricity load payment (>10%), and results in further savings compared with option 1ab: the regional dimensioning and the ability given to TSOs to procure their balancing reserve capacities abroad translate into additional savings of 1.6 B€ compared to option 1ab.

The following table shows the breakdown of the cost and load payment figures by region, and compares them to the option 1ab results.

Table 34 - MDI Option 1b - Regional impacts (and comparison with option 1ab)

Option 1b	Region 1		Region 2		Region 3		Region 4		Region 5	
Electricity production (TWh)	1 820	(-)	450	(-)	400	(-)	360	(-10)	520	(-)
Electricity load payment (B€)	137.5	(-19.8)	33.6	(-5.7)	30.2	(-1.3)	19.0	(+0.1)	36.4	(-0.6)
Generation costs (B€)	39.4	(-0.6)	4.8	(-0.5)	9.6	(-0.2)	5.0	(-0.1)	14.6	(-0.1)

Option 2

Dimensioning

Option 2 foresees a strengthened cooperation between TSOs at a European level. Reserve capacity needs are computed at an EU level. As in option 1b, the statistical cancellation of imbalances of opposite directions results in a reduction of reserve needs. In option 2, reserve needs are reduced by 54% compared to option 1ab. This is 20 percentage points higher than what was achieved when reserves were dimensioned regionally (option 1b). The following table presents the results of the dimensioning at EU level and compares them with option 1ab:

Table 35 - MDI Option 2 – Dimensioning (and comparison with option 1ab)

Option 2	Active power				mFRR			
	Upwards		Downwards		Upwards		Downwards	
Reserve needs	9.5	(-42%)	9.0	(-40%)	5.8	(-67%)	5.3	(-66%)

Just as in option 1b, the difference between the relative impacts on active power reserve needs and mFRR needs is explained by the fact that only FRR is assumed to benefit from the strengthened cooperation between TSOs. FCR being already dimensioned at an EU-level, its dimensioning is not impacted by the measures introduced in option 1b and option 2.

Procurement

The strengthened collaboration amongst TSOs introduced in option 2 is assumed to result in a higher interconnection capacity available to market participants (+ 5% compared with option 1b). Moreover, this MDI option foresees that further distributed resources are pulled into the market. RES can participate in the reserve procurement exercise, and further demand-response capacities are available to provide balancing services.

The following table presents the results of the electricity dispatch and of the reserve procurement, and compares them with option 1ab.

Table 36 - MDI Option 2 – Procurement (and comparison with option 1ab)

Option 2	Energy (TWh)		Active power				mFRR			
			Upwards (MW)		Downwards (MW)		Upwards (MW)		Downwards (MW)	
Wind	730	(-)	50	(+50)	240	(+240)	30	(+30)	50	(+50)
Solar	300	(-)	-	(-)	190	(+190)	-	(-)	70	(+70)
Hydro	610	(-20)	4 060	(-53%)	2 570	(+11%)	4 990	(-60%)	1 690	(-24%)
Biomass	70	(-10)	680	(-46%)	180	(-33%)	280	(-81%)	10	(-)
Nuclear	800	(+10)	330	(-59%)	2 080	(-21%)	-	(-100%)	1 760	(+23%)
Coal	270	(-10)	340	(-78%)	970	(-19%)	-	(-100%)	990	(+1%)
Lignite	280	(+10)	70	(-85%)	2 370	(-2%)	-	(-100%)	1 540	(-1%)
CCGT	510	(-)	500	(-83%)	6 020	(-1%)	-	(-100%)	9 180	(+4%)
OCGT	10	(-)	30	(-96%)	150	(-17%)	110	(-94%)	190	(-69%)
Oil	-	(-)	-	(-100%)	-	(-)	10	(-98%)	-	(-100%)
Other RES	10	(-)	-	(-)	-	(-)	-	(-)	-	(-)
DSR	-	(-)	3 450	(+3450)	-	(-)	590	(+590)	-	(-)

Just as in option 1b, where regional cooperation was introduced, the most cost-efficient reserve capacity procurement strategy is to have a strong cooperation for upwards reserves, which are costly, and a lower level of cooperation for downwards ones in order to save the opportunity costs associated with the reservation of cross-zonal interconnectors. This lower level of cooperation can be observed by comparing the procured capacity with the reserve capacity needs (e.g. 14.8 GW *vs* 9.0 GW for downwards active power reserves).

The introduction of an EU-wide collaboration and the ability for RES and further DSR resources to participate in the reserve procurement exercise have an important impact on the portfolio of technologies providing reserves, as shown in **Table 36**. The most important impact originates from the introduction of further DSR resources[42]: these resources are used both for upwards active reserves (more than 1/3 of the procured reserves), and for mFRR reserves, although in a less important way.

Allowing RES to provide reserves has an impact on the optimal operations of thermal units. Wind has the ability to provide upwards reserves when the simulation predicts that wind power should be curtailed. The case of downwards regulation is particularly interesting. In some situations, the participation of RES in the downwards reserve capacity procurement exercise can save start-up and fuel costs, as is illustrated in the following.

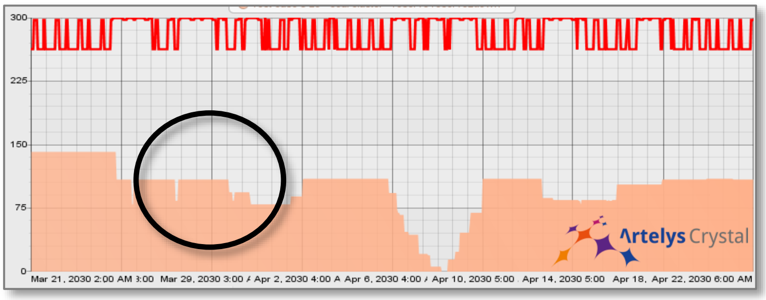
Figure 11 illustrates a situation in which RES are not allowed to participate in the downwards reserve procurement exercise. One can see that even if RES production is greater than the demand (RES is shown in green colours), coal (in orange) still has to run

[42] The DSR potentials are based on the following study "Impact Assessment support Study on downstream flexibility, demand response and smart metering", COWI (2016). The BaU potential was used in all previous options, while the more ambitious PO2 scenario is considered here. The difference between the two scenarios is storage-based DSR (water heating, electric vehicles charging) or other DSR (cooling, heating).

and produce electricity in order to be able to lower its production to provide downwards balancing energy if the system were to face imbalances.

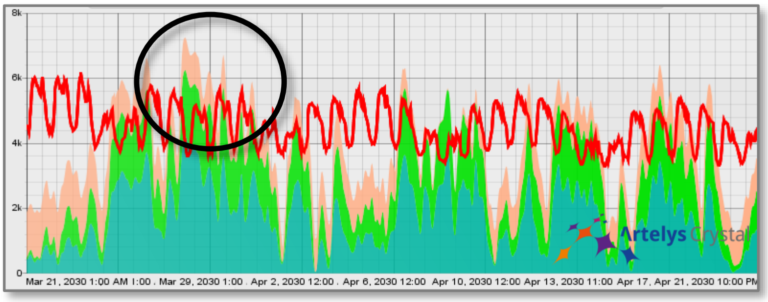
Figure 11 - Impact of RES on downwards reserves (option 1b)

Downwards active power reserve



Downwards synchronized reserve is allocated to coal

Electricity



Coal has to be kept online for reserve while it is not needed for pure supply-demand equilibrium reasons.

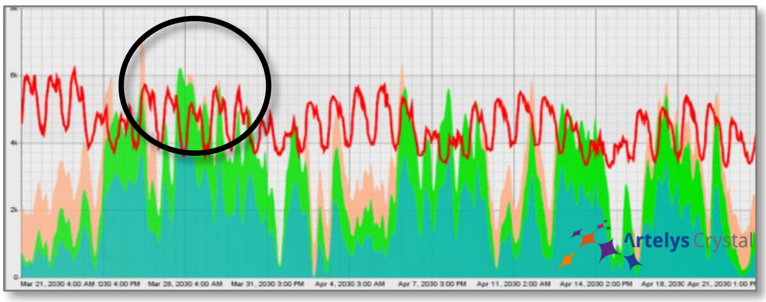
On the other hand, when RES are allowed to provide balancing capacity, the situation changes. **Figure 12** shows the impact of RES participation in the downwards active power reserve procurement exercise. One can see on the upper image that coal can avoid start-up costs as well as fuel costs (and therefore can be turned off much more often, see lower image) thanks to the provision of downwards reserves by wind power.

Figure 12 - Impact of RES on downwards reserves (option 2)

Downwards active power reserve

Wind replaces coal in downward reserves

Electricity



Coal fleet can be turned off when RES generation exceeds demand

The average reservation of interconnectors in option 2 is found to be 8.4%. This figure is found by averaging interconnectors' reservations over the year. Note that since the portfolio of reserves changes from hour to hour, the need for interconnection reservation does too. Moreover, some countries are better interconnected than others, leading to various interconnection reservation rates, which often reach double-digit figures.

Costs

The following table provides general characteristics of the option and its costs, and compares them with the baseline.

Table 37 - MDI Option 2 – Costs (and comparison with baseline)

Option 2	Total	
Electricity production	3590 TWh	(-20)
CO2 emissions	598 $MtCO_2$	(-16)
Electricity load payment	246.3 B€	(-47.1)
Total cost	**72.4 B€**	
Cost savings vs baseline	**4.5 B€**	

Option 2 results in a further cost reduction. The 4.5 B€ of savings generated by option 2 represent a 6% reduction of costs, and generate an important impact when measured in terms of electricity load payment (16% reduction). Several drivers explain these savings: the lower reserve capacity to be procured, the participation of RES and further DSR in the procurement exercise, as well as the increase of cross-zonal transmission capacity.

The following table shows the breakdown of the cost and load payment figures by region, and compares them with option 1ab results to highlight the impacts of the specific measures introduced in this option.

Table 38 - MDI Option 2 - Regional impacts (and comparison with option 1ab)

Option 2	Region 1		Region 2		Region 3		Region 4		Region 5	
Electricity production (TWh)	1 810	(-10)	450	(-)	390	(-10)	360	(-10)	520	(-)
Electricity load payment (B€)	125.6	(-31.7)	30.3	(-9.0)	29.9	(-1.6)	19.1	(+0.2)	36.6	(-0.4)
Generation costs (B€)	38.6	(-1.4)	4.4	(-0.9)	9.3	(-0.5)	5.0	(-0.1)	14.9	(+0.2)

Summary

In this section, we have estimated the savings that would result from three different models for the reserve dimensioning and procurement. To do so, we have first dimensioned reserves for different levels of regional cooperation and then used a joint simulation of optimal electricity dispatch and reserve procurement.

The following table provides a comparison between the most relevant indicators for all the considered models of reserve dimensioning and procurement. The country-level savings can be found in Appendix E.

Table 39 - MDI - Summary

Summary	Baseline	Option 1ab	Option 1b	Option 2
Reserve needs (GW)	65.8	64.5	42.3	29.6
Load payment (B€)	293.4	289.8	262.0	246.3
Costs (B€)	76.9	75.1	73.5	72.4
Savings vs baseline (B€)	**-**	**1.8**	**3.4**	**4.5**

The 1.8 B€ savings in option 1ab are mainly due to the removal of current market inefficiencies. This option in particular assumes that all sub-optimal reserve procurement practices, such a fixed annual allocation to large thermal plants, are abandoned. Furthermore, the independent procurement of upwards and downwards balancing products allows the system to use cheap generation technologies to generate electricity instead of using them to provide reserves, which would restrict their ability to participate in the electricity market.

Option 1b introduces the possibility for TSOs to procure less balancing reserve capacity by sharing reserve capacity at a regional level and assumes that TSOs can make a better use of the cross-zonal transmission capacities. Additional savings of the order of 1.6 B€ are generated due the fact that, thanks to the statistical cancellation of imbalances, the reserve needs at a regional level are lower than the sum of the national reserve needs. Regional cooperation is shown to be exploited mostly for upwards reserves since it allows the system to lower its running capacity. Downwards reserve capacity being cheap to procure, the system tends to secure most of it domestically (i.e. without cooperation) so as to decrease the opportunity costs associated with the reservation of interconnectors.

Finally, option 2 introduces a number of policy measures: participation of RES and further DSR resources in the reserve procurement exercise, a better exploitation of cross-zonal transmission infrastructure, and a EU-level dimensioning of reserves. This results in 2.7 B€ of savings compared to option 1ab (national approach), or 1.1 B€ compared to option 1b (regional approach).

Table 40 - MDI – Detailed results

Summary	Baseline	Option 1ab	Option 1b	Option 2
Reserve needs (GW)	**65.8**	**64.5**	**42.3**	**29.6**
of which upwards active power	16.7	16.4	11.5	9.5
of which downwards active power	16.1	15.1	11.0	9.0
of which upwards mFRR	17.4	17.4	10.2	5.8
of which downwards mFRR	15.6	15.6	9.6	5.3
Upwards active power reserve capacity procurement (MW)				
of which wind	-	-	-	50
of which solar	-	-	-	-
of which hydro	6 370	8 600	6 560	4 060
of which biomass	1 030	1 260	1 030	680
of which nuclear	1 730	800	490	330
of which coal	1 950	1 570	840	340
of which lignite	530	470	240	70
of which CCGT	4 290	2 900	2 270	500
of which OCGT	700	680	300	30
of which oil	10	10	-	-
of which other RES	-	-	-	-
of which DSR	-	-	-	3 450
Downwards active power reserve capacity procurement (MW)				
of which wind	-	-	-	240
of which solar	-	-	-	190
of which hydro	4 200	2 320	2 190	2 570
of which biomass	460	270	170	180
of which nuclear	2 220	2 640	2 420	2 080
of which coal	1 520	1 200	1 140	970
of which lignite	1 990	2 410	2 430	2 370
of which CCGT	5 570	6 060	6 000	6 020
of which OCGT	130	180	170	150
of which oil	10	-	-	-
of which other RES	-	-	-	-
of which DSR	-	-	-	-
Upwards mFRR reserve capacity procurement (MW)				
of which wind	-	-	-	30
of which solar	-	-	-	-
of which hydro	12 780	12 390	8 600	4 990
of which biomass	1 380	1 490	740	280
of which nuclear	130	130	-	-
of which coal	100	60	10	-
of which lignite	160	160	-	-
of which CCGT	360	370	60	-
of which OCGT	1 680	1 900	900	110
of which oil	560	660	250	10
of which other RES	-	-	-	-
of which DSR	10	10	-	590

Downwards mFRR reserve capacity procurement (MW)				
of which wind	-	-	-	50
of which solar	-	-	-	70
of which hydro	2 190	2 210	2 090	1 690
of which biomass	10	10	10	10
of which nuclear	1 400	1 430	1 440	1 760
of which coal	730	980	1 000	990
of which lignite	1 850	1 550	1 540	1 540
of which CCGT	8 750	8 830	9 000	9 180
of which OCGT	690	620	380	190
of which oil	20	20	10	-
of which other RES	-	-	-	-
of which DSR	-	-	-	-
Electricity production (TWh)				
of which wind	730	730	730	730
of which solar	300	300	300	300
of which hydro	620	630	620	610
of which biomass	80	80	70	70
of which nuclear	770	790	800	800
of which coal	270	280	270	270
of which lignite	270	270	280	280
of which CCGT	530	510	510	510
of which OCGT	10	10	10	10
of which oil	-	-	-	-
of which other RES	10	10	10	10
of which DSR	-	-	-	-

6.3. SUMMARY OF THE RESULTS

6.3.1. OPTIONS FOR THE GUIDELINE ON ELECTRICITY BALANCING

The following table presents the costs and benefits associated with the different models of cross-zonal exchange of balancing energy that have been considered in this study.

Table 41 - Guideline on Electricity Balancing - Costs and benefits

Options for the Guideline on Electricity Balancing	Option A		Option B		Option C	
	One-off	Ongoing	One-off	Ongoing	One-off	Ongoing
Costs	18.1–20.7 M€	660 k€–1.3 M€	76.1–96.4 M€	1.8–4.6 M€	76.1–96.4 M€	1.8–4.6 M€
Benefits	-	212 M€	-	479 M€	-	817 M€
NPV[43]	1.7 B€		3.8 B€		6.5 B€	

Option A is by far the cheapest. Imbalance netting is expected to only incur minor transitory costs. The costs associated with TSO-TSO or TSO-BSP trading are also expected to be minimal and predominantly one-off. Option B is considerably more expensive due to the significant one-off cost of creating a Europe-wide Common Merit Order list for balancing energy. This cost, combined with the one-off and ongoing costs of setting up 5 regional regulated entities performing the tasks of supranational balancing operators, means that option C is materially more expensive again.

We expect the missing cost categories for the Guideline on Electricity Balancing to broadly reflect this ordering, and therefore, they are unlikely to affect the cost ordering implied by the quantitative estimates alone.

On the benefits side, option A captures the benefits of allowing the TSOs to net their imbalances, taking into account network constraints. The total activated volume decreases by around 50%, which results in savings of the order of 212 M€. Option B introduces the possibility to exchange balancing energy across zones, allowing cheaper resources to displace more expensive ones. In particular, the system can better exploit cheap balancing resources since TSOs are not restricted to local resources for balancing their systems. This results in savings of the order of 479 M€. Finally, in option C, the introduction of regional regulated entities performing the tasks of supranational balancing operators is assumed to decrease the need for security margins. As a result, more cross-zonal transmission capacity will be available to net imbalances and exchange of balancing energy, leading to savings of the order of 817 M€ compared to the baseline.

Due to the relatively low ongoing costs, the net present values (NPVs) are dominated by the one-off costs and, mostly, by the benefits. All NPVs are positive: 1.7 B€ for option A, 3.8 B€ for option B, and 6.5 B€ for option C.

[43] The Net Present Value (NPV) is computed using a 4% discount rate on an indicative 10 year duration. This should not be interpreted as the benefits over a 10-year period (the capacity mix and demand would be different).

6.3.2. MDI OPTIONS

The following table presents the costs and benefits associated with the different models of reserve capacity dimensioning and procurement of balancing capacity that have been considered in this study.

Table 42 - MDI - Costs and benefits

MDI options	Option 1ab		Option 1b		Option 2	
	One-off	Ongoing	One-off	Ongoing	One-off	Ongoing
Costs	-	-	58.8-218.5 M€	23.0-42.2 M€	23.9-125.1 M€	7.3-12.3 M€
Benefits	-	1.8 B€	-	3.4 B€	-	4.5 B€
NPV[44]	15 B€		27 B€		36 B€	

As for the Guideline on Electricity Balancing, the option entailing the smallest change (option 1ab) involves costs significantly lower than those of the other two options. It is difficult to establish a priori, whether the regional approach of MDI option 1b is more or less costly than the Europe-wide approach of MDI option 2. Critically, the trade-off in costs between more duplication and greater complexity isn't understood well enough.

The quantitative estimates imply that for ongoing costs, option 1b is likely to be more expensive as a result of the degree of duplication among multiple balancing agencies, notwithstanding the ability to create these agencies by extending the functions of pre-existing RSCs. However, the non-quantified costs, such as the risk to security of supply and the costs of cross-zonal transmission capacity reservation, may well be higher under option 2.

On the benefits side, removing suboptimal practices such as the fixed annual allocation of reserves to large thermal power plants, and procuring upwards and downwards balancing capacities independently result in savings of the order of 1.8 B€. Exploiting the statistical cancellation of imbalances, which results in lower regional reserve capacity requirements, allows the system to procure less reserve capacity provided it secures enough cross-zonal transmission capacity. The optimal trade-off between these two options (local procurement of reserves and interconnectors' reservation) is shown to generate further savings of the order of 1.6 B€. Finally, further policy measures are introduced in option 2. The EU-wide dimensioning of reserve capacity requirements and the participation of RES and further DSR in the reserve procurement exercise result in savings of around 1.1 B€ compared to option 1b.

In all MDI options, the annual benefits clearly outweigh the ongoing costs. As a result, the net present values (NPVs) are dominated by the one-off costs and, mostly, by the benefits. All NPVs are positive: around 15 B€ for option 1ab, 27 B€ for option 1b, and 36 B€ for option 2.

[44] The Net Present Value (NPV) is computed using a 4% discount rate on an indicative 10 year duration. This should not be interpreted as the benefits over a 10-year period (the capacity mix and demand would be different).

7. CONCLUSION

This study presents the costs and benefits of different models for the cross-zonal exchange of balancing energy, and for the regional dimensioning of reserve capacity requirements and procurement of balancing capacities. These two sets of options have been investigated independently, but it has to be noted that the implementation of the cross-zonal exchange of balancing energy is a necessary first step before the regional dimensioning of reserve capacity requirements and the regional procurement of balancing capacities can be envisaged. Indeed, models of regional dimensioning of reserve capacity assume that MSs will partly be relying on the same units to provide balancing services. It is therefore necessary to first implement option B or option C of the Guideline on Electricity Balancing before considering option 1b or option 2 of the Market Design Initiative.

As made clear earlier in this report, it is important to stress that this cost benefit analysis should only form one part of a more comprehensive decision-making process by the Commission. The limitations in our methodology as well as the inherent uncertainty around cost and benefit estimates mean that it is not possible to give a definitive answer as to which options should be chosen. Acceptability and legal aspects have not been considered in this study. Moreover, both costs and benefits may have been overestimated. The cost estimates are partly based on pilot projects and one might expect costs to decrease for future projects. The savings have been estimated without taking current initiatives into consideration.

Overall, all the measures investigated in this report appear hugely beneficial in terms of system costs: the benefits clearly outweigh the ongoing costs for both the options for the Guideline on Electricity Balancing and the MDI options. Their adoption, by increasing the flexibility of the power system, strengthening regional cooperation and pulling additional resources into the market, would lessen the overall cost of the power system to the ultimate benefit of EU citizens and businesses.

Appendix A METIS - Presentation and configuration

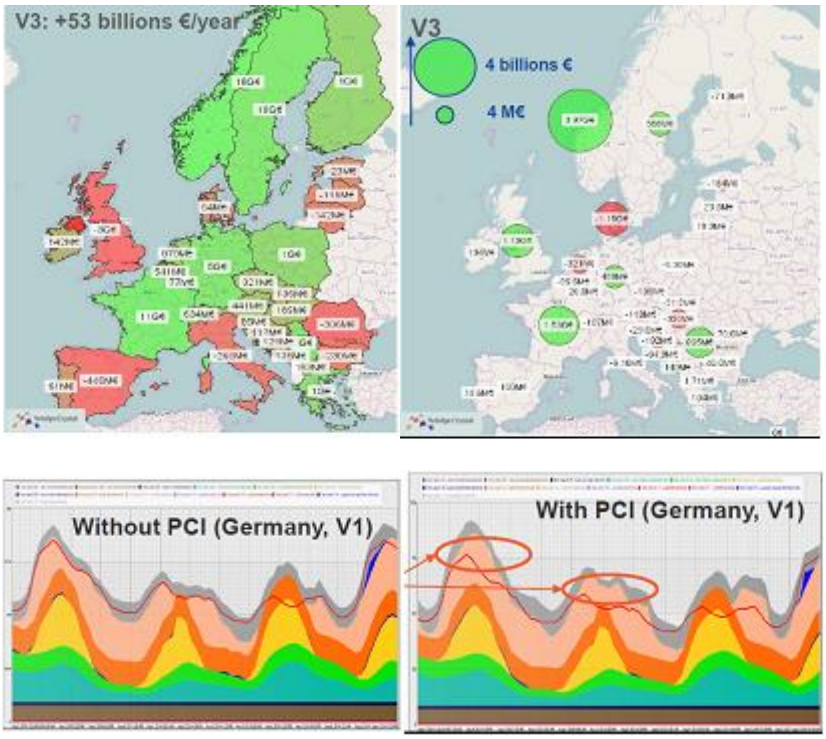
This Appendix presents the model that has been used in this study, METIS, and the way it has been configured to answer the requests of the Commission.

General presentation

METIS is an on-going project initiated by DG ENER[45] for the development of an energy modelling software, with the aim to further support DG ENER's evidence-based policy making, especially in the areas of electricity and gas. The software is developed by a consortium (Artelys, IAEW, ConGas, Frontier Economics), which already delivered a version covering the power system, power market, and gas system modules to DG ENER.

METIS[46] is an energy modelling software covering in high granularity (both in geographical space and time) the whole European power system and markets. For the scope of this impact assessment, simulations adopted a Member State level spatial granularity and an hourly temporal resolution of year 2030 (8760 consecutive time-steps year), capturing also the uncertainty related to demand and RES power generation.

Figure 13 – Screenshots of the METIS graphical user interface



The software replicates in detail the market participant's decision processes, as well as the operation of the power system. For each day of the studied year, all market time frames were modelled in detail: day-ahead, intra-day, balancing. Moreover, METIS also simulates the dimensioning and procurement of balancing reserves, as well as imbalances.

METIS works complementary to long-term energy system models (like PRIMES from NTUA and POTEnCIA from JRC). For instance, it can provide hourly results on the impact of higher shares of intermittent renewables or additional infrastructure built, as determined by a long-term energy system models.

[45] http://ec.europa.eu/dgs/energy/tenders/doc/2014/2014s_152_272370_specifications.pdf

[46] From hereon, METIS is mainly referring to its power market module.

Uncertainties regarding demand and RES power generation are captured thanks to weather scenarios taking the form of hourly time series of wind, irradiance and temperature, which influence demand (through a thermal gradient), as well as PV and wind generation. The historical spatial and temporal correlation between temperature, wind and irradiance are preserved.

All the *METIS Technical Notes* are available on the DG ENER website dedicated to METIS[47], which also contains the *METIS Studies*, which are used by EC experts to further support DG ENER evidence-based policy making.

Main characteristics of the power module

- **Calibrated Scenarios** – METIS has been calibrated to a number of scenarios of ENTSO-E TYNDP and PRIMES. METIS versions of PRIMES scenarios include refinements on the time resolution (hourly) and unit representation (explicit modelling of reserve supply at cluster and MS level). Data provided by the PRIMES scenarios include: demand at MS-level, primary energy costs, CO_2 costs, installed capacities at MS-level, interconnection capacities. This work uses the 2030 METIS EuCo27 scenario, which is based on the 2030 PRIMES EuCo27 scenario. More details are available in *METIS Technical Note T1 - Methodology for the integration of PRIMES scenarios into METIS*

- **Geographical scope** – In addition to EU Member States, METIS scenarios incorporate ENTSO-E countries outside of EU (Switzerland, Bosnia, Serbia, Macedonia, Montenegro and Norway) to model the impact of power imports and exports to the EU power markets and system.

- **Market models** – METIS market module replicates the participants' decision process. For each day of the studied year, the generation plan (including both energy generation and balancing reserve supply) is first optimised based on day-ahead demand and RES generation forecasts. Market coupling is modeled via NTC constraints for interconnectors. Then, the generation plan is updated during the day, taking into account updated forecasts and asset technical constraints. Finally, imbalances are drawn to simulate balancing energy procurement.

- **Imbalances** – Imbalances are the result of events that could not have been predicted before gate closure. METIS includes a stochasticity module which simulates power plant outages, demand and RES-e generation forecast errors from day-ahead to 1-hour ahead. This module uses a detailed database of historical weather forecast errors (for 10 years at hourly and sub-national granularity), provided by ECMWF[48], to capture the correlation between MS forecast errors and consequently to assess the possible benefits of Imbalance Netting.

- **Reserve product definition** – METIS simulates FCR, aFRR and mFRR reserves. The product characteristics for each reserve (activation time, separation between upward and downward offers, list of assets able to participate, etc.) are inputs to the model.

- **Reserve dimensioning** – The amount of reserves (FCR, aFRR, mFRR) that has to be secured by TSOs can be either defined by METIS users or be computed by METIS stochasticity module. The stochasticity module can assess the required level of reserves that would ensure enough balancing resources are available under a given probability. Hence, METIS stochasticity module can take into account the statistical cancellation of imbalances between MS and the potential benefits of regional cooperation for reserve dimensioning.

[47] https://ec.europa.eu/energy/en/data-analysis/energy-modelling/metis

[48] European Centre for Medium-Range Weather Forecasts

- **Balancing reserve procurement** – Different market design options can also be compared by the geographical area in which TSOs may procure the balancing reserves they require. METIS has been designed so as to be able to constrain the list of power plants being able to participate to the procurement of reserves according to their location. The different options will be translated in different geographical areas in which reserves have to be procured (national or regional level). Moreover, METIS users can choose whether demand response and renewable energy technologies are allowed to provide balancing services.

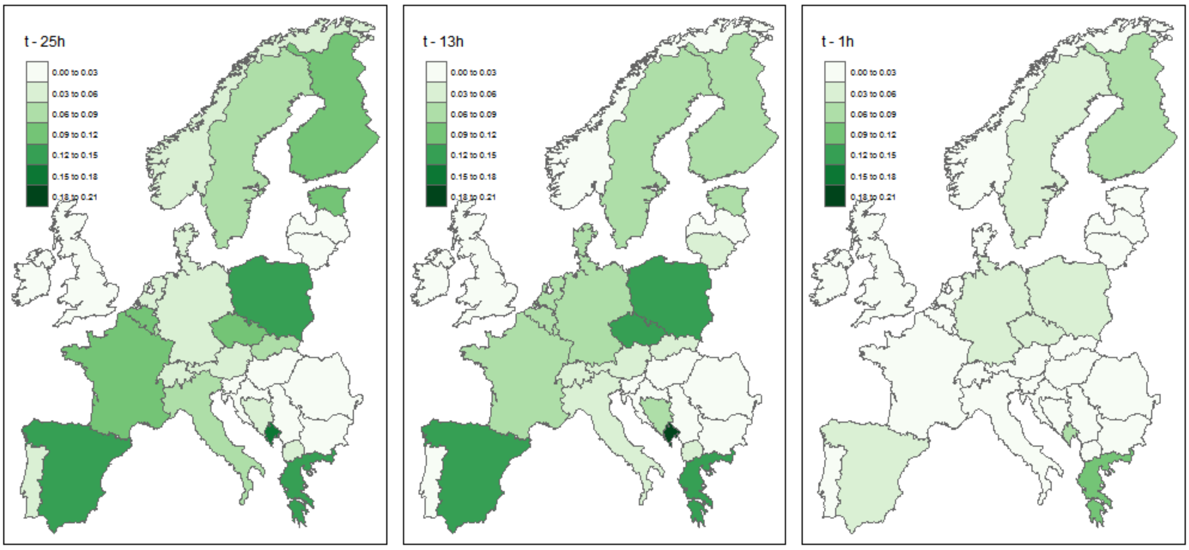
- **Balancing energy procurement** – The procurement of balancing energy is optimised following the same principles as described previously. In particular, METIS can be configured to ban given types of assets, to select balancing energy products at national level, or to optimise balancing merit order at a regional level.

- **Joint energy and reserve optimal dispatch** - METIS jointly optimises power generation and reserve procurement: the commitment of units is not only constrained by the power they have to generate to meet the demand, but also by the reserves they have to provide. As a consequence it is not possible to disentangle the costs of power generation from the costs of reserve procurement.

- **Balancing activation costs** - The activation cost of balancing energy is assumed to have two components: a fixed activation cost plus the variable cost (fuel costs). The same is valid for downwards reserves: fixed activation minus variable cost (saved fuel costs). The fixed activation costs has been estimated by comparing historical balancing costs to the costs of electricity. This analysis suggests producers add a mark-up of around 8€/MWh to their variable cost. Competitive pressure would likely drive this mark-up down. This effect has not been modelled.

More details regarding the METIS power modules are provided in the *METIS Technical Notes,* in particular in *METIS Technical Note T2 – METIS Power Market Models* and *METIS Technical Note T3 – Focus on day-ahead, intraday and balancing markets.*

Figure 14 - Example of wind power forecast errors

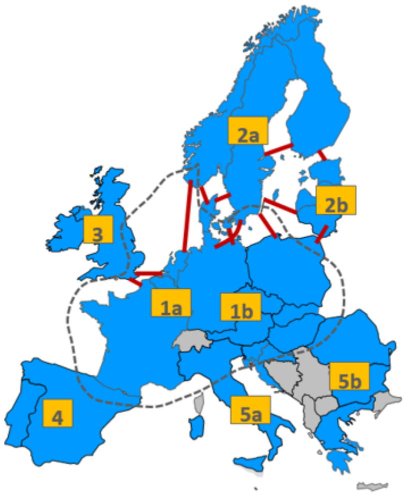


Source: METIS

The next figure shows the regions that have been used for the regional dimensioning of reserves, which is introduced in MDI option 1b. Note that Norway is assumed to be part of Region 2, and that Switzerland is assumed to dimension and procure its reserves independently in all options.

Figure 15 - Regions used for reginal dimensioning of reserves

Region 1	Region 2	Region 3	Region 4	Region 5
Austria	Estonia	United Kingdom	Spain	Bulgaria
Belgium	Finland	Ireland	Portugal	Cyprus
Czech Republic	Lithuania			Greece
Germany	Latvia			Croatia
Denmark	Norway			Italy
France	Sweden			Malta
Hungary				Romania
Luxembourg				
Netherlands				
Poland				
Slovenia				
Slovakia				



Since the Cyprus power system is not interconnected with neighbouring systems, the policy measures discussed in this report do not impact its costs, and therefore do not generate any savings. Moreover, it is assumed that the balancing reserves in Malta are provided by Italy. As a consequence, no savings are shown for Malta.

The Baltic countries are synchronously interconnected with the IPS/UPS synchronous grid. It is therefore assumed they will not be impacted by the policy measures considered in the Guideline on Electricity Balancing. However, in order to be consistent with other Impact Assessments, they are included in the analysis of the MDI options.

Appendix B Guideline on Electricity Balancing - MS-level costs

This Appendix presents the detailed costs results of the different models for Electricity Balancing[49]. Costs have been allocated to individual Member States using the following process. Where the headline costs have been developed on the basis of a cost estimate that has been scaled by the number of Member States involved, this generic single-country cost has been allocated to all Member States. Where there are elements of the cost that are not scaled with the number of Member States involved, for example because they are assumed to scale with the number of platforms used or because the cost is incurred at a regional or supra-national level, these costs have been apportioned among Member States based, in part, on each State's modelled share of total electricity consumption. Specifically, of these non-national costs, five-sixths is allocated on the basis of a State's share of total consumption and one sixth is apportioned on an equal basis to all States. This attribution is purely indicative, but is consistent with the principles of cost sharing set out in the existing Guideline on Capacity Allocation and Congestion Management[50].

One-off costs

One-off costs (k€)	Option A		Option B		Option C	
	Low	High	Low	High	Low	High
AT	589	675	2 510	3 128	2 510	3 128
BE	596	683	2 524	3 173	2 524	3 173
BG	573	657	2 477	3 019	2 477	3 019
CH	585	670	2 500	3 095	2 500	3 095
CY	-	-	-	-	-	-
CZ	587	672	2 505	3 110	2 505	3 110
DE	777	890	2 889	4 398	2 889	4 398
DK	575	659	2 481	3 029	2 481	3 029
EE	-	-	-	-	-	-
ES	668	765	2 668	3 659	2 668	3 659
FI	594	681	2 520	3 161	2 520	3 161
FR	750	860	2 835	4 218	2 835	4 218
GR	581	666	2 493	3 072	2 493	3 072
HR	567	650	2 465	2 976	2 465	2 976
HU	577	661	2 485	3 044	2 485	3 044
IE	572	655	2 474	3 006	2 474	3 006
IT	686	786	2 705	3 783	2 705	3 783
LT	-	-	-	-	-	-
LU	564	646	2 458	2 953	2 458	2 953

[49] These estimates exclude the potential costs associated with the creation of regional regulated balancing entities because the Guideline on Electricity Balancing cannot create or oblige the creation of these entities. When these costs are excluded, the total costs of Options B and C are identical, as shown in **Table 6**.

[50] See Regulation (EU) 2015/1222, Article 80, Paragraph 3.

LV	-	-	-	-	-	-
MT	-	-	-	-	-	-
NL	605	694	2 542	3 237	2 542	3 237
NO	610	699	2 552	3 270	2 552	3 270
PL	629	721	2 590	3 396	2 590	3 396
PT	581	665	2 493	3 070	2 493	3 070
RO	583	668	2 497	3 085	2 497	3 085
SE	619	709	2 570	3 330	2 570	3 330
SI	566	649	2 463	2 971	2 463	2 971
SK	573	656	2 476	3 014	2 476	3 014
UK	702	804	2 738	3 892	2 738	3 892

Ongoing costs

Ongoing costs (k€)	Option A		Option B		Option C	
	Low	High	Low	High	Low	High
AT	22	43	46	116	46	116
BE	22	44	53	136	53	136
BG	21	42	27	69	27	69
CH	21	43	40	102	40	102
CY	-	-	-	-	-	-
CZ	21	43	43	109	43	109
DE	29	57	261	668	261	668
DK	21	42	29	74	29	74
EE	-	-	-	-	-	-
ES	25	49	136	347	136	347
FI	22	43	51	131	51	131
FR	28	55	231	590	231	590
GR	21	42	36	92	36	92
HR	21	41	20	50	20	50
HU	21	42	31	80	31	80
IE	21	42	25	64	25	64
IT	25	50	157	401	157	401
LT	-	-	-	-	-	-
LU	21	41	16	41	16	41
LV	-	-	-	-	-	-
MT	-	-	-	-	-	-
NL	22	44	64	164	64	164
NO	22	45	70	178	70	178
PL	23	46	91	233	91	233
PT	21	42	36	91	36	91

RO	21	43	38	98	38	98
SE	23	45	80	204	80	204
SI	21	41	19	48	19	48
SK	21	42	26	67	26	67
UK	26	52	175	448	175	448

Appendix C Guideline on Electricity Balancing - MS-level benefits

This Appendix presents the detailed saving results of the different models on Electricity Balancing.

Savings (M€)	Option A	Option B	Option C
AT	10	26	39
BE	0	16	26
BG	9	18	8
CH	9	7	22
CY	-	-	-
CZ	7	24	47
DE	-1	72	170
DK	11	0	11
EE	-	-	-
ES	29	53	53
FI	-2	35	61
FR	56	95	81
GR	13	29	14
HR	0	3	9
HU	-6	-41	-25
IE	3	19	22
IT	11	41	57
LT	-	-	-
LU	2	15	30
LV	-	-	-
MT	-	-	-
NL	1	-18	14
NO	10	13	-7
PL	-7	-11	69
PT	9	13	11
RO	15	28	14
SE	10	-14	-17
SI	3	-41	-29
SK	12	45	60
UK	9	51	74

It is important to note that the savings shown in the above table reflect the evolution of the balancing energy activation costs in each country. In particular, the settlement between TSOs related to imbalance netting (i.e. the way the benefits generated by imbalance netting are redistributed) and cross-zonal exchange of balancing energy (i.e. the payment of the TSO of one zone to the TSO of another zone for the provision of balancing energy) are not modelled, as it requires taking into account criteria such as fairness when allocating costs between MS, which is outside the scope of this study. As a result, some countries may be characterised by negative savings (see discussion below). However, we can expect that the implementation of settlement mechanisms among TSOs would result in a redistribution of savings that benefit all countries.

The possibility to net imbalances at an EU-level is introduced in option A. The remaining imbalances (after imbalance netting) have to be faced with the local balancing reserve capacities (no cross-zonal exchange of balancing energy). Consequently, those countries which generate most of their downwards balancing energy with expensive technologies (e.g. Hungary, which uses CCGTs for a large share of its downwards activations) can lose revenues when netting imbalances. Indeed, without imbalance netting these countries were saving fuel costs via downwards activations. When imbalance netting is introduced, Hungary has fewer opportunities to save these costs, leading to negative savings. Other countries however benefit from netting their imbalances with Hungary since they save the corresponding upwards balancing costs. At the EU level, balancing costs have been shown to decrease (by 212 M€ in option A). A fair settlement mechanism between countries such as Hungary and the beneficiaries of imbalance netting should be introduced to redistribute these benefits.

In options B and C, TSOs can exchange balancing energy across zones to exploit cheaper resources before more expensive ones for upwards activations, and to save more fuel costs by activating expensive resources first for downwards activations. As a result, some countries activate more balancing energy than is required to face their local imbalances. This can result in negative savings for countries with cheap upwards resources, since these resources will partly be activated to help other countries face their imbalances. The increased interconnection capacity available for balancing that is introduced in option C can result in either positive or negative savings compared to option B, since the additional capacity can result in a further displacement of expensive resources. One should again stress that the savings shown in the above table only take the local balancing energy activation costs and do not take the settlement between TSOs into account.

Appendix D Market Design Initiative – MS-level costs

This Appendix presents the detailed costs results for the different models of regional dimensioning and procurement of balancing capacity. Costs have been allocated to individual Member States using the following process. Where the headline costs have been developed on the basis of a cost estimate that has been scaled by the number of Member States involved, this generic single-country cost has been allocated to all Member States. Where there are elements of the cost that are not scaled with the number of Member States involved, for example because they are assumed to scale with the number of platforms used or because the cost is incurred at a regional or supra-national level, these costs have been apportioned among Member States based, in part, on each State's modelled share of total electricity consumption. Specifically, of these non-national costs, five-sixths is allocated on the basis of a State's share of total consumption and one sixth is apportioned on an equal basis to all States. This attribution is purely indicative, but is consistent with the principles of cost sharing set out in the existing Guideline on Capacity Allocation and Congestion Management[51].

One-off costs

One-off costs (k€)	Option 1ab		Option 1b		Option 2	
	Low	High	Low	High	Low	High
AT	-	-	1 514	6 039	663	3 762
BE	-	-	1 726	6 630	727	3 956
BG	-	-	1 008	4 627	512	3 299
CH	-	-	1 361	5 612	618	3 622
CY	-	-	-	-	-	-
CZ	-	-	1 432	5 809	639	3 686
DE	-	-	7 421	22 526	2 431	9 170
DK	-	-	1 055	4 758	526	3 342
EE	-	-	702	3 773	420	3 018
ES	-	-	3 985	12 936	1 403	6 024
FI	-	-	1 667	6 466	709	3 902
FR	-	-	6 586	20 194	2 181	8 405
GR	-	-	1 255	5 317	586	3 525
HR	-	-	808	4 069	452	3 115
HU	-	-	1 126	4 955	547	3 406
IE	-	-	949	4 463	494	3 245
IT	-	-	4 562	14 545	1 575	6 552
LT	-	-	738	3 871	431	3 051
LU	-	-	702	3 773	420	3 018
LV	-	-	702	3 773	420	3 018
MT	-	-	-	-	-	-
NL	-	-	2 020	7 451	815	4 225

[51] See Regulation (EU) 2015/1222, Article 80, Paragraph 3.

NO	-	-	2 173	7 878	860	4 365
PL	-	-	2 761	9 520	1 036	4 904
PT	-	-	1 244	5 284	582	3 514
RO	-	-	1 314	5 481	603	3 579
SE	-	-	2 456	8 666	945	4 624
SI	-	-	785	4 003	445	3 094
SK	-	-	985	4 561	505	3 277
UK	-	-	5 068	15 957	1 726	7 016

Ongoing costs

Ongoing costs (k€)	Option 1ab		Option 1b		Option 2	
	Low	High	Low	High	Low	High
AT	-	-	561	1 029	178	300
BE	-	-	659	1 208	209	352
BG	-	-	327	600	104	175
CH	-	-	490	899	156	262
CY	-	-	-	-	-	-
CZ	-	-	523	959	166	280
DE	-	-	3 289	6 034	1 044	1 759
DK	-	-	349	640	111	187
EE	-	-	186	341	59	99
ES	-	-	1 702	3 123	540	910
FI	-	-	631	1 159	200	338
FR	-	-	2 903	5 326	921	1 552
GR	-	-	441	810	140	236
HR	-	-	235	431	74	126
HU	-	-	381	700	121	204
IE	-	-	300	550	95	160
IT	-	-	1 968	3 611	625	1 053
LT	-	-	202	371	64	108
LU	-	-	186	341	59	99
LV	-	-	186	341	59	99
MT	-	-	-	-	-	-
NL	-	-	794	1 458	252	425
NO	-	-	865	1 587	275	463
PL	-	-	1 137	2 086	361	608
PT	-	-	436	800	138	233
RO	-	-	468	859	149	250
SE	-	-	996	1 827	316	532
SI	-	-	224	411	71	120

SK	-	-	316	580	100	169
UK	-	-	2 202	4 040	699	1 178

Appendix E Market Design Initiative – MS-level benefits

This Appendix presents the detailed saving results of the different models of dimensioning and procurement of balancing reserves.

Savings (M€)	Option 1ab	Option 1b	Option 2
AT	16	141	68
BE	7	17	59
BG	-16	-28	-71
CH	10	30	46
CY	0	0	0
CZ	-6	-44	-84
DE	-191	247	1135
DK	97	364	513
EE	17	8	6
ES	207	133	143
FI	20	219	442
FR	482	528	554
GR	-1	82	78
HR	37	34	46
HU	1	46	256
IE	-63	177	135
IT	119	223	-30
LT	142	256	250
LU	0	-3	-28
LV	6	164	273
MT	-3	-2	-2
NL	-44	-46	-321
NO	23	66	109
PL	-129	-321	-499
PT	22	144	187
RO	27	15	-13
SE	-44	-15	-30
SI	22	-6	-11
SK	62	62	67
UK	910	864	1235

It is important to note that the savings shown in the above table reflect the evolution of the day-ahead electricity dispatch and reserve procurement costs. In particular, settlements between TSOs related to the cross-zonal reservation of balancing capacity are not modelled. This can therefore result in negative savings for some countries. However, we can expect that the implementation of settlement mechanisms among TSOs would result in a redistribution of savings that benefit all countries.

Abandoning sub-optimal reserve procurement practices (option 1ab) can translate into more costs for some countries. Poland is for example found to modify its reserve portfolio so as to be able to better exploit its coal plants and CCGTs by producing more electricity than in the baseline. The extra electricity produced by Poland is exported to help other countries meet their needs. Since settlements are not taken into account (i.e. the financial arrangements between Poland and the countries which import its electricity), this phenomenon translates into more costs for Poland in option 1ab.

Similarly in option 1b and 2, the cheapest resources are predominantly used to produce electricity (rather than reserves). This results in additional costs for countries in which these generation assets were providing reserves in the baseline and option 1ab. The policy measures introduced in option 2 (further distributed resources pulled into the market, EU dimensioning and procurement of reserves) can result in either positive or negative savings compared to option 1b. Since several measures are introduced at once, the dynamics are different for each country. The increased interconnection capacity in particular allows the system to better exploit the cheapest resources. This translates into additional costs in the countries hosting such resources, and in lower costs in the importing countries. One should again stress that the savings shown in the above table only take the local day-ahead electricity dispatch and reserve procurement costs and do not take the settlement between TSOs into account.

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MJ-01-16-420-EN-N

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Publications Office
doi:10.2833/388577