SEM-14-059

DS3 - Delivering a Secure Sustainable Electricity System

SSE response to SEM Committee Consultation on DS3 System Services Procurement Design

September 2014

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Introduction and Executive Summary

SSE and DS3 System Services

Thank you for giving SSE the opportunity to comment on the SEM Committee's consultation paper on DS3 System Services Procurement Design. As noted in the consultation paper, the System Services Workstream is a key part of the DS3 programme. Enhanced performance from generation[1] is not an optional component of reaching Ireland and Northern Ireland's 2020 targets.

SSE is a utility with both generation and supply interests in Ireland and Great Britain (GB). We own and operate over 500MW of wind generation capacity in the Single Electricity Market and over 1000MW of thermal generation capacity, with a new 461MW CCGT being commissioned later this year. SSE also owns over 11,000MW of generation capacity in GB. Across these core markets, we supply more than 9 million customers with energy.

To secure energy for its retail customers, SSE is involved in wholesale electricity generation and energy portfolio management. Amongst other things, the company is the leading generator of electricity from renewable sources across the UK and Ireland. Its wholesale business priorities are competitiveness, sustainability and flexibility - those priorities are shared with the DS3 programme.

The system services framework is a fundamental part of achieving a competitive, sustainable and flexible Irish electricity system. Without a robust system services framework in place, Ireland's 2020 renewable energy targets cannot be met. The system is already close to the limit of curtailment levels that are tolerable by investors with high risk appetites. The level of instantaneous non-synchronous penetration (SNSP) will need to be raised for further investment to proceed with any level of confidence.

As the services the TSO needs require investment in existing units, the owners of those units will need to make commercially acceptable /bankable investment cases. Procurement design cannot be focused on 'sweating' existing assets on the Irish system; it should be on enhancing existing units where possible and bringing forward new units or technology if required. Commercial insight and awareness will be the critical ingredients in getting enhancements to take place.

Our concerns

While the paper is styled as a consultation paper, the RAs have clearly settled on **Option 5** – in essence this is a proposed decision paper. Given that **Option 5**, in our opinion, has some clear flaws in bringing forward any investment, our summary highlights why we suspect the option has been chosen, why it cannot bring forward investment from existing generation

[1] Compliance with Article 16 of Directive 2009/28/EC is not optional, either.

sets and what modifications could be made to make it investable, while preserving some of its design advantages.

Value or Cost

The heavy weighting given to **consumer interest** in the analysis has translated into a procurement design based around minimising costs and ‘sweating’ as yet unenhanced assets. The assets currently sitting on the Irish system cannot physically deliver the performance required under the DS3, hence the reason for creating the DS3 system services framework. Value is assumed to primarily go to consumers and a couple of in-merit generators who receive additional inframarginal rents, with fierce competition driving the uniform prices for each service down to the cost of investment.

This is optimistic, even unrealistic. With very limited value on the table for existing generation units, only a limited return on capital and very substantial quantities of market and regulatory risk, the end result will be ‘cheap’ only on the basis that very limited investment will take place. **If the RAs want to quantify the value that consumers can capture, which seems clear from the paper, they should do so.** Having done so, focus can then turn to making enhancements investable by underwriting costs (to some extent) and allowing enhanced units to compete over the value unlocked.

At present, the procurement design would work excellently for sweating newly enhanced assets, but very poorly for bringing those enhancements forward in the first place. **Fierce competition entails uncertainty and risk. Neither of these is conducive to a broad range of investment decisions taking place over the 2017 to 2020 period.**

Interactions with the Energy Trading Arrangements

The preferred option has very heavy interactions with the energy market, because of the new availability definition. These are not simply with reference to long term investment decisions but also short run optimisation and bidding behaviour (and therefore pricing) at the margin.

An undiluted set of payment streams on an **availability** and **dispatch** payment basis, as shown below for **Option 5** is effectively co-optimisation of unit commitment and system services.

Table 12 Potential Interactions with the Energy Market				
Service	**Regulated Tariff**		**Multiple Bid Auctions**	
SIR	Capability	No interaction	Availability	Some interaction
FFR	Availability	Some interaction	Availability	Some interaction
FPFAPR	Capability	No interaction	Availability	Some interaction
SRP	Capability	No interaction	Availability	Some interaction
DRR	Capability	No interaction	Availability	Some interaction
Op Reserve	Dispatch	Some interaction	Dispatch	Some interaction
RRS/RRD	Dispatch	Some interaction	Dispatch	Some interaction
Ramping	Dispatch	Some interaction	Dispatch	Some interaction

All offers for system services will have to take account of expectations of market running, and all energy bids in near term timeframes (DA, ID and Balancing) will be constrained by offers in the system services market. Co-optimisation has been explicitly ruled out by the SEM Committee for the I-SEM High Level Design. The RAs cannot then choose co-optimisation by the backdoor with the DS3 System Services Framework.

SSE would also note that **the fewer bidding restrictions that are necessary in procurement design, the less likely arbitrage and thus misallocation between capacity, energy and service provision is.** Option 5 appears to require a great deal of volume intervention (and an unspecified level of price intervention) and therefore risks arbitrage and misallocation between the different revenue streams.

The middle ground?

SSE would suggest a middle ground between the two options fully considered in the paper. A PFLOOR or cost minima can be set, with regulated tariffs used to allocate payment to units capable of providing a service. This would underpin investment decisions to enhance existing plant.

Competitive Auctions can then be used to allocate value to the most efficient providers of system services, exerting downward pressure on the uniform prices set for each service and fairly allocating value between providers and consumers. This hybrid option would have a tiered structure of payments described as follows:

- **Regulated Tariffs based on capability set up to a price floor based on the supply analysis i.e. close to estimated cost:** this would provide investors with certainty around cost recovery, and visibility of a price signal and volume that will be procured for each service.

- **Competitive Multiple Bid Auctions based on availability/dispatch with a price cap based around a demand analysis:** this would overcome the split incentives that apply to providers, particularly those existing generators. Providers could compete for the value they are creating on the system; with competitive forces and a price cap ensuring that consumers capture a fair amount.

The remainder of our consultation response covers each of the detailed consultation questions. SSE looks forward to working with the RAs on the detailed procurement design. If you wish to clarify or discuss any of the points made in our response, please don't hesitate to contact Connor Powell (connor.powell@sserenewables.com) or Emeka Chukwureh (emeka.chukwureh@sserenewables.com).

Detailed Consultation Questions

I. It is requested that respondents provide a summary of their position any general comments on the system services review and the economic analysis

The **Introduction and Executive Summary** provides a summary of our position on the system services review and the economic analysis.

II. Respondents are asked to provide views on the approach to the demand and supply analysis, the results and the interpretation of those results

Supply Analysis

The RAs and the IPA report published alongside the consultation paper acknowledge that:

"[T]here is limited available information worldwide on the costs of the enhancements envisaged under DS3. This to some extent reflects the fact that the SEM is at the forefront of the transition of the traditional electricity system to one with a large penetration of intermittent, asynchronous renewable energy."

The cost estimates for enhancements to plant range from a 3.7% increase to a 22% increase on normalised build costs, depending on the capital intensity of capacity (taking coal capacity against existing OCGT capacity, for example). The capital costs of standalone grid solutions (termed network investments in the paper) are a significant step above the capital costs of investing in existing units or making incremental investments in new units.

While the cost estimates are acknowledged as uncertain, given the lack of available information on delivering these services, the Supply Analysis should reveal two important things to the RAs:

- **A significant amount of new capital investment is required:** the procurement design must therefore focus on making a wide number of enhancement projects investable. Given that the RAs appear minded to move from a definition of *capability* to *availability* (based on market position and expectations of future market running), uncertain revenue streams and a WACC of 6.6% are by no means realistic assumptions of the return that investors would expect for enhancement or incremental investments.

- **The cost of providing system services through generation enhancement is significantly less than the cost of providing system services through network solutions:** this is recognised in the consultation paper, the DNV KEMA study and the IPA review of the KEMA study. Network investments are likely to be the only 'new' units added to the system, new generation investments are unlikely, given the proposed design of the I-SEM Capacity Mechanism[2]. If enhancement of existing generation can take the place of network investment, there will be a lower total cost and a larger 'surplus' to share between consumers and providers.

Two conclusions can be drawn:

I. **Substantial capital investment is required – investment is more efficient in enhancement of existing generation rather than network solutions.**
II. **However, the owners of existing generators that can be enhanced face split incentives – any enhancements will displace market running.**

The paper also states that:

"The analysis suggests that new[er] builds have significantly lower incremental costs than the incremental costs of retrofitting existing units."

This is important to note, because those split incentives are particularly apparent for new units – enhancement will definitely displace a greater volume of their in market running – however, it is not clear that these conclusions have been adequately recognised in the procurement design.

Demand analysis

The demand analysis is more straightforward. The TSO analysis and the assumptions requested by the SEM Committee lean toward a conservative view of the value that can be unlocked by system services (RoCoF is assumed resolved, despite the TSOs revised delivery date) and an optimistic view of market functions (arbitrage thresholds have been reduced in a model that references the current SEM design).

This would tend to produce a lower 'value' for consumers in the base case, although the other scenarios reveal substantial production savings and consumer savings even at lower SNSP limits. SSE would agree with the conclusion drawn from the analysis – procurement

[2] Short term capacity contracts are the only product currently available. Given Ireland's existing generation surplus, new generation units are unlikely to be built without longer term products.

design should focus on delivering the desired outcomes from a higher SNSP – i.e. the outputs rather than the means, otherwise the project could be futile.

Combined?

While this remains partially unstated in Section 4, the primary conclusions drawn from the economic analysis carried out appear to be quantifying the cost of delivery and evaluating an implicit price cap. These conclusions remain implicit, but guide the procurement design proposed. SSE believes that, if the goal is to quantify minima and maxima for values that can be captured by investors/operators, it may be better to simply quantify them as a PFLOOR and PCAP.

Explicit guidance rather than implicit guidance from the demand and supply analysis would mean that procurement can be based around facilitation of investment rather than control of costs and payment flows. We have outlined a straw-man tiered structure in our **Introduction and Executive Summary.**

III. Do you agree with the criteria and analysis used by the SEM Committee to evaluate the options?

The assessment criteria have been defined as follows:

- **Consumer Interest: efficient cost, protected from over-payment, payments do not exceed total value.**

  These criteria are fair, although it is not clear how 'over-payment' would be defined; in the high level analysis it suggests that mispricing of individual services and long-term contracting could give rise to 'over-payment'. Both bundling of services and long term contracting are likely to be required for investment decisions to take place. A long term contract for early delivery may be more expensive than a long term contract signed in a mature market, but it is not clear that that would mean consumers had overpaid – the investment would be brought forward and would be sourced from an undeveloped market, but system performance could also be improved earlier.

  There is very little analysis of how 'efficient cost' will be achieved, given the clear split incentives for existing generators. It is simply assumed that existing generators will invest in enhancements that allow them to deliver new system services, and immediately discount the asset as it facilitates its own displacement in the market, and is moved from recovery of average costs to short run marginal costs.

- **Investment: certainty for investors, entry signals, exit signals, incentivises efficient providers**

While most of these criteria clearly relate to investment, SSE would strongly disagree with the inclusion of exit signals. In fact, earlier in the paper, it is stated that:

"The interaction with the current Capacity Payment Mechanism is limited to the revenues earned by the Best New Entrant (BNE). However, volume based Capacity Remuneration Mechanism (CRM) such as a reliability option, will likely incentivise generators to lower their capacity bids by an amount equivalent to their System Service revenue. In other words there is less "missing money" for those generators providing system services."

Exit signals are a function of an auction for capacity – "missing money" is not going to be adequately resolved by an annual product strongly linked to expectations of market running (under the new definition of availability put forward by the RAs). In fact, exit signals and incentivisation of efficient providers both act as an extension of consumer interest criteria into the investment criteria. This could be more simply achieved by (further) explicit weighting being placed on consumer interest.

We would suggest that the investment criteria is rejigged so that it more accurately references the criteria by which investment decisions in enhancement projects will be taken. **Visibility of price signals** over the typical investment horizon of an enhancement project mean that a case can be made for the investment. **Guarantees** around volume reduce another risk exposure. Similarly, **clearly defined performance arrangement/scalars** that cap liabilities limit risks in an investment case[3].

- **Curtailment: minimises curtailment**

  This is effectively is the same as the investment criteria. Any design feature that brings forward investment will minimise curtailment.

- **Renewable Targets: contributes to meeting the 2020 renewable targets efficiently**

  This is effectively is the same as the investment criteria. Any design feature that brings forward investment will contribute to meeting the 2020 renewable targets.

Given that the approach the RAs have settled on is to focus on the output, rather than the explicit means like 75% SNSP, SSE would suggest that the **curtailment** criteria is removed, and that design is focused on **investment** (primarily, how to design a mechanism that can actually bring investment forward) and on **consumer interest** (how to ensure that investment is efficient for consumers) – this will contribute to meeting the 2020 renewable targets efficiently.

[3] They also work to 'incentivise efficient providers'

Again, **consumer interest** could potentially be resolved by minima/maxima criteria based on the supply and demand analysis, setting a floor and cap so the Regulators are comfortable with a likely level of surplus accruing to consumers and overcoming split incentives that apply to existing generators. This would simplify procurement design, and prevent distortions in the procurement design chosen based on analysis against irrelevant or hard to evaluate criteria like **efficient cost, overpayment** and **exit signals**.

The heavy weighting given to **consumer interest** has translated into a procurement design based around minimising costs and 'sweating' as yet unenhanced assets. With very limited value on the table for existing generation units, inadequate return on capital and very substantial quantities of market and regulatory risk, the end result will be 'cheap' only on the basis that very limited investment will take place – the real risk is not overpayment, but under provision.

IV. Do you agree with the design of the procurement options? Are there any different design elements or procurement options that the SEM Committee should consider?

Do you agree with the SEM Committee's analysis of the procurement options?

Which option do you prefer?

Given that investment to enhance existing plant is the most efficient outcome and the desired end point (a system with multiple units that can reliably provide the volume of services required by the TSO with a comfortable margin), **we would suggest a hybrid of Option 5 and Option 1.**

Very limited investment will take place on the basis of **Competitive Multiple Bid Auctions** not as a consequence of the fundamental design, but in relation to what they reference – the RA's new definitions of 'availability' and 'dispatch' for payment purposes. Existing and new units would be submitting mutually exclusive bundles of bids, whose prices would be calculated by reference to an assumed running regime[4]. The paper states:

"Providers submit bundled bids for all of their investment decisions. Therefore each bid would include a price, quantity and contract length for every service the provider is willing to offer. Multiple (but mutually exclusive) bids would be permitted. This allows the generator to

[4] Over the course of 1 year, an assumed running regime can vary widely. Over the course of a 5 year, or 10 year contract, providers would be exposed to major market risk, which cannot be effectively hedged. They might have a contract for an acceptable, investable price, but one that turns out to have no volume associated with it. A take or pay contract is investable, a master agreement is not.

reflect the interdependent relationship between the services through their bids and allow the market to price the risk premium on shorter-term contracts."

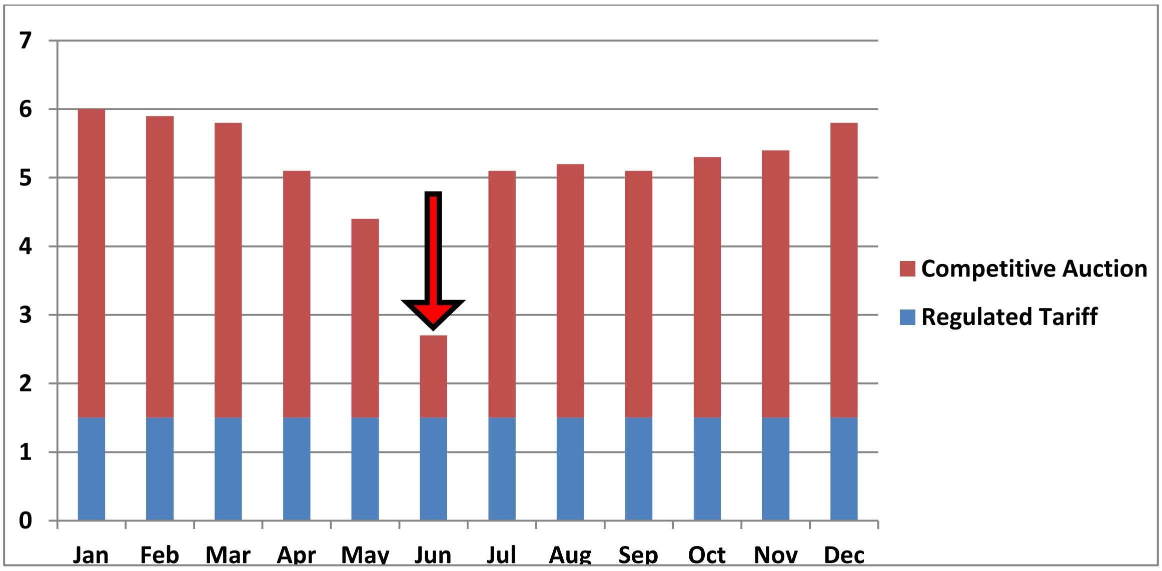
These design features are desirable for a mechanism that would allocate value to units that have brought forward investments (incentivising units to compete for some of the surplus). They are not desirable for a mechanism that needs to underwrite substantial investment costs in a manner acceptable to owners and financiers of generation assets.

SSE would suggest a tiered structure of payments:

- **Regulated Tariffs based on capability set up to a price floor based on the supply analysis i.e. close to cost:** this would provide investors with certainty around cost recovery, and visibility of a price signal and volume that will be procured for each service.

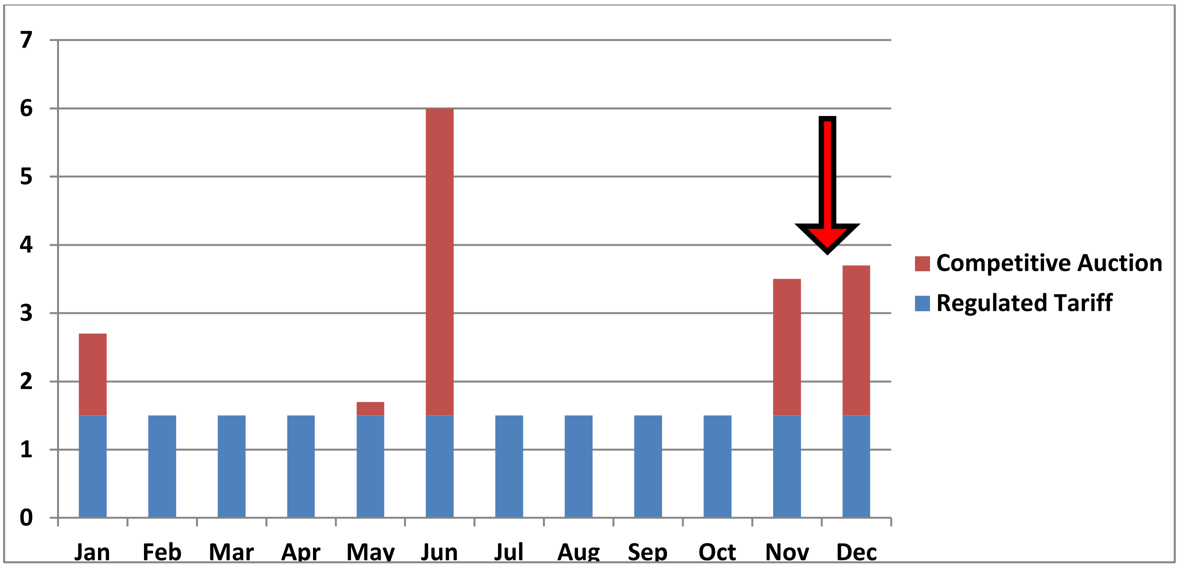
- **Competitive Multiple Bid Auctions based on availability/dispatch with a price cap based around a demand analysis:** this would overcome the split incentives that apply to providers, particularly to existing generators. Providers could compete for the value they will be creating on the system; with competitive forces and a price cap ensuring that consumers capture a fair amount.

For a typical service, the payment structure for an 'in-merit' gas generator (**Generator A)** could look like the stylised chart below:



In June, the 'in-merit' gas generator has been on a scheduled outage; hence the competitive payments for a service they are providing were reduced, as they were not in the market.

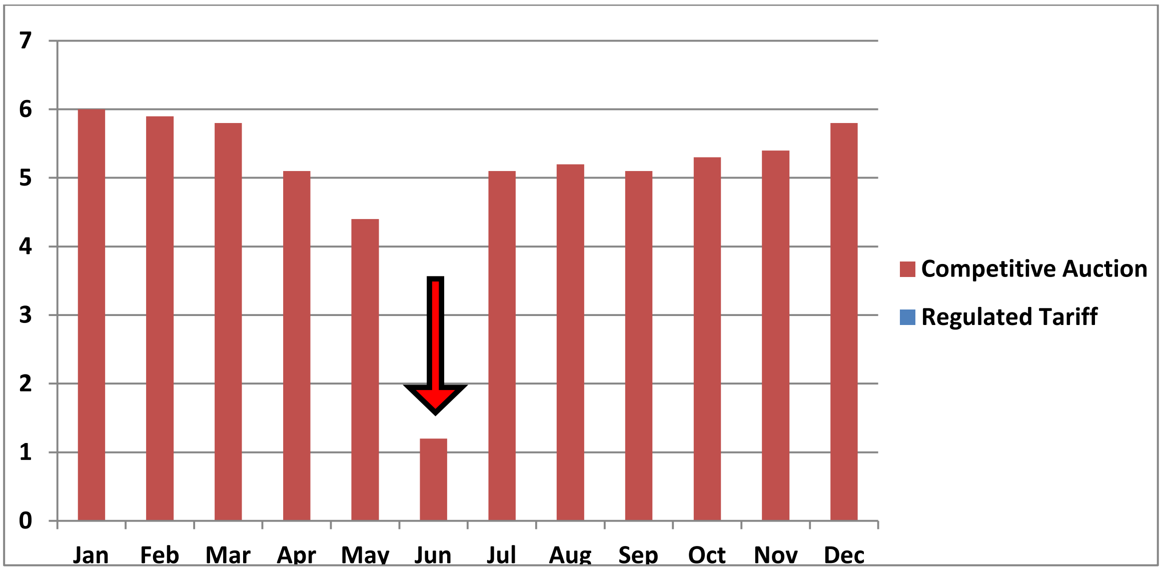
A stylised payment structure for a 'mid-merit' gas generator (**Generator B**) with less competitive bids for the same service is shown below:



This generator, while technically capable of providing the service, has not been in a market position that makes it available to provide the service. However, for the month of June, its bid for this service became competitive because of the scheduled outage of **Generator A**. Similarly, in the months of November, December and January, a greater volume of the requested service was required by the TSO in order to manage the system, and a number of the 'in-merit' generators were running baseload, which reduced the volume they could provide.

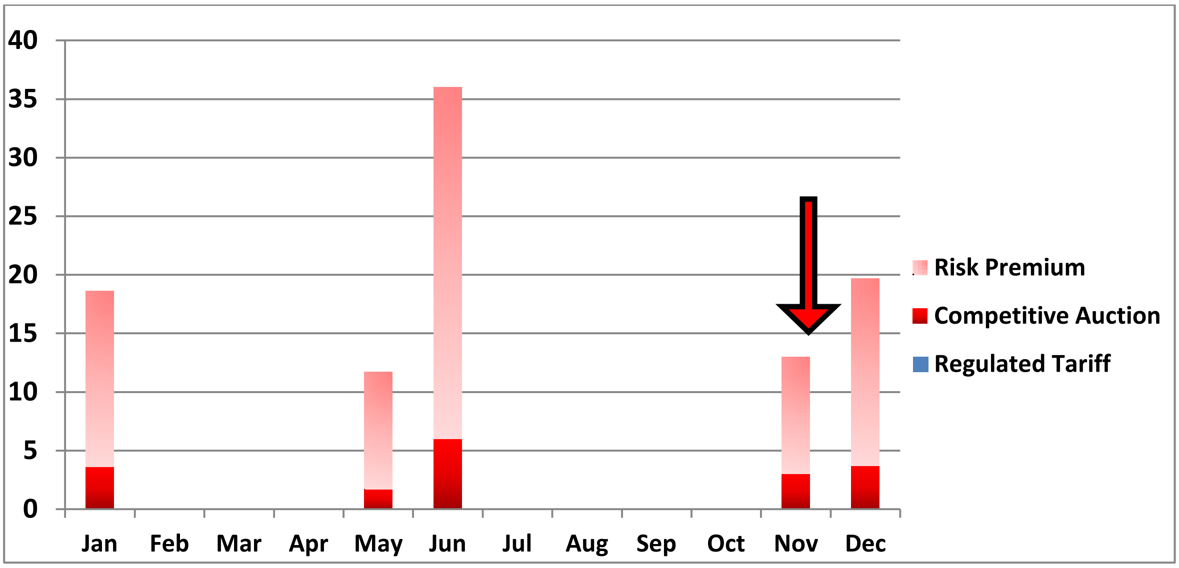
Comparing the outcomes of Generator A and B under a **'pure'** version of Option 5 as proposed by the RAs, we can see a very different set of outcomes:

Generator A in a **Competitive Multiple Bid Auction:**



Generator A would be in a position to make an investment decision to enhance, on the basis of its expected running in Year 1. However, assuming these revenues over the repayment period of its investment wouldn't be realistic – it could look like **Generator B** below if a new plant entered the system, or if a commodity input price or transportation cost changed. They would adjust their bid to reflect these risks, potentially looking to recover their investment over a very short time horizon.

Generator B in a **Competitive Multiple Bid Auction:**



Generator B would be able to assume some revenues to underpin its investment, but those revenues would not be within its control – they would be driven by TSO demand for these services i.e. high wind output in November and December and scheduled outages of in merit plant. It is very unlikely that **Generator B** could make an investment decision without adding a substantial risk premium to its offers, which in turn could unnecessarily increase the clearing price of the auction for all generators, including **Generator A.**

If **Generator B** could not make an investment case for enhancement, the TSO would be left with insufficient plant on the system during the periods in which those services are most likely to be required i.e. forced/scheduled outages of key plant and high wind periods. This is not an efficient outcome for consumers – they would be missing out on any share of substantial production cost savings because only a limited number of investment cases could be made.

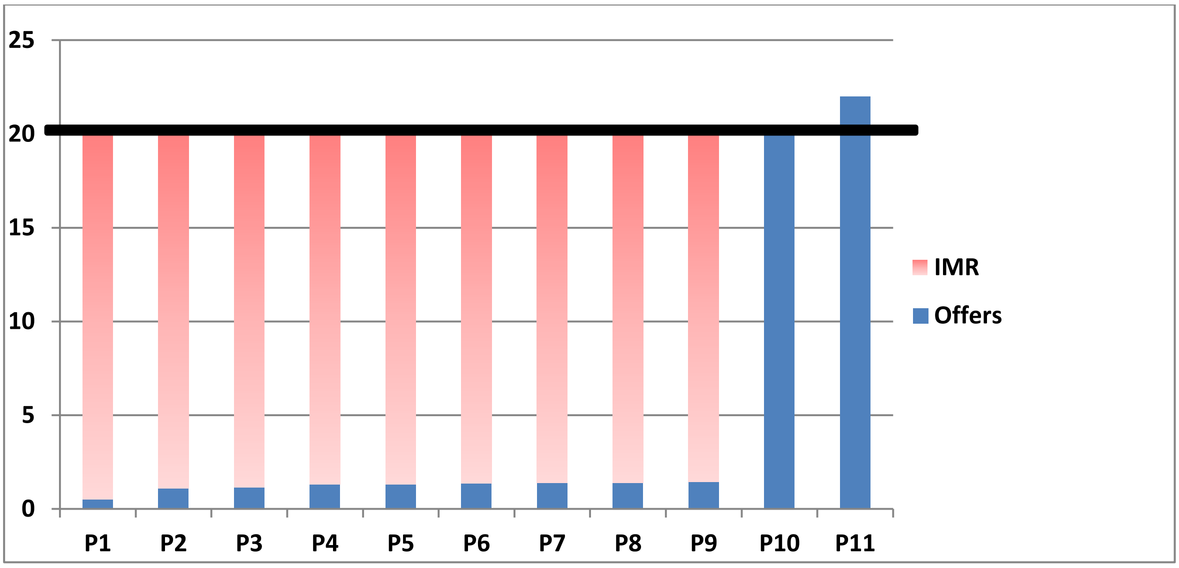
Finally, the risk premiums added by mid merit plant to their auction offers would likely be unacceptable to the RAs – forcing them to revert to a regulated tariff for some products, and further complicating the bidding strategy and undermining the investment cases of both **Generator A** and **Generator B.**

Interactions with the energy market?

It is very clear that any scenario under a 'pure' version of Option 5 will have very heavy interactions with the energy market, not just in the sense of long term investment decisions, but in terms of short run optimisation and bidding behaviour. This has been acknowledged to some extent in the paper – but we would note that some potential scenarios are effectively moving toward co-optimisation, which has been explicitly ruled out by the SEM Committee in I-SEM design.

V. Do you agree with the SEM Committee's proposal to adopt this option and only to fall back on Option 1 (Regulated Tariffs) where the auction fails to deliver the required volume of services.

We are assuming that the only **[auction fail]** criteria is a failure to deliver the required volume of services, but it is not clear that the RAs would not intervene in a scenario similar to that shown below, if the least-cost overall outcome selected services that guaranteed substantial amounts of inframarginal rent to a number of providers.



Given that the paper explicitly states that an objective of the procurement design is to *"ensure that payments do not exceed value"* it is difficult to imagine that a least cost overall outcome that exceeds the estimated value would be allowed. It is not much of a stretch to assume that services with a merit order similar to that above would be the first to declared as **[auction fail]**.

Similarly, a mix of entirely regulated prices for some products and purely competitive prices for other products does not seem consistent with a mutually exclusive bid structure. Effectively, if an **[auction fail]** was declared for one product, it would have to be declared for all products. This would further complicate the bidding strategies and investment cases for any generator participating in the auction.

Are there any specific issues the SEM Committee should consider regarding the auction design?

Do you agree that market power mitigation measures are required?

Are SEM Committee proposals regarding market power sufficient? Should alternative or additional measures be considered?

Are there any specific requirements that the SEM Committee should include in the bidding rules?

The IPA report lists potential market concentration by defined product group, alongside potential market concentration in a highly optimistic scenario in which the dominant generator chooses to relinquish market power[5]. The second scenario is not realistic.

Table 27: Potential market concentration by group

Product Group	Main generation sources of group	Group HHI
Group 1	CCGT, Pumped storage, Interconnector, Wind	2,864
Group 2	CCGT, OCGT	2,391
Group 3	CCGT, Pumped Storage, Interconnector	2,009
Group 4	CCGT, OCGT, Pumped Storage	2,572

It is unclear how:

- A tolerable level of market concentration could be achieved by October 2016.
- How market power mitigation measures for highly concentrated product groups could work.

Under Option 5, the two market power mitigation features chosen appear to be:

"[A]ll existing units be required to submit bids reflecting their current technical capabilities for a contract duration of one year."

SSE assumes that these bids would not be as price takers, as this would make Option 5 entirely uninvestable[6]. If those bids were price making, no restrictions could be placed on the formulation of those bids, because those bids would be on the basis of assumed volumes of market running. A generator could not be restricted from pricing a service with an

[5] A reference is made to Centrica's choice to dispose of 2.2GW of CCGT assets in the UK – this isn't really a realistic comparison. Centrica has not decided to dispose of a large volume of capacity, nor does BETTA suffer from similarly high levels of market concentration. The dominant generator in Ireland has very different incentives to a smaller generator in a larger market.

[6] Enhancing generators would effectively have to assume zero revenue from system services once the required volume of products have been delivered, alongside existing the GPIs associated with grid code mandated services.

conservative assumed load factor of 20%, even if it was likely that that generator would be in the market at 40-50% of the time.

"[T]he sealed bid element is also important given the nature of the services and the design of the auction. This process permits all bids for all products to be entered simultaneously and evaluated comprehensively with all the available information. The amount of information available to the TSO is therefore maximised, facilitating the optimal procurement of services over the long run, while the information revealed to participants is limited to the clearing prices."

As noted in the consultation paper, a sealed bid approach is a necessity under the **Competitive Multiple Bid Auction**, and does provide some market power mitigation. Repeated auctions reduce the potential for coordination.

Nevertheless, given the RAs definition of 'availability' for payment basis, it is hard to see how the RAs could effectively monitor or control bids in the DS3 system services framework (or whether it would be desirable to do so). A broad brush approach that sets minima/maxima i.e. PFLOOR and PCAP based on the supply and demand analysis, respectively, could protect consumers, but would not necessarily protect market participants from the exercise of market power.

VI. Do you agree with the proposed payment basis for each service/option?

The consultation paper defines the different payment basis as follows:

- **Dispatch –** only when 'used'.
- **Availability –** only when the unit could have been 'used'.
- **Capability –** units that are technically capable of providing the service.

The RAs have made a radical addition through **'availability'** as a payment basis. This would effectively concentrate payment on units with market running (or constrained on running due to redispatch actions[7]. Under the capability definition, payments would be diluted and spread across a wider number of units.

The total sum of payments is unlikely to change, but the distribution of those payments will. SSE believes that this choice has been made on the basis of the **investment** criteria '**exit signals'** which the RAs have given fairly high priority[8]. We would suggest that '**availability'** as a payment basis without a tiered structure would effectively make any incremental investment impossible, unless costs can be recovered over a 1 year period.

[7] This effectively locks some units out of markets for certain products i.e. peaking and mid merit plant and some network investments will no longer have any incentive to enhance their units to provide availability based services.
[8] Especially considering that the aim of DS3 is to bring forward investment.

SSE would suggest the following payment basis:

Service	Regulated Tariff (Tier 1)	Competitive Auction (Tier 2)
SIR	**Capability**	**Availability**
FFR	**Capability**	**Availability**
FPFAPR	**Capability**	**Availability**
SRP	**Capability**	**Availability**
DRR	**Capability**	**Availability**
Op Reserve	**Capability**	**Dispatch**
RRS/RRD	**Capability**	**Dispatch**
Ramping	**Capability**	**Dispatch**

Cost will be underwritten so investment decisions can actually be taken by providers through **Regulated Tariffs**, and competition can be brought to bear on the distribution of value to different generators through **Competitive Auctions**.

VII. Do you agree with the SEM Committee's views on the interaction with the energy market?

Under Option 5 as currently defined, the construction of bidding strategies and offers from providers requires a conservative estimate of energy market volumes (or Balancing Market redispatch).

The paper states that:

"In principle the SEM Committee considers that the three revenue streams (energy, system services and capacity) should collectively work together to provide the appropriate incentives to the market for entry and exit. Therefore it is important not only that there is no double payment between revenue streams but also that the total revenues should incentivise the type of generation most needed by the system."

In an unconstrained market with no bidding restrictions, effective competition and perfect information (i.e. properly staggered system services and capacity auctions), double payment should be impossible – bids will simply be discounted. However, information is likely to be imperfect, market concentration remains high and the RAs appear willing to place restrictions on how providers of capacity/energy/services offer into each respective market.

The fewer bidding restrictions that are necessary in procurement design, the less likely arbitrage (and thus misallocation between capacity, energy and service provision) is to take place. Option 5 appears to require a great deal of volume intervention (and an unspecified level of price intervention), therefore risks arbitrage and misallocation.

One other concern we would flag is that offers and the overall supply curve for certain products like **Operating Reserve** will bound bidding in the energy market. A unit that has submitted a certain offer for an **Operating Reserve** product will need to adjust their balancing market bids in I-SEM to account for the opportunity cost of not providing reserve at a particular moment in time. Constraining near term energy market bids is effectively partial co optimisation – something that has explicitly been ruled out by the SEM Committee.

It is not clear why co optimisation is being reintroduced through the DS3 System Services procurement design, given that it was rejected by the SEM Committee and stakeholders including the majority of the industry, previously.

Do you have any views on the potential interactions and appropriate measures to address these interactions?

By introducing competitive bidding and a new definition of '**availability'**, the only means to address interactions with the energy market is through dilution – i.e. ensuring that some of the payment stream will be through capability, rather than through a payment basis that is linked to bidding behaviour in the near term energy and balancing markets. Our rough outline of a two tier payment structure could achieve that.

VIII. Are there any other issues not raised in this paper the SEM Committee should consider?

SSE would highlight the delays to various aspects of the DS3 programme since **SEM/13/010** on **Treatment of Curtailment in Tie-break situations**. The final decision paper and previous decision papers redefined where the economic cost of a system, unable to cope with zero marginal cost generation, would lie.

Eliminating compensation for curtailment shifted all of the cost and future risk from the market (particularly, the TSO and the RAs, who have the levers necessary to influence the level of curtailment) to wind generators alone. While this removed the metric used to measure the cost of an out-dated system, the opportunity cost is still clear, as the demand analysis in this paper demonstrates. The table below shows how changes to SNSP have been consistently delayed following this shift in incentives:

SNSP Level	2010	April 2013 (Immediately after SEM/13/010)	April 2014
55%	2013	2014	Q4 2016
60%	2013	2014	Q4 2017
65%	2015	2015	Q4 2017
70%	2017	2017	2019
75%	2019	2019	2019

The RAs have removed any visible incentive for themselves or the TSO to resolve the issue of curtailment. This has already translated into substantial delays in the delivery of DS3. The opportunity cost is still there, however, as the demand analysis shows. **Delays due to complexity in design, delivery and implementation will mean more time before consumers and generators can share the production cost savings that DS3 will deliver.** Time is still of the essence, even though cost and risk have been removed from the RAs and TSO.