Integrated Single Electricity Markets (I-SEM)

High Level Design for Ireland and Northern Ireland from 2016

Draft Decision Paper

SEM-14-045

on behalf of

AES Kilroot Power Ltd and AES Ballylumford Ltd

25th July 2014

1. Introduction

AES Kilroot Power Limited ("AES Kilroot") and AES Ballylumford Limited ("AES Ballylumford") (collectively "AES") welcomes the opportunity to comment on the I-SEM High level Design draft decision paper SEM-14-045.

AES is a global energy company with assets in the all island market consisting of coal and gas fired conventional and CCGT plant with additional distillate fired peaking gas turbine plant. AES is a non-vertically integrated independent generator which owns and operates Kilroot and Ballylumford power stations in Northern Ireland with a combination of merchant and contracted base load, mid merit and peaking plant. The responses to this consultation are therefore conditioned by the nature of our current position and portfolio of assets operating in the SEM.

AES welcomes the publication of the High Level Design decision consultation document, and the additional explanatory information contained in the Initial Impact Assessment (SEM-14-046) relating to the assessment of the options for energy trading arrangements and capacity remuneration mechanisms. AES appreciates that this decision relates to a high level design stage and therefore not all of the subsequent detail which market participants would wish to have available to conduct analysis and form opinions has yet been determined.

Decision Paper consultation response – Key Messages

The decision paper provides an overview of the proposed energy trading arrangements and integrated capacity remuneration mechanism that will replace the current SEM market design at the end on 2016. AES has identified a number of important issues were there is a need for further clarity and more substantive detail than that provided in the High Level Design minded-to decision paper.

Overall market design process

There is an urgent need for certainty around process and timing

Due to delays associated with the Committology process regarding the CACM code in particular and the lack of progress on pan European Intraday market:

- It is crucially important to have a clearly defined transition date – 1st January 2017 – to allow for planning and an orderly transition to the new market design.
- Market participants are now looking to trade on a forward basis out to end of 2016, and there is a pressing need for certainty around market regime in 2016 in particular.
- AES would suggest a phased transition is considered with introduction of energy market measures first with capacity mechanism following within a 2 / 3 year period.
- Significantly more detail is required in some areas of the market design, and AES has specific concerns with regards to the lack of detail regarding for example the treatment

of balancing actions, constraints and methodology for tagging energy / non-energy actions.

- AES seeks clarity on EirGrid's role and mandate for drafting the new TSC – and seeks a commitment from the SEMC with respect to transparency and non-discrimination relating to lines of governance as the project moves to the detailed design phase.
- AES would welcome the publication of a detailed scope and programme of work for the detailed design phase including proposals for continued industry involvement and engagement at the earliest opportunity.

Energy market design

In conducting its own analysis, AES had arrived at a preferred high level design energy market structure of **Option 4** which AES believes preserves the principles and value of the current SEM. However, AES recognises the imperative of increasing European market integration and the central importance of compliance with the EU Target Model in the new I-SEM. AES is therefore broadly supportive of the draft energy market design decision, but believes the following key areas of the proposed energy market design require amendment.

Day-ahead market participation should be mandatory

A key aspect of the new market design is the creation of sufficient liquidity in the forward and particularly day ahead market timeframes to enable market participants to hedge against scheduling and commodity risk. The original concept of mandatory day ahead participation provided a number of benefits to the market structure:

- Mandatory participation is important to ensure a robust day-ahead price reference against which forward contracts can be priced.
- Mandatory day-ahead participation is important to mitigate market power and deliver liquidity.
- Mandatory day ahead participation is critical if SRMC bidding principles are relaxed.
- Reliability Options CRM could reinforce the need for day-ahead liquidity to reveal a strong day ahead price (depending on the RO reference price basis).
- Mandatory approach mitigates concerns that voluntary participation could favour vertically-integrated players.
- Mandatory approach is critical to the coherent design of this Option 3 – voluntary day-ahead participation undermines many of the advantages.
- In relation to wind generation, AES strongly believes that wind should participate fully in the market, including at the day-ahead stage as mandatory participation at the day ahead stage maintains incentives to improve day-ahead wind forecasting accuracy.

Concerns around EUPHEMIA must be addressed

As Euphemia is the starting point for the dispatch process for the I-SEM and a key aspect of the High Level Design, AES still has significant concerns regarding the functionality and output from the PCR process with regard to the following:

- Scheduling risk –The schedules produced by the EUPHEMIA algorithm are unlikely to be fully feasible and will need to be adjusted to take into account ramping characteristics of plant and transmission constraints. Therefore a mid-merit plant cannot be certain whether it will be "in-merit" and scheduled making the task of managing earnings risk through hedging forward its output and fuel requirements more difficult.
- In order to quantify the scheduling risk that generators will experience in the I-SEM, AES in association with other market participants, commissioned an independent report from Baringa. This report (Scheduling Risk Under the Proposed I-SEM High Level Design – Attached) highlighted a number of potential risks associated with using the Euphemia algorithm as the primary mechanism for scheduling plant.
- The comfort required that the algorithm can cope with the volume and complexity of bids and can solve sufficiently quickly.
- The need to be certain that the full range of complex products will be offered by the eventual day-ahead power exchange(s).
- Key challenges as to how to internalise start and no load costs into offers when uncertainties pertain in relation to bid structures, running hours and/or constraints applied as a plant cannot determine its own schedule and there is a risk of under recovery.
- The potential for rejection of sophisticated orders by Euphemia even when in merit – termed "paradoxically rejected orders" which can create additional scheduling risk needs to be understood fully to minimise. This could be mitigated by a liquid Intraday Market to enable generators to trade out their positions from the day ahead market quickly, however the timescale on provisions of a harmonised European intraday trading platform is unclear.

Measures to mitigate (local) market power need to be spelled out

- We note that detailed market power mitigation measures are still lacking in the market design.
- Robust measures are needed to address market power across all timeframes.

Clarity on the process for identification of energy and non-energy balancing actions

- More detail is required on the mechanism for the identification and treatment of energy and non-energy balancing actions taken by the TSO due to system constraints.

CRM – Reliability Options

A robust and compliant long-term price based capacity mechanism remains AES' preference.

AES welcomes the decision to complement the energy trading arrangements with a capacity remuneration mechanism however we are surprised at the draft decision to introduce a centralised Reliability Options in the I-SEM. We strongly believe that a long-term price based CRM remains the most appropriate choice for the I-SEM, taking account of the special requirements of a small and relatively isolated island market as it:

- Provides a stable long-term price signal which is required to maintain existing plant on the system and for new investment.
- Could be made compatible with EU Target Model and day-ahead market coupling if CRM pricing was made ex-ante.
- Provides a capacity price that is transparent and market-wide.
- Avoids the significant market power and gaming potential of quantity-based models such as reliability options and capacity auctions.

Reliability options are unnecessarily complex and increase market risk

AES notes that the responses to the I-SEM high-level design consultation show a substantive lack of cross-industry support for Reliability Options, and we are concerned that this could undermine their success.

Reliability Options were at one stage DECC's preferred form of capacity mechanism for the GB Electricity Market Reform package, but were subsequently dropped in favour of capacity auctions due to a lack of physical delivery guarantee. We would question why the RAs are considering the introduction of a CRM (into a small Island system) which was considered in detail and rejected by the SEM's neighbouring market.

We also note that international experience with Reliability Options has been mixed at best, and that the ISO of New England is in the process of transitioning away from this form of capacity mechanism to a more price based mechanism as the RO CRM resulted in boom and bust prices and a subsequent shortage of capacity.

We also note that in the example quoted of Colombia, a market where AES has operational assets, Reliability Options are used to address a specific issue caused by a set of circumstances peculiar to that market. The Colombian generation portfolio is nearly 70% Hydro and is at risk of low hydrology due to the "El Nino" phenomenon on an average 5 yearly cycle. The Reliability Option is to ensure that generators (Hydro and Thermal) are obligated to deliver firm quantities of energy during the El Nino period when water is scarce and the RO effectively acts as a price cap for the provision of that energy. It is not for the purpose of addressing capacity levels as there is surplus capacity in Colombia – it specifically addresses an energy inadequacy.

We are concerned that Reliability Options could fail to deliver an appropriate balance between maintaining security of supply at least cost for consumers.

- Reliability Options appear unnecessarily complex and risky, and the full costs of implementation may have been underestimated.
- Market participants will need to anticipate the amount of infra-marginal rent they will capture in the energy market in order to inform their auction bidding strategy – there is a high degree of risk associated with this judgement (an issue shared by both reliability options and capacity auctions)
- The high risk of the mechanism is likely to result in a high risk premium being applied to auction bids, resulting in high costs to consumers.
- Further clarity is needed on whether or not this is a financial derivative, and the implications for compliance with derivative trading regulations, consequential costs of participation and impact on the forward trading of energy.

Priority should be given to the following aspects of any Reliability Options scheme design

Notwithstanding the above points, we suggest that priority should be given to the following aspects of any Reliability Option scheme design:

- Reliability Options already penalise contract holders for non-delivery during periods of system stress (high prices), and therefore additional penalties for non-delivery should be avoided.
- Additional penalties would result in high risk of participation, and leading to concerns around the bankability of the mechanism, and increased costs to consumers.
- While transmission constraints remain between Northern Ireland and the Republic of Ireland, locational pricing in the RO should be considered in order to ensure that there is sufficient capacity where it is needed. We note that strategic reserve is presented as a complementary option in the impact assessment -- this should form an explicit part of the design decision.
- AES is aware that Eirgrid have recently tendered for additional capacity in Northern Ireland to address a foreseen capacity inadequacy. The proposed RO mechanism introduces significant market and regulatory risk in terms of the main market revenue stream for any market based solution. This has the potential to undermine the required investment in NI to ensure generation adequacy post 2015.
- Measures should be put in place to ensure an appropriate, robust and liquid reference market.
- RO contracts should be backed by physical capacity, and should not be purely financial in nature.
- Consideration should be given to contract length under RO with multi-year contracts preferred to provide longer term stability.

The timetable for introduction of a Reliability Options CRM does not appear feasible

We do not believe that the timetable for the introduction of centralised reliability options is feasible. We note that the similar capacity auction mechanism in GB commences in December 2014 – four years ahead of first delivery under the scheme in Winter 2018. It seems unlikely that a new Reliability Options mechanism in the I-SEM could be initiated to deliver capacity by the end of 2016. This reinforces our view that a long-term price based CRM is preferable, and that in any case a longer transition phase would be required with a delayed introduction of reliability options 2 / 3 years beyond the go-live of the revised energy market arrangements.

Scheduling risk under the proposed I-SEM High Level Design

An issues paper

CLIENT: Tynagh, Viridian, AES, Bord Gáis Energy

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TABLE OF CONTENTS

1. INTRODUCTION 4

2. PARTICIPATING IN THE I-SEM 5

3. WHAT IS SCHEDULING RISK? 6

- 3.1. Definitions 6
- 3.2. Scheduling Risk in the current SEM 7
- 3.3. Potential scheduling risk issues under the proposed I-SEM HLD 8

4. I-SEM DAY-AHEAD SCHEDULING AND EUPHEMIA 9

- 4.1. EUPHEMIA offer types 9
- 4.2. Mapping of generator technical and commercial parameters to offer types 10
- 4.3. Potential bidding approaches for SEM generators 13

5. IMPLICATIONS 27

- 5.1. Introduction 27
- 5.2. Single Asset 27
- 5.3. Different technologies 29
- 5.4. Asset portfolio 29
- 5.5. Market clearing, balancing and dispatch 30
- 5.6. Forward trading 31

6. CONCLUSIONS 31

1. INTRODUCTION

The SEM Committee published the I-SEM High Level Design Proposed Decision on the 9th June 2014. The proposed design will consist of a financial forward hedging contract market referenced against a physical unconstrained day-ahead schedule produced by the EUPHEMIA algorithm as a part of the European market-coupled auction, together with bilateral within-day trading and a balancing market operated by the system operator. The SEM Committee proposes that the centralised Day-ahead Market (DAM), Intra-day Market (IDM) and Balancing Market will be the exclusive routes for physical contract nomination and physical scheduling of generation. It is proposed that participation in the DAM and IDM will be exclusive but not mandatory, whereas participation in the Balancing Market will be mandatory.

The proposed I-SEM High Level Design is formulated to ensure that the Irish electricity market is compliant with the EU Target Model by 2016. Whilst the proposed design will bring the market more in line with other European markets in some respects, for example allocating interconnector capacity implicitly through day-ahead market coupling and making participants more responsible for balancing their own positions, it would still be unique amongst other European markets which typically are centred around full self-dispatch and voluntary participation in multiple physical traded markets. Furthermore, the proposed design does not explicitly tackle one of the key issues in the current SEM, namely the lack of forward liquidity which is important for a well-functioning market. One of the contributing factors behind poor liquidity in the current SEM is the scheduling risk faced by generators, since they cannot with confidence assume that they will be appropriately scheduled under the central market arrangements against their forward commitments.

Liquid and transparent forward markets enable suppliers to hedge efficiently, thereby shielding consumers from volatile spot markets and enabling competitive tariff structures. Forward markets also provide open access to mitigate market power and concentration, and generate price signals to drive investment. Effective functioning of forward markets is therefore essential for competition and consumer choice.

In this paper, we explore the extent to which scheduling risk would remain under the proposed I-SEM design and the implications for forward market liquidity. We are not implying or proposing solutions to these potential issues within the contents of this paper.

2. PARTICIPATING IN THE I-SEM

The day-ahead market (DAM) forms a central part of the proposed I-SEM High Level Design, providing:

- The basis for the day-ahead dispatch schedule
- The mechanism for allocating capacity on interconnectors with the GB market
- The reference price for settling forward financial contracts, and
- The (likely) reference price for settling reliability options under the proposed Capacity Remuneration Mechanism (CRM)

Since the DAM will be exclusive, dispatchable generators will be strongly incentivised to offer their output through this market (even if it were not mandatory)[1]. Each day the generator will need to formulate its offers using the available exchange offer formats, and consider how best to reflect its underlying costs in its pricing approach. In doing this, it will need to consider external factors such as the level of demand and wind output, and the potential strategies of competitors. It will also need to take a view of the likely initial status of the plant at the start for the trading day, for example whether the plant will be already operating or needs to be started which would require start costs to be recovered in its offer price.

The schedules produced by the EUPHEMIA algorithm at the day-ahead stage are unlikely to be fully feasible, and will need to be adjusted to take into account actual ramping characteristics of individual plant, as well as for system operational reasons, such as managing transmission constraints.

At this stage, it is not decided how much responsibility individual generators will have post the DAM for creating feasible schedules versus the system operator. If it is to be generators, a liquid within-day market will be essential, since the proposed marginal imbalance price arrangements would represent a significant risk for generators (particularly independent generators) constrained to the relatively blocky nature of offers in the DAM.

Participation in the balancing market is mandatory for generators. In pricing their balancing bids and offers, generators will need to consider the impacts on their assumed starting positions used for preparing offers into the next day's DAM. For example, had the generator assumed that it would begin the day generating, any bid to switch off in the balancing market would need to factor in the costs of re-starting the plant (which were not included in the DAM offer price).

Overall, the proposed I-SEM HLD places far more risk on generators associated with managing their own dispatch and internalising their own costs when compared to the current SEM based around a pool and central dispatch. To manage this risk effectively will require access to the tools typically available in bilateral markets based on self-dispatch, namely day-ahead and within-day liquidity and real-time information on system conditions. An imbalance price that accurately reflects the costs of achieving an energy balance across the system (i.e. a price that is not 'polluted' by balancing actions required to maintain the physical integrity of the network such as constraint management), and established through effective competition between providers of balancing energy, will also be essential.

[1] The alternative of attempting to transact all its output in the within-day market would expose the generator to considerable liquidity risk.

3. WHAT IS SCHEDULING RISK?

3.1. Definitions

Scheduling risk occurs in centralised markets, such as the current SEM and the proposed I-SEM, since a generator cannot be certain that its plant will be appropriately scheduled under the market or exchange algorithm. This makes the task of managing earnings risk through hedging forward its output and fuel requirements more difficult than is the case in a self-scheduled market.

A baseload generator, one whose short run costs are predictably below the market price, is unlikely to have significant exposure to scheduling risk. There are no start costs to be recovered, and the baseload generator can hedge its output and its fuel (and carbon) costs in forward markets (to the extent there is sufficient liquidity) and lock in a margin.

Scheduling risk is most acute for mid-merit plant, those generators whose output fluctuates according to system conditions and which may need to be frequently switched off and restarted. High efficiency CCGTs already operate as mid-merit units in the SEM and this trend is likely to continue with even more efficient currently baseload generation moving to mid-merit operation in the future with increasing levels of renewable generation.

A mid-merit generator cannot be certain whether it will be “in-merit”. In a bilateral market with self-dispatch, the mid-merit generator is able to sell electricity forward and hedge its fuel cost for periods with positive spreads (taking into account potential start costs). Having the option to self-dispatch at the time of delivery then guarantees it can lock in the margin on its forward sale. If at the time of delivery the day-ahead price for electricity is above its short run costs (taking into account its start costs if it is not already running) it will choose to generate. However, if the day-ahead price is below its short run costs, it will re-optimise its position, choosing not to generate and instead purchasing its requirements from the day-ahead (or other prompt) market. This allows the generator to then stockpile its fuel (in the case of coal) or sell it (in the case of gas) to achieve additional margin. Under this dynamic, a generator can only improve on the margin it has locked in through its forward hedging strategy.

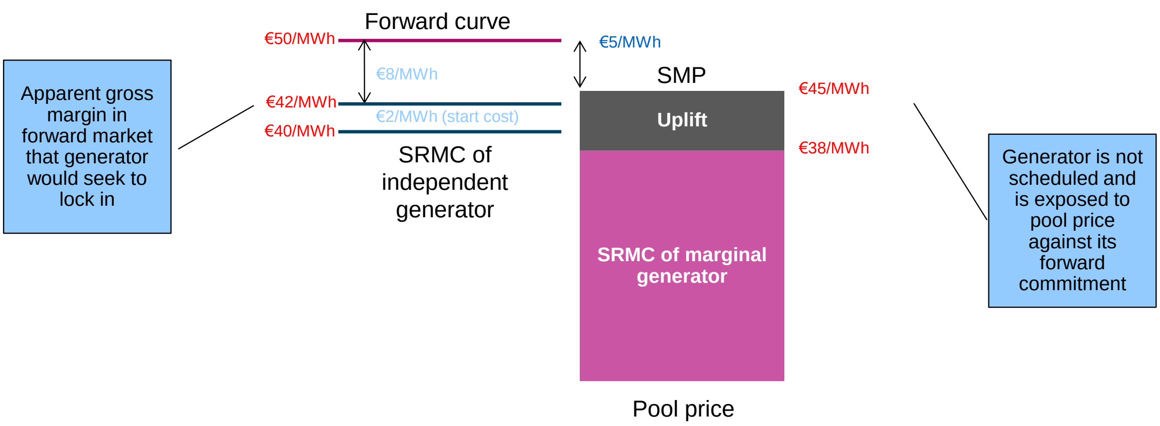
Under a centralised market, the hedging task for a mid-merit plant becomes more complex since it will be dispatched based on the outcome of the market algorithm. At the day-ahead stage there will be considerable uncertainty regarding market conditions, particularly with respect to wind output, and the potential bidding strategies of competitors. In the absence of a Bidding Code of Practice it will be significantly more difficult than under the current SEM to anticipate the offers of competitors, which will increase scheduling risk. A key challenge for generators will be how to internalise start costs and no load costs into offers when there is a high degree of uncertainty regarding the fixed output that these costs can be spread over without increasing risk of exclusion from the DAM schedule. Generators also face the additional problem of how to construct commercial offers that ensure the DAM schedule they receive respects the dynamic technical constraints of their unit(s). It is therefore possible under the proposed design that a generator, bidding at cost, will not be scheduled, even if the DAM price is higher. In this scenario a generator that had hedged forward would be exposed to the market price, at a loss relative to its SRMC. This is scheduling risk.

In the current SEM these important issues are addressed (albeit imperfectly as discussed in Section 3.2 below) through complex commercial and technical offer formats, and the Uplift algorithm, but under I-SEM the under recovery of start-up and no load costs and the receipt of a technically infeasible schedule are likely to represent an increased material risk for generators. The reasons for this are discussed in Section 4 below.

3.2. Scheduling Risk in the current SEM

Under the mandatory pool structure of the current SEM, it is difficult for a mid-merit generator to execute a forward hedging strategy because it cannot determine its own schedule. This creates an anomaly whereby the generator can be 'in the money' in the forward market but is unable to capture the implied margin because it is not guaranteed to be scheduled appropriately through the mandatory pool. This problem is illustrated in Figure 3.1 below.

Figure 3-1 Risks associated with forward hedging under the SEM



In this example, the forward curve (€50/MWh) is trading above the generation costs (including the plant's start cost – spread across its anticipated running hours) of the independent mid-merit generator (€42/MWh). It therefore sells electricity forward and simultaneously hedges its fuel costs, thus in theory locking in a €8/MWh gross margin. At the day-ahead stage the generator submits an offer to the SEM based on its SRMC (€40/MWh). In this illustrative example, the generator's offer price is slightly above the SRMC of the marginal unit on the system (€38/MWh), causing the generator not to be scheduled in the pool. The generator therefore sells back its fuel hedges and in so doing generates a revenue equivalent to its SRMC. This payment offsets the costs of buying power from the pool (€45/MWh) to meet its forward commitments but because the pool has priced above the SRMC of the generator it results in the generator retaining a residual exposure to the pool. This residual exposure constitutes scheduling risk and means the generator only achieves a gross margin of €5/MWh, lower than the €8/MWh expected on its forward sale. This risk may have contributed to the substantial premium on forward sales evident in the current SEM.

In a bilateral market this dynamic is less likely to occur. Generators still face a challenge in optimising their traded position, as this is done primarily with relatively simple traded products, albeit through multiple channels, but they do have the ability to self-schedule to meet physical forward commitments if they are unable to purchase power below its own costs in the day-ahead market, guaranteeing the margin on forward sales.

3.3. Potential scheduling risk issues under the proposed I-SEM HLD

As the example above illustrates, a key source of scheduling risk under the current SEM design is the separation of no load and start costs from SRMCs in the pricing algorithm. This can create a situation where a plant is not dispatched even when prices are apparently above its costs.

Under the proposed I-SEM High Level Design, the generator's no load and start costs are internalised by the generator and hence this specific example would not happen.

However, scheduling risk is unlikely to be eliminated under the new market design since dispatch still relies on the outcomes from a central algorithm (in this case EUPHEMIA) which market participants may not be able to anticipate reliably, particularly in the absence of a Bidding Code of Practice. EUPHEMIA supports complex and sophisticated offer formats to help participants manage their technical and commercial constraints within the day-ahead scheduling process. However, with the exception of the possible partial acceptance on profile offers, complex or sophisticated orders can normally only be executed fully or rejected fully, and this constraint can lead to EUPHEMIA rejecting some complex orders even if they are priced below the outturn market prices. Rejected orders that are apparently in-the-money at outturn prices are termed 'paradoxically rejected orders' in the EUPEHMIA literature.

In the absence of short run cost bidding principles, the generator may, however, have the option of offering at zero price into the centralised day-ahead market, although it is not clear from the Draft Decision Paper whether zero bidding would be allowed. Zero bidding would guarantee dispatch (unless the marginal unit was also bidding zero[2]) and reduce scheduling risk. The downside for the generator though is that it may have been able to fulfil its forward commitment at lower cost (if the day-ahead market outturned below its own costs). Also zero bidding puts downward pressure on day-ahead prices, particularly in a small market such as the SEM, which may undermine the value of forward contracts. Whilst there could be a rationale for a single unit to bid below cost (if others were not doing it), the price dynamics associated with multiple parties doing so are likely to be unfavourable to generators, and hence we would not expect this to be a sustainable strategy in the longer run.

Exposure to scheduling risk under the I-SEM is compounded by the proposed design of the Capacity Remuneration Mechanism which will be based on financial Reliability Options that are likely to be settled against the DAM price. It is possible under the design that a generator will be exposed to payments under Reliability Options but not been scheduled.

In the next section we provide some worked up case studies to illustrate the options for generators to reflect their cost structures using EUPHEMIA offer structures and the limitations of this which contribute to scheduling risk.

[2] This situation is possible, particularly in periods of high wind output.

4. I-SEM DAY-AHEAD SCHEDULING AND EUPHEMIA

4.1. EUPHEMIA offer types

The pan-European day-ahead market clearing algorithm, EUPHEMIA, can handle a multitude of order formats, ranging from simple hourly and block products through to more complex block formats (e.g. linked, exclusive) and sophisticated conditions (e.g. Minimum Income Conditions). A brief description of each order type is as follows:

- ***Simple Hourly Orders*** consisting of a price and quantity pair for a given hour
- Block Orders applying to multiple hours:
    - ***Simple Block orders*** consisting of a price with a fixed quantity over a set time
    - ***Profiled Block Orders*** consisting of a price with a varying quantity over a set time
    - ***Linked Block Orders*** introducing conditionality such that the acceptance of a 'child' or 'grandchild' block is dependent on the acceptance of a 'parent' block
    - ***Exclusive Groups*** consisting of Simple or Profiled Block Orders where the combined acceptance ratio cannot exceed 1
    - ***Flexible Block Orders*** consisting of a price and quantity pair for a set duration but with the block start time not specified
- ***Sophisticated Orders*** consisting of simple orders with constraints such as Minimum Income Conditions, Scheduled Stop or Load Gradients

While the EUPHEMIA algorithm has been designed to support the full suite of order formats listed above, in practice only subsets of these order formats have been implemented by individual power exchanges to date. EUPHEMIA has been deployed in the North-Western European (NWE) and Iberian regions since 4 February 2014. At present, only OMIE in the Iberian market is supporting sophisticated orders such as Minimum Income Conditions, which are based on the legacy order formats in that market. In the NWE region, the local power exchanges such as EPEX and N2EX have been rolling out 'smarter' block formats but we understand there are no immediate plans to introduce sophisticated orders. Relative to the proposed I-SEM design, the requirements for sophisticated offer formats are less in other European markets given their larger size and more diverse and flexible generation mixes, and the fact that EUPHEMIA is not used as an exclusive route for creating the market schedule.

The RAs' proposed HLD does not specify which EUPHEMIA order formats will initially be supported in the I-SEM DAM. However, as stated in the proposed decision paper, recent analysis has focused on the potential application of Block Orders, and "the requirements for sophisticated constraints such as the Minimum Income Condition may not be as important or as necessary as was previously thought". It is also worth noting that the offer formats available to market participants may not be decided unilaterally by the RAs but through the EUPHEMIA governance arrangements. For the purposes of this study, we assume that Simple Hourly Orders and complex Blocks Orders will be available to I-SEM participants, but not sophisticated orders.

4.2. Mapping of generator technical and commercial parameters to offer types

The current SEM trading arrangements feature a centralised scheduling and pricing algorithm which ensures that generator market schedules are both technically feasible and commercially viable. Generators explicitly submit technical parameters (such as ramp rates, minimum stable levels and minimum run times) for consideration by the algorithm. The Uplift component of the market price in the current SEM guarantees the recovery of variable operating costs, including start and no load costs, for generation plant selected to run in the market schedule.

However, in the I-SEM DAM, as in other more decentralised European power markets, participants will be expected to internalise decisions on how to factor generation technical and cost constraints within their scheduling and pricing. I-SEM participants may consider applying some of the more complex order formats supported by EUPHEMIA to proxy the technical and commercial parameters that are handled explicitly in the current SEM. Here we can consider the potential mapping of current SEM technical and commercial parameters to EUPHEMIA order formats.

Table 4-1 Mapping of Commercial Offer Data

SEM Parameter	Explicit I-SEM proxy	EUPHEMIA Order Types	Observations
Price Quantity Pairs	✓	All formats, including Hourly Orders and Block Orders	• Prices as well as volumes may differ from hour to hour (current SEM limits generators to one set of prices per day)
No Load Costs	×	All formats, including Hourly Orders and Block Orders	• No load costs need to be internalised within Hourly or Block prices • Higher prices for part-load operation can be represented using Linked Block Orders with the parent block incorporating no load costs
Start Up Costs	×	Block Orders, *or* Sophisticated Orders with Minimum Income Condition	• Start costs need to be internalised within Hourly or Block prices • Using Linked Block Orders, start costs could be assigned to the parent block

Table 4-2 Mapping of Technical Offer Data

SEM Parameter	Explicit I-SEM proxy	EUPHEMIA Order Types	Observations
Minimum Stable Generation	✓	Block Orders	• 'All or nothing' acceptance criteria provides a proxy for minimum stable generation (MSG) • The parent block of a Linked Block could be sized at MSG
Minimum On Time	✓	Block Orders	• Duration of a Block Order can represent minimum on times • Except for a Flexible Block Order, the generator will need to pre-determine the hours of the day to which the block applies
Minimum Off Time	✓	Block Orders	• Duration of a Block Order can represent minimum off times •
Ramp Up , Ramp Down Rates	✓	Profiled Block Orders , *or* Sophisticated Orders with Load Gradient	• Unlike the current SEM, generators will need to pre-determine the hours in which the ramp profile applies

The generation and load resources in the SEM have differing commercial and technical characteristics. Technical constraints will be more significant for inflexible resources, while start costs may be more material for some generation types than others. SEM participants may consider applying different EUPHEMIA order formats, reflecting these characteristics. Here we summarise key features and limitations of the different order types, and their potential application (ignoring sophisticated orders, as discussed above).

Table 4-3 Summary of order types

Order Type	Features	Limitations	Potential Application
Simple Hourly Orders	Orders in each hour clear independently.	Risk of technically infeasible schedules for baseload and mid-merit generators, since no modelling of technical constraints.	• Flexible peaking generators • Hydro generators • Pumped storage • Load
Simple Block Orders	Block duration can represent minimum on time constraints. 'All or nothing' acceptance criteria proxies MSG.	Participant needs to pre-determine the hours in which the block applies.	• Baseload generators • Mid-merit generators • Less flexible peaking generators • Load
Profiled Block Orders	Profile shape can reflect technical ramp constraints and/or expectations of market value (e.g. lower volumes offpeak).	Participant needs to pre-determine the profile shape based on market fundamentals as well as internal constraints.	• Baseload generators • Mid-merit generators • Hydro generators
Linked Block Orders	No load and start costs may be allocated to parent block, allowing competitive pricing of incremental energy in child blocks. Allows reflection of higher costs for part-loading. Sale and purchase blocks may be linked.	Required for detail modelling of start and no load costs and technical constraints. Other power exchanges have limited the number of child blocks per parent, reducing potential flexibility. Order may be paradoxically rejected.	• Mid-merit generators • Pumped storage
Exclusive Groups	Allows participant to submit alternative profiles for the market algorithm to optimise, without risk of over-commitment.	Algorithm delivers market optimal outcomes, which may not be the profit maximising outcome for participant. Cannot be combined with Linked Block Orders. Order may be paradoxically rejected.	• Mid-merit generators • Hydro generators • Energy limited plant • Load response
Flexible Block Orders	Fixed duration and volume block with flexible start time to be optimised by market algorithm.	Other power exchanges have limited the number of Flexible Block Orders per portfolio. Order may be paradoxically rejected.	• Energy limited plant • Flexible peaking generators • Load response

In the following section, we consider worked examples of how EUPHEMIA order formats could be applied by different SEM resources, such as baseload or mid-merit generation.

As we note in the table, many power exchanges have placed limitations on the number and size of block orders and other complex bidding formats that participants can submit in the DAM for consideration by EUPHEMIA. These limitations can help ensure the market clearing algorithm reaches a timely and feasible solution. For example, EPEX has restricted Linked Block Orders to only one child per parent, and one 'family' per portfolio and market area. In GB, N2EX allows up to three child (or grandchild) blocks per parent (or child) block. The proposed HLD for I-SEM does not specify what limitations, if any, are likely to be placed on the use of complex order formats by I-SEM participants.

4.3. Potential bidding approaches for SEM generators

In this section, we have developed a series of worked examples to consider how different SEM generation categories (baseload, mid-merit, peaking) could make use of the various EUPHEMIA order formats to manage their scheduling risks. The challenge of achieving a technically and commercially viable schedule is arguably most pressing for mid-merit generators. Peaking generators are typically more flexible, while baseload generators are less concerned about start cost recovery. Given the growing contribution of renewables in the SEM, the majority of CCGT and coal assets will operate as mid-merit going forward. Mid-merit generators are therefore the focus of our worked examples.

We have considered the cases of a typical CCGT and coal-fired unit operating in the SEM. The table below summarises the assumed technical and commercial parameters for these two units, which are based on representative mid-point values in the published 2013 Validated Model, together with observation of actual commercial offer data (for start costs).

Table 4-4 Generic plant assumptions

Parameter	Unit	CCGT unit A	Coal unit B
Maximum Capacity	MW	400	250
Minimum Stable Generation	MW	200	100
Minimum On Time	Hours	4	5
Minimum Off Time	Hours	4	3
Start Cost	€	95,000	30,000

Given these assumptions on the generator's cost structure and technical constraints, we then consider how EUPHEMIA orders could be formulated.

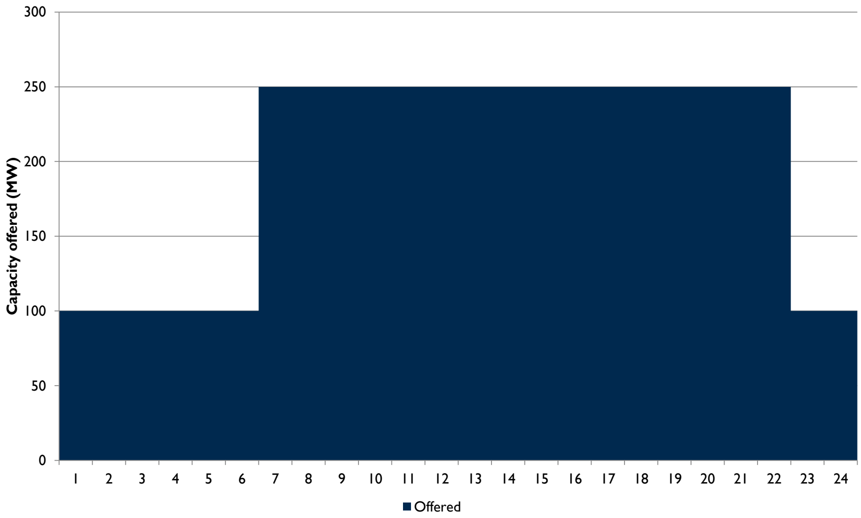
For the purpose of this study, we have not attempted to simulate the day-ahead market clearing and price formation process in the I-SEM and interconnected markets. For illustrative purposes, we assume that the CCGT and coal units are operated by independent generators and essentially operate as price takers in the DAM. We used historical spot commodity prices (gas, coal, carbon) and electricity price profiles (SEM, GB day-ahead, GB within-day) to illustrate potential scenarios for characteristic days. We also note that the success of a particular offer strategy (in producing a cost-optimal generation schedule for an asset) will also be dependent on the strategies deployed by other generators, which will of course not be known in advance. As we are not simulating the algorithm, this is not something we are aiming to demonstrate directly with these examples, but to which we return in considering the implications in Section 5. Furthermore, the simplified methodology for our illustrative examples assumes that block orders will always be accepted if they are in-the-money, whereas in practice block orders can be paradoxically rejected in the EUPHEMIA market clearing algorithm.

Baseload

The economics of baseload generators are such that they expect to be in-the-money in most periods. Start cost recovery is not generally a consideration given the continuous running profile. A Simple or Profiled Block Order format may be appropriate to represent technical constraints (such as minimum on time) and to ensure the plant is scheduled for the whole day in the DAM.

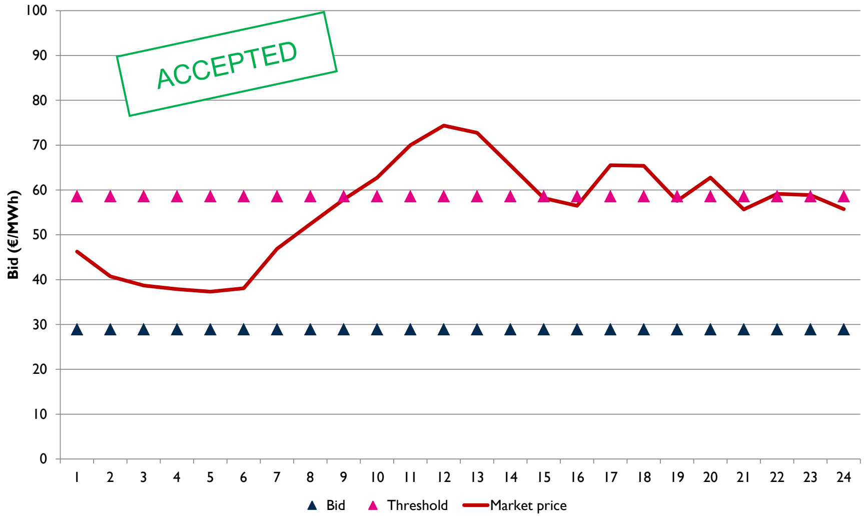
<u>Case 1: Profiled Block Order</u>
In this example, Coal Unit B expects to be near-the-money during the summer overnight periods and submits a Profiled Block Order to EUPHEMIA, as follows:

Figure 4-1 Case 1 submitted Block Order for Coal B



Coal Unit B is scheduled to be running at the end of the previous day, and so start costs do not need to be factored into its day-ahead bids. The unit's block bid price (reflecting its incremental and no load costs) is below the threshold of the volume-weighted average market clearing price, and the order is accepted.

Figure 4-2 Case 1 Block Order pricing for Coal B



The market price profile in this example implies that Coal Unit B could have sold incremental output overnight. Incremental power could be traded subsequently in the Intra-Day or

Balancing Markets. Alternatively, a Linked Block Order could be submitted to the DAM with child blocks representing incremental output above the base profile of the parent block.

EUPHEMIA does support partial acceptance of Profiled Block Orders, but this feature has not yet been implemented by all participating power exchanges.

Mid-merit

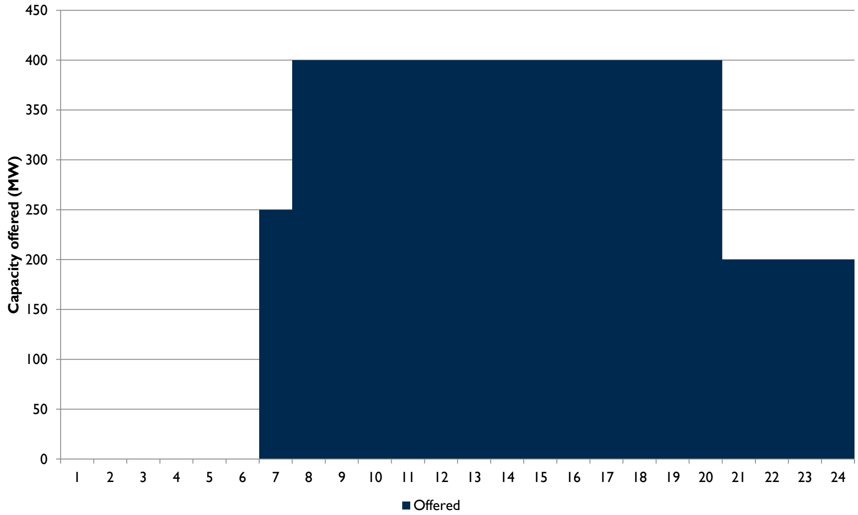
Mid-merit plant may be in or out of the money depending on system and market conditions. As a result, these plant may need to be switched off and restarted on a regular basis. We consider three EUPHEMIA order formats that mid-merit could potentially utilise to manage scheduling risks in the I-SEM DAM – Profiled Block Orders, Linked Block Orders and Exclusive Groups.

Profiled Block Order

Case 2: Profiled Block Order

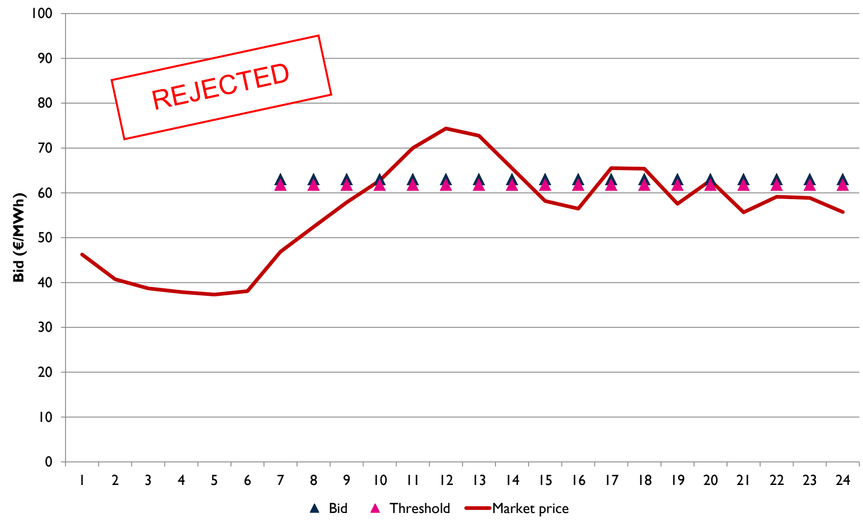
In this example, CCGT Unit A does not expect to be running at the start of the day. It submits a Profiled Block Order to EUPHEMIA, with the offer price reflecting its incremental, no load and start costs. The Profiled Block is 18 hours in duration, and allows for the plant to ramp down to MSG after the expected evening peak.

Figure 4-3 Case 2 submitted Block Order for CCGT A



On this characteristic summer day, the bid price for the Profiled Block Order is marginally above the threshold of the volume-weighted market price, and the order is rejected. Note that the incremental and no load costs of CCGT A are around 47 €/MWh at full load in this example, below the hourly market price for the duration of the Profiled Block Order. The block order is out-of-the-money in this case as a result of the internalisation of the assumed start costs.

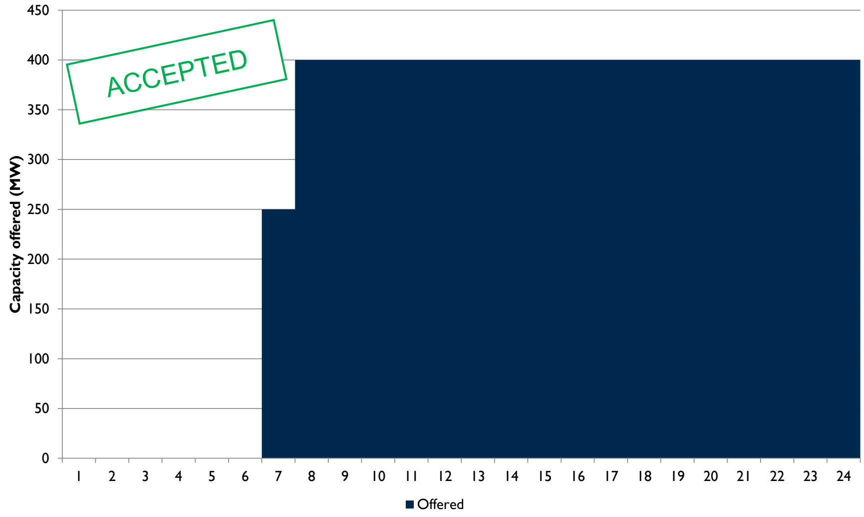
Figure 4-4 Case 2 Block Order pricing for CCGT A



Case 3: Profiled Block Order

Taking the same example as Case 2, let us consider an alternative Profiled Block Order, again 18 hours in duration but with the volume maintained at maximum capacity until the end of the day.

Figure 4-5 Case 3 submitted Block Order for CCGT A



Applying the same (exogenous) market price profile as before, the block offer price in this case is slightly below the volume-weighted average market price, and the order is accepted. The allocation of start costs is key to the comparison of Cases 2 and 3. Spreading start costs over a larger block volume reduces the profile bid price (by 1.5 €/MWh relative to Case 2), which makes the Block Order more competitive in Case 3. This is despite the fact that Case 2 is perhaps a more accurate representation of the likely running profile of mid-merit plant in the SEM.

These examples are of course schematic (and ignore the interaction between EUPHEMIA orders and price formation) but illustrate some of the challenges facing mid-merit generators, such as the potential need to second guess market requirements. These two examples are alternatives for representing the underlying commercial and technical characteristics of the plant and yet lead to different outcomes, and provide a good example of scheduling risk under the I-SEM. Linked Block Orders provide an alternative bidding option and may be better suited to handle uncertainty around off peak running patterns, as we explore below.

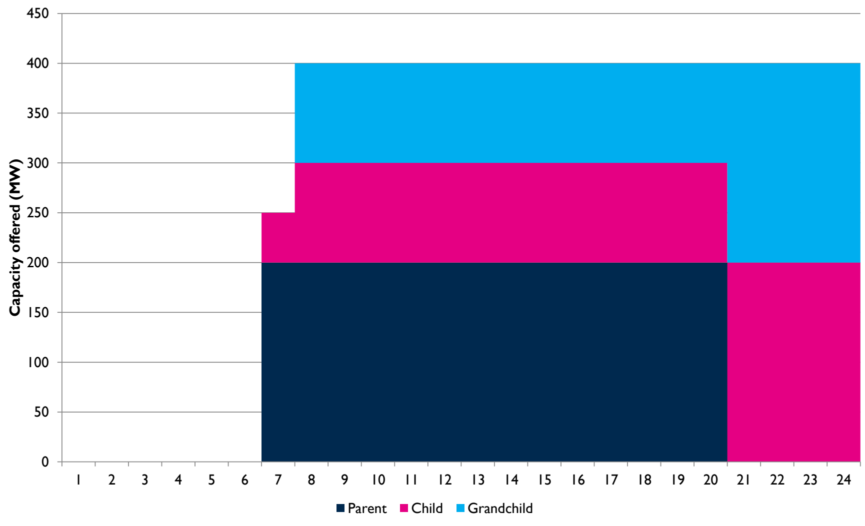
Linked Block Order
Case 4: Linked Block Order

Building on the example of Cases 2 and 3, let us consider how a Linked Block Order could be applied in this scenario instead of a Profiled Block Order. Taking the same overall availability profile as Case 3, a Linked Block Order could comprise a parent block at the MSG level of 200 MW for an extended period (14 hours here). Incremental output up to 300 MW is represented by one or more child blocks, with additional grandchild blocks reflecting incremental costs at the maximum capacity of 400 MW. A single child block at MSG covers the final 4 hours of the day, with incremental output represented by one or more grandchild blocks.

As noted above, day-ahead market operators in other jurisdictions using EUPHEMIA have placed limitations on participants' use of Linked Block Orders, which would rule out some of the formulations we have developed in these case studies. In principle, the flexibility of mid-merit generators to vary their output profile above MSG could be offered to the market as a 'strip' of hourly child blocks for incremental output above the parent block. In practice, participants in, for example, EPEX, are restricted to one child block per parent. If similar bidding restrictions are imposed in the I-SEM, generators will be limited in their ability to adequately incorporate their technical and commercial characteristics within their day-ahead orders.

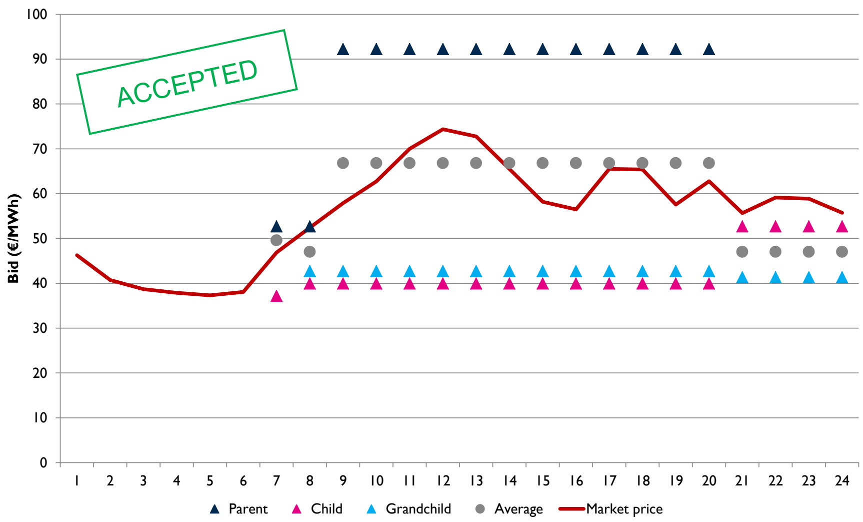
The Linked Block Order structure for this day is illustrated below.

Figure 4-6 Case 4 submitted Block Order for CCGT A



In this example, we assume that the start costs and no load costs for CCGT Unit A are fully allocated to the parent block (with no load costs for the final 4 hours allocated to the adjacent child block). Applying the same market price profile as the previous cases, the combination of parent, child and grandchild blocks is in-the-money and all blocks are accepted. The parent block, incorporating start costs, is out-of-the-money in this example, but this loss is outweighed by the positive margin on the child and grandchild blocks.

Figure 4-7 Case 4 Block Order pricing for CCGT A

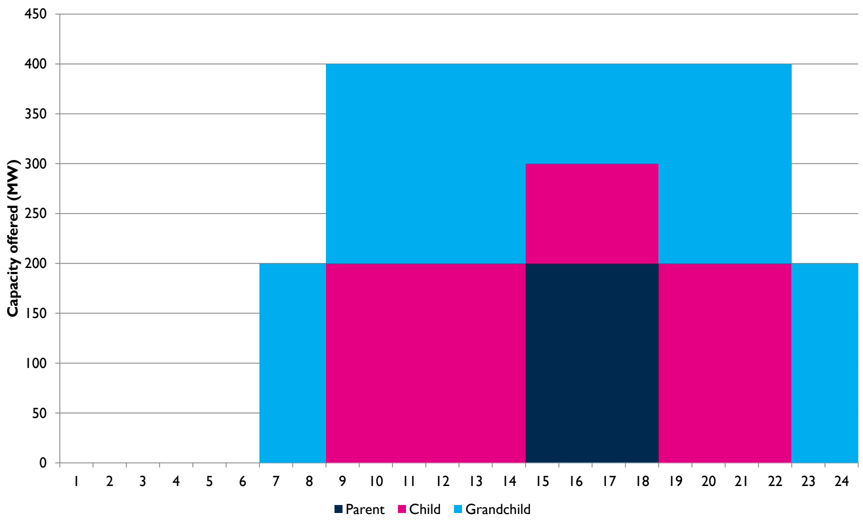


The Profiled and Linked Block Orders for CCGT A in Cases 3 and 4 are near-the-money. As a sensitivity, we found the block orders did not clear if the market clearing price was 1.2% lower across the day. This illustrates that CCGT A could be exposed to scheduling risk by having its block order paradoxically rejected by EUPHEMIA or of misjudging the timing of blocks and offer prices across the day.

Case 5: Linked Block Order

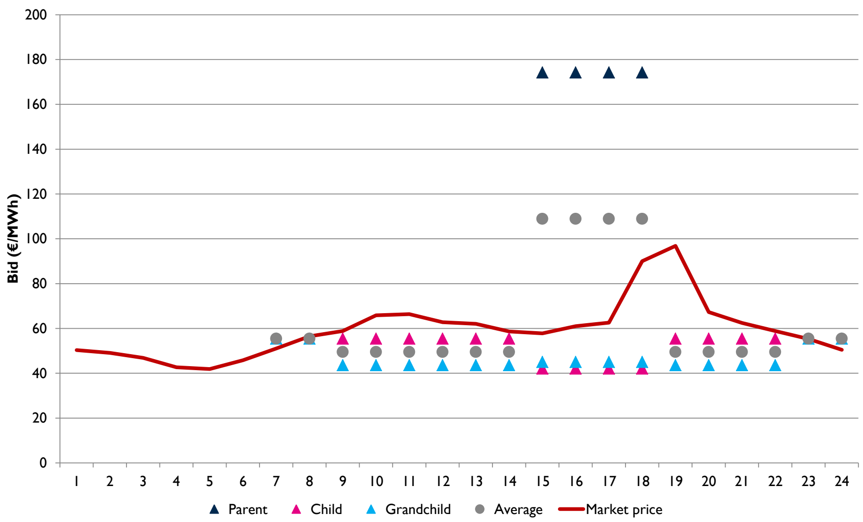
In this example, we construct a Linked Block Order for CCGT Unit A with the intention of presenting the most accurate representation of the unit's technical characteristics and cost structure. In a sense, this is analogous to the bidding methodology in the current SEM trading arrangements. The duration of the parent block matches the unit's minimum on time of 4 hours and the volume represents the unit's MSG of 200 MW. Start and no load costs are fully allocated to the parent block, such that any additional output can be offered at incremental cost. Child and grandchild blocks are then constructed for incremental output and for adjacent periods, as illustrated below.

Figure 4-8 Case 5 submitted Block Order for CCGT A



Given our cost assumptions, the parent block in this example is priced at 174 €/MWh. Applying a market price profile for a characteristic winter day, we find that the parent block is out-of-the-money. However, the combination of the parent, child and some grandchild blocks is in-the-money in this example.

Figure 4-9 Case 5 Block Order pricing for CCGT A



Note that the timing of the parent block in this case does not coincide with the period of highest outturn market prices. Ultimately this did not impact the acceptance outcome in this example (because the family of parent, child and grandchild blocks are considered in combination), but may have done so in other scenarios. In practice, the timing of peak prices in the SEM is likely to become less predictable, due to uncertainty in both the level of intermittent generation and its participation in the I-SEM DAM.

The resulting acceptance profile for CCGT A is as shown below.

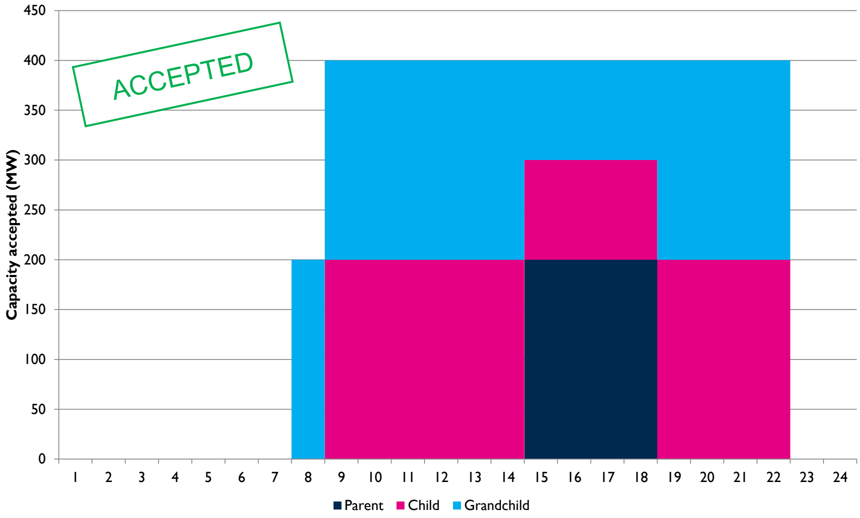
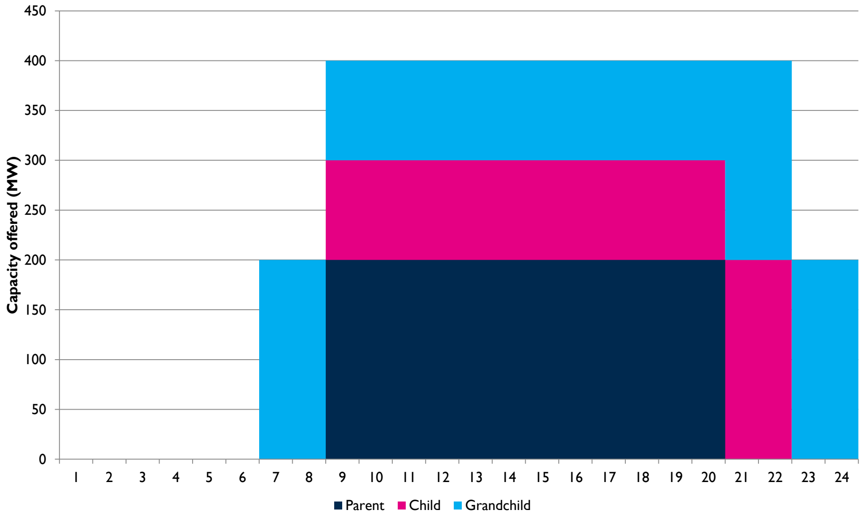


Figure 4-10 Case 5 accepted order volumes for CCGT A

<u>Case 6: Linked Block Order</u>

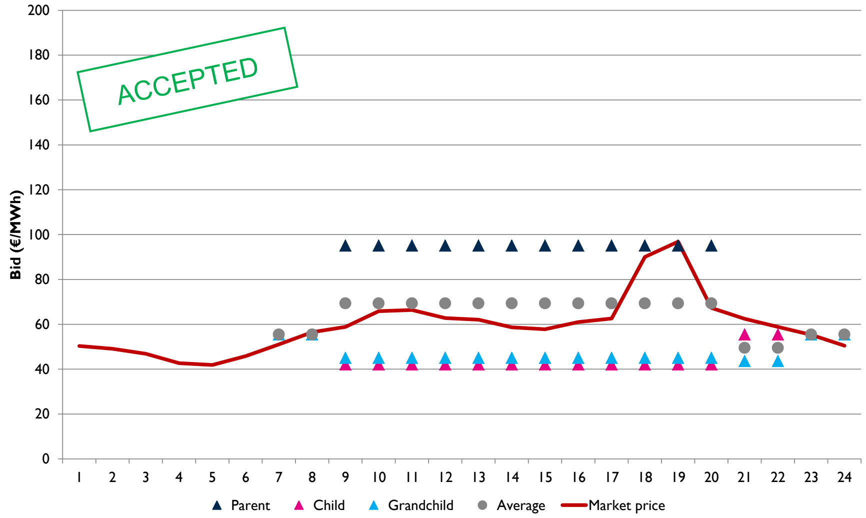
Building on Case 5, let us consider an alternative Linked Block Order using a larger parent block. Applying a 12 hour parent block allows start costs to be spread over a larger volume, potentially creating a more competitive bid price.

Figure 4-11 Case 6 submitted Block Order for CCGT A



As in Case 5, we assume that start and no load costs are fully allocated to the parent, resulting in a parent block price of 95 €/MWh in this example.

Figure 4-12 Case 6 Block Order pricing for CCGT A



Applying the same exogenous market price profile, we obtain the same result in terms of accepted orders. Although margins on individual parent, child and grandchild blocks differ between Cases 5 and 6, the combined margin across the family of blocks does not. In practice, we would expect to see different outcomes in Cases 5 and 6 due to the interaction between near-the-money orders and price formation. Moreover, the mechanics of handling of complex configuration of block orders in EUPHEMIA may mean that the prospects of a paradoxically rejected order differ between the two cases.

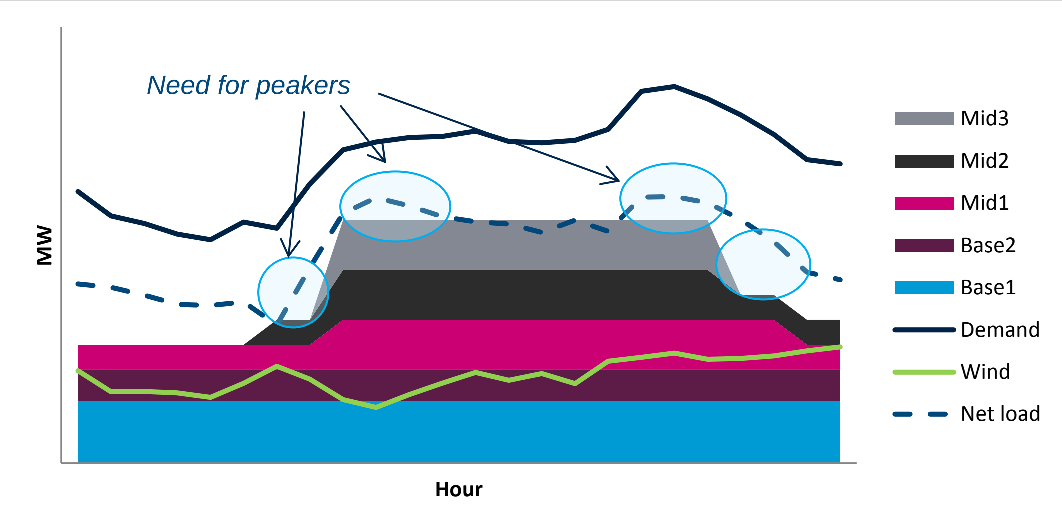
The Linked Block Orders for CCGT A in Cases 5 and 6 are near-the-money. We found that a 0.2% reduction in the market clearing price across the day would lead to the orders being rejected in these cases. Again this illustrates the sensitivity of the outcomes from the central dispatch algorithm to small differences in offer strategies and the potential for increased scheduling risk.

Implications for system flexibility and predicting net load

As we have illustrated in the case studies, baseload and mid-merit generators could potentially use Profiled or Linked Block Orders in the I-SEM day-ahead market to reflect their technical and commercial operating parameters. However, the use of block formats could reduce the flexibility offered to the market, relative to the current SEM arrangements, with generators opting to extend block durations and spread cost recovery. Flexibility may be reduced further by any limitations imposed on the order formats (e.g. a limit on the number of child blocks may prevent a strip of hourly orders being offered for output above the parent block level). Reduced flexibility from baseload and mid-merit market participants would place a greater reliance on peaking generators to ‘fill the gaps’ around the block orders.

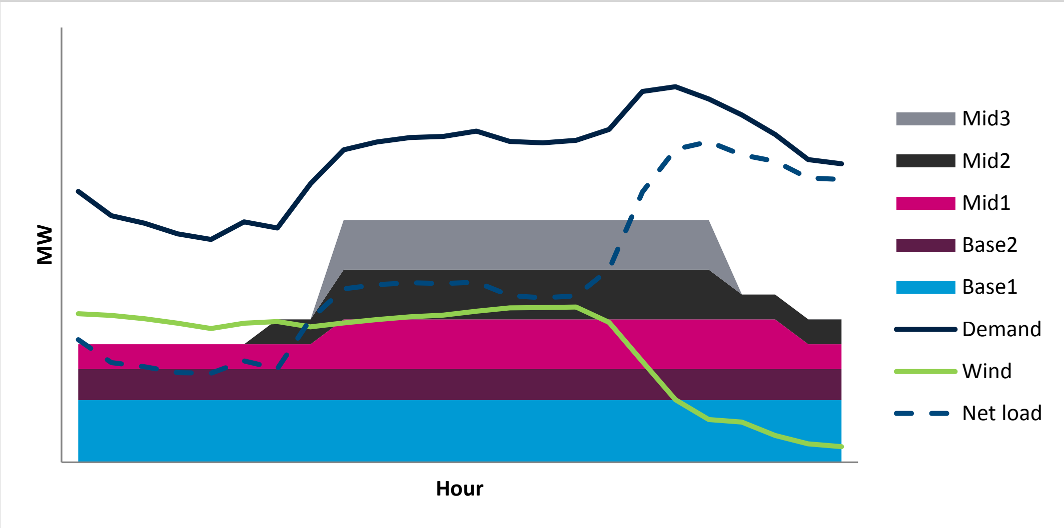
The schematic figure below illustrates how a combination of block orders from base and mid-merit generating units could stack up across the system relative to overall demand, net of wind generation. In this example, the combined profile of block orders broadly follows the system net load profile across the day, but more flexible (e.g. hourly) orders would be needed to match load in each hour. This reliance on flexible hourly orders is accentuated around the edges of the mid-merit blocks.

Figure 4-13 Block orders and system net load



Profiled and Linked Block Orders require participants to pre-determine the start and end times of each block. Participants are therefore at risk of misjudging their block timings and either failing to clear their orders or potentially under-recovering costs (if the profile of accepted orders differs from that expected for cost allocation purposes). With increasing variability in intermittent generation, the net load profile on some days may differ materially from the predicted demand shape. The figure below shows the same demand profiles and block orders with a different aggregate wind profile. Mid-merit block orders structured around day-time operation would be less likely to clear on this day than those supporting a later start and overnight operation.

Figure 4-14 Block orders and wind variability



Case 7: Linked Block Order

Our previous Linked Block Order examples have assumed:

- Start costs are fully allocated to the parent block
- No load costs are fully allocated to the first block (parent or child) in each hour.

Other bidding strategies could consider alternative allocations of start or no load costs, for example:

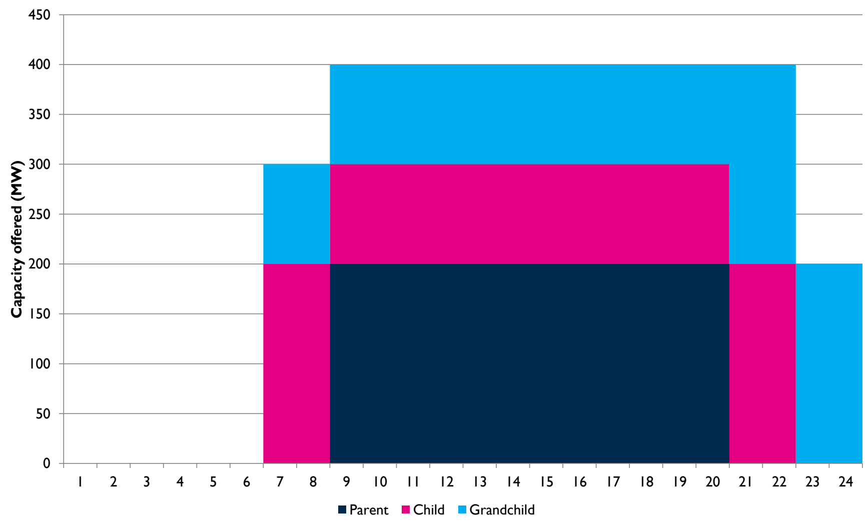
- To improve the competitiveness of the parent block price by allocating some start or no load costs to child and grandchild blocks
- To re-allocate costs between peak and off-peak periods, reducing the price of overnight blocks and potentially avoiding a shutdown

The risk of re-allocating costs away from the parent block or between hours is that some blocks may not be cleared, leading to the potential under-recovery of costs.

For Case 7, we consider a 12 hour parent block structure for CCGT A, as in Case 6. Start costs are fully allocated to the parent block, but no load costs are smeared across the parent, child and grandchild blocks. To improve the competitiveness of overnight pricing, a proportion of the no load costs for the final 2 periods are re-allocated to the grandchild blocks during peak periods (17 to 20).

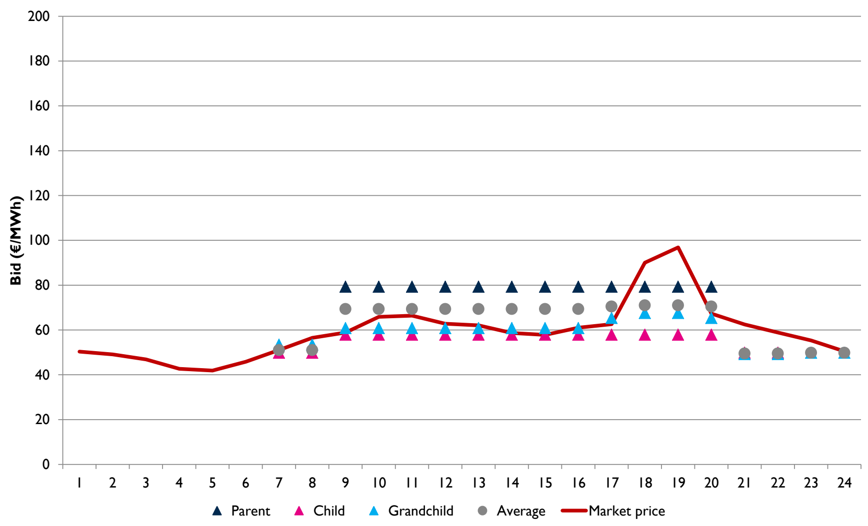
The submitted Linked Block Order structure is shown below.

Figure 4-15 Case 7 submitted Block Order for CCGT A



Having re-allocated a proportion of no load costs, the parent block price is reduced to 79 €/MWh in this example. Applying the same winter price profile, the parent block remains out-of-the-money but a combination of parent, child and grandchild blocks is cleared.

Figure 4-16 Case 7 Block Order pricing for CCGT A

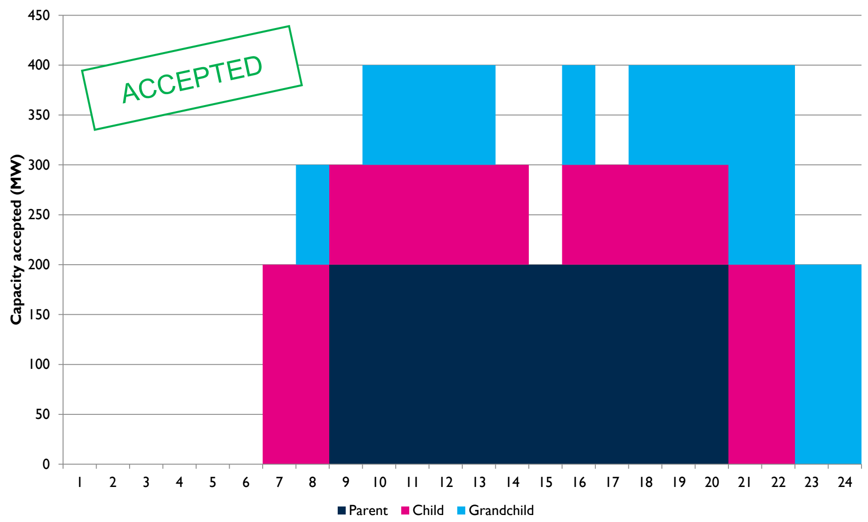


The resulting accepted offer profile is shown below. Compared to Case 6, we find that the addition of no load costs results in child or grandchild blocks not clearing in certain daytime periods (14,15,17). However, additional blocks are cleared during off-peak periods (7,8,23,24), potentially enabling the plant to avoid an overnight shutdown.

In this example, the operating costs for CCGT A are under-recovered by around €7,300 (due to the allocation of no load costs to blocks that were not cleared).

As a sensitivity, we found that a 0.6% reduction in the market clearing price across the day would lead to the family of Linked Block Orders being rejected. Orders would therefore be cleared at lower prices in Case 7 than Cases 5 and 6 for the same characteristic day, but this would result in cost under-recovery.

Figure 4-17 Case 7 accepted order volumes for CCGT A



Case 7 illustrates how different operating outcomes and gross margins could be achieved by varying the allocation of start and no load costs between blocks. Participants may wish to explore a large range of pricing strategies to strike an appropriate balance between achieving a desired operating profile and ensuring cost recovery. However, it is likely that bidding strategies will need to evolve dynamically in response to changing market fundamentals and the actions of competitors.

Managing the scheduling risk associated with this dynamic spot market position will introduce additional complexity for independent generators compared to the current SEM arrangements, and may lead to participants seeking a higher risk premium on forward contracts.

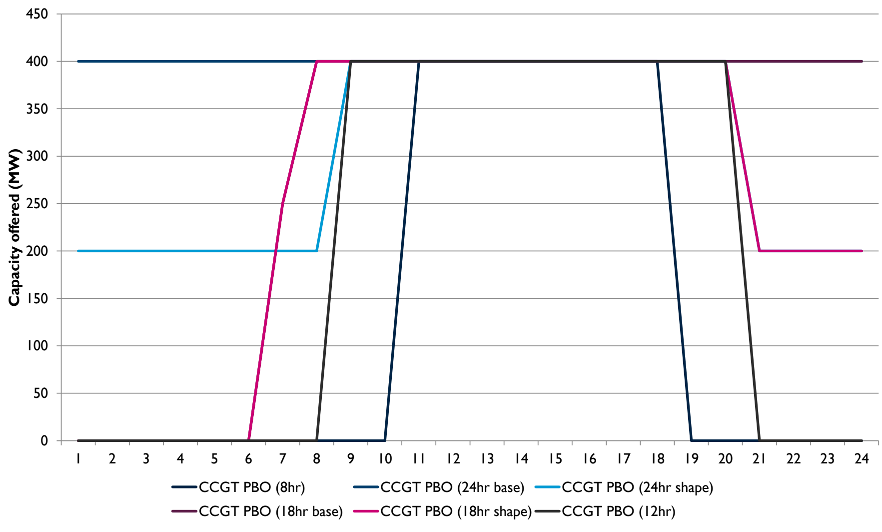
Case 8: Exclusive Groups

As the previous examples have illustrated, Profiled and Linked Block Orders require participants to make judgements regarding block start and end times, and to some extent, the relative competitiveness of their asset across the day. These judgements will be based in part on expectations of market fundamentals and the likely profile of clearing prices. With the increasing growth in intermittent renewables, we can envisage that historical relationships between electricity demand and market prices will no longer hold and the timing of daily peak prices will become less predictable.

Given these uncertainties, there is a risk that participants misjudge the timing of their Block Orders and they fail to clear. Exclusive Groups may help mid-merit generators mitigate this risk by allowing generators to submit a range of alternative operating profiles, leaving the choice of the optimal schedule to be resolved by the EUPHEMIA algorithm. Conversely, Exclusive Groups cannot be combined with parent and child combinations, thus limiting the ability to represent other commercial and technical parameters.

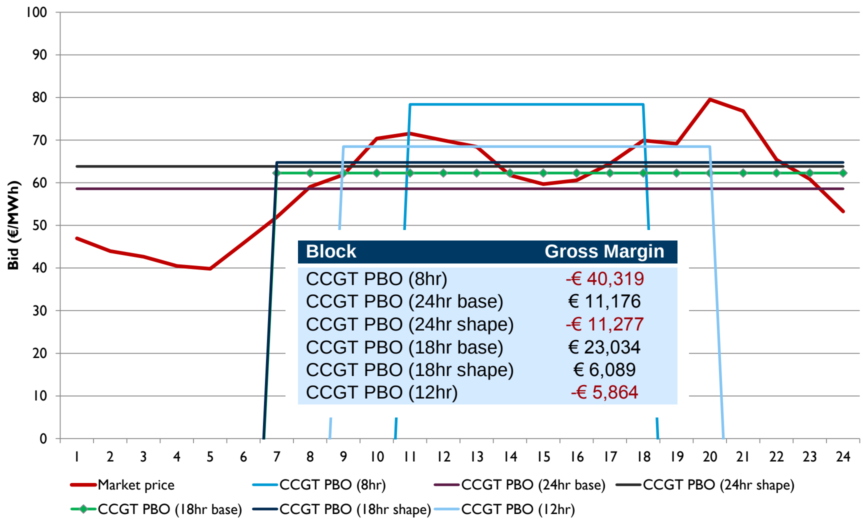
For Case 8, we assume that CCGT A submits an Exclusive Group of six Profiled Block Orders, ranging in duration from 8 to 24 hours. These orders are mutually exclusive, and each is priced to fully recover incremental, no load and start costs over the operating profile.

Figure 4-18 Case 8 submitted Block Order Groups for CCGT A



Applying a characteristic autumn price profile, three of the six Block Orders are out-of-the-money. If multiple blocks are in-the-money as in this case, EUPHEMIA will select the Block Order which maximises social welfare. Here we assume the accepted Block Order has the highest implied gross margin. This is a 18 hour base profile, as shown in Case 3.

Figure 4-19 Case 8 Block Order pricing for CCGT A



Peaking

Peaking plant are generally more flexible than mid-merit plant. This flexibility can be offered to the DAM using Simple Hourly Orders, assuming plant technical constraints are not binding (e.g. minimum on time of 1 hour or less).

Less flexible plant may consider applying Simple Block Orders, Profiled Block Orders or Linked Block Orders to ensure their technical constraints are adequately represented.

As with mid-merit generators, one of the challenges for peaking participants using Block Orders will be judging the most appropriate block timings for the market. Exclusive Groups may provide one solution to this problem. Flexible Block Orders also rely upon EUPHEMIA to optimise the timing of accepted orders from a market perspective, removing the need for participants to pre-determine their operating schedule. Flexible Block Orders may be particularly suitable for energy-limited resources, as well as demand response.

5. IMPLICATIONS

5.1. Introduction

In this section we lay out the implications of the I-SEM arrangements for scheduling risk, and the broader market impact. This draws on the illustrative examples explored in Section 4, but also takes into account a broader set of considerations, given the limitations of the simplified approach we have used for these.

5.2. Single Asset

Reflecting flexibility and costs is not straightforward

From the perspective of a single mid-merit asset, as the examples above demonstrate the I-SEM arrangements mean that it is not straightforward to reflect the technical characteristics and costs of the asset effectively through the available EUPHEMIA offer structures. This could be further exacerbated if there are limitations on how participants can apply the offer structures (such as limiting the number of children in a Linked Block Order). This means that a generator who has hedged forward will face scheduling risk in attempting to re-optimise a position at the day-ahead stage – as this could result in the asset not being scheduled in periods where prices clear above the cost of running the plant, creating a negative outcome relative to the hedged forward margin.

Risk is greatly exacerbated without a liquid IDM

This risk would be significantly mitigated if the DA market was accompanied by a liquid intraday market, actively trading from the publication of the DA auction results through to gate closure. This would enable generators to trade out positions from the DA swiftly at limited cost. In the long run the intent is for this to be provided by the harmonised European intraday trading platform, but the timeframe for that is unclear, and it is almost certain that this will not be in place for a material period of time following the introduction of I-SEM.

Exclusive DAM also limits position management

In no other European market is the DAM the exclusive route for physical trading. This means that market participants can manage their position through a combination of auction participation, standard bilateral trading, and structured products, enabling a much greater level of control, particularly important for mid-merit plant, even prior to the intra-day market, enabling further re-shaping and refinement. None of these will be options for I-SEM participants. Only under I-SEM would generators be reliant on the specifics of EUPHEMIA offer structures to reflect cost and flexibility.

There is a possible incentive to zero-bid, reducing market efficiency

A possible consequence of this is that mid-merit plant may choose to avoid this risk by 'zero-bidding' at the DA stage to match forward contracted positions, unless a less prescriptive version of the Bidding Code of Practice was retained in some format. This enables the plant to reduce scheduling risk and therefore risk to hedged margin. However, at times where the cost of generation for the plant was higher than the resulting clearing price, this would be neither an efficient market solution nor an optimal economic outcome for the plant.

There may be an incentive to reduce the level of asset flexibility offered

There are further consequences for a single asset that make the bidding strategy more difficult. There are clearly a reduced set of options for offering generation flexibly to the market compared to the current SEM. The need to recover start costs could lead to a tendency to offer longer duration 'blocks' than could be technically offered (such that the increment associated with the start cost is spread more widely). In addition, it is likely that there will be limits on the number of child blocks that could be offered, which could mean that a potential "hourly strip" of child blocks on a single parent block would need to be aggregated up.

Risk of cost under-recovery depending on cost allocation in bidding strategy

Further, the offer strategy for a single asset using Linked Block Orders will face choices about how to spread start-up and no load costs across the parent and child block prices. Loading the full possible start-up cost and no-load cost into the parent block increases the risk that the parent will be out-of-the-money, although these losses may be offset by positive margins on child blocks in determining the final clearing outcome. On the other hand, spreading no-load or start costs across child blocks increases the competitiveness of the parent block, but at the risk of cost under-recovery if child blocks are not cleared with the parent. The examples in Section 4 (albeit simplified through imposing an exogenous change to market price) demonstrated how sensitive offer acceptance could be. Taken together with the potential for paradoxically rejected bids this highlights the potential for significant scheduling risk associated with judgements around offer parameter choices.

Risk associated with start-of-day state uncertainty will be reflected in balancing bids and offers

A key uncertainty at the point of submission for DA offers is the running state of the asset at the start of the offer period. Whilst there will be a current traded position, there will still be uncertainty as to any balancing actions that may be executed in the interim. Offers will need to be made based on an assumed schedule. If a balancing bid or offer is then accepted, then additional costs may be incurred (for example, start costs if a balancing bid is accepted for the plant to turn off) and it is likely that the plant would seek to recover these through an appropriate premium (discount) on its balancing offer (bid).

Generators cannot combine complex options and hence cannot mitigate all risks

Given that participants will have to choose between the use of offering a set of alternative profiles, versus using a parent-child structure, this implies that they will need to weigh up the uncertainties associated with the within-day shape of prices against the uncertainties associated with accepted volume and duration (and corresponding risk of under-recovery). For example, on a day with significant uncertainty as to wind generation, and hence to the profile of net demand, the participant might choose to utilise a set of profiles to have alternative blocks covering different potential peak periods, rather than offering a parent that might turn out to have been set at a period of low net-demand. This suggests that additional information will be important, particularly in regard to wind and demand forecasts.

Risk increased due to uncertainty in competitor strategies

In developing an offer strategy, a generator will need to take into consideration the potential strategies that could be followed by competing generators. The issues outlined above are likely to drive diversity in strategies, and these are likely to evolve in a dynamic way in response to analysis of market outcomes (assuming that such strategies are relatively unconstrained by bidding principles). It is likely that market participants with sufficient resources will aim to model the EUPHEMIA algorithm to enable them to test and develop the sophistication of their strategies. So the scheduling risk inherent in the limitations in EUPHEMIA offer structures will be magnified by the uncertainty and potential instability in strategies applied by different competitors. This is compounded at times when GB and SEM price levels are similar as generators will then need to consider both SEM participant strategies and the potential level and shape of GB offers. Whilst it is difficult without conducting detailed modelling to compare the scheduling risk under current SEM arrangements (associated with the Uplift methodology) and under the proposed I-SEM arrangements, it could be that this "competitive strategy dynamic" leads to a higher degree of scheduling risk. It is possible that over time there could be some stabilisation as strategies mature, but a risk of a return to a more volatile environment will always be present.

5.3. Different technologies

Risks are most material for mid-merit thermal assets

For plant that are typically running baseload, or for wind (or other intermittent plant) with very low short-run costs, this risk is not relevant. For very flexible plant designed specifically as peakers (such as OCGTs), then the risk is low as these plant can have a more straightforward strategy of offering fully loaded hourly prices (whereby they would recover start costs even if they were scheduled for a single hour). The type of plant for which the risk is most material will be thermal plant that are at mid-merit positions in the stack – which could, depending on relative commodity and carbon price levels, be either gas or coal plant. This is likely to be a substantial subset of I-SEM installed thermal capacity given the high levels of wind generation in the I-SEM.

Very flexible peaking plant may be beneficiaries

Given the implications above for such plant, and in particular that there could be a tendency to create offer structures which are less flexible than under the SEM, that would suggest, as illustrated above, that peaking plant could be direct beneficiaries, as there could be more reliance on these assets to provide the hourly profile given the possibility of more 'blocky' offers from mid-merit plant. The impact of scheduling of peaking units (potentially at unintuitive times) could lead to price volatility increasing the market risk for other participants.

5.4. Asset portfolio

Portfolio provides a diversity benefit

As I-SEM requires unit level bidding, then similar considerations to those described above will be relevant for mid-merit assets within a broader portfolio. However, having a portfolio position is nevertheless likely to bring benefits. A portfolio player knows what the rest of its portfolio is doing with regards to commercial offers. In the context of the proposed High Level Design this provides an information advantage over a stand-alone generator who needs to guess this information to determine its most effective strategy. The advantage increases with the size of portfolio. In the current SEM this information asymmetry is managed through the Bidding Code of Practice which guarantees generators can compete on equal terms. However, without bidding principles it is very difficult to estimate the offer prices of competitors. Furthermore, it is not clear how unit-based bidding would in practice be interpreted where offers can be 'co-ordinated' across a portfolio. For example, with a hypothetical portfolio of three mid-merit plant, a strategy might involve zero-bidding for some volume of generation whilst offering capacity from other similar assets through parent/child offers placed at different times of the day.

We note that the High Level Design proposal for a single price cash-out means that longs and shorts in a generation portfolio will effectively net out. While unit bidding is proposed for the DAM and IDM, cash-out will be at a portfolio level. This would potentially advantage portfolio players and reduce within day liquidity, although other aspects of the detailed design may constrain participant behaviour from benefitting from this apparent anomaly.

Complex algorithm likely to encourage complex portfolio strategies

More generally, those players with a portfolio of assets are likely to be able to develop more sophisticated strategies over time, given the complex nature of the DAM in terms of offer structures and price setting. This may be especially true in a small market such as the I-SEM, where single plants represent a material share of the stack. It is likely that these players will aim to replicate the EUPHEMIA algorithm to develop and test these strategies, and assess the potential portfolio benefits in terms of an increased level of infra-marginal rent. It may prove very difficult from a regulatory perspective to distinguish between valid commercial strategies and strategies that are potentially anti-competitive or abuse a position of market power at certain times.

Given the potential for additional value to accrue to very flexible plant, then a portfolio with a significant proportion of such capacity could benefit.

5.5. Market clearing, balancing and dispatch

Potential for artificial price spikes and troughs, and increased volatility

We have discussed above the implications for a single asset or a group of assets. There is a further consideration as to how the combined strategies across the market may interact within the algorithm and how this could affect clearing prices in the auction. This is obviously contingent on the interaction between multiple strategies across different market participants, and is also likely to be dynamic, as strategies are evolved based on experience and observation of competitors. However, there is a concern that the consequence of strategies designed to mitigate scheduling risk, when translated across the market, could lead to inefficient outcomes. For example, if a material number of mid-merit plant were to zero-bid, this could exacerbate an issue that will face the market anyway as wind deployment increases, potentially leading to spuriously low prices at times, possibly combined with spikes as more peaking plant are required to create required shape. Such inefficient volatility is likely to deter forward trading and new investment, to the extent that prices are in part an outcome of the specifics of EUPHEMIA and associated strategies, rather than fundamental costs. In a similar manner, interconnector flows could be distorted in an inefficient manner.

Mismatch between DAM schedule and feasible physical schedule could be exacerbated

Given the nature of the EUPHEMIA algorithm, which was not designed to determine optimal physical dispatch, it is clear in any event that there is no guarantee that the result of the DA auction will be technically feasible, particularly for mid-merit plant. It is not yet clear in the I-SEM design how this will be managed (at least prior to any intra-day market) in terms of the steps to a feasible dispatch schedule that EirGrid can operate against. The types of issues discussed above could exacerbate this issue further.

5.6. Forward trading

Potential impacts on forward liquidity

Relative to the current SEM, the complete removal of bidding principles would mean in theory that an individual generator could ensure dispatch in the DAM to match a forward traded position by offering at a very low price below cost (assuming others were not doing the same). However, in doing so, it is likely to be reducing its expected earnings (since it will not be re-optimising at the day-ahead point, and since that strategy may restrict its ability to offer close to cost at other times), which could either deter forward hedging or result in an inefficient premium on forward prices. This could ultimately increase costs to consumers.

Further, to the extent that a material volume of mid-merit capacity did hedge forward, and then employed adapted DAM strategies to reduce scheduling risk, this could distort price formation in the DAM, in turn presenting a concern for the further development of liquidity.

Forward liquidity may also be impacted by uncertainty around price setting in the DAM, given the volatile nature of prices that could emerge as a result of the dynamic evolution of participant bidding strategies and the clearing algorithm's handling of complex orders in a small market.

6. CONCLUSIONS

In this paper, we have highlighted a number of potential risks associated with using the EUPHEMIA algorithm as the primary mechanism for scheduling plant, a concept without precedent in other European markets.

We believe that scheduling risk, present in the current SEM, is likely to endure and may increase under the proposed design, at least initially, impacting on forward market liquidity and prices. We have illustrated a number of examples that illustrate the potential risks. Uncertainty surrounding estimating the level of net demand and how to internalise start-up and no-load costs in offer structures represent the greatest challenge. The uncertainty is further compounded by the proposed relaxation of the Bidding Code of Practice which will make it more difficult to anticipate the offer strategies of competitors. In this respect, portfolio players will have a key advantage.

Given that the primary requirement for a liquid forward market is full confidence that the day-ahead index is reflective of supply/demand fundamentals, transparently derived, and free from potential distortion associated with particular participant strategies, we believe that the set of issues outlined in this document warrants careful consideration if this key objective of the new arrangements is to be met.