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Subject: Integrated Single Electricity Market (I-SEM), High Level Design for Ireland and Northern Ireland from 2016 – Draft Decision Paper SEM-14-045 (the "Draft Decision")

Dear Jean-Pierre and Philip,

Bord Gáis Energy (**BGE**) welcomes this opportunity to comment on the proposals in the Draft Decision.

In general, BGE supports certain of the decisions proposed by the Regulatory Authorities (RAs) in the Draft Decision. In particular, BGE supports the proposals: to enhance liquidity in the forwards timeframe; to require that the Day Ahead Market (DAM) and Intraday Market (IDM) be "exclusive"; to prohibit decentralised physical bilateral trading in any timeframe; to make the balancing market (BM) mandatory; and to retain a Capacity Remuneration Mechanism (CRM). Such measures could facilitate hedging opportunities and the pooling of trading volumes, enable robust reference prices to develop and allow a more level playing field to develop between the incumbent and smaller market players. In our view the Draft Decision therefore retains some key elements of the Single Electricity Market (SEM), which have worked well to develop cost reflective pricing and encourage competition in the market.

BGE does however have certain concerns regarding the High Level Design (HLD) proposals. We are concerned that the draft HLD does not provide comfort with regard to the issue of reduced liquidity that could result in I-SEM across all timeframes. Such low liquidity could arise due to the market power position of ESB and scheduling risk in I-SEM in particular, both of which will likely increase as compared to the SEM. BGE thus urges the RAs to include explicit principles and measures to address liquidity through market power mitigation, transparency and monitoring measures that address the issue in all four trading timeframes. BGE is also concerned that the HLD will not appropriately provide for the effective participation of wind in the market (thereby enabling robust price formation); that a single marginal balancing price will exponentially increase the risk for suppliers in the market; that the BM will not effectively incentivise flexibility; and, that a proper assessment of the proposed Reliability Option (RO) cannot be conducted given the limited detail thereon.

While we appreciate that it is proposed that many of the issues will be addressed as part of the detailed design and understand the difficulty in carrying out reliable quantitative analysis at the HLD stage, we believe that the principles, objectives and a roadmap through which the detailed design will emerge need to be more clearly set out as part of the HLD decision. We therefore urge the RAs to provide more detail to their principles and objectives (specifically in the areas of liquidity, market power and transparency, the operation of the balancing market and imbalance settlement, and the relationships between market and dispatch schedules and the treatment of priority dispatch). This needs to be supported by a quantitative analysis of the proposed HLD, which would not necessarily be binding on the RAs but would demonstrate more clearly to stakeholders the considerations and rationale behind the RAs decision. Subsequently, participants need to be fully engaged in the development of the detailed market design in order to ensure that the arrangements work efficiently and are robust at a detailed level within the HLD framework.

1. Liquidity in the I-SEM

BGE's key concerns regarding liquidity in I-SEM are that on the basis of the current Draft Decision, it is apparent that a dilution of liquidity across all four timeframes will exist in I-SEM due primarily to the fact that a) the current dominant position of ESB Group will endure and could possibly strengthen in I-SEM, and b) there will be increased market scheduling risk in I-SEM due to the level of assumptions that market participants will have to make in submitting bids to Euphemia. The current SEM mitigates such risks through for example the application of Directed Contracts (DCs), the mandatory nature of the pool, the Bidding Code of Practice (BCoP) and the monitoring role of the MMU. There are however potential solutions to this issue that emulate the positive effects of DCs, BCoP and the MMU's role in particular. These are discussed further below.

1.1 The Continuing and Growing Market Power Concern

ESB Group's dominant position will persist and is likely to grow under I-SEM if it continues to own so much of the SEM generation fleet. Notwithstanding ESB's suggestions[1] that divestment of its peat plants will erode its market share and that compared to other EU energy markets its position is "median", the fact is that ESB has a high market share, presently above usual metrics of dominance, and would succumb to many market power tests including the "pivotal supplier" and HHI tests. ESB's further argument that it is not marginal at peak times is misleading. Firstly, being marginal is not always predictable and a generator does not need to be marginal to influence supply and/or prices.[2] Secondly, and of more strategic importance, ESB has a portfolio of units (baseload, mid-merit and peakers) unlike any other market participant, and therefore knows that certain of its units will be required across all market timeframes. Changes to the market to introduce four market timeframes and at least three settlement prices for each trading period provides ESB Group with more markets in which to exercise market power as it will be able to strategically manage availability and influence prices across all timeframes. Given the balancing responsibility that will be placed on all market participants, and therefore the importance of liquidity across all timeframes, this will give rise to greater risks for other participants in the market (both generators and suppliers) and therefore greater opportunity for ESB to exploit its dominance. Consequently, in the absence of divestment the continuation of explicit liquidity, transparency and market power mitigation measures will remain central to the success of any future electricity trading arrangements.

1.2 Scheduling Risk in I-SEM

BGE acknowledges that an element of scheduling risk exists in the current SEM DAM but strongly believes that it is mitigated by the application of BCoP which gives market participants parameters on which to assess potential market outcomes and prices, which is central to enabling an understanding and management of commercial risk. As mentioned above, scheduling predictability in the spot markets is important for retaining confidence in being able to underwrite CfDs. Without such confidence, forward CfD volumes may not exist. Our concern relates to the heightened risk under I-SEM due to the level of assumptions that market participants will have to make in order to effectively bid into Euphemia which will completely undermine predictability in scheduling and prices. This in turn undermines confidence in hedging ability and thus also affects forwards liquidity.

To support this concern, BGE has procured a multi-client report from Baringa[3] which demonstrates that:

- The scheduling risk in SEM is mitigated in particular by the existence of the BCoP;

[1] In its response to the February 2014 consultation on the I-SEM High Level Design
[2] A generator does not have to be marginal to influence prices. A generator who can exercise market power by withholding capacity is also able to influence prices. With its portfolio of units, ESB can be considered a pivotal supplier of power in the SEM, therefore it holds the potential to exercise market power and affect prices.
[3] Please see Baringa report appended to this response

- Given the breadth of assumptions that need to be made by market participants in bidding into Euphemia, volatile, unpredictable, inequitable and unintuitive scheduling results can outturn;
- Scheduling risk is not as much of a concern for those with a portfolio among which bidding strategies can be more easily and quickly optimised as market experience is gained;
- Without transparency in the bidding parameters within which market participants can bid, the ability to manage risk as well as the predictability and stability of pricing for end consumers will be severely undermined.

Thus, the heightened scheduling risk that will exist in I-SEM compared to SEM will further reduce forwards liquidity and may act as an exit signal in the market.

1.3 Liquidity – Potential Solutions

While the market power and scheduling risk issues have been problematic in SEM, the discussion above highlights the ability for these issues to worsen in the I-SEM. There are however solutions that could address these issues, all of which require regulatory intervention to oversee the market and give confidence that ESB cannot abuse its position of dominance and that liquidity will prevail across all market timeframes.

The application of DCs in the forwards market and the mandatory nature of the SEM pool in particular are central to current SEM liquidity.[4] BGE opines that the effect of such measures should be maintained and improved where possible in I-SEM.

Forward CfDs enable market participants to hedge commercial risks and they thus influence market entry and exit decisions. ESB is the primary provider of forwards CfDs in the current SEM as it is the only market player with such a large portfolio of baseload, mid-merit and peaker plants, comprised of different fuels and technologies, which helps ensure that it accounts for 55% of the SEM DA market schedule. While there has been some improvement in CfD volumes from the ESB and other parties in recent years, historic figures demonstrate however those CfD volumes are still extremely low and no where near the level required that would enable effective on-island hedging. This liquidity may reduce further in the I-SEM as the ability to predict dispatch and prices will become more difficult for parties – particularly non-portfolio players - than it is now. If liquidity in the forwards timeframe is to develop then measures in addition to those of similar effect to current DCs such as for example a market-making role for the incumbent, would assist.

The liquidity of the forwards timeframe will also be heavily impacted by the liquidity of the DAM and Intraday Market (IDM)[5]. The "exclusivity" of the DAM and IDM will assist its liquidity but the DAM liquidity could be further undermined by the ability of ESB to arbitrage between the DAM and Balancing Market (BM) in particular. This runs contrary to the RAs' assumption that market participants would not wait until the BM to trade positions and as such liquidity will emerge predominantly in the DAM. Despite the BM being mandatory, this is presumably only for volumes that have not been committed in DA (or ID),[6] and there is a compelling case that ESB could, for example, withhold some of its generation from the DAM when it anticipates that the market will be heavily reliant on BM trades for under/ over forecasts or unforeseen outages. This would result in an illiquid DAM and in a limited number of market participants in control of BM prices.

One alternative to the DAM/BM balance is to mandate volumes in the DAM. Alternatively, and as a minimum BGE believes that ensuring bidding transparency and monitoring in the market could reduce the risk of this issue arising and could also better enable management of market scheduling risk in the DAM and IDM.

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[4] However as discussed further below, there is still an insufficient level of liquidity in forwards hedging volumes in SEM

[5] BGE makes the following comments on the basis that the system operators will respect DAM and IDM commercial positions, and that these positions are "firm" from a price and volume perspective – we would however welcome confirmation of this assumption in the HLD decision?

[6] BGE would however welcome confirmation that this is the case

As discussed above in section 1.2, the heightened risk of scheduling in I-SEM compared to SEM, which will further undermine forwards liquidity, is heavily driven by the lack of bidding principles or parameters within which market participants might be expected to bid. While the BCoP in its present form may not prevail in a dynamic market environment, the transparency benefits effected by the BCoP should not be lost in the I-SEM. Transparency of bid compilations across the market timeframes and confidence that the market prices are reflective of supply/demand fundamentals and free from distortions is: key to the stability and predictability in pricing; important for assessing hedging needs and supply entry opportunities and; facilitates the development of competition and liquidity in all timeframes .

BGE believes that the role of the MMU will become more critical to the operation of the market, and the RAs need to give specific consideration as to how an enhanced MMU role will operate. This role must go beyond the "soft" ex ante checks proposed in the Draft Decision and include measures to actively identify and govern market power as well as implementing timely interventions to avoid adverse customer impacts. Recognising that the ex-ante regulation of dynamic markets will be more difficult than it is currently, precedence from the U.S. markets may be helpful in providing guidance on how one might deal with retaining transparency, predictability and confidence in bidding outcomes in the transition to a dynamic market construct. A number of US markets operate Automatic Market Power (AMP) regimes under which, where market power is identified, the bids of the relevant party (or parties) are capped at benchmarked competitive levels before being inputted into the market schedule. The approaches vary between market, from "structural" tests in PJM and "conduct and Impact tests" in ISO-NE. Such approaches (particularly the "conduct and impact" test) could deal with both market-wide and local market power instances as they apply ex-ante measures solely to those able to exercise market power at times when market outcomes are outside the modelled competitive price level – and would consequently (a) address the specific drivers of adverse market outcomes, (b) protect customers form the consequences of market power abuse, and (c) provide an assurance that the market price provides a fair basis for financial hedging – thus driving efficient pricing outcomes.

1.4 Liquidity – Conclusion

In summary, ESB's dominant position will endure in the I-SEM and may even potentially grow considering ESB's diverse portfolio, current dominance of the market schedule and ability to arbitrage across a higher number of trading timeframes in I-SEM. Market scheduling risk hinders forward market liquidity in SEM but this scheduling risk will increase due to the diverse assumptions required to be made in submitting bids into Euphemia which will result in volatile unpredictable scheduling and pricing outcomes.

The current DCs and mandatory pool aid liquidity in the forwards and DAM timeframes respectively and BCoP and MMU monitoring aids transparency and confidence in bidding facilitating hedging, predictability, stability in prices and ultimately market schedules. Measures that emulate these outcomes in I-SEM must be adopted. Absent the divestment of ESB and the potential benefits that may bring from a market power and liquidity perspective, DCs or measures of similar effect, and further liquidity enhancing measures such as a market maker obligation for ESB in forwards trading may assist. BGE supports the "exclusive" nature of the DAM and IDM and in terms of balancing DAM and BM liquidity, which timeframes ESB is best able to arbitrage, a volume obligation may be imposed in one or both markets.

However the overarching measures that will mitigate DAM and IDM scheduling risk thereby contributing to forwards liquidity, and that should ensure competitive outcomes in DAM and BM participation, are transparency and monitoring. The adoption of transparent bidding parameters to assist price and schedule predictability and hence hedging ability, as well as an enhanced role for the MMU in monitoring bid submissions of those with the potential to exercise market power (e.g. similar to US "conduct and impact" tests) are considered by BGE as useful tools that should be considered by the RAs for application in I-SEM.

The remit of the forwards liquidity taskforce should therefore address the power held by the ESB to ensure it provides liquidity fairly and transparently across all four timeframes and examine enhancement of the role of the MMU and bidding transparency in I-SEM.[7]

2. Wind policy and participation in the DAM

BGE's key concern with regard to wind's interaction in I-SEM is the need for wind to be involved in DAM price formation. Otherwise DAM prices (and ultimately BM prices) will be severely undermined.

One of the main risks to wind in the new market is its exposure to balancing prices. It is thus foreseeable that, given difficulties in accurate forecasting, wind receiving supports would wait until as close to real-time as possible to participate in the market. In light of at least 5,000MW of wind due to be on the system to meet 2020 targets, and the continued application of the priority dispatch rule as proposed in the Draft Decision, this would completely undermine BM prices. This would also increase DAM prices and undermine the market schedule whereby constraints, curtailment and countertrading will rise to deal with excessive volumes of wind in the BM, likely impacting end consumer prices negatively.

The RAs appear to recognise the risks of inefficient DAM, IDM and BM prices that would outturn if wind withheld until the BM. However, it appears to be proposed (in paragraph 6.4.26), that these outcomes will be dealt with by requiring participants to notify their expected production schedules after the DAM which will encourage DAM participation as certainty in output will be desired, and design rules will incentivise meeting these production schedules. We do not agree with this as firstly, certainty of output is not an issue for wind and therefore the DAM price will not necessarily reflect the availability of wind accordingly. Secondly, given its priority dispatch status and the nature of the REFIT support mechanism (in ROI at least), wind will be protected from volatile balancing prices and therefore the balancing risk of participating in the DAM far outweighs the revenue risk for wind generators.

Notwithstanding the above, BGE supports the RAs' proposal that participation in the DAM and IDM should not be mandatory, particularly for demand and wind. It is however critical that the RAs deliver a market that accommodates wind to avoid undermining investments and to ensure that the market design delivers prices that are reflective of all relevant supply and demand fundamentals. Wind must therefore have a role in DAM price formation and in the BM without necessarily being mandated to trade DA. This could be facilitated through an aggregator to deal with market participation and balancing requirements though the risks and balancing inherent in the use of such aggregators should be limited solely to those parties that participate through an aggregator. This is unlikely to just be a transitory measure as suggested in the Draft Decision and the enduring nature of the aggregator mechanism should be considered in the detailed design.

3. The Role of Demand in the I-SEM

In theory, BGE supports the opportunities that interaction in a dynamic market will allow for suppliers and consumers in demand side participation. Concerns exist however with regard to the huge exposure to penal and volatile balancing price risk faced by demand and the inability and uncertainty with how such, and if such, risk can in fact be managed in I-SEM when the tools (e.g. smart metering) will not yet be available at I-SEM's inception.[8] Knock on impacts on consumer prices due to risk premiums will ultimately develop. One potential method of mitigating this risk is to provide for less penal imbalance pricing approaches than that proposed in the Draft Decision.

The proposed step change from the current SEM's socialised imbalance market to an I-SEM marginal priced imbalance market is extreme and unnecessary in our view. Although we recognise the obligation

[7] BGE wishes to highlight a concern with regard to the proposal (p. 85) that all forward contracts may be required to be cleared through a clearing house. Before such decisions are made, BGE urges the RAs to consider the potential impact of financial regulations on market participants – such a decision could for example bring currently EMIR exempt contracts within EMIR's scope resulting in huge administrative and cost requirements for market participants.

[8] The system wide roll-out of smart meters is currently not expected until 2018 – 2020 which lags the implementation of the I-SEM by a number of years.

under the Balancing Network Code for all parties to be balance responsible, the proposal to introduce a single marginal balancing price – which will in turn be set as the imbalance settlement price - has not in our view been given due consideration and analysis. Applying the same price to all imbalances is not proportionate, especially for demand whose forecasting risk is even higher than that of wind and who do not have the appropriate technology to participate actively in the market.

Further analysis must be carried out before a decision on the application of a single marginal balancing price is taken. The GB project on this issue indicates the complexities involved. The requisite analysis must include for example clear objectives as to what the balancing market is aiming to incentivise. Are the RAs for example in favour of parties trading forward to balance their own positions rather than the overall system and how averse are the RAs to parties being incentivised to "spill" energy in the attempt to anticipate system length? Different application of imbalances could for example be applied to production and consumption accounts; the option to apply a dual price approach might be retained for instances when imbalances are consistently high; or the decision of applying a single/ dual price approach might depend on whether the system is long or short. These are just some limited examples of balancing price options that have far-reaching consequences, particularly from a demand perspective, and further analysis is needed to understand the risk and to assess other options before a final decision can be taken.

The Balancing Network Code makes explicit provision for balancing prices and imbalance prices to be calculated separately.[9] We believe that this distinction should be mirrored in the I-SEM such that proportionate signals are provided for the desired investments and the desired behaviours separately. BGE urges the RAs to re-visit the proposition that a single marginal balancing (and imbalance) price is applied in light of their duty to the consumer and the need to enable predictability and stability in end consumer prices. Otherwise, and without the necessary smart tools to mitigate balancing risk, demand will be exposed to unmanageable risk which will have knock on effects for end consumer prices.

4. Flexibility and its Remuneration in the I-SEM

BGE's concern with the proposal to remunerate non-energy services through pay-as-bid (PAB) payments is that it will not result in the requisite incentives needed to deliver the large increase in flexible plants that must occur to facilitate RES development as we move towards our 2020 target levels.

The Draft Decision proposes that non-energy actions will be taken from the same merit order as energy actions but will only be PAB. This in BGE's view will not incentivise investment in those system services which, the studies conducted as part of the DS3 programme clearly show, bring significant value to the market and the system. This is likely the reason why the DS3 Programme will continue in parallel with the development of the I-SEM, but in our mind it undermines the value of the BM. That is, the BM should provide market signals and incentivise investment in both system services and energy services. The BM should be designed, with the requisite provisions to mitigate market power (both local market power and the market power of the incumbent) and to value flexible services appropriately. Rather than looking for 'fixes' outside of the market, at this stage of the market design, we should be seeking to deliver a market which provides the correct signals for the correct level and type of investment (i.e. those investments that deliver clear value). BGE is of the view that the proposal to value 'system services' as pay as bid in the BM should be reviewed and that the overlap between the DS3 project and the BM design is assessed in greater detail. An understanding of the distinction between what each is incentivising and what investments should result is requested.

Related to this issue is the proposed delineation between system services and energy services. This delineation will require very explicit and transparent methods of determining what a system only balancing action is and what an energy only balancing action is. In light of the experience in GB, which has examined the tagging and flagging issue for over 15 years, and the current difficulty experienced by the Irish TSOs in choosing and sufficiently explaining constraint and curtailment actions, confidence in the acceptable delineation between system only and energy only balancing actions is low. Clarity on how the RAs foresee this will operate in the I-SEM is requested in the HLD decision.

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[9] Articles 38(2) and 60, for balancing energy pricing and imbalance pricing, respectively in the Balancing Network Code (23/12/2013 version)

5. Detailed Issues, Requests for Clarification in I-SEM Energy Trading Arrangements

On foot of the analysis carried out by BGE there are a number of other aspects of the Draft Decision which BGE believes require further consideration and for which clarity (at least in principle or approach) is requested as part of the decision on the I-SEM HLD:

- What is the ability of the Euphemia algorithm to deliver both technically and commercially feasible outcomes? Complex bidding currently prevents market schedules and dispatch schedules deviating widely, thereby reducing the need for independent TSO actions and increasing the complexity of balancing. Can the I-SEM include a level of bid complexity not replicated in its neighbouring market(s)?
- How will the TSOs manage their exposure to Financial Transmission Rights?
- How will Financial Transmission Rights (FTRs) deliver more efficient IC trading relative to PTRs?
- With respect to the proposal for FTRs in the forwards timeframe, we understand that this requires cross-border agreement for implementation. Have discussions with the relevant GB parties commenced and what are the timelines expected for a final decision on this given its potential impact on the HLD?
- There appears to be an assumption that any revenues from the sale of transmission rights on the interconnectors will pass through to end consumers via the TUOS charges. BGE requests confirmation that this will be mandated in the I-SEM?
- Will the IDM provide for inter-dependencies between trading hours – i.e. potentially through IDM auctions? Independent hourly trading periods will likely give rise to very volatile prices in the IDM. Is such an outcome expected and acceptable to the RAs?
- How will participants be incentivised not to move away from TSO balancing actions taken ahead of the BM? The reference to committing plant before the DAM schedule is available presumably refers to the need to bring plant on for system reasons. Clarity on the interaction between commercial schedules and system directions is necessary. This may best be provided by numerical examples of the interaction expected between commercial scheduling and system scheduling and related revenue impacts in I-SEM.
- In terms of participation in the BM, is the requirement to submit BM incs/ decs immediately on availability of the DAM schedule a pre-requisite to participating in the BM? Do all anticipated BM volumes have to be submitted at that earlier time or are any pre-requisites/ limitations on BM participation foreseen? Can the RAs confirm that there will be an opportunity for generation to dec in the IDM similarly to the BM?
- Does the "mandatory" nature of the BM apply only for volumes not already committed in DA/ ID or do you always have to submit BM incs/ decs or does it merely mean that you must be balanced?
- Unit based bidding in I-SEM is welcomed but how will unit based imbalance payments be enforced in I-SEM, i.e. how will the RAs control parties from optimising cash-out payments across their portfolio?
- Dispatch: further discussion with industry on the process mentioned in paragraph 6.4.56 whereby all hourly prices from Euphemia are converted into more granular nomination profiles is required in order to understand how this can best be administered in the market;
- How will priority dispatch in the balancing market be practically implemented? If the wind blows, will wind be automatically dispatched with subsequent requirements for a balancing action by the TSO?
- An indication of the treatment of issues such as firm access, losses and credit risk (which will also be a major potential issue for the CRM) in the HLD is requested.

6. The Proposed Reliability Option (RO) as the Capacity Remuneration Mechanism

BGE welcomes the decision to adopt a Capacity Remuneration Mechanism (CRM) in the I-SEM as a CRM should provide investment certainty and exit signals for underperforming plant. BGE cannot however comment fully on the expected benefits or impacts of the RO given the dearth of information on the design and application of the mechanism of which there are many variations. In particular, without knowing the definition of the "product" being auctioned, what bids should represent, what ensuing obligations apply if successful in the auction and the potential for explicit penalties, a comprehensive assessment and commentary on the RO is impossible.

On foot of BGE's empirical analysis of the operation of the RO in other markets, a number of concerns arise as well as possible methods of mitigating these. BGE is ultimately concerned that the proposed RO may not deliver against the objectives of a CRM.

6.1 Main concerns for the RO

Without further detail and based on an empirical assessment of other quantity based CRMs, BGE has a number of concerns. These concerns include: the ability of the RO to deliver on the "missing money"; whether the RO will deliver sufficient capacity; the ability of demand to participate in the RO; and the potential for market power exertion in RO auctions.

In terms of recovering "missing money", the experience of ISO-NE is instructive. ISO-NE is undertaking a review of its RO as it has been found not to adequately deliver missing money, has lead to boom-bust cycles of investment and resulted in inadequate capacity. Thus the detailed design of the chosen CRM must necessarily ensure the recoverability of missing money having regard to the significant investment that has been made in SEM on foot of the reliability of the revenue stream under the current CRM.

The RAs allude to the fact that the RO may be a financial-only CRM. There is no global example of such a CRM and BGE firmly believes that the definition of the "capacity product" must ensure a definite link between the chosen CRM and physical capacity. Without a physical link, capacity adequacy will be threatened and the potential for introducing huge financial regulatory obligations in this market will be high. [10]

BGE is also unsure of the anticipated participation of demand side in the RO. In light of policy on demand side participation, BGE requests a commitment to ensure its fair contribution to capacity adequacy will be facilitated by the ultimate CRM chosen.

Another major concern that exists regardless of the quantity-based CRM chosen is the ability of the incumbent to exercise market power, which in I-SEM will be ESB. This might occur for example by ESB withholding a small part of their portfolio in order to offset the lost opportunity for revenue on strategically bid assets; ultimately absorbing more revenues for the plant in the RO auction. Alternatively they might also declare a plant as being 'retired' or near retirement, which subsequently does not happen, then submit that plant at a higher price for a subsequent "fine-tuning" auction for the same initial capacity period.[11]

These risks could be addressed by certain mitigation measures, such as:

a. Mandating withheld (often the cheapest) capacity to be subjected to the RO strike price in the energy market (thus providing the supplier hedge without receipt of the RO option fee). This mitigates market power in both the RO and spot markets;
b. In the case of so-called "retired" plants, they could be precluded from partaking in subsequent auctions for the same capacity period[12] further assisting the exit signals for adversely selected plant, making room for more useful low carbon generation;
c. Enhancing the MMUs's role to also monitor RO procurement and operation;

[10] A financial-only option implies significant financial trading in the capacity mechanism which raises the question of the applicability of financial regulations to the energy market. Any arrangements that could compel energy/ capacity trading transactions to be financial regulation compliant should be limited if high increases in market participants' costs of participation in I-SEM are to be avoided. Main financial regulations of concern are EMIR and MiFID II. They introduce high administrative burdens & may require holding of additional collateral possibly acting as a market exit signal

[11] For a market power assessment see for example "Capacity Market Gaming and Consistency Assessment, Final Report", dated 17/09/2013, carried out by Charles River Associates for DECC on the proposed GB capacity auction approach

[12] If for example one assumes that for a particular capacity period, there will be one main auction X years in advance following by a "fine tuning" auction, one year ahead for that capacity period (a type of secondary trading opportunity)

d. Applying capacity obligations on a unit as opposed to on a portfolio/ company basis.

Other non-exhaustive market power mitigation measures include:

e. Facilitating the participation of demand side response in the RO. Actively providing for demand side participation in the RO would for example help mitigate high prices that outturn on foot of market power exertion whereby demand participants could offer to reduce consumption in periods of high prices;
f. Measures to enhance competition in any quantity based CRM including for example lag periods of at least 4 years which can enable new competition to develop; and prohibiting information arbitrage by ensuring all information on all auctions is given to all market participants at the same time.

6.2 Key Design Elements

In order to complete a detailed assessment of the RO, a number of items and areas will require further detail and analysis. Specifically:

- Setting the capacity requirement: Changes in the requirement have given rise to uncertainty in other markets, undermining the principles of a capacity mechanism. The current 8 hours LOLE in the ROI has been the regularly justified standard for many years, although we note that other markets (France, GB, Holland have a higher security standard i.e. assume less hours of unserved load). Any move away from this LOLE must be fully justified and impact assessed, notably how the LOLE level and other capacity market parameters drive the risk reward balance associated with the provision of generation adequacy, and signal efficient entry/exit. Assuming that the TSO will have this role, BGE urges the process to be objective, transparent and open to challenge. The adoption of different LOLE levels merely due to their use in other (different) EU markets is not sufficient validation to change it;
- Setting the strike price: BGE agrees with the standard setting of the strike price at a premium to the most expensive provider on the system. Decision on a single or multiple strike prices depends on whether RO auctions will be technology specific or neutral. BGE does not believe that any technology should be explicitly excluded from participation in the RO but requests further information on the method of interaction anticipated by wind, demand and interconnectors in the RO;
- Low Carbon Generation (LCG) incentives: in line with 2030 and 2050 low carbon generation objectives, BGE believes that the future CRM provides an opportunity to incentivise the appropriate energy mix for the future. Thermal generation plants should be obliged to consider the expected cost of their plant emissions in their auction bids. The correct pricing of emissions is critical in this regard and BGE urges the RAs to use their influence wherever possible in pushing for delivery of an appropriate ETS price on an EU level.
- The reference price: A liquid reference price will be important for a successful RO and will depend heavily on the energy market and the liquidity measures adopted therein. BGE believes that the DAM may be the appropriate source but is concerned at the statement that the use of the IDM or BM as a reference price for ROs possibly "to incentivise greater flexibility from providers." Flexibility and adequacy are two completely separate issues and must be treated as such -clarity on what the RAs mean by this comment is requested;
- An explicit penalty: If explicit penalties are to apply in certain time periods, the penalties should apply on a unit as opposed to portfolio/ company basis; both penalties and scarcity periods must be a) fairly, transparently defined and; b) warnings thereof should be given to the market before such scarcity events are expected to occur;
- Contract lengths: Related to our concern regarding the ability of the CRM to recover "missing money", BGE believes that it is difficult to comprehend how an annual auction for 1 year capacity contracts will deliver investor certainty and thus ensure capacity adequacy in the market. Further detail demonstrating how this issue would be addressed by the RO is requested in the final HLD; and,
- CRM rules: A stable, predictable institutional and regulatory framework is required which must include a comprehensive definition of the "product" to enable its appropriate evaluation by potential RO participants. This should be set in legislation/ a Trading and Settlement Code type document so as to provide regulatory certainty of minimal intervention to I-SEM investors.

Intervention should be explicitly limited to a certain number of circumstances, for e.g. on review every 3+ years. Confirmation of this in the HLD is requested.

6.3 RO - Conclusion

Ultimately further detail and assessment on the operation of the RO is needed, including consideration of the possible need for interim arrangements before the first RO auction before a decision on the HLD is made. As BGE believes is demonstrated above, intricate design of any CRM must be tailored to the market in question but without an insight into the anticipated product, potential penalties and what bids should represent, an informed commentary is impossible.[13] BGE is not entirely satisfied that the RO will deliver missing money and capacity adequacy particularly in light of the recent difficulties in this area experienced by ISO-NE.

The CRM is a topic at least as worthy of a separate work-stream in the detailed design phase as the issue of liquidity in energy trading arrangements. BGE requests that if indeed a quantity-based CRM is ultimately chosen in the HLD decision: the pitfalls of quantity based CRMs and methods to address these should be identified and assessed the CRMs should be robustly assessed against CRM objectives and against each other and this must be carried out before the final HLD decision. The CRM detailed design should be developed in tandem with industry; should be transparent; must establishing and apply objective assumptions; and all detailed design aspects must be open to comment and consultation with detailed qualitative and quantitative assessments provided.

7. Summary and Conclusions

While recognising the need for change to the market, the success of the SEM to date is clearly premised on its effectiveness to deliver: transparency; competition and capacity adequacy to a small island market. The I-SEM should ensure that it retains these positive attributes and in so doing ensure that the all-island market remains a positive global example for the facilitation of renewables and retail competition.

BGE supports certain of the decisions made in the Draft Decision. Our underlying concerns relate predominantly to the lack of explicit principles and measures to address liquidity, market power, transparency and monitoring across all four energy trading timeframes. Other concerns include: a) the participation of wind in the DAM and BM timeframes and price formations; b) a single marginal balancing (imbalance) price and its impact on demand side participation and supplier market entry and hedging risks; c) the inability of the BM to incentivise flexibility in energy and system services; and d) the decision to implement a CRM without any detail or assessment as to how it will apply.

Before a final decision is made on the HLD and in the interests of ensuring a market design which is compliant with the EU Target Model and also meets the requirements of the local island market, BGE urges the RAs to consider the following:

i. The SEM's forwards liquidity issue will remain in I-SEM and is likely to grow given a) the portfolio benefits of ESB and its ability to dominate in any and all of the four I-SEM market timeframes; and b) the increased scheduling risk that will arise in I-SEM by virtue of the uncertainty of the operation of the Euphemia algorithm. Measures to mitigate this issue include:
   a. Further divestment of ESB's generation portfolio beyond its peat plants;
   b. Explicit measures to enhance on-island forwards market liquidity which may be assisted by ensuring DAM, IDM and BM liquidity volumes (the "exclusive" nature of DAM and IDM will assist though further measures such as volume mandates may be required);
   c. Ensuring transparency in bid outcomes in relevant timeframes for predictable and stable pricing and to enable confidence in the hedging capabilities of market players;

[13] The RAs note that the RO can encourage increased liquidity in certain market timeframes. Insight into how the RAs anticipate this result would be welcomed?

d. MMU monitoring of the potential of market power abuse through effective bid monitoring and possible ex ante/post controls.

ii. Wind, while not being mandated to, must have a role in DAM price setting so as not to undermine DAM and BM price robustness and the consequential incentive to balance and incentivise flexibility. The proposed HLD does not appropriately provide for the participation of wind in DAM price setting in our view;

iii. BGE is concerned that the decision to apply a single marginal balancing (and imbalance) price to balancing actions will expose suppliers to unmanageable risk. In light of the breadth and potential impacts of such a decision (as demonstrated by GB's project on the issue), BGE urges the RAs to re-visit the explicit decision to introduce a single marginal imbalance price. There is scope within the Balancing Network Code to consider moving to an averaged imbalance settlement price approach. At this stage, BGE suggests that it would be prudent to withhold making a firm decision on the specifics of the BM until the detailed design stage and more detailed quantitative assessments can be carried out;

iv. The efficient operation of a balancing market is critical for incentivising flexibility in I-SEM to facilitate meeting 2020 RES targets. However the proposed 'pay-as-bid' approach for all system services provided in the BM and the running of the DS3 programme in parallel, undermines the confidence with which one can rely on the BM to remunerate all types of flexibility. The BM should incentivise energy and system services in parallel. Insight into the distinct objectives of what BM and DS3 will incentivise in terms of investment is requested in the HLD;

v. Transparency in the flagging and tagging process in the BM is also critical to engendering confidence in the TSOs' role in the market and more detail in the HLD is requested on the differentiation of system and energy services;

vi. The proposal to introduce a RO as the CRM for I-SEM was made without any detailed commentary or assessment on its merits. An empirical review has revealed the plethora of possible issues and permutations with a RO. Major concerns include the RO ability to remunerate missing money and ensure capacity adequacy. A more detailed assessment of capacity based CRMs against each other and the I-SEM CRM objectives, is necessary before a decision on the CRM can be made.

I hope you find the above comments helpful and should you have any queries, please do not hesitate to contact me.

Yours sincerely,

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Julie-Anne Hannon
Regulatory Affairs – Commercial
Bord Gáis Energy

{By email}

{1 attachment – "20140723 Baringa report – Scheduling Risk under the Proposed I-SEM HLD"}

Scheduling risk under the proposed I-SEM High Level Design

An issues paper

CLIENT: Tynagh, Viridian, AES, Bord Gáis Energy

DATE: 23/07/2014

FINAL

V1.2

Version History

Version	Date	Description	Prepared by	Approved by
1.0	16/7/2014	Draft for review and comments	DS, AS, AP	
1.1	23/7/2014	DRAFT FINAL Updated following comments from clients	DS, AS, AP	DS
1.2	23/7/2014	FINAL	DS, AS, AP	DS

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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.

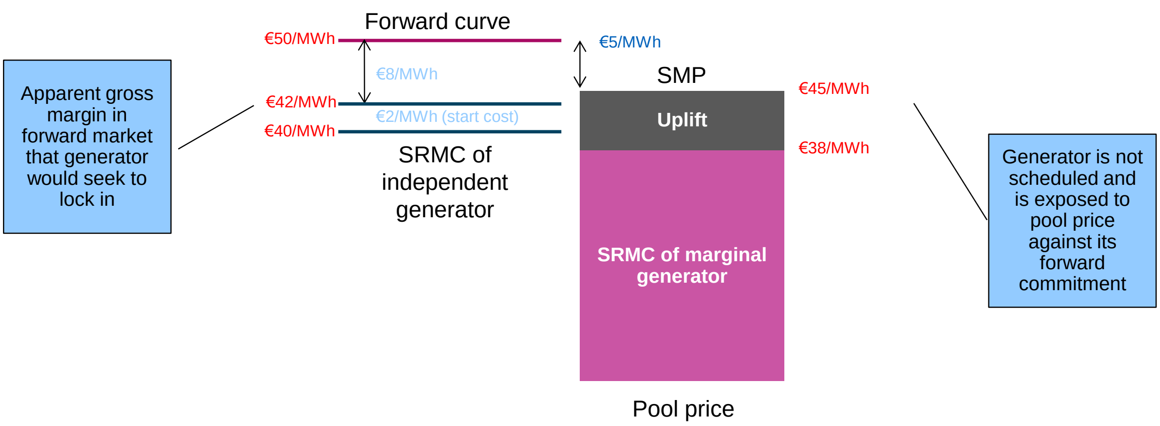
Under a centralised market, the hedging task for a mid-merit plant becomes more complex since it will be dispatched based on the outcome of the market algorithm. At the day-ahead stage there will be considerable uncertainty regarding market conditions, particularly with respect to wind output, and the 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.

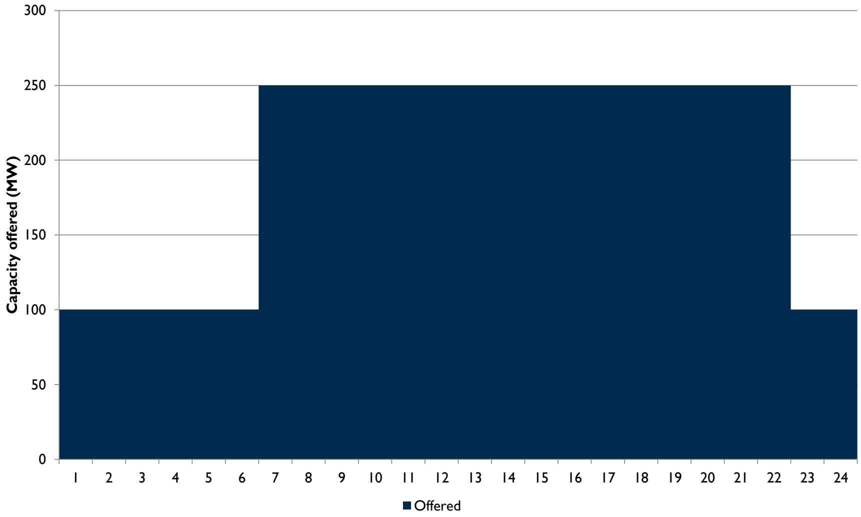
For the purpose of this study, we have not attempted to simulate the day-ahead market clearing and price formation process in the I-SEM and interconnected markets. For illustrative purposes, we assume that the CCGT and coal units are operated by independent generators and essentially operate as price 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.

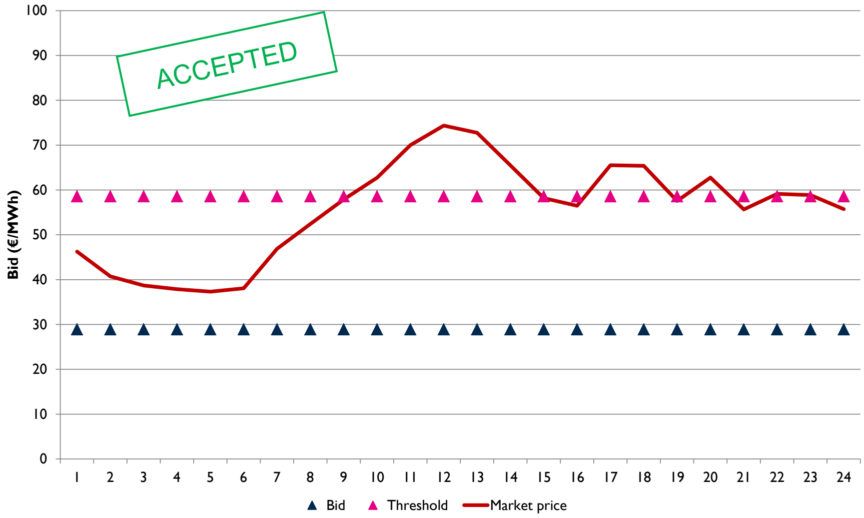
Case 1: Profiled Block Order
In this example, Coal Unit B expects to be near-the-money during the summer overnight periods and submits a Profiled Block Order to EUPHEMIA, as follows:

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

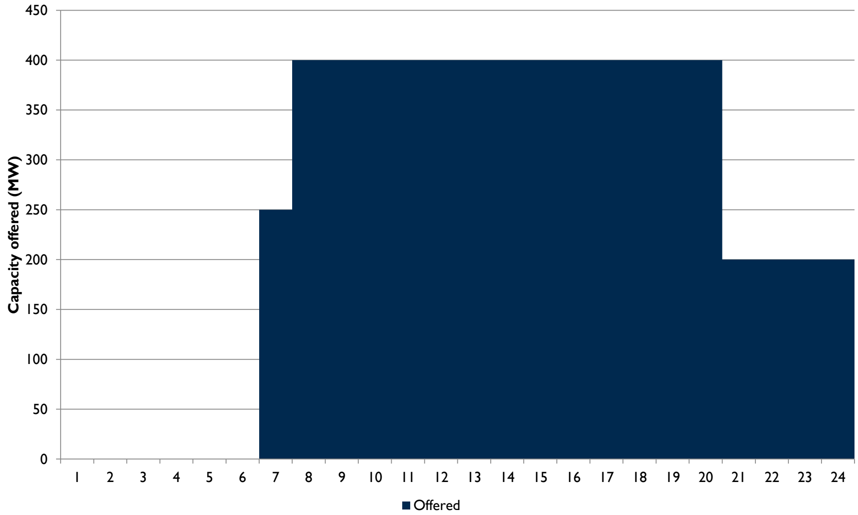
Mid-merit plant may be in or out of the money depending on system and market conditions. As a result, these plant may need to be switched off and restarted on a regular basis. We consider three EUPHEMIA order formats that mid-merit could potentially utilise to manage scheduling risks in the I-SEM DAM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

Profiled Block Order

Case 2: Profiled Block Order

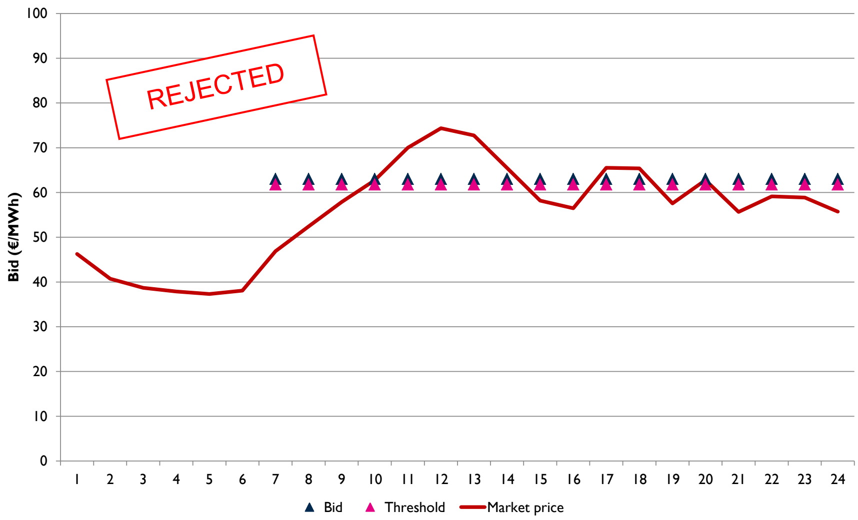
In this example, CCGT Unit A does not expect to be running at the start of the day. It submits a Profiled Block Order to EUPHEMIA, with the offer price reflecting its incremental, no load and start costs. The Profiled Block is 18 hours in duration, and allows for the plant to ramp down to MSG after the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

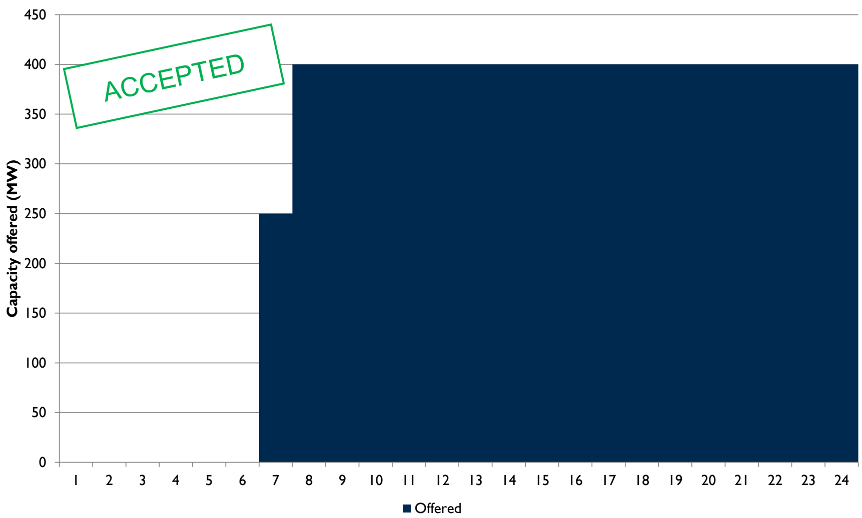
Figure 4-4 Case 2 Block Order pricing for CCGT A



<u>Case 3: Profiled Block Order</u>

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.

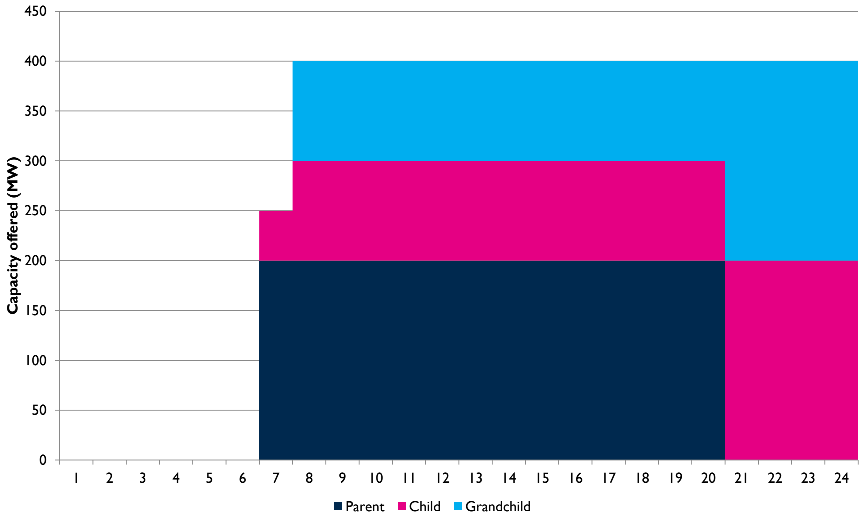
Linked Block Order
<u>Case 4: Linked Block Order</u>

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.

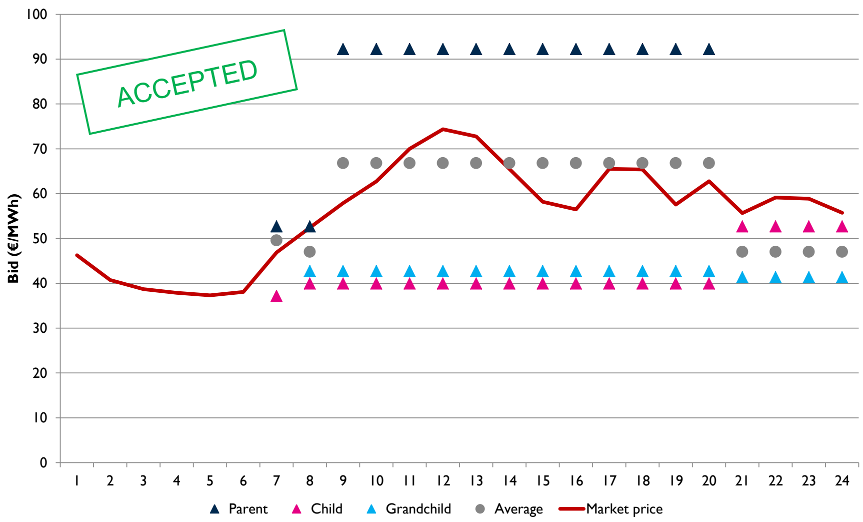
The Linked Block Order structure for this day is illustrated below.

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

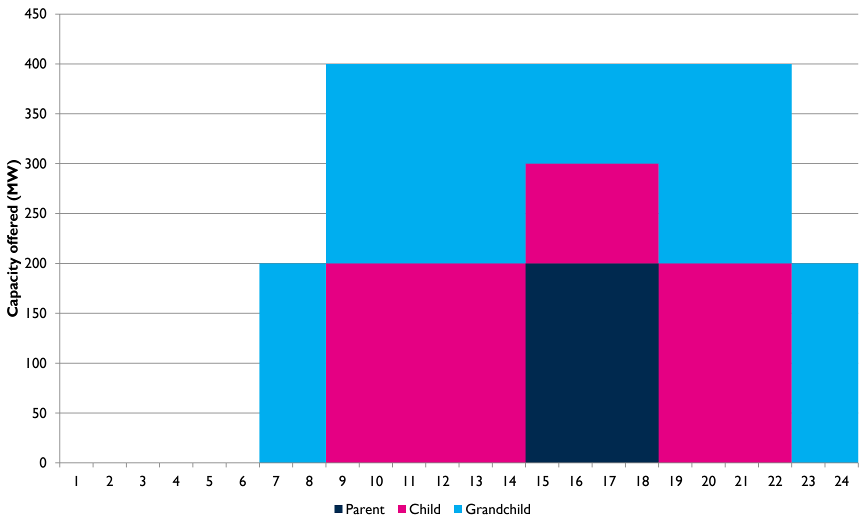


The Profiled and Linked Block Orders for CCGT A in Cases 3 and 4 are near-the-money. As a sensitivity, we found the block orders did not clear if the market clearing price was 1.2% lower across the day. This illustrates that CCGT A could be exposed to scheduling risk by having its block order paradoxically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

<u>Case 5: Linked Block Order</u>

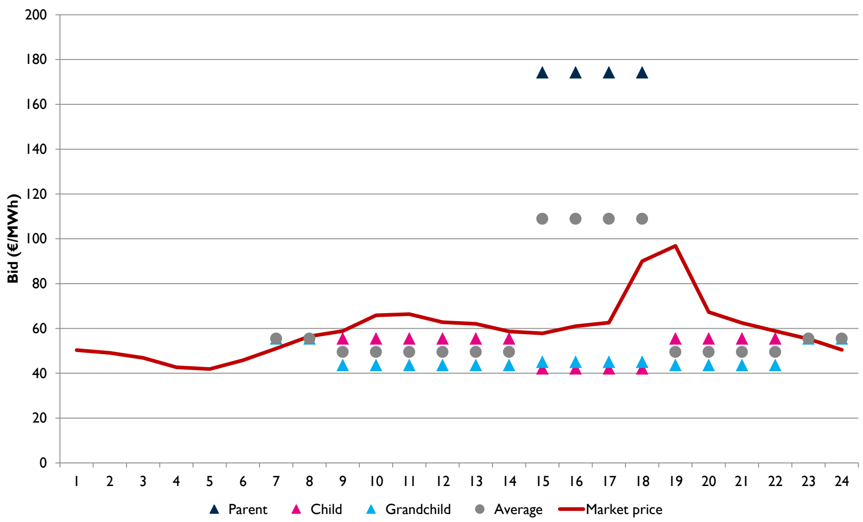
In this example, we construct a Linked Block Order for CCGT Unit A with the intention of presenting the most accurate representation of the unit's technical characteristics and cost structure. In a sense, this is analogous to the bidding methodology in the current SEM trading arrangements. The duration 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.

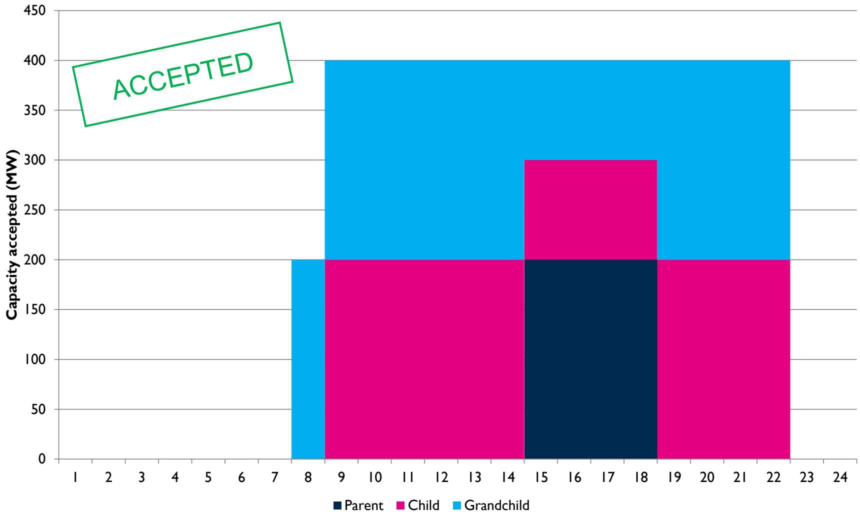
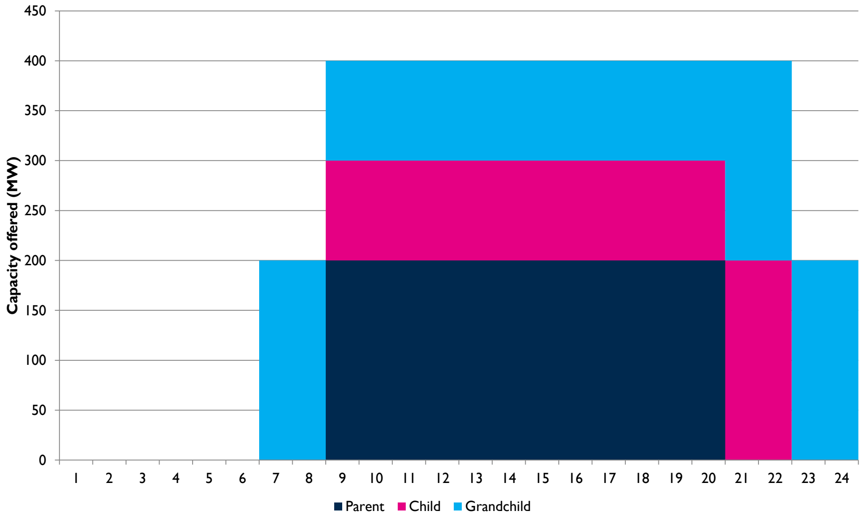


Figure 4-10 Case 5 accepted order volumes for CCGT A

Case 6: Linked Block Order

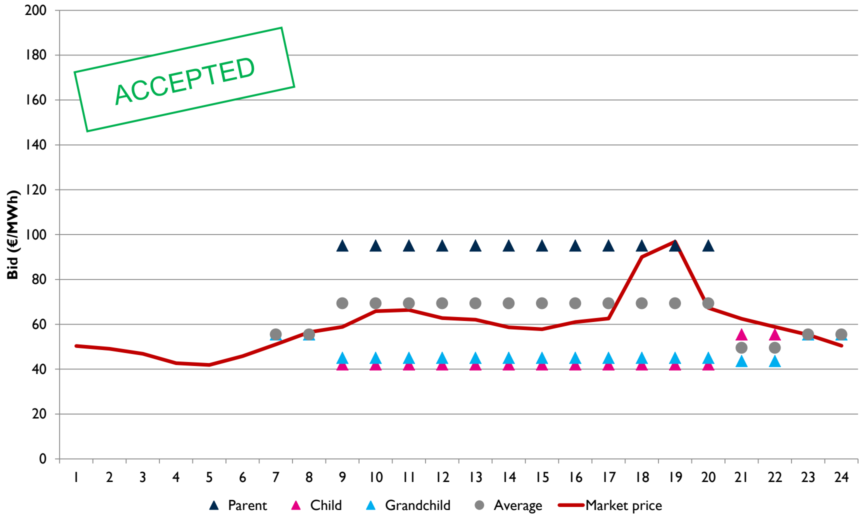
Building on Case 5, let us consider an alternative Linked Block Order using a larger parent block. Applying a 12 hour parent block allows start costs to be spread over a larger volume, potentially creating a more competitive bid price.

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.

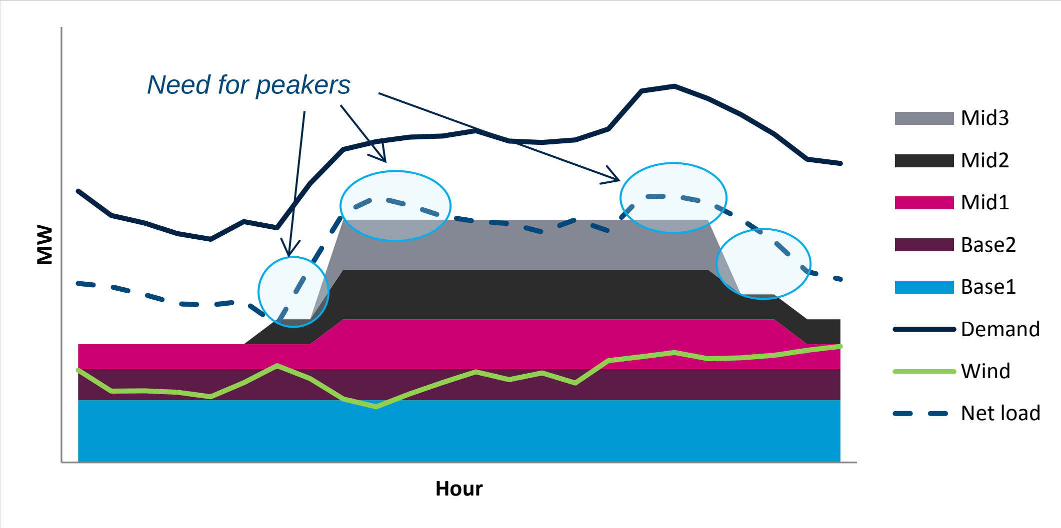
The Linked Block Orders for CCGT A in Cases 5 and 6 are near-the-money. We found that a 0.2% reduction in the market clearing price across the day would lead to the orders being rejected in these cases. Again this illustrates the sensitivity of the outcomes from the central dispatch algorithm to small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

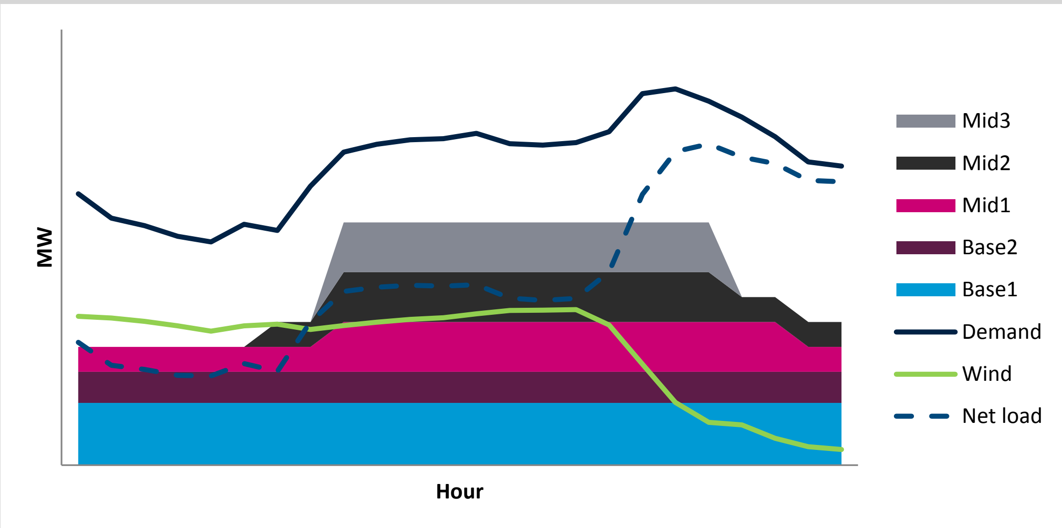
The schematic figure below illustrates how a combination of block orders from base and mid-merit generating units could stack up across the system relative to overall demand, net of wind generation. In this example, the combined profile of block orders broadly follows the system net load profile across 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:

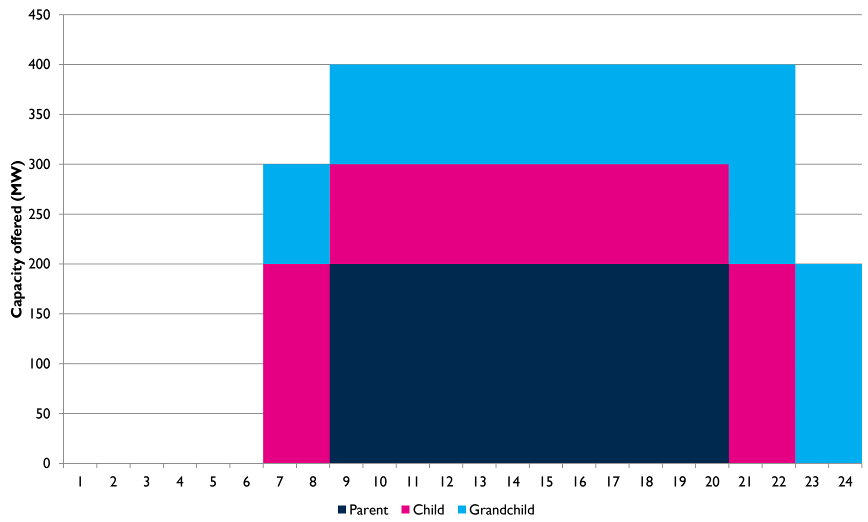
- To improve the competitiveness of the parent block price by allocating some start or no load costs to child and grandchild blocks
- To re-allocate costs between peak and off-peak periods, reducing the price of overnight blocks and potentially avoiding a shutdown

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).

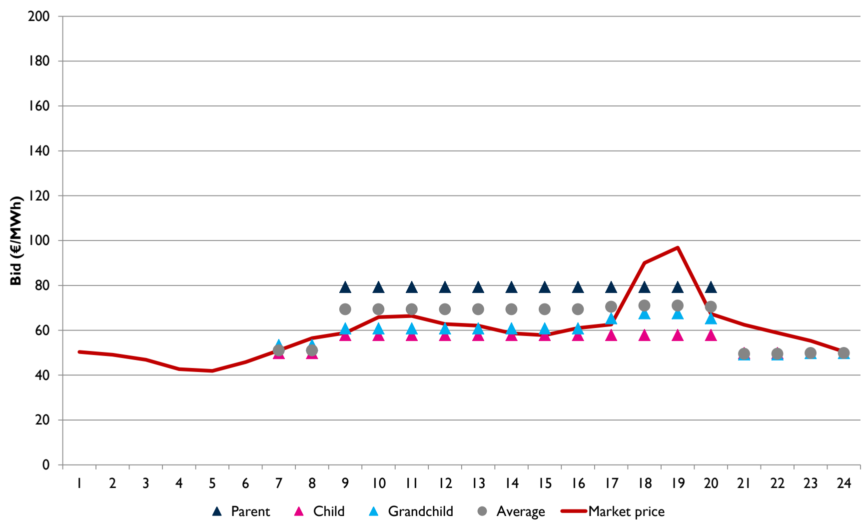
The submitted Linked Block Order structure is shown below.

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

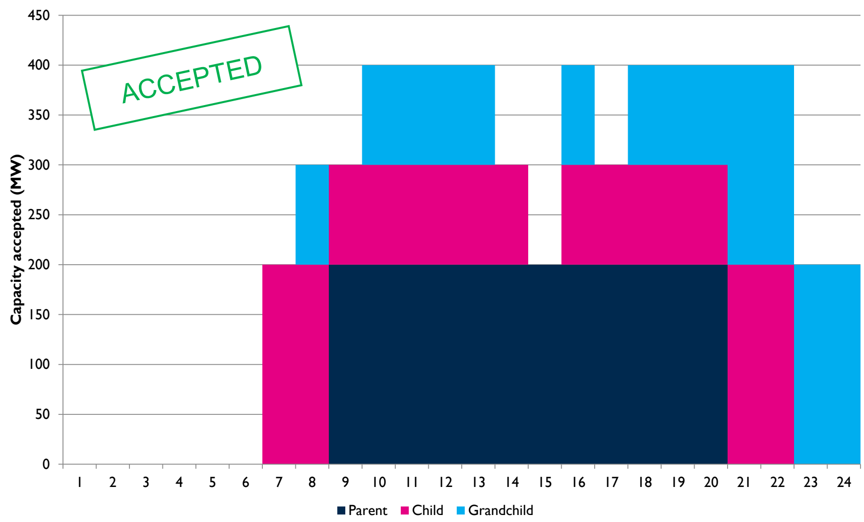


The resulting accepted offer profile is shown below. Compared to Case 6, we find that the addition of no load costs results in child or grandchild blocks not clearing in certain daytime periods (14,15,17). However, additional blocks are cleared during off-peak periods (7,8,23,24), potentially enabling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

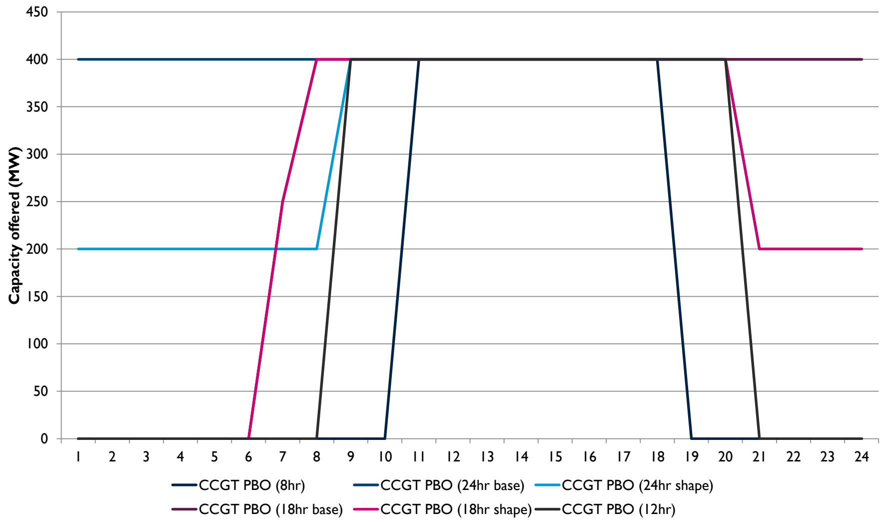
<u>Case 8: Exclusive Groups</u>

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.

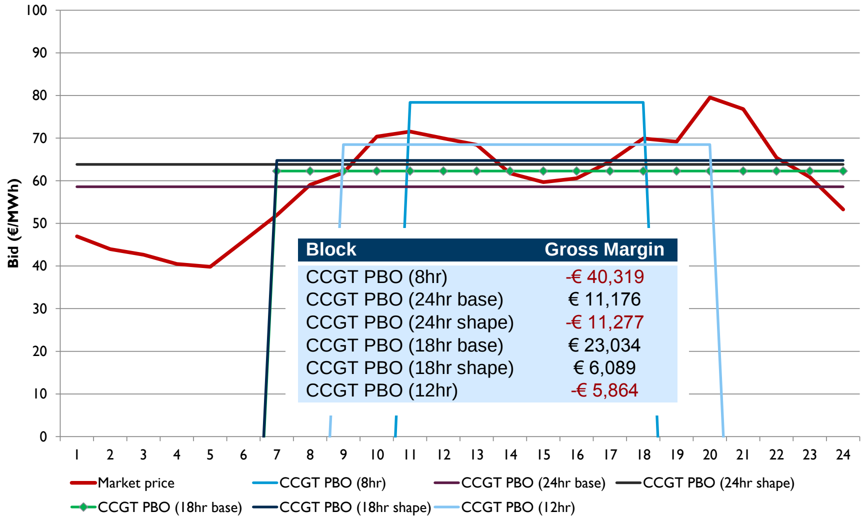
For Case 8, we assume that CCGT A submits an Exclusive Group of six Profiled Block Orders, ranging in duration from 8 to 24 hours. These orders are mutually exclusive, and each is priced to fully recover incremental, no load and start costs over the operating profile.

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



Block	Gross Margin
CCGT PBO (8hr)	-€ 40,319
CCGT PBO (24hr base)	€ 11,176
CCGT PBO (24hr shape)	-€ 11,277
CCGT PBO (18hr base)	€ 23,034
CCGT PBO (18hr shape)	€ 6,089
CCGT PBO (12hr)	-€ 5,864

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.