

REVIEW OF THE ENERGY MARKET AUTHORITY'S THIRD CONSULTATION ON DEVELOPING A FORWARD CAPACITY MARKET

A note from AFRY Management Consulting to Energy Market Company

11 June 2020

Introduction

This note contains summary outputs from a review of third consultation paper on Developing a Forward Capacity Market (FCM) issued by the Energy Market Authority (EMA). It seeks to collate reactions to and thoughts arising from the latest FCM design proposals contained within the consultation document.

The review looks at the proposals in general, but also considers them through the lens of potential distributed energy resource (DER) providers to complement ongoing work under the remit of the Market Advisory Panel (MAP) in relation to integration of DER into the market. The intention is that this feedback helps to sharpen the proposals both in general and, wherever relevant, in terms of their application to DER.

As agreed with EMC, the review does not focus on whether the FCM is the correct solution for Singapore to progress. Rather it takes the proposed framework as given and provides neutral feedback based on AFRY's international experience with the intent of improving the FCM design to suit Singapore's context.

The note has two sections: first, a summary of high level observations is provided followed by, second, provision of more detailed observations on specific elements of the proposal package.

High level observations

This section focuses on aspects of the proposals that we consider to be well defined and in line with good practice or areas that raise may require attention in future, as well as issues to explore further for DER participation specifically. Areas where questions exist or additional clarity is needed are contained within the subsequent 'more detailed observations' section.

Effective design

No short-run marginal cost bidding requirement

The requirement for short-run marginal cost bidding proposed in earlier consultation rounds has been dropped, which is positive. It has been replaced

with the suggestion that suppliers who fail a 1 pivotal supplier test will have real-time market bids mitigated to a maximum of 3 x short-run marginal costs for a CCGT (based on F class CCGT, a figure of €355/MWh is proposed).

This alternative is preferable to blanket short-run marginal costs bidding requirements, as suggested in previous consultations. Nevertheless, it is still a restriction on energy price formation, albeit with reduced impact than could otherwise have been the case.

Qualification and capacity ratings

The proposed minimum participation threshold of 1MW in de-rated capacity terms is positive as a first step to provide scope for and experience of participation from smaller scale resource. The threshold should be under review, with the expectation that it could be reduced (e.g. to 0.1MW in line with demand response participation thresholds), which could help to unlock more DER in time.

The proposed approaches for performing capacity ratings are pragmatic and rightly acknowledge differences between technologies in terms of their technical characteristics and performance e.g.:

- For solar and demand response appears to focus on ability to deliver in a subset of hours, reflecting limited hours of operation.
- Proposed self-nomination of demand response resource availability by the aggregators is also helpful, but need clarity on the review process that EMA will apply to this.

Bilateral transactions

Allowing bilateral transactions to transfer obligations between eligible parties is positive. We understand that transfers can be conducted at a 30 minute temporal granularity and are supportive of this, as it allows for period by period sculpting of obligations across a day to reflect conditions.

Issues for early attention

The following topics could benefit from immediate attention to ensure that the FCM is designed in a manner that delivers against policy objectives from the outset.

Commitment terms

The general commitment term for capacity obligations is 1 year. However, the proposal is that new/repowering CCGTs with a 25 year economic lifetime only will have access to a term of 10 years. This gives preferential treatment to new over old capacity, which may serve to unduly hasten closure of existing plant. It also risks skewing new build investment towards CCGTs to the detriment of development of different resources (e.g. batteries, DSR, aggregation) that could help to meet adequacy needs. This type of discrimination in terms of commitment period resulted in legal challenge in the context of the GB capacity market and arrangements have now been revised

in response¹. If there is to be differentiation between new and existing capacity, it would be preferable for non-discriminatory treatment across all new resource types.

In the context of growing solar and reduced potential operating hours for a CCGT fleet, this risks locking in technology with an enduring missing money problem, when there are alternative technologies available. Ongoing reviews (e.g. in relation to integration of imports, integration of renewables and allocation of reserve costs) all create uncertainties in respect of potential CCGT revenue expectations - how much of this risk will operators seek to cover through capacity payments?

In relation to the above points, we are aware that there are wider policy considerations (e.g. back-up fuel provisions for CCGTs as part of security of supply toolset) and practical considerations (e.g. available space), which may influence delivery of security of supply. Nevertheless, explicitly providing only new CCGTs with access to longer term commitment may result in a deviation from the long-term goals of the FCM from an energy market perspective.

The rationale provided also cites that advanced CCGTs will also support requirements for frequency response and spinning reserves. This may result in unintended consequences such as creating a non-level playing field in respect of balancing services by favouring CCGTs at the expense of other newer viable technologies. In this space, technologies such as batteries and demand side response are well able to fulfil the service requirements (with operational experience available from other jurisdictions) and they are better suited than conventional technologies to provision of particularly rapid response requirements, for example.

Supply type floor requirements and caps

In addition to the commitment term, the requirement for 9GW of resource to be secured from conventional generation, combined with caps on participation of 200MW each from demand response and storage risk introducing or reinforcing distortions and compromising technology neutrality. The 200MW caps in particular risk hampering the development of these more innovative technology types. Developers will face regulatory uncertainty linked to this cap, as it not clear how it may change and over what timescale. Whether or not these conditions are absolutely necessary is a critical question for the final design.

¹ The Great Britain Capacity Remuneration Mechanism (CRM) originally offered contracts of up to 15 years for new generation and storage technologies only. New demand side response resource was only eligible for 1 year contracts and not the longer tenure. Following legal challenge and temporary suspension of the scheme during the legal process, demand side resource is now eligible for contracts of up to 15 years.

Market power mitigation measures

Non-participation in a capacity auction for a delivery year is required to also mean non-participation in the energy market in that delivery year. However, there may be genuine reasons why, for example, older plant approaching closure may prefer not to commit to the 4 year ahead capacity auction given commercial uncertainties. But to prevent it from energy market participation, may hasten a closure decision and contribute towards bringing an adequacy issue forward. An alternative would be to allow for opt-out with explicit adjustment to the auction demand requirement to reflect potential ongoing contribution of an opted out plant.

So if, for example, a 400MW station wishes to opt-out of the capacity auction but gives a clear indication (or possibly commitment) that it will remain active in the energy market, the capacity auction demand curve can be shifted left by an amount equivalent to the de-rated capacity of the opted-out station. This means that the quantity of resource that the auction needs to secure is explicitly adjusted (specifically reduced) to account for the expected contribution of the opted-out station.

Obligations and performance penalties

Resources that are available but not scheduled in the real time market can be activated for emergency purposes via out of market commitment by the PSO. However, the indication is that these actions will not be remunerated and this is expected to be reflected in capacity auction offer prices (i.e. implying a premium to cover costs that cannot be recovered). If resource is not scheduled in the real-time market it is reasonable to assume that it:

- is one of the higher cost units with lower running hours;
- will have relatively high missing money from the energy market; and
- is reasonably likely, therefore, to be amongst the price setting resource in the FCM.

Given this, any premium to cover out of market commitment costs has the potential to influence the overall FCM clearing price, increasing the costs of the FCM. Assessment of this potential outcome and its implications for FCM costs would be of use to understand its validity and scale.

Issues for future attention

The following topics will benefit from early review and update following some operational experience.

Product design

The capacity product is structured around a 4 hour notification period. Arguably, this feature is intended to suit the existing largely CCGT fleet, for which a 4 hour start up period is typical. However, this may not be the speed of response that the system needs to deliver adequacy now or in the future. The risk is that the 4 hour parameter becomes enshrined in the arrangements

and changing it, even when justified for system requirements, (or the potential that changes will be made), creates regulatory risk for investments made on the basis of the 4 hour notification period.

While the product design may be considered fixed for the initial auction, implicit design features such as the notification period and expected shortage duration should be revisited to ensure that product design is appropriate for Singaporean needs and is adaptable to evolving circumstances in a way that does not introduce instability.

Bilateral transaction

It is sensible and appropriate for there to be reporting of transfers and an up to date registry of CSO allocation. However, the wording relating to transfers raises a concern that there is a requirement for EMA to agree to bilateral trades, which could create a barrier to trade and has the potential to reduce the likelihood of transactions occurring. This creates potential for regulatory risk, depending on the type of review and involvement EMA intends to have.²

As is the case in the current spot market arrangements, it would be preferable for there to be no EMA role in approving bilateral trades. If this cannot be achieved for the first auction, it should be the objective for the next round of auctions.

DER participation specific issues/queries

The following are potential areas to explore further specifically regarding DER participation:

- **Scope for lower participation threshold:** Reducing the participation level below the currently proposed 1MW threshold will help to increase the scope for involvement of DER within the FCM. This will be advantageous for DER business models, as it provides access to an additional revenue stream. It is also beneficial for the operation of the FCM, as it increases competitive pressure and should be expected, other things being equal, to reduce the costs associated with the capacity market.
- **Caps on demand response and storage:** The proposed 200MW caps have the potential to frustrate development of DER business models and it would be preferable for these to be removed if possible or, if caps are to be retained, for the cap level to be increased.
- **EMA review process for review of self-certification of DER/aggregated capacity potential:** It is helpful that the qualification process acknowledges that there is diversity in the makeup of aggregated resource and allows for self-declaration followed by EMA review. DER providers can approach this

² The GB CRM allows for transfer of capacity agreements, with transferring parties each required to register transfers but without the need for regulatory approval. The Irish CRM allows for secondary trading through a centralised marketplace, with activity monitored by the regulatory authorities but regulatory approval is not required.

proactively and engage with the EMA to present different DER formations (including potential combinations across resource types) in advance to help to smooth this process.

- Ability for Firm Service Level (FSL) consumers and guaranteed load drop (GLD) consumers to be combined into an aggregated portfolio: Linked to the above, if the arrangements allow for FSL and GLD consumers to be combined and aggregated for purposes of FCM participation, this will allow for more resource to participate and greater flexibility for aggregators.
- Clarification of potential penalty arrangements: There is a need for more clarity on the potential penalty exposure for DER in the event of extended system stress events, such that the risk can be assessed and priced appropriately within capacity offers.
- Interactions between existing demand response and interruptible load schemes in terms of qualification, obligations and operation: The EMA notes the need to consider linkages between the FCM and existing demand response schemes. Contributions from the DER community into this process will help to deliver appropriate compatibility between the different arrangements.

More detailed observations

Product definition

Table 1 – Product definition: observations/comments

Feature	Observation/comment
<ul style="list-style-type: none"> ▪ Product is 1MW of Capacity Supply Obligation (CSO) for a year 	Deliberately simple availability based, non-locational product
<ul style="list-style-type: none"> ▪ CSO requires resource to offer into the spot energy market / ancillary services market 	Associated obligations considered below (Table 9).
<ul style="list-style-type: none"> ▪ Penalties for unavailability and non-performance 	Associated obligations considered below (Table 9).

Administrative demand curve

Table 2 – Administrative demand curve: observations/comments

Feature	Observation/comment
<ul style="list-style-type: none"> ▪ Downward sloping demand curve with price points set with reference to net CONE 	Common approach applied in various Europe and US markets.

Feature	Observation/comment
<ul style="list-style-type: none"> Target capacity to 3 hour loss of load expectation set at the price cap of 1.5x to 1.75x net CONE 	<p>In GB and Irish contexts, the target capacity is priced at net CONE. Other things being equal, pricing the target capacity at 1.5x or 1.75x net CONE would be expected to result in a higher clearing price and/or a larger quantity of capacity secured compared to the GB/Ireland approach.</p>

Supply resource qualification and capacity ratings

Table 3 – Supply resource qualification and capacity ratings: observations/comments

Feature	Observation/comment
General	
<ul style="list-style-type: none"> Minimum requirement for 9000MW of installed capacity from traditional generation sources of frequency response to be secured through the FCM until other technologies are proven 	<p>Understand that this is to have access to resource that can provide spinning reserve to fulfil requirements of the Transmission Code. This minimum requirement introduces a distortion to the intended technology neutrality of the FCM and complicates the clearing process for the auction itself. It also creates differentiation in the underlying capacity product, with some resource needing to be frequency responsive but this not needed for other resource. It may also introduce some discontinuities in the operation of the auction itself.</p> <p>Given that CCGT/cogen/trigen accounted for ~8GW in 2019, the 9GW 'traditional generation source' requirement is expected, therefore, to lock in new build CCGT. While this may be the most likely source of new build, the minimum requirement has the potential to have a distortionary impact.</p> <p>It would be interesting to understand how 9GW compares to the expected capacity target needed to meet the 3 hour loss of load standard to understand the space for other technologies.</p> <p>If a minimum quantity of frequency responsive capacity is a requirement, then this should be technology neutral and allow for all forms of frequency responsive resource, rather than limiting this to traditional generation sources only.</p>

Feature	Observation/comment
<ul style="list-style-type: none"> ▪ Cap of 200MW of cleared capacity of each of demand response resource and storage 	<p>As above, this introduces a distortion to the intended technology neutrality of the FCM and complicates the clearing process for the auction itself.</p> <p>The proposed cap on potential contribution from these non-conventional resource types risks harming the business case for and development of these resources. While the desire to gain operational experience of these resource types is understandable and the expectation is that the maximum cap will be reviewed, the mere existence of this cap creates regulatory uncertainty for potential developers that could stifle deployment of innovative solutions.</p>
<ul style="list-style-type: none"> ▪ Capacity ratings determined based on Qualified Capacity (QCAP) rather than Installed Capacity (ICAP) 	<p>Sensible to de-rate installed capacity to reflect expectations of reliable availability, so QCAP-type approach is appropriate. Challenge for de-rating is how to achieve equivalent reliability across resource types.</p>
<ul style="list-style-type: none"> ▪ Minimum participation threshold of 1MW expressed in ICAP terms 	<p>It would be preferable for the threshold to be expressed in QCAP terms, rather than in ICAP terms, to allow for de-rating effect to be factored in. The ICAP approach increases the size requirements for resource types with higher de-ratings, which are likely to be the less conventional resources.</p> <p>A lower threshold would help to increase participation from smaller scale distributed resource. How much extra resource could be able to participate if the threshold was lowered to, for example, 0.1MW (noting that the Demand Response Programme caters for aggregate consumption reductions of 0.1MW)? The potential for downward to the participation threshold could be considered based on operational experience.</p>
Traditional	
<ul style="list-style-type: none"> ▪ QCAP will be based on ICAP with adjustments for planned and unplanned outages 	<p>Common approach used elsewhere.</p>

Feature	Observation/comment
<p>Solar</p> <ul style="list-style-type: none"> <li data-bbox="240 344 735 506">▪ Proposal for solar de-rating to be based on simplified 'on-peak' performance factor, with analysis suggesting a de-rating to 31.5% of installed capacity <li data-bbox="240 528 735 685">▪ For existing solar installations, latest year of historical data will be used as basis for de-rating. For new installations, class averages will be used. 	<p data-bbox="762 338 1430 528">Three potential models for de-rating solar capacity are discussed. One is a simple average of hourly capacity factors. The other two include some form of weighting of average hourly capacity factors by the probability of lost load.</p> <p data-bbox="762 539 1430 663">The former gives a de-rated capacity of 18% while the latter give values in the range 31-32%, reflecting the correlation of solar generation with demand.</p> <p data-bbox="762 674 1430 864">The proposal is for adoption of a de-rating approach based on average load factor during on-peak periods (9am to 10pm), which gives reported de-rating of 31.5%. This is preferable to the rejected simple, straight average approach.</p> <p data-bbox="762 887 1430 1402">There is an open question as to whether the more complicated probability of lost load approach could be more appropriate as an enduring solution given the expectation of increased solar penetration. To monitor this issue, the outcomes from each of the more complex methods can potentially be compared at regular intervals to assess performance/implications, with the potential for a switch in methodology if it appears from the comparison that the third option is more appropriate and robust for a higher solar penetration. Such a switch could be triggered based on an ex-ante, transparently defined metric (e.g. when solar capacity is x% of peak demand) to signal intention in this regard.</p> <p data-bbox="762 1424 1430 1626">Are peak hours of 9am to 10pm appropriate? How well aligned are they in their entirety with periods of highest probability of lost load? Are they likely to be stable over time, given potential implications for investment incentives?</p>

Feature	Observation/comment
Demand response	
<ul style="list-style-type: none"> <li data-bbox="229 324 750 571">▪ Demand response qualification based on submission by aggregators of customer acquisition and retention plans, including development milestones. EMA will review plans and de-rate capacity. 	<p data-bbox="750 324 1433 828">There is acknowledgement that aggregators do not necessarily precisely know the make-up of their portfolio and the available resource in T-4 year timescales. The proposed response is to allow qualification based on forward looking plans and effectively self-declaration by the parties themselves, with checking by the EMA. This is helpful as a principle. But no clarity is provided on the principles or processes to be applied in terms of the EMA's review and the approach for reaching de-rated capacities, including its methodology for assessing potential duplication between aggregators. Need clarity here, including dispute resolution process for any disagreements.</p> <p data-bbox="750 828 1433 1052">Interactions between the existing demand response and interruptible load schemes in terms of qualification and obligations need to be reviewed further to ensure that inconsistencies or incompatibilities are avoided wherever possible.</p>
<ul style="list-style-type: none"> <li data-bbox="229 1052 750 1276">▪ Demand response rating linked to availability during 'required hours', most likely weekday peak hours. Lower de-rating if only partially available during the required hours. 	<p data-bbox="750 1052 1433 1299">Need for sufficiently advanced transparency and also stability in terms of when required hours are expected to fall to allow for aggregators to develop business plans for submission. Will the required hours for demand response be aligned with the obligation hours for solar?</p> <p data-bbox="750 1299 1433 1411">Is de-rating for partial availability based on a straight average or is there any weighting between the required hours?</p>
<ul style="list-style-type: none"> <li data-bbox="229 1411 750 1500">▪ Demand response notification time to be identified 	<p data-bbox="750 1411 1433 1612">Suggestion is for a defined, single maximum notification time for all demand response. Need clarity on what this value is likely to be. It appears that there will be no upside for resource that is able to respond faster than this notification time.</p>
<ul style="list-style-type: none"> <li data-bbox="229 1612 750 1736">▪ Demand response duration time provisionally 4 hours to cover most shortage events 	<p data-bbox="750 1612 1433 1883">If there is a system stress event lasting longer than 4 hours, it appears, however, that demand response providers will face penalties if they are unable to sustain response over a lengthier period. The penalty risk that this creates may be expected to be translated into an increment to capacity offer prices as a mitigation measure.</p>

Feature	Observation/comment
<ul style="list-style-type: none"> ▪ No limitations on the potential number of interruptions for demand response 	<p>Reasonable rationale on basis that it is equivalent to expectations for conventional generators.</p> <p>If this is clear from the outset, then aggregators can construct their portfolio and the associated commercial arrangements on this basis.</p>
<ul style="list-style-type: none"> ▪ Distinction between Firm Service Level (FSL) consumers, with baseload essential loads and varying non-essential loads, guaranteed load drop (GLD) consumers, with varying consumption band 	<p>Reasonable rationale for this distinction. Compliance seems sensible too with FSL resource needing to reduce consumption to the FSL level and GLD resource needing to reduce consumption by GLD relative to consumption in preceding periods.</p> <p>Can both consumer types be included in the same aggregated demand response or do they need to be handled in separate portfolios?</p>
<ul style="list-style-type: none"> ▪ If a shortage event is anticipated, demand response resource will receive notification to offer into the energy/ancillary services market at prices up to the relevant market price cap 	<p>The consultation notes the need to consider interactions with the existing interruptible load framework. This action needs to be undertaken. Issues to be considered include: allowed configurations and compatibility between FCM and other schemes; performance obligations and compliance requirements; interactions with energy market participation and bidding; testing requirements; metering specifications.</p>
<p>Storage</p>	
<ul style="list-style-type: none"> ▪ Storage rating based on maximum sustained output over 4 hours 	<p>Means that shorter duration storage will be more heavily de-rated, which is reasonable. As the anticipated shortage duration is 4 hours, this means that a 4 hour duration battery will have a comparable de-rating to thermal capacity.</p>

Feature	Observation/comment
<p>Solar plus storage</p> <ul style="list-style-type: none"> <li data-bbox="229 338 762 448"> ▪ Distinction between AC coupled and DC coupled solar plus storage <li data-bbox="229 1077 762 1111"> ▪ Not clear what obligation will be 	<p>Suggested AC coupled approach based on sum of individual solar and storage ratings.</p> <p>Suggested DC coupled approach is based on historical performance for existing assets based on developer's proposed rating for new assets.</p> <p>Flexibility in approach sensible given challenges of combined assets.</p> <p>What is the process for reviewing developer proposals in case of new DC coupled assets?</p> <p>What is the approach / timeframe for considering historic performance for existing DC coupled assets? Will anomalies e.g. line outages be adjusted for somehow?</p> <p>What is the dispute resolution process for each?</p> <p>Need to gauge with developers whether the proposed approach would skew installation decisions</p> <p>How will required hours approach for solar and the more blanket approach for storage be balanced in terms of setting the obligation for integrated resources?</p>
<p>Imports</p> <ul style="list-style-type: none"> <li data-bbox="229 1261 762 1624"> ▪ Acknowledgement that treatment of imports could focus on qualification of specific capacity resource from an external market in a manner similar to specific domestic resource or qualification of generic capacity not tied to an individual resource but which can be provided via an interconnector 	<p>In Europe, there are cases of interconnectors themselves participating. For example, the GB and Irish CRMs currently allow for interconnector assets to participate in capacity auctions and to hold obligations if successful in auctions. This approach is, however, being phased out in line with the European Commission preference for non-domestic assets to participate directly. The reasoning for this is that interconnectors cannot themselves provide active energy or availability, as they are transmission assets. It is the non-domestic resources that are the source of energy and, therefore, the preference is for them to participate directly.</p>

Feature	Observation/comment
<ul style="list-style-type: none"> ▪ Additional requirements for qualification of specific external resource; first one is non-recallability 	<p>Non-recallability requirement asks for a guarantee from the host region that resources are not committed to provide capacity in their home region and that the host region will not curtail associated exports.</p>
	<p>Challenge is that the resource itself cannot offer guarantee, as it is contingent on system operation decisions regarding the interconnector. Requires broader cooperation. What consideration has been given to practicalities of this?</p>
<ul style="list-style-type: none"> ▪ Additional requirements for qualification of specific external resource; second one is non-deliverability 	<p>Deliverability requirement means that generation must be supported by firm access to its own domestic grid and to the interface between it and Singapore, with accompanying demonstration of proof of rights. Are the access regimes consistent with this and can external providers obtain the required proof?</p>
<ul style="list-style-type: none"> ▪ External providers face same performance requirements and obligations as domestic 	<p>Seems reasonable. But actual ability to deliver is dependent on system operator decisions, so, even if resource is available, domestic grid issues may affect performance.</p>
<ul style="list-style-type: none"> ▪ De-ratings based on equivalent approach for relevant technology in Singapore but with additional de-rating for possible interconnector failure/outages 	<p>Seems reasonable. Systematically discounts non-domestic capacity given additional interconnector outage risk.</p>
	<p>Will different de-ratings apply to different interconnectors? Probably should be different rating given different engineering and possibly different connected markets.</p>
<ul style="list-style-type: none"> ▪ Non-domestic resource eligibility includes all technologies excluding demand side based on technical challenges 	<p>Challenges are genuine. But unsure whether this blocks a significant quantity of resource and so merits more attention.</p>
<ul style="list-style-type: none"> ▪ Alternative model of interconnector participation flagged but not fleshed out 	<p>As indicated above, interconnector based participation currently forms the basis of participation of non-domestic resource in GB and Ireland. Interconnectors have a specific asset by asset de-rating and can then participate in capacity auctions along with other resource types. If successful in auctions, interconnectors hold obligations comparable to other resource types.</p>

Feature	Observation/comment
<ul style="list-style-type: none"> Implications for interconnected markets 	<p>A challenge for this is buy-in and cooperation from the connected markets, as it requires support and data for things like qualification and performance monitoring, as well as acceptance that resources may be committing to support Singapore's adequacy and not adequacy on their own system. We do not have sight of the wider process in this regard, but it clearly requires political, regulatory and system operator buy-in in both jurisdictions.</p>
Timeline	
<ul style="list-style-type: none"> Acknowledgement that qualification timeline will likely include an initial application, followed by a more detailed application and then disputes 	<p>Details still to be provided on a proposed timeline, the information requirements attached and the responsibilities for running the process.</p>

Financial assurance requirements

Table 4 – Financial assurance requirements: observations/comments

Feature	Observation/comment
<ul style="list-style-type: none"> Propose financial assurance requirement for new resource set at 0.3 * Net CONE 	<p>Fixed rate provides simplicity and certainty for new investors.</p> <p>Any sensitivity to potential changes in reference technology used in net CONE calculation?</p>
<ul style="list-style-type: none"> Propose allowing transfer of financial assurance requirements if obligations are transferred 	<p>Agree with principle. Needs supporting monitoring and processes to deliver this.</p>

Feature	Observation/comment
<ul style="list-style-type: none"> Propose ongoing credit requirement for new and operational resources of .25 * 0.3 * clearing price received to cover any penalties linked to underperformance relative to obligation. Suggestion that this requirement could be waived for resources demonstrating good reliability and/or have low risk of failure to meet obligations. 	<p>Understand rationale for some form of credit to provide coverage for penalty fees. Need to see assessment of proportionality of the proposed rate of credit to form view on appropriateness of the level. Is it proportionate for all participant types?</p> <p>There is an open question regarding the possible effects of the credit requirement on bids into the auction, as this is an additional cost/liability to be covered.</p> <p>Need to see more details regarding circumstances in which this credit requirement can be waived (transparent, objective and non-discriminatory) and to what extent (and also, how is this reversed if performance deteriorates). This may be a topic for review with some experience of FCM operation.</p>

Market power monitoring and mitigation

Table 5 – Market power monitoring and mitigation requirements: observations/comments

Feature	Observation/comment
<ul style="list-style-type: none"> Must offer requirement for existing resources. Existing resources, including aggregated resources, with ICAP of 10MW or more will be required to offer their full QCAP unless exemption secured, which requires that they do not participate in the energy market in the delivery year 	<p>This appears to preclude the option for plant to opt out of the capacity market while still being able to participate in the energy market.</p> <p>Plant may genuinely wish to opt out if they are uncertain at 4 year-ahead stage whether or not they will still remain open in the delivery timeframe. But to explicitly block them from energy market participation risks accentuating or triggering an adequacy issue.</p> <p>One option is to allow plant to opt out and then explicitly reduce the capacity requirement that the auction is seeking to secure to reflect the expected contribution from opted out plant.</p> <p>Interaction with transfer of obligations needs to be explored. Plant that did not participate in an auction but remains on the system is a likely party to which an obligation could be transferred if, for example, a new build project hits some delivery issues.</p>

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| <ul style="list-style-type: none"> ▪ Must offer requirement to apply for potential entrants holding scarce land. Need to agree with EMA the delivery year in which they will begin to operate and then bid into the relevant auction | <p>Need clarity on how EMA will handle this. What is the methodology and approach? Need to make sure any agreement with / decision by EMA in relation to project timing is objective and transparent, especially if there are multiple potential new projects seeking to connect in a similar timeframe.</p> <p>Intention could be thwarted by generators by bidding in at cap in the agreed year if they are not ready or not prepared to progress a project. This would not prevent site withholding issues, as intended.</p> |
| <ul style="list-style-type: none"> ▪ Capped offer prices for existing non-demand response capacity linked to providers with incentive and ability to exercise market power based on 1 pivotal supplier test | <p>Exclusion of existing demand response from offer capping is appropriate as it allows for different price tiers of demand response to be reflected in offers.</p> <p>It would be useful to see output from 1 pivotal supplier test analysis to understand the scope of offer price capping</p> |
| <ul style="list-style-type: none"> ▪ For affected suppliers, not all offers will be mitigated, but rather only those above pre-defined thresholds, based on assessment of fixed annual running cost without deducting net E&AS revenues with \$55/kW/year referenced as the 'no review' threshold. | <p>Having some measure to allow bids above the 'no review' threshold is reasonable and similar approaches are adopted elsewhere.</p> |
| <ul style="list-style-type: none"> ▪ A resource specific offer cap can be defined based on net avoidable going forward cost for resources with costs above the 'no review' threshold | <p>Presume this is intended to apply across all resource types, not just conventional generation. If so, might it act as a disincentive for gentailers close to or above the 25% level with conventional generation to include DER of different forms in their portfolio?</p> |
| <ul style="list-style-type: none"> ▪ Proposed 25% capacity market share cap for a supplier's CSOs in each delivery to limit structural concentration | <p></p> |
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Forward capacity auction

Table 6 – Forward capacity auction: observations/comments

Feature	Observation/comment
<ul style="list-style-type: none"> ▪ Single round, sealed bid and uniform clearing price auction 	<p>Cleared pricing approach appropriate for market wide capacity mechanism and in line with practice elsewhere. Examples of single and multi-round processes in various international arrangements.</p> <p>The requirement for a minimum of 9GW of frequency responsive capacity creates the potential for a differentiation between capacity provide types (i.e. frequency response capable and non-capable). This potentially creates pressure for a differentiated capacity price, which would complicate the arrangements and potentially detract from a common, market wide scheme.</p>
<ul style="list-style-type: none"> ▪ Clearing price set as the higher of the value of the demand curve at the cleared quantity and the offer price of the marginal offer 	<p>Marginal / incremental pricing approach adopted in several other markets.</p>

Feature	Observation/comment
<ul style="list-style-type: none"> New/repowered CCGTs with economic lifespan of 25 years that meets proposed heat rate standard for generation can get multi-year commitment of 10 years. Otherwise commitment is 1 year. 	<p>We are aware that there are wider policy considerations in play here, but the comments below focus on the FCM and electricity market impacts only.</p> <p>This gives preferential treatment to new over old capacity, which may serve to unduly hasten closure of existing plant.</p> <p>This risks skewing new build investment to CCGTs to the potential detriment of development of different resources (e.g. batteries, DSR, aggregation) to help meet adequacy requirements.</p> <p>Rationale also cites that advanced CCGTs will also support requirements for frequency response and spinning reserves. This risks distorting the balancing services space also and skewing it in favour of CCGTs at expense of other viable technologies.</p> <p>What consideration has been given to distortionary effects of this technology specific approach and to the ability of other resource to provide both adequacy and system stability services?</p>

Rebalancing auctions

Table 7 – Rebalancing auctions: observations/comments

Feature	Observation/comment
<ul style="list-style-type: none"> Rebalancing auctions effectively re-run the auction for a delivery year to account for things like demand variations, to allow for additional resource to participate and to allow for resource that secured an obligation in the forward auction to revise this downwards if capacity is not available 	<p>Our understanding is that the re-balancing auctions are intended to be settled on a net basis. It may be helpful for a wider range of scenarios than considered in the document to be explored to provide more clarity on the intended approach.</p>

Feature	Observation/comment
<ul style="list-style-type: none"> Net settlement for variations that clear in the rebalancing auction 	<p>Assuming that the norm will be for most capacity to have price taker status, this should limit the extent of net settlement.</p> <p>Systems implications for more involved settlement processes need to be considered, though (with bilateral transactions also needing to be accommodated).</p>

Bilateral transactions

Table 8 – Bilateral transactions: observations/comments

Feature	Observation/comment
<ul style="list-style-type: none"> Transactions can occur between qualified and rated resource only 	<p>There are differences in obligations on different resource types e.g. solar only expected to be available in peak hours, demand side only committed in required hours. If, once allocated, 1MW CSO is equivalent regardless of the underlying resource, this supports feasibility of bilateral transactions and implicitly assumes the same reliability value for CSOs regardless of resource type.</p>
<ul style="list-style-type: none"> Bilateral transactions need to be monitored by EMC 	<p>Support principle of allowing bilateral transactions.</p> <p>Monitoring will require processes/systems to track trades, reallocate obligations, manage financial assurances, etc. Consideration needs to be given to requirements in these regards. Presume that transactions will be settled bilaterally rather than through the central settlement systems, but this needs to be confirmed.</p>
<ul style="list-style-type: none"> Obligations can be transferred for a full delivery year or portions of a delivery year 	<p>Support allowing obligation trade to be granular. We understand that transfers can be conducted at a 30 minute temporal granularity and are supportive of this level of granularity as it allows for sculpting of obligations across a day to reflect conditions.</p>
<ul style="list-style-type: none"> Obligations can be exchanged in increments of 0.1MW and a minimum obligation of 1MW must be held for a particular resource 	<p>Supportive of ability for an original obligation to be split into multiple parts with portions potentially being transferred to a different counterparty or retained by the original holder.</p>

Feature	Observation/comment
<ul style="list-style-type: none"> Bilateral transactions subject to approval from EMA 	<p>If EMA approval is needed, this appears quite a heavy requirement given that trade can only occur between resources that are already prequalified. Likely to create a barrier to bilateral trade. By way of comparison, neither GB nor Ireland requires regulatory approval for obligation transfers, although there are transparency and reporting requirements in relation to trades.</p> <p>Need clarity on the appraisal framework within which EMA will reach its decision.</p>

Supply obligations and performance penalties³

Table 9 – Supply obligations and performance penalties: observations/comments

Feature	Observation/comment
<ul style="list-style-type: none"> Mandatory for obligation holders that are available to participate in the real-time market – must offer requirement 	<p>May need clarity on legitimate cases for not bidding in e.g. planned outages, forced outages.</p> <p>We assume that this obligation will correspond to the approach taken for de-rating e.g. for demand response the obligation to offer into the real time market should be linked to the required hours. Details for storage and imports in relation to real-time participation are lacking and need to be set out.</p>

³ Annex A includes an overview of a reliability option approach, which provide a potential alternative in terms of penalty arrangements.

Feature	Observation/comment
<ul style="list-style-type: none"> ▪ Resources not scheduled in real-time market may still be liable for activation for emergency, out of market reasons by the TSO. No compensation is expected for this and parties are expected to calibrate their capacity offers accordingly. 	<p>The implication of this is that such resource will only receive their capacity payment and will not receive payment for either the value of the energy delivered or to cover the marginal costs incurred in the provision of energy. The absence of compensation could create issues. First, it is likely to result in an increment to FCM offers for resource that might not be expected to be scheduled in the real-time market i.e. more expensive resource that is expected to operate infrequently. This type of resource may have a high missing money requirement anyway given limited energy market revenues and so could be price setting in the FCM. An additional premium to cover for lack of real-time market compensation could result in a higher clearing price, payable to all parties. Second, not compensating or pricing this type of action in the real-time market dampens energy price formation in relevant periods.</p>
<ul style="list-style-type: none"> ▪ Penalty if average capacity availability throughout the year is below the obligation level. 	<p>De-rating takes account of expectations of planned and unplanned outage, so penalty applies if actual outages are greater than expectations.</p> <p>This attaches importance to reliable availability throughout the year.</p>
<ul style="list-style-type: none"> ▪ Scarcity periods 	<p>Understand that existing market advisories will be used to notify forecast scarcity periods and CSO holders will then need to offer into the real-time market for up to 1.5 days. What this means for energy limited resource in terms of the obligation to offer requires elaboration.</p>
<ul style="list-style-type: none"> ▪ Penalty structure creates potential exposure to at least 130% of capacity market revenue (i.e. full pay back of revenue plus penalty of 30% on top). 	<p>If this is applied to annual average delivered capacity, then it would take a major, extended failure and/or high incidence of scarcity periods with 100x weighting and non-availability within them to get close to the maximum penalty. Useful to see some analysis of how this would outturn based on recent outturn availability performance.</p> <p>Caps annual losses at 1.3x capacity revenue.</p>

Feature	Observation/comment
<ul style="list-style-type: none"> ▪ No value for over-performance at annual level but within year over-performance in one month can help to offset under-performance in another month 	<p>Allowing within year offsetting of under- and over-performance helps to maintain incentives to maintain or improve availability.</p> <p>One dimension of this to be considered is the potential for ex-post bilateral transfer of obligations between qualified resources. This changes the nature of the obligation from being purely physical to a blend of physical and financial, which may or may not be considered desirable. It also creates specific requirements in terms of monitoring, settlement and transaction functionality that need to be considered as part of the design choices.</p>
<ul style="list-style-type: none"> ▪ Settlement of penalties estimate monthly 	<p>Need processes to support this. Important to set out more clearly because the average delivered capacity across the year is taken as a measure to calculate the monthly penalty applicable.</p>
<ul style="list-style-type: none"> ▪ Performance assessment of different resources 	<p>Non-performance during any scarcity periods occurring outside of the peak period used for qualification would not impact resources' average available capacity calculation.</p>
<ul style="list-style-type: none"> ▪ Availability for demand response and storage based on realised performance rate which is linked to MW delivered when dispatched 	<p>Use of realised performance rate within the calculation could underplay the actual availability of resources if they are only partially utilised or rarely called. The latter is acknowledged, with performance during testing to be incorporated into the calculation for resource called less than once per quarter. Potentially, this could additionally be considered for application in cases of partial utilisation as well.</p>

Settlement and cost allocation

Table 10 -Settlement and cost allocation: observation comments

Feature	Observation/comment
<ul style="list-style-type: none"> ▪ Capacity costs to be allocated across a set of pre-established hours using an ex-ante wide-peak approach, allocating costs on all peak (and potentially mid-peak) periods of consumption by applying a volumetric rate (\$/MWh). 	<p>Volumetric rate on total consumption. Is this gross or net total consumption? Is this methodology netting out the treatment of EG consumers perhaps?</p> <p>Think a gross consumption approach is generally most appropriate as a fairer base allocation of costs (noting that EG consumers will have a choice of net or gross).</p>
<ul style="list-style-type: none"> ▪ After FCM is implemented for a few years, we can undertake a study to determine the effect of FCM on load shifting, and whether accuracy improves when a shorter historical timeframe. (slide 5 from Settlement Framework ppt) 	<p>Some wider challenges on maintaining a methodology to reflect a fair distribution of costs to the marginal reliability cost with incremental electricity usage</p>
<ul style="list-style-type: none"> ▪ Propose to use a constant set of hours throughout the year to define peak period, only to non-holiday weekdays. 	<p>In line with allocating costs on the basis of the wide peak consumption profile, it is appropriate to allocate such costs only to working weekdays. As consumption on weekends does not correlate with the correction the FCM is aiming for.</p> <p>Agree it is appropriate to have pre-established hours of cost allocation as long as it is reflective of demand profile in providing cost stability/visibility to consumers.</p>
<ul style="list-style-type: none"> ▪ The volumetric rate capacity charge would be calculated to recover the appropriate capacity costs over the expected volume of consumption. ▪ To cope with under/over collection, monthly or quarterly "true-ups" could be used to continually adjust the rate. 	<p>Would be useful to set out more precise mechanics of how the reconciliation of payments process would occur. This is an important point as the allocation of costs will be initially informed from historical load profile.</p>

Feature	Observation/comment
<ul style="list-style-type: none"> ▪ Propose to manage under-recovery from capacity charges via a bank to be undertaken by EMC. Propose to manage over recovery by keeping the monies and use them to offset future under-recovery. (slide 10 from Settlement Framework ppt) ▪ The capacity charge is to be reviewed and updated on a quarterly basis for a start and set a +/- 5% threshold which the capacity charge can fluctuate for each delivery year. (slide 9 from Settlement Framework ppt) 	<p>While probability of under-recovery may be low, involving a third-party to cope with under recovery would add risks and, if used, loan interest payments would need to ultimately be funded by customers.</p>
<p>Costs to self-suppliers with embedded generation.</p> <ul style="list-style-type: none"> ▪ EG Consumers can choose whether to pay capacity charges based on a declared maximum withdrawal (DMW) from the grid, or on a gross basis. If the EG Consumer does not nominate their choice, capacity charges will be allocated based on gross treatment ▪ For over-forecasting: this method sets a price floor on capacity charges based on 95% of the peak demand projection. ▪ For under-forecasting: the EG Consumer is required to pay the prevailing capacity charge for 105% of its peak demand projection and twice the prevailing capacity charge for consumption in excess of 105% of its PD projection, for the first two half-hourly occurrences in a given delivery month. 	<p>The DMW treatment requires the EG Consumer to project its peak demand to be drawn from the grid four years ahead of each delivery year, and pay the capacity charge during a given delivery year based on this forecast. (provides a +/-5% tolerance)</p> <p>The 4-year ahead forecasting commits the EG Consumer to a substantial amount of forecasting risk but with the potential benefit of being able to offset its peak consumption with EG.</p> <p>The reasoning has fair principles in nature where an error in forecasting consumption would result in a direct error of procurement, thereby transferring the risk of FCM procurement to the source of uncertainty.</p>

Feature	Observation/comment
<ul style="list-style-type: none"> ▪ Costs to self-suppliers with embedded generation. ▪ EG Consumers that choose to pay capacity charges based on half-hourly gross consumption will be charged on total consumption drawn from the grid plus electricity generated from the EG and consumed on site. 	<p>This is a fairly standard approach, also followed in other jurisdictions (e.g. GB CRM).</p>
<ul style="list-style-type: none"> ▪ EG consumer can choose to participate on a voluntary basis in the FCM, provided it meets the standard obligations. However, it will not be precluded from participating in the spot energy/ancillary services market if it chooses not to participate in the FCM. 	<p>We have observed that participating in the FCM does expose generating suppliers to a substantial amount of regulatory risk.</p> <p>Allowing EG to participate on a voluntary basis places them on an uneven footing with the rest of the suppliers who are required to partake if they wish to participate in spot energy/ancillary services market.</p> <p>We think this may potentially skew investment decisions towards EG. If so, is this due or undue?</p> <p>It would be helpful to understand why EG consumer can choose to participate on a voluntary basis. Does the thought process include avoiding unintended consequences for requiring EG consumer to participate in all in FCM as a pre-requisite to participating in spot energy market/ancillary services?</p>
<ul style="list-style-type: none"> ▪ Additional comments 	<p>More details on the following will be useful:</p> <ul style="list-style-type: none"> ▪ Mutualisation process for capacity charges ▪ Information on suppliers credit cover and any draw down mechanism for non-payment of invoices ▪ Payment of invoices and accruing interest: ie late payment interest payable at base rate of Central Bank? <p>(Reg 8) Penalty residual supplier amount: In GB, suppliers who have paid CMS charges are entitled to receive from the settlement body a share of the capacity provider penalty charges collected from capacity providers.</p> <p>Payment of credit notes (to suppliers/consumers)</p>

Reforms to energy/ancillary services

Table 11 – Reforms to energy/ancillary services

Feature	Observation/comment
<ul style="list-style-type: none"> Suggestion that suppliers who fail a 1 pivotal supplier test will have real-time market bids mitigated to a maximum of 3 x short-run marginal costs for a CCGT. Based on F class CCGT, a figure of €355/MWh is proposed 	<p>This is preferable to blanket short-run marginal costs bidding requirements, as suggested in previous consultations. Nevertheless, it is still a restriction on energy price formation.</p>
<ul style="list-style-type: none"> \$4,500/MWh real-time market price cap to be retained 	<p>No change from present. But cap may reduce access to demand response that requires a price above the cap to be feasible.</p>

Heat rate standard

Table 12 – Heat rate standard: observations/comments

Feature	Observation/comment
<ul style="list-style-type: none"> Heat rate standard to apply to new, repowered and refurbished fossil fuel power plants (e.g. natural gas, diesel, fuel oil) 	<p>If a standard is to be applied, it needs to be grandfathered for new assets to provide certainty, given the potential for future tightening of standards.</p> <p>Plants that use non-fossil fuel inputs are excluded from the standard. Whether this applies to co-firing with of fossil fuels with biofuels is unclear.</p>
<ul style="list-style-type: none"> New generation that does not meet the standard but offers greater flexibility for the system may be allowed onto the system up to an administered cap of 400MW 	<p>Need clarity on what is termed as offering greater flexibility. How will this be defined in context of changing system conditions?</p> <p>If a new generation technology is included in the administered cap in year 1, does it remain in the cap thereafter for a period of time or could it fall out/be displaced in year 2?</p>

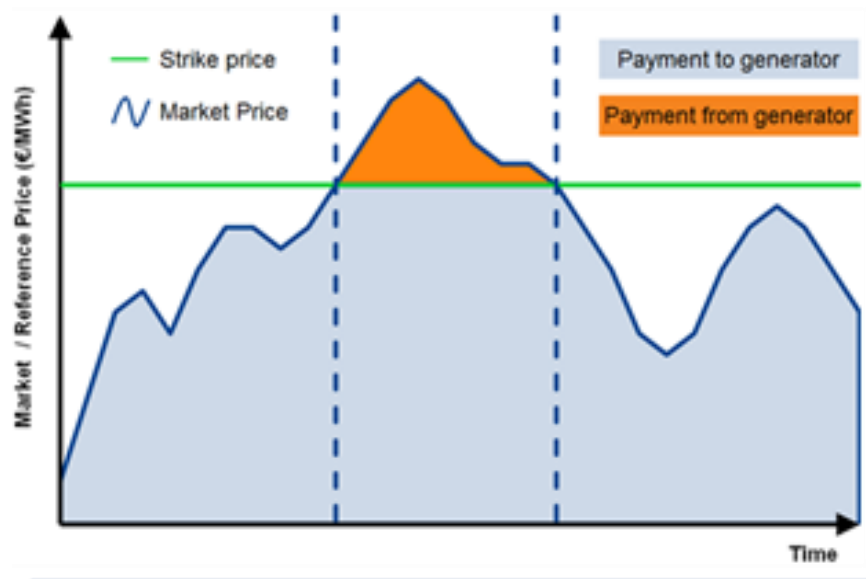
ANNEX A – CENTRALISED RELIABILITY OPTION

Reliability options provide an alternative approach under which capacity providers have a financial obligation for delivery of energy rather than any physical obligation. The approach works as set out below.

Capacity providers (or demand response providers) sell call options for an upfront fee to retailers, which give the retailers the right (but not the obligation) to obtain the contracted quantity of energy (or demand response) at a specified strike price. When the reference market price exceeds the defined strike price, the option holder is entitled to a difference payment from the capacity provider. The holder is, therefore, insured against wholesale prices in excess of the strike price. The capacity provider forgoes revenue in excess of the strike price in exchange for the upfront option fee, which contributes to fixed cost recovery. The call option acts as a method for sharing risk between resource providers and retailers – resource providers share fixed cost recovery risk via the upfront fee while retailers share spot price risk via the difference payment.

The difference payment operation is illustrated in Figure 1. This compares the contract strike price (the green line) to the chosen reference market price, here the day-ahead market (the blue line). When the reference price exceeds the strike price, the capacity provider pays back to the contract counterparty based on the revenues in excess of the strike price (the orange area). The capacity provider has an incentive to run in the high priced period because it is required to make the different payment regardless of whether or not it was actually delivering in line with its contract. Based on the illustration below:

- if it is running, it captures the high wholesale price through market trading and then pays back the revenue in excess of the strike price as the difference payment, but has a positive revenue for the affected periods; or
- if it is not running, it does not capture the high wholesale price through market trading and still pays back the revenue in excess of the strike price as the difference payment, meaning that it has a negative revenue for the affected periods.

Figure 1 – Reliability option illustration


Under a centralised reliability option approach:

- a central body (e.g. the system operator) buys reliability options on behalf of consumers;
- the quantity of contracts secured is driven by a centrally determined requirement, typically set based on forecast peak load plus a reserve margin; and
- the strike price is set administratively at a level above the highest marginal cost of generation.

Contracts are struck through a competitive tendering exercise or auction, which allocates contracts to providers that have the lowest option fee requirement, with all successful providers typically receiving a common option fee based on the clearing price.

Examples of application of a centralised reliability option approach include Ireland and Italy.



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