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To Ministerie van Economische Zaken en Klimaat

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Subject Co-optimisation of energy and balancing capacity
in the EU day-ahead electricity market

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1. Introduction

1.1. Background and legal framework

In order to enhance the performance of EU electricity markets, the European Commission (EC) has implemented since the 1990s a gradual, but profound process of liberalising, harmonising, and integrating electricity markets across EU Member States. As part of this process, the EC published Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management (CACM Regulation). This regulation laid down a range of requirements for cross-zonal capacity allocation and congestion management in the day-ahead and intraday electricity markets, including specific provisions for the development and maintenance of a price coupling algorithm and of a continuous trading matching algorithm for the single day-ahead coupling (SDAC) of EU electricity markets (EC, 2015; ACER 2024a). On behalf of the responsible ‘*Nominal Electricity Market Operators*’ (NEMOs, i.e. the European power exchanges) the concerning price and market-clearing algorithm – called ‘*EUPHEMIA*’ – has been developed and maintained by the algorithm consultancy company N-Side.¹

In addition, on 23 November 2017, the EC released Regulation (EU) 2017/2195 establishing a guideline on electricity balancing (EB Regulation). This guideline focused on defining standard balancing products, developing European balancing platforms for the exchange of balancing energy, and harmonising balancing capacity markets (BCMs) across European countries. More specifically, in order to integrate European BCs, the EB guideline requires all European Transmission System Operators (TSOs) to develop and implement terms and conditions or methodologies (TCMs) for the allocation of cross-zonal capacity (CZC) for the exchange of balancing capacity (BC) and sharing of reserves between EU countries. In particular, EB Regulation Art. 40 stipulates the elaboration of a methodology for a co-optimised allocation process of CZC for the exchange of BC or sharing of reserves and cross-border matching of day-ahead (DA) energy bids, hereafter referred to as ‘*co-optimisation*’, notably of cross-zonal energy and balancing capacity in the European DA electricity market (EC, 2017; ENTSO-E, 2021).

As part of the co-optimisation preparation phase, the European TSOs carried out an Implementation Impact Assessment (IIA; ENTSO-E, 2021), followed by a co-optimisation Roadmap Study conducted by N-Side (2022) on behalf of both the European TSOs and NEMOs. During this preparation phase, it became clear that introducing co-optimisation of energy and balancing capacity in SDAC is not merely a technical update or a simple exercise to revise the SADC price and market-clearing algorithm (EUPHEMIA). On the contrary, as stated by the NEMOs, TSOs, and emphasized by Market Participants (MPs) during webinars organised by ACER, co-optimisation represents a substantial redesign of the existing SDAC framework. This change will have significant implications for the efficiency of European electricity markets and will have a major impact on the SDAC organisation that has been in place for over a decade (ACER, 2024a; MCSC, 2025e).

¹ For further details on SDAC and EUPHEMIA, see N-Side (2025b), All NEMO Committee (2025) and ENTSO-E (2026).

Therefore, as part of Decision No 11/2024 on amending the required algorithm methodology (AM), ACER acknowledges the need for further research and development (R&D) before deciding on the specific design and implementation issues regarding co-optimisation (ACER, 2024b). This R&D is a joint effort between the involved European TSOs and NEMOs under the governance of their joint Market Coupling Steering Committee (MCSC) in close alignment with relevant ENTSO-E working groups (MCSC, 2025e). The R&D process is focused on specific co-optimisation issues, notably on bidding products, bid design and pricing (see Section 4 below).

The co-optimisation R&D includes the following phases, timeline, and deliverables (see Figure 1):

- Phase I (2024Q4 – 2025Q4):** Based on a conceptual study by N-Side (2025a), TSOs and NEMOs released the initial R&D report in May 2025 - referred to as *R0* – targeting on bidding products, bid design and pricing (MCSC, 2025a). After an assessment of the R0 report by ACER (2025), a public consultation process was launched in May-June 2025 in which market participants and other stakeholders could give their feedback on the R0 report (Elia, 2025; Energy Traders Europe, 2025b; MCSC, 2025b and 2025c; All NEMO Committee and ENTSO-E, 2025). Based on this consultation feedback, both N-Side (2025c) and MCSC (2025e) published an update of their initial R&D report – referred to as *R1* – in November 2025.
- Phase II (2025Q4 – 2027Q1):** Besides some specific topics and technical issues, the R&D work during the second phase will, more broadly, focus on gathering representative input data and conducting real-world simulations to validate theoretical insights and quantify potential trade-offs of co-optimisation (ACER, 2024c; MCSC, 2025e and 2025f; N-Side, 2025c). The (preliminary) results of this phase will be published in R&D report R2 (planned in 2026Q2) and – after consultation and feedback by the market participants and other stakeholders – updated in R&D report R3 (scheduled in 2026Q4).

ACER expects that the outcomes of the R&D work will provide sufficient information to determine the most appropriate approach to implement co-optimisation in the SDAC algorithm and to estimate the timeline for this implementation (ACER, 2024b).

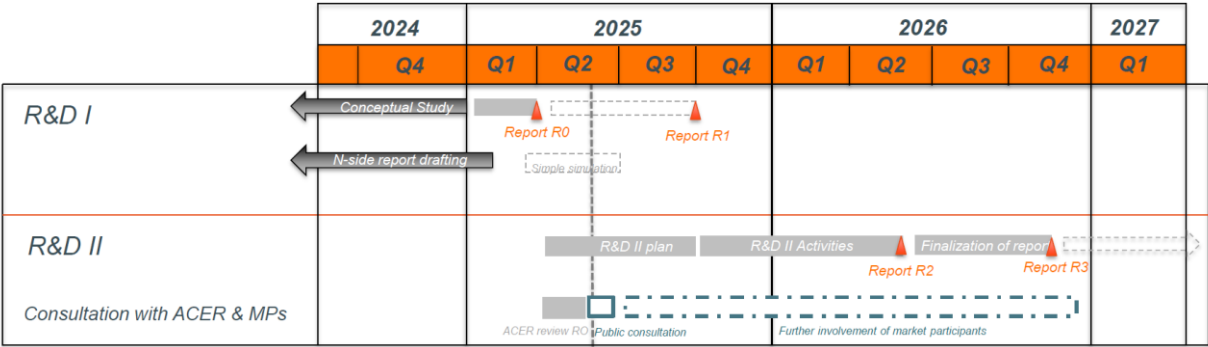


Figure 1: Co-optimisation R&D timeline planning and deliverables
Source: Elia (2025).

1.2. Objective, scope, and structure of current note

This note is part of the second phase of the KVE2025 project on flexibility of the power system in the Netherlands, including the fragmentation and resulting potential inefficiencies of separated

electricity markets such as the day-ahead and electricity balancing markets.² This project has been conducted by TNO and supported by the NL Ministry of Economic Affairs and Climate (EZK). The objective of this note is to provide a brief, non-technical update overview of the present, ongoing discussion on co-optimisation of energy and balancing capacity in the EU day-ahead electricity market, in particular to inform NL policy makers (EZK) and other stakeholders – e.g., TenneT, ACM, market parties – on this complex, but interesting and relevant issue.

The next section starts with a discussion of three approaches for the (cross-zonal) allocation of energy and balancing capacity in the European day-ahead electricity market, including the current (*status quo*) approach (Section 2.1), the *co-optimisation* approach (Section 2.2) and the alternative, so-called *‘market-based’* approach (Section 2.3).³ Subsequently, Section 3 considers the major benefits (*‘pros’*) of co-optimisation (Section 3.1), followed by the major challenges and concerns (*‘cons’*) of this approach (Section 3.2). Next, Section 4 discusses briefly the three major specific (ongoing) R&D issues on co-optimisation, i.e. bidding products (Section 4.2), bid design (Section 4.2) and pricing (Section 4.3), including the feedback of TSOs, NEMOs and other market participants on these issues. Finally, Section 5 provides a brief summary and look forward on the topic of co-optimisation.

2. Approaches for allocating energy and balancing capacity

2.1. Current approach (*‘status quo’*)

Currently, in most European countries, balancing capacities (*‘reserves’*) and energy are traded in separated, sequential markets. On the one hand, to maintain the real-time balance between power demand and supply (*‘load frequency control’*), TSOs procure enough upward and downward balancing capacity (BC)⁴ well in advance (from months to one day ahead), mainly on a national basis and prior to the clearing of the DA electricity market. Consequently, the actual market value of DA electricity is not known during the BC market clearing, including the (implicit) value of limited cross-zonal (transmission) capacity in case of cross-zonal energy/BC trading. As a result, the procurement and market clearing of BC is based on cost biddings offered by Balancing Service Providers (BSPs), including an estimate (*‘forecast’*) of the opportunity cost for not participating in the DA electricity market.

On the other hand, in most European countries energy is currently usually traded separately from – and sequential to – balancing capacity. This applies in particular for the (large, highly relevant) SDAC electricity market (where SDAC stands short for *‘Single Day-Ahead Coupling’*). The purpose of SDAC is to maximise welfare by establishing and strengthening a single pan-European, cross-zonal DA electricity market. More specifically, SDAC aims to allocate cross-border transmission capacity in the most efficient way by coupling wholesale electricity markets from different European zones, while

² In the first phase of the project, several flexibility challenges for power systems were identified of which a few challenges were selected for further research (Rijken *et al.*, forthcoming). Co-optimisation is a solution to address both challenge 1: Limited role for intraday and balancing markets due to inefficient allocation of interconnection capacity and challenge 4: Inefficient allocation of flexibility to different electricity markets, including balancing markets, congestion, and ancillary services.

³ In addition to the market-based approach and the co-optimisation approach, the Electricity Balancing (EB) Guideline also mentions a third method for cross-zonal capacity allocation for the exchange of balancing capacity or sharing of reserves, i.e. the so-called *‘Economic efficiency analysis’*. This method is based on a comparison of the forecasted market value of cross-zonal capacity for the exchange of balancing capacity or sharing of reserves, and the forecasted market value of cross-zonal capacity for the exchange of energy (EB GL, Art. 42; EC, 2027; Schittekatte *et al.*, 2020). This third approach, based on economic efficiency analysis, is not considered further in the current note (mainly because of a lack of interest and attention in the available literature and among the stakeholders involved).

⁴ Upward BC is used to increase power generation or reduce electricity consumption to address supply shortfalls, while downward BC reduces generation or increases consumption to manage oversupply. These two complementary but distinct products ensure that the power system can respond to both positive and negative imbalances.

simultaneously considering cross-border transmission constraints, thereby maximising social welfare. SDAC makes use of a common price and market-clearing algorithm (EUPHEMIA) to calculate electricity prices across European countries and to implicitly allocate auction-based cross-border transmission capacity between these countries. Input data to EUPHEMIA are the network capacities and constraints by the TSOs and the DA electricity bids and offers by the European power exchanges (NEMOs) on behalf of their participating market parties (i.e., electricity producers and consumers). Output data of EUPHEMIA are clearing prices, matched trades, scheduled exchanges, and the net position of bidding areas (ENTSO-E, 2026; All NEMO Committee, 2025).

The separate trading of balancing capacity and energy, however, ignores the interdependencies between these items. This can be illustrated simply by a typical power generation unit. Such a unit can utilise the same available capacity either for the provision of energy or upward balancing capacity, but not both simultaneously, as they draw from the same (limited) source of capacity.⁵ In other words, generating energy reduces the capacity available for providing upward balancing, and vice versa, i.e. they are *mutually exclusive* (N-Side, 2025c).

Offering downward balancing capacity is conditional on producing energy and delivering power at a sufficiently high level to allow a reduction in terms of balancing energy. If a production asset is already generating energy, (part of) that generation can be used to offer downward balancing capacity. This creates a '*parent-child*' relationship, where energy production acts as the parent and downward balancing capacity is the child that depends on the energy already being generated (N-Side, 2025c).

The above examples on the interdependencies between energy and balancing capacity can be easily extended to other types of assets, such as consumption or storage assets (including demand response). In addition, more complex interdependencies emerge when investigating larger portfolios including several generation, storage, and demand (response) assets.

Ignoring the interdependencies between balancing capacity and energy products may introduce economic inefficiencies. These inefficiencies relate in particular to (i) market price forecast errors, and (ii) short-term quasi-fixed costs.⁶ As mentioned above, bids by Balancing Service Providers (BSPs) include an estimate ('forecast') of the opportunity costs for not participating in the DA electricity market. Errors in these DA market price forecasts can distort the efficient allocation of balancing capacity under separate, sequential market clearing, which in turn can lead to suboptimal matching in the DA electricity market (Van der Welle, 2016; Papavasiliou and Avila, 2021a).

Short-term quasi-fixed costs – such as startup and minimum load costs – are costs incurred by a power generation unit for producing a non-zero amount of output. These costs may be another source of inefficiencies as they are incurred for providing both energy and Frequency Restoration Reserve capacity. Once a unit is started for one or the other reason, it can provide both energy and balancing capacity (BC). However, quasi-fixed costs are fundamentally non-separable when it comes to delivering energy and balancing capacity. Forcing a separation in the market-clearing processes can lead to a situation where units with lower quasi-fixed costs and higher variable costs are inefficiently committed. This traces back to the misrepresentation of quasi-fixed costs in the energy

⁵ Besides the same (limited) source of power generation capacity, trading both energy and balancing products also occupies common limited capacity on the transmission network for their delivery (Papavasiliou and Avila, 2024a).

⁶ To some extent – depending on the (ir)revocability of day-ahead (DA) decisions – some of the inefficiencies concerned can be reduced by adjustments in the intraday (ID) market, where market participants are allowed to modify their DA positions by trading (bilaterally) in discrete auctions or continuous trading schemes. For further details and impact analyses of these ID adjustments, see Papavasiliou and Avila (2024a).

and BC auctions under separated, sequential market designs (Wilson, 2002; Papavasiliou and Avila, 2024a).⁷

2.2. Co-optimisation approach

Co-optimisation is a process in which available resources – including in particular cross-zonal (transmission) capacities – for the delivery and exchange of DA energy and balancing capacity are allocated simultaneously, resulting in a joint market clearing and pricing of DA energy and balancing capacity, with the objective of enhancing economic efficiency and social welfare.⁸ More specifically, in the European context – in line with Article 40 of the Electricity Balancing (EB) Regulation – co-optimisation requires three functions to be optimised parallel to maximise European economic surplus (EC, 2017; ENTSO-E, 2021):

1. The *cross-zonal capacity allocation optimisation function (CZCAOF)* determines the cross-zonal capacity (CZC) of day-ahead (DA) and balancing capacity (BC) market purposes.⁹
2. The *capacity procurement optimisation function (CPOF)* defines which offers of Balancing Service Providers (BSPs) should be procured by TSOs for balancing capacity reservation.
3. The *Single Day-Ahead Coupling (SDAC) function* provides the welfare maximising clearing of day-ahead electricity market bids using EUPHEMIA.

Practically, co-optimisation implies that the first two functions mentioned above have to be integrated in the SDAC algorithm EUPHEMIA.

There are some non-European markets in which co-optimisation of energy and BC has already been established, notably in Australia and North America. These markets, however, have fundamentally different structures, including central dispatch and unit-based bidding in particular. When co-optimising BC and energy market products, this makes it easier to account for complex technical constraints and the resulting interdependencies between these products. The European market design, on the other hand, is predominantly based on self-dispatch and portfolio bidding, which makes it harder and more challenging to implement co-optimisation (see Section 2.3 below).

Balancing capacity products co-optimised with DA energy products

EB Regulation (EU) 2017/2195 distinguishes three general types of balancing capacity ('reserves'), i.e. (i) *Frequency Restoration Reserve (FRR)*, (ii) *Frequency Containment Reserve (FCR)*, and (iii) *Replacement Reserve (RR)*. According to ACER Decision No 11/2024, however, co-optimisation – notably during its present, ongoing R&D stage – is focused on FRR only, while FCR and RR are currently excluded from the R&D on co-optimisation (ACER, 2024b and 2024c).

As discussed before, balancing capacity is usually categorised into upward and downward capacity. Balancing products, notably FRR products, also differ by activation method: automatic Frequency Restoration Reserve (*aFRR*) versus manual Frequency Restoration Reserve (*mFRR*). In normal operations, *aFRR* is automatically activated in response to frequency deviations, and provides a continuous, dynamic response within seconds. It is highly flexible and suited for correcting smaller, frequent imbalances. In contrast, *mFRR* is manually activated by the TSO, has a slower response time, is used for larger disturbances that require more significant correction, and is activated for a longer duration (N-Side, 2025c).

⁷ The impact of short-term quasi-fixed costs on the performance of interdependent but separated markets for energy and balancing capacity is further illustrated and analysed in Section 4 and Appendix B of Papavasiliou and Avila (2024a).

⁸ For a detailed description and analysis of the different elements of the co-optimisation process, see ENTSO-E (2021).

⁹ For the analysis of cross-zonal capacity allocation in a co-optimisation set-up, in cases with or without (transmission) congestion, see N-Side (2025c).

Hence, in the current R&D co-optimisation phase, the existing energy products in SDAC are co-optimised with the following four specific balancing products (N-Side, 2025c):

- *Upward aFRR*: Automatically increases power generation or decreases electricity consumption to address small supply shortfalls;
- *Downward aFRR*: Automatically decreases generation or increases consumption to manage small oversupplies;
- *Upward mFRR*: Manually increases generation or decreases consumption to address significant supply shortfalls;
- *Downward mFRR*: Manually decreases generation or decreases consumption to manage significant oversupplies.

2.3. Market-based approach

Article 41 of the EB Regulation allows for an alternative, voluntary approach (besides the co-optimisation method), which is referred to as the ‘*market-based (MB) approach*’ for cross-zonal allocation of transmission capacity for the exchange of balancing capacity or sharing of reserves.¹⁰ This MB approach falls somewhere between the current approach (‘*status quo*’) and the co-optimisation approach (but is likely closer to the former than the latter approach).

In the *current approach*, as outlined in Section 2.1 above, balancing capacity in most European countries is contracted and allocated mainly on a national basis, and separately from the DA electricity market, i.e. the pricing and market clearing of BC is based on an in-house or externally sourced forecast by each market participant of the opportunity costs for not participating in the SDAC electricity market and ignoring the allocation of transmission cross-zonal capacity for the exchange of BC or sharing of reserves. In the *market-based approach*, balancing capacity is contracted and allocated at the cross-zonal level, i.e. between bidding zones or countries, based on an optimal allocation and market clearing of cross-zonal capacity for the exchange of BC or sharing of reserves, but still on a forecast by each market participant of the SDAC opportunity costs. Finally, in the *co-optimisation approach* (as described in Section 2.1.2 above), available resources – including cross-zonal capacities – for the delivery and exchange of DA energy and balancing capacity are allocated simultaneously by the modified price coupling algorithm (under development), resulting in a joint market clearing and pricing of DA energy and balancing capacity.¹¹

In accordance with Article 41 of the EB Regulation, the market-based approach for the (cross-zonal or cross-border) procurement of FRR balancing capacity products has recently been introduced and operated in both the Nordic countries (since December 2022) and the Baltic states (since February 2025; for further details, see MCSC, 2025e).

¹⁰ EB Regulation (EU) 2017/2195 defines two options for cross-border procurement of reserve capacity, i.e. (i) exchange of balancing capacity, and (ii) sharing of reserves (EC, 2017). *Exchange of balancing capacity* (BC) means the provision of BC to a TSO in a different balancing area than the one in which the procured BSP is connected (EB Regulation, Art. 2), with the objective to save costs by procuring cheaper BC. By exchange of BC, TSOs can activate balancing energy from other balancing areas instead of balancing energy in their own balancing area. *Sharing of reserves* means a mechanism in which more than one TSO take into account the same reserve capacity unit to fulfil their respective reserve requirements, with the objective to procure less and, hence, prevent costs. Since TSOs do not always use their maximum procured BC simultaneously, TSOs can share part of their reserves. Consequently, they can reduce the total amount of BC to be reserved within the two balancing areas and, therefore, prevent unnecessary BC procurement costs (ENTSO-E, 2021).

¹¹ For a further comparison and analysis of the three approaches for the allocation of cross-zonal capacities between DA energy and reserves, see Papavisiliou and Avila (2024a and 2024b), Elia (2024) as well as Consentec and IAEW-RWTH (2025).

3. Co-optimisation: Pros and Cons

3.1. Benefits of co-optimisation ('pros')

The key advantage ('benefit') of co-optimisation is that it can enhance economic efficiency, lower electricity prices and increase social welfare by facilitating the integration of DA electricity and balancing capacity markets, in particular by allowing for a more optimal use of scarce resources and cross-zonal capacities between these markets. Moreover, owing to co-optimisation the costs for procuring balancing capacity are expected to decrease by making use of cheaper bids from other areas and/or reducing the individual TSOs demand for balancing capacity through sharing of reserves (Eurelectric, 2024).

A study conducted by NTUA and UCL has quantified the welfare gains from the introduction of either the co-optimisation approach or the market-based approach, compared to the current approach ('status quo') of allocating DA energy and balancing capacity (Papavasiliou and Avila, 2024a and 2024b). For the Core region of Europe, these welfare gains are estimated at 678 million Euro (m€) per annum of savings in operational costs owing to co-optimisation and 159 m€ per year in case of the market-based approach.¹² Extrapolating these figures to the EU level (2670 TWh, compared to 1340 TWh for the Core region) results in a potential cost saving of 1281 m€ per annum from co-optimisation, relative to the status quo, and of 159 m€ per year from the market-based approach (Papavasiliou and Avila, 2024a and 2024b).

Although in absolute terms a cost saving of 1281 m€ per annum is quite substantial, in relative terms – given the large volume of the EU electricity market – the welfare gain due to co-optimisation is rather small, i.e. approximately 0.5 €/MWh consumed.

The first of a kind study by NTUA and UCL has been questioned because of its modelling methodology and underlying assumptions, including in particular the following issues (Consentec and IAEW-RWTH, 2025):

- The study employs a unit commitment modelling approach whereas in practice – notably in European countries – market participants follow a portfolio approach, i.e. they retain the ability to modify the schedules of individual portfolio assets, allowing for some degree of portfolio optimisation between energy and BC markets even after market clearing. This relates to the lack of available data for portfolios and according to NTUA and UCL is mitigated by sensitivity analysis (ACER, 2024a). Consentec and IAEW-RWTH (2025) confirm that due to the lack of publicly available information on portfolio structures in Europe, it is impossible to model partial coordination resulting from portfolio-based bidding, but postulate that one could overcome this by modelling two extremes; complete coordination and no coordination.
- The study employs a basic, simple price-forecasting approach based on historical differences of energy prices whereas more advanced forecasting techniques may achieve greater accuracy.
- The study assesses welfare gains based on a case study of the Core region, using historical data from the years 2020 to 2023. Due to the dominant role of thermal power plants in this case study, their fixed costs and technical minima are identified as key drivers of the efficiency gains due to co-optimisation. In the future, however, the role of thermal power plants – particularly in BC markets – is expected to decline, while emerging technologies such as battery storage and demand response – which are not considered in the NTUA-UCL study – will play a more prominent role.

¹² The Core region includes the following countries in Central Western Europe (CWE): Austria, Belgium, Croatia, Czechia, France, Germany, Hungary, Luxembourg, the Netherlands, Poland, Romania, Slovakia, and Slovenia.

As a result, these issues may lead to an underestimation of the efficiency of both the status quo and the market-based approach of allocating energy and BC markets sequentially and, hence, to an overestimation of the welfare gains of co-optimisation (relative to the status quo). Commissioned by the European Power Exchange (EPEX) and the four German TSOs (Amprion, 50Hertz, TenneT and Transnet BW), Consentec and IAEW-RWTH have conducted an alternative quantitative assessment of the welfare effects of the co-optimisation approach.¹³ Compared to the NTUA-UCL study, a key distinction of this assessment refers to the data used: while the NTUA-UCL study is based on historical data, the assessment by Consentec and IAEW-RWTH (2025) employs a 2030 scenario to reflect expected developments in the energy system. Moreover, it applies a more sophisticated price-forecasting approach with probability distributions for forecast errors for renewable energy generation and load and investigates the implications of various levels of coordination (full coordination and no coordination) between energy and BC markets for the potential cost savings due to co-optimisation. As a result, compared to the estimated 678 m€ cost savings per year owing to co-optimisation in the Core region of Europe - according to the NTUA-UCL study - the quantitative assessment by Consentec and IAEW-RWTH finds significantly lower values ranging from 16 to 179 m€ per annum (i.e., varying from approximately 0.01 to 0.13 €/MWh consumed). The lower amount of the range of cost savings is based upon strong assumptions though; it assumes full coordination in the status quo as if all units across a bidding zone were optimized jointly within one single portfolio and also disregards the current differences in gate closure times for the day-ahead energy and balancing capacity markets. Furthermore, it is non-intuitive that in the latter study the market-based approach is found to perform worse than the status quo.

Although the findings of the studies by Papavasiliou and Avila (2024a) as well as Consentec and IAEW-RWTH (2025) are interesting and relevant, they are not the definitive answer to the possible welfare effects of co-optimisation. First, according to the co-optimisation R&D programme (ACER, 2024b), the analysis of these welfare effects is a major part of this programme and will probably be published later this year (2026). Second, most likely ACER will reflect on the outcomes of these studies - from a social welfare point of view - and, all things considered, come with a decision (to which parties can appeal by ACER and, if not successful, by the European court subsequently).

3.2. Challenges and concerns regarding co-optimisation ('cons')

Over the past years, both TSOs, NEMOs and market participants have expressed their concerns and identified major challenges with regard to the implementation of co-optimisation in the European day-ahead electricity market. More specifically, these concerns and challenges include in particular;

- The implementation of co-optimisation enhances the complexity of the current bidding process to capture the intricate interdependencies between (a portfolio of) balancing capacity and energy market products/technologies, including diverse types of generation units, storage, demand response, etc. (Eurelectric, 2024; Energy Traders Europe, 2025b; Consentec and IAEW-RWTH, 2025). Although block or complex bids reflecting start-up and ramping costs of conventional generators are already common practise in the current SDAC, and additional complex bids reflecting intertemporal restrictions are under development (e.g. for storage), this may induce a higher share of complex bids. The preparation of complex bids necessitates tools and processes, with associated costs, which could be burdensome notably for smaller market participants. NEMOs and TSOs acknowledge this, but note that market participants retain the full flexibility of their portfolio to satisfy the obligations from market clearing, as is the case today. Besides, they note that burdens for smaller participants 'may be reduced by properly designed combined bids

¹³ The study seems to be motivated by concerns of NEMOs and German TSOs. NEMOs fear that co-optimisation cannot be implemented in EUPHEMIA given that, already today, the EUPHEMIA algorithm appears to be very close to hitting its limits in terms of what it is feasible to solve in a relatively short amount of time. For the German TSOs, besides the added complexity and the fear of losing control over their own national balancing capacity market, they are still rather far away from implementing market-based allocation, while co-optimization is a step further. Source: Personal communication with ACER.

for common assets' (MCSC, 2025e). Furthermore, market participants fear that market and technology interdependencies cannot be adequately captured with complex bids and therefore they will be forced to submit simplified bids, with potential effects on market efficiency and liquidity (Consentec and IAEW-RWTH, 2025). This can be considered as a transitional effect though, given that it is profitable for market participants to bid in a more cost-representative way (MCSC, 2025e).

- The implementation of co-optimisation and the resulting, increasing complexity of the bidding process may also pave the way towards unit-based bidding and, in the longer term, even a development towards a central dispatch system (Consentec and IAEW-RWTH, 2025). However, a change towards a central dispatch system would imply a fundamental reorganisation of the current market design in European countries, which is characterised by portfolio bidding in most EU member states¹⁴ but most essentially by self-dispatch following EB Regulation 2017/2195 (Van der Welle, 2016). Consequently, a shift to a central dispatch model would require a fundamental revision of EB Regulation 2017/2195 which is deemed rather unlikely in the short term.
- The increasing complexity of the bidding process due to the implementation of co-optimisation will also further stress the SDAC market clearing algorithm EUPHEMIA. More specifically, it will enhance computational complexities and, hence, computational (timing) requirements. However, across all stakeholders computational feasibility is considered as an absolute requirement for the implementation of co-optimisation (MCSC, 2025e).

Overall, market participants fear that co-optimisation – while elegant and promising welfare gains in theory – could in practice increase bidding and computational complexities and limit possibilities for portfolio bidding and therefore could not outweigh potential social welfare gains. Many participants agree that, rather than implementing co-optimisation, incremental improvements to current sequential market designs – i.e., the status quo and the market-based approach – would deliver higher benefits with lower risks. At the same time, NEMOs and TSOs recognize that several concerns will be addressed and potentially solved during the dedicated co-optimisation R&D programme (MCSC, 2025e), as discussed above.

4. Specific co-optimisation R&D issues

As indicated in Section 1, the ongoing R&D on the implementation of co-optimisation focusses in particular on the following three issues: (i) bidding products ('cost representations'), (ii) bid design, and (iii) pricing. The current section discusses briefly these three issues, notably the main findings regarding these issues during the first R&D phase as laid down in R&D reports R0 and R1, including the feedback by TSOs, NEMOs, market participants and other stakeholders.

4.1. Bidding products ('cost representations')

The R&D issue 'bidding products' refers particularly to the question which cost types are – or should (not) be – included in the bidding process by market participants under a co-optimised auction setting. Basically, there are two general options, i.e. *implicit bidding* versus *explicit bidding*. In the case of implicit bidding, market participants only include so-called '*fundamental costs*' in their bids – e.g., production costs for energy and reservation costs for balancing capacity – without adding a forecast of '*endogenous costs*' on top such as the *opportunity costs* for providing upward balancing capacity of energy, or *negative profits* for producing energy at a loss in order to provide downward balancing capacity. These endogenous costs are directly determined and considered by the co-optimisation market clearing algorithm, which ensures that these costs are recovered through the

¹⁴ Unit-based bidding is applied in France, Italy, Norway, Spain, and Portugal.

market pricing of energy and balancing capacity products. Hence, these costs are not (should not be) included explicitly in market participants' bids offering both energy and balancing capacity.¹⁵

In the case of explicit bidding, market participants explicitly add to their bids a forecast of the endogenous ('opportunity') costs they expect to face in the co-optimisation process. This option, however, is identified by a variety of issues, such as forecast errors of the day-ahead energy price (degrading social welfare gains), double cost counting, and suboptimal market outcomes.¹⁶

Because of these issues, the N-Side reports (2025a and 2025c) recommend implicit bidding as the preferred option for the co-optimisation auction process. Both TSOs and NEMOs agree with this recommendation while – with a few exceptions – the majority of other market participants and stakeholders support the proposal for implicit bidding in a co-optimised auction setting (MCSC, 2025e).

4.2. Bid design

Within a market design, bids are intended to enable market participants to express their economic preferences and technical constraints. In the simplest case, bids can consist of just a price-quantity pair. They can also contain a large number of parameters to enable a detailed description of underlying physical properties. More specifically, to maximise social welfare, the bid design must allow for a correct representation of fundamental costs and technical restrictions of the underlying assets and portfolios. Co-optimisation enhances this challenge in terms of identifying a suitable bid design that can adequately capture the intricate interdependencies between balancing capacity and energy (MCSC, 2025a and 2025e; Elia, 2025).

To represent these intricate interdependencies, the R&D co-optimisation reports by N-Side (2025a and 2025c) consider two different bid design concepts, i.e. 'linked bids' and 'combined bids'.

Linked bids refer to a family of bids for single products, either energy or a given capacity product, connected to each other by 'links' modelling specific interdependencies between these products. Two types of links are already implemented in EUPHEMIA for block orders: exclusive and parent-child links. *Exclusive links* are links where the acceptance of one block is conditioned on the rejection of another. *Parent-child links* are links where the acceptance of one block is prerequisite to the acceptance of another. In addition, new types of links are proposed for further investigation during the R&D co-optimisation phase II (N-Side, 2025c; MCSC, 2025e; Elia, 2025).

Combined bids offer multiple energy and balancing capacity products, with linking constraints capturing the interdependencies between these products included directly within the bid. Certain parameters, such as the total offered capacity, are shared across all products within the bid. The concept of combined bids allows to extend existing bids – such as '*step bids*', '*interpolated bids*' and '*block bids*' – to a co-optimised market including balancing capacity features. Besides extending the existing bids for co-optimisation, N-Side proposes to introduce also specific combined bids for thermal assets, storage assets, and potentially other assets, e.g. demand response assets (for further details and illustrations of combined bids, see N-Side, 2025c).

For a co-optimisation market setup, the N-Side report (2025c) recommends to use and further investigate both bid design concepts – and implement both concepts in EUPHEMIA – as each concept

¹⁵ For further definitions, examples and illustrations of the concepts '*fundamental costs*', '*endogenous costs*', '*implicit bidding*' and '*explicit bidding*', see N-Side (2025a and 2025c).

¹⁶ For further details and illustrations of these issues, see N-Side (2025a and 2025c).

has its advantages and disadvantages.¹⁷ On the one hand, a key advantage of bid linking is that it offers a lot of flexibility, i.e. it can represent different cost structures and capture complex interactions, which is particularly useful for advanced trading strategies under portfolio bidding. Major drawbacks of bid linking, however, are that it is more complicated to construct, less user friendly, less computationally efficient, while it may not be able to represent in a granular way the costs and technical constraints of specific assets such as thermal and storage assets (N-Side, 2025c; MCSC, 2025b and 2025e; Elia, 2025). On the other hand, the major advantage or added value of combined bids is that they are more user friendly and computationally more efficient (and, hence, they may positively affect the performance of EUPHEMIA). Moreover, for specific assets – notably thermal or storage assets – tailored combined bids allow for better capturing the specificities of the fundamental costs and the technical constraints of these assets. A major drawback of combined bids, however, is that they do not allow to represent advanced portfolio strategies as they are tailored for specific assets (N-Side, 2025c; MCSC, 2025b and 2025e; Elia, 2025).

In general, almost all stakeholders – i.e., TSOs, NEMOs, market participants, etc. – welcome and support the recommendation to consider both linked and combined bids as the preferred (hybrid) bid design for co-optimisation. Many stakeholders, however, perceive the proposed bid design as highly complex and doubt whether this complexity can be implemented and managed computationally within EUPHEMIA without overly restricting the flexibility of market participants (which could result in more inefficiencies and less welfare). In addition, some stakeholders specifically point out that there is concern and uncertainty as to whether CHP units and complex hydro strings can be adequately represented within the proposed bid design. Finally, several stakeholders emphasize that both proposed and additionally required bid design extensions should be further explored and investigated under real-world simulation conditions before any final decisions on co-optimisation in general and bid design issues in particular can be taken (MCSC, 2025e; Energy Traders Europe and Eurelectric, 2025; Energy Traders Europe, 2025b). Note though that such real-world simulations are already envisaged as part of the co-optimization R&D programme (ACER, 2024b).

¹⁷ More specifically, in order to balance expressiveness and usability for market participants, the N-Side report (2025c) recommends to apply and further explore a *hybrid* approach where linked bids remain available for complex portfolio strategies while combined bids streamline simpler bidding scenarios or allow for the granular representation of asset-specific costs and constraints.

4.3. Pricing

Under marginal pricing, in the absence of ‘non-convexities’, the welfare-maximising market outcome ensures that no participant would prefer a different allocation of their bids at the resulting marginal, market-clearing prices. Optimal marginal pricing implies that the market price of a product reflects the marginal system cost increase for serving an additional unit of that product. This general principle also applies in a co-optimised market setting where energy and multiple balancing capacity products are auctioned simultaneously (MCSC, 2025e).

Real-world power markets, however, are characterised by so-called ‘*non-convexities*’, i.e. relevant decision parameters are discrete (‘indivisible’) rather than continuous variable. Examples of non-convexities in power markets include start-up and shut-down costs, minimum generation levels, and minimum up and down times (O’Neill et al., 2005; Gribik et al., 2007; N-Side, 2025c).

Non-convexities in power markets pose two major challenging problems (N-Side, 2025c; MCSC, 2025e):

- In price formation, non-convexities prevent the straightforward use of marginal pricing to determine market-clearing prices, as they preclude in general the existence of uniform prices supporting a competitive market equilibrium.
- From an algorithmic point of view, non-convexities often turn what would have been a simple convex optimisation problem into an intrinsically harder and more time-consuming non-convex problem to solve.

Non-convexities in the European SDAC market are not a new issue resulting from the introduction of co-optimisation. There is reason to believe, however, that non-convexities become more pervasive due to the cost structure of balancing capacity bids and the inclusion of additional constraints and links to represent the interdependencies between energy and balancing capacity. Hence, co-optimisation may increase the scale of the problems mentioned above (MCSC, 2025e).

More specifically, power markets with non-convexities often results in what are known as paradoxically accepted or rejected bids (N-Side, 2025e):

- *Paradoxically Rejected Bids (PRBs)*. These are bids that are economically viable given the calculated market prices (i.e., ‘*in the money*’) but are rejected due to the non-convex nature of the problem. In the current European day-ahead market, PRBs are tolerated.
- *Paradoxically Accepted Bids (PABs)*. These are bids that are economically not viable given the calculated market prices (i.e., ‘*out of money*’) but are accepted, nonetheless. The current European day-ahead market design generally prohibits PABs (which in the following is referred to as the ‘*No PAB*’ design option).

To address the issues outlined above, the N-Side report (2025c) considers in particular the following market design options:¹⁸

1. No PAB;
2. Non-Uniform Pricing (NUP);
3. Most Expensive Bid (MEB) Pricing.

¹⁸ Each design option – notably ‘No PAB’ and ‘Non-Uniform Pricing (NUP)’ – can be used jointly for both balancing capacity and energy markets but also separately, i.e. No PAB for energy and NUP or ‘Most Expensive Bid (MEB) Pricing’ for balancing capacity. For further details and illustrations, see N-Side (2025a and 2025c).

These options are considered further below.

1. *No PAB*

The No PAB option does not allow for PABs in the market-clearing process (as in the current European day-ahead market). Prices are determined following classic marginal pricing principles. Market-clearing solutions may contain PRBs but rule out PABs. Under this design option, energy/balancing capacity markets cannot accept bids that are incurring losses (negative profits) given the calculated market-clearing prices. By strictly avoiding PABs, this option seeks to maintain a clear and consistent uniform pricing mechanism (N-Side, 2025c).

The main advantage of the No PAB option is that it ensures market coherence, and that all settlements solely depend on the uniform market prices applying to all accepted bids. Since no PABs are allowed, all accepted bids align perfectly with the market-clearing price, simplifying the interpretation of market outcomes and reinforcing the integrity of the pricing mechanism (N-Side, 2025c).

The main issue with the No PAB option, however, is liquidity. Non-convexities are an inherent property of balancing capacity bids, and a No PAB design could potentially disqualify many bids, leading to a shortage of balancing capacity in the co-optimised SDAC market although, in reality, no shortage exists. Moreover, disqualification of large volumes of bids will also reduce the efficiency of the balancing capacity market, and possibly the energy market. A further concern is that bidders will have incentives to misrepresent their bids or misrepresent the true links between the bids. If such concerns materialise, the expected increase in economic surplus due to optimisation may become illusory. Realistic quantitative simulations are required to understand the severity of potential problems with liquidity and efficiency. Modelling of balancing capacity bids in such simulations are, however, challenging because no empirical data exists, and the assumptions made will have a significant impact on the results. Using historical balancing capacity bids is not an option, because these bids are based on totally different assumptions and, moreover, because it is not known how they are related to SDAC bids. The lack of empirical data will in any case lead to added uncertainties regarding the simulation results (MCSC, 2025c).

2. *Non-Uniform Pricing (NUP)*

The NUP design option allows for PABs (as well as PRBs) with compensation provided through side-payments to ensure that market participants are not economically worse off as a consequence. Under this option, social welfare is optimised without considering market-clearing prices during the allocation process. Prices are determined afterwards based on specific rules or approaches, where all accepted bids are not necessarily settled at the same uniform price. There are several ways to calculate such non-uniform prices, notably the *Integer Pricing (IP)* method and the *Convex Hull Pricing (CHP)* approach (N-Side, 2025c).¹⁹

The main advantage of the NUP option is that it allows for greater flexibility and liquidity in the optimisation process, which can lead to higher welfare. Moreover, the separation of volume and price determination simplifies the initial market clearing process, which makes it algorithmically easier to solve (N-Side, 2025c).

Nevertheless, there is the risk that market participants may engage in strategic bidding if they anticipate compensation for PABs, which could undermine the efficiency gains of co-optimisation. In addition, the NUP option raises the issue how the side payments could or should be settled and financed, including its equity or income distribution impacts (N-Side, 2025e; MCSC, 2025e).

¹⁹ For further details and illustrations of these NUP methods and approaches, see O'Neill et al. (2005); Gribik et al. (2007), Schiro et al. (2016); Hyder et al. (2024), and Xiao et al. (2025).

3. Most Expensive Bid (MEB) Pricing

The MEB pricing option is used specifically for balancing capacity markets (while applying either the No PAB or NUP option for the energy market). In this option, the market-clearing price for balancing capacity is set at the level of the most expensive bid, thereby ensuring that no PABs are present without relying on side payments.

On the one hand, the advantage of using MEB pricing for balancing capacity is that it provides a straightforward mechanism to avoid PABs. All accepted balancing capacity bids are remunerated the same (high) price, ensuring fairness among accepted participants. In addition, this option avoids the need for side-payments, simplifying the financial settlement process.

On the other hand, the MEB pricing option creates opportunities (risks) for strategic bidding and market manipulation, as participants could inflate the balancing capacity price for a bid that is otherwise paradoxically accepted, thereby leading to inefficiencies and increasing procurement costs for the system (N-Side, 2025c).

N-Side recommendations and stakeholders feedback

Based on the considerations outlined above, N-Side (2025a and 2025c) recommends opting for the implementation of the No PAB pricing rule, which aligns with the current European day-ahead market rules. This approach ensures pricing consistency and avoids unnecessary complexities. However, in case realistic quantitative simulations reveal a non-negligible risk that the No PAB rule substantially limits social welfare, poses severe liquidity concerns, or proves to lead to material algorithmic challenges, a variant of the Non-Uniform Pricing (NUP) option should be reconsidered and further explored as a viable alternative. The MEB pricing option, however, is regarded as ‘less suitable’ as it was found to increase procurement costs and pose risks of price manipulation (N-Side, 2025a and 2025c).

Basically, stakeholders (TSOs, NEMOs, market participants, etc.) agree with the N-Side recommendations on the co-optimisation pricing options. Most stakeholders, however, stress the importance of the challenges and concerns regarding the liquidity, efficiency and (algorithm) complexity of the No PAB pricing option. In addition, the feasibility of more sophisticated, non-uniform pricing options – such as integer or convex hull pricing – is also questioned by market participants due to their computational demands and the risks posed to transparent price formation. Therefore, stakeholders emphasise the need for further research - based on real-world simulations with appropriate, empirical data – before any final decision on co-optimisation pricing issues can be taken (MCSC, 2025e; Energy Traders Europe, 2025b). Note though that such real-world simulations are already envisaged as part of the co-optimization R&D programme (ACER, 2024b).

5. Summary & look forward

Co-optimisation is an approach in which available resources – including in particular cross-zonal (transmission) capacities – are allocated simultaneously for the delivery and exchange of day-ahead energy and balancing capacity, resulting in a joint market clearing and pricing of day-ahead energy and balancing capacity, with the objective of enhancing economic efficiency and social welfare. Consequently, the envisaged key benefit of co-optimisation is that it enhances economic efficiency, lowers electricity prices and increases social welfare by facilitating the integration of day-ahead electricity and balancing capacity markets (across European countries), in particular by allowing for a more optimal use of scarce generation resources and cross-zonal capacities between these markets.

Co-optimisation, however, is a complex issue and represents a substantial reorganisation of the current (SDAC) power market design in Europe, which raises a variety of questions and concerns among the stakeholders involved, notably among TSOs, NEMOs and (private) market participants. Stakeholders fear that co-optimisation – while elegant and promising welfare gains and lower electricity prices in theory – could in practice significantly increase bidding and computational complexities, limiting the achievable social welfare gains.

Given the challenges and complexities associated with co-optimization, and following ACER Decision No 11/2024, TSOs and NEMOs have launched a multi-year (2024-2027) R&D process, including several market consultations. Main research topics include choices around bidding products, bid design, and pricing, which have been discussed in this report. Several (preliminary) R&D results have already been released last year (2025), and more detailed, quantitative modelling results are scheduled for this year (2026). Given the complexity of co-optimisation and the current status of modelling this topic, significant efforts are needed to arrive at a feasible and meaningful way to implement co-optimisation in SDAC at the end of the R&D trajectory that is acceptable for the major stakeholders involved. Although implementation of the co-optimisation method is mandatory due to EC (2017), its application is voluntary though. In case at least two TSOs and/or NRAs decide to apply the co-optimisation method, this is unlikely to take place before 2030. In the shorter term, implementation of the market-based approach is an alternative possibility to reap the benefits of more integrated European electricity markets. The Netherlands is involved in developing a harmonized algorithm for this approach in the COBRA project²⁰.

5.1. Implications for the Netherlands

Although co-optimisation is currently a European R&D process rather than an immediate Dutch policy decision, the ongoing discussion raises several strategic questions that are relevant for Dutch stakeholders.

For the Ministry of Economic Affairs and Climate (KGG), the main relevance lies in monitoring whether the eventual European design improves overall market efficiency while remaining compatible with the Dutch policy objectives of affordability, security of supply and sustainability.

For ACM and TenneT, the discussion is particularly relevant because co-optimisation fundamentally changes the interaction between day-ahead markets, balancing capacity procurement and cross-border transmission capacity allocation. This may ultimately influence balancing costs, market liquidity, transparency and incentives for flexibility investments.

For Dutch market participants, the current European R&D trajectory mainly creates uncertainty rather than immediate implementation requirements. The outcome of the ongoing R&D programme will determine whether the expected welfare gains outweigh the additional market and computational complexity and whether co-optimisation becomes preferable to incremental improvements of the current sequential market design.

Consequently, we advise Dutch stakeholders not to advocate a specific implementation option, but to remain actively engaged in the European R&D process, monitor the quantitative evidence emerging from the R2 and R3 studies, and assess future implementation options against explicit Dutch policy objectives.

²⁰ https://www.entsoe.eu/network_codes/eb/cobra/

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