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Submitted by email

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Dear Sirs,

Response from EnerNOC to the "Smart, Flexible Energy System" call for evidence

EnerNOC is grateful for the opportunity to contribute to this timely review, and welcomes its focus on the increasing importance of involving customer load in the operation of the power system.

The call for evidence is wide ranging and likely to attract many voluminous responses, for which you have budgeted only a few months to assess. In an attempt to limit duplication of effort, we are not responding to all questions, but are instead restricting our comments to areas in which we believe we may be able to offer a different perspective from other respondents.

1 We should learn from overseas

EnerNOC works with commercial and industrial energy users in 12 countries to develop demand-side flexibility and offer it into more than 50 wholesale capacity, energy, and ancillary services markets and utility programmes.

Our perspective is hence largely shaped by our experience in other markets. We welcome the acknowledgement in the call for evidence that the changes the GB system is undergoing are also occurring in many other markets, and that lessons can be learned from elsewhere. It is all too easy to fall into the trap of believing that each country's power system is unique and special; we are glad this is being avoided. Other power systems are ahead of the GB system in facing many of these challenges.

2 The time to act is now

It would be entirely possible to continue to operate the power system in the traditional, supply-centric way, ignoring customers' potential flexibility. However, to do so would soon become ruinously expensive. This is because both the changing generation mix and potential changes in consumption patterns are likely to lead to the average utilisation of both generating and network capacity continuing to fall.

We agree strongly that now is the time to act:[1] until the right structures are in place to allow new technologies to compete to meet the increasing flexibility needs, the GB power industry will continue to build traditional infrastructure and lock in its high costs. Since some of the necessary reforms may take several years to implement, we will need to look some way ahead to assess their importance. Not much consumer harm may be occurring yet, but it will unless we act now.

3 The real world matters

Many of the real issues that affect the provision of flexibility by customer load would not occur if, as sometimes assumed, retail markets were perfectly competitive and all customers had perfect information and a completely objective approach to risk.[2]

Unfortunately, we do not live in that world. Pretending that we do would lead to demand-side flexibility continuing to be underdeveloped. Rather that saying that a particular approach ought to work in theory, we should look for approaches that have been shown to work in practice.

4 Removing policy and regulatory barriers for aggregators

Q7A What are the impacts of the perceived barriers for aggregators and other market participants? Please provide your views on: balancing services; extracting value from the balancing mechanism and wholesale market; other market barriers; and consumer protection.

The PA Consulting report commissioned by Ofgem[3] describes most of the barriers quite well. In our view, the most important barriers to the provision of flexibility from customer load are as follows:

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1 Call for evidence, p. 9, para. 13.

2 The NordREG paper cited in the PA Consulting report is a classic example of this "assume spherical cows" approach.

3 PA Consulting, *Aggregators – Barriers and External Impacts*, May 2016.

Balancing services

- *Poor product design.* The services procured by National Grid seem to be based around the capabilities of particular technologies, rather than what is actually needed to manage the system. This advantages those technologies over all others. For example, requiring fixed volumes of frequency response to be offered throughout daily availability windows causes no problem when the service is being provided by a generator, as it is a dedicated asset. In contrast, the volume of frequency response that can be provided by customer load depends on those customers' demand patterns. These can be quite predictable, but not constant. Figure 1 shows how the volume of 1-second frequency response offered by customer loads in New Zealand's North Island varied across a week. It averages 160 MW.[4] If they were required to offer a fixed volume, they could only offer the 43 MW minimum, and their additional capabilities would go unused and unremunerated. The system would realise less benefit from the load resources that participated, and have to dispatch more supply-side resources at higher cost. In addition, the reduction in value available would lead to many customers choosing not to participate: it would no longer seem worthwhile.

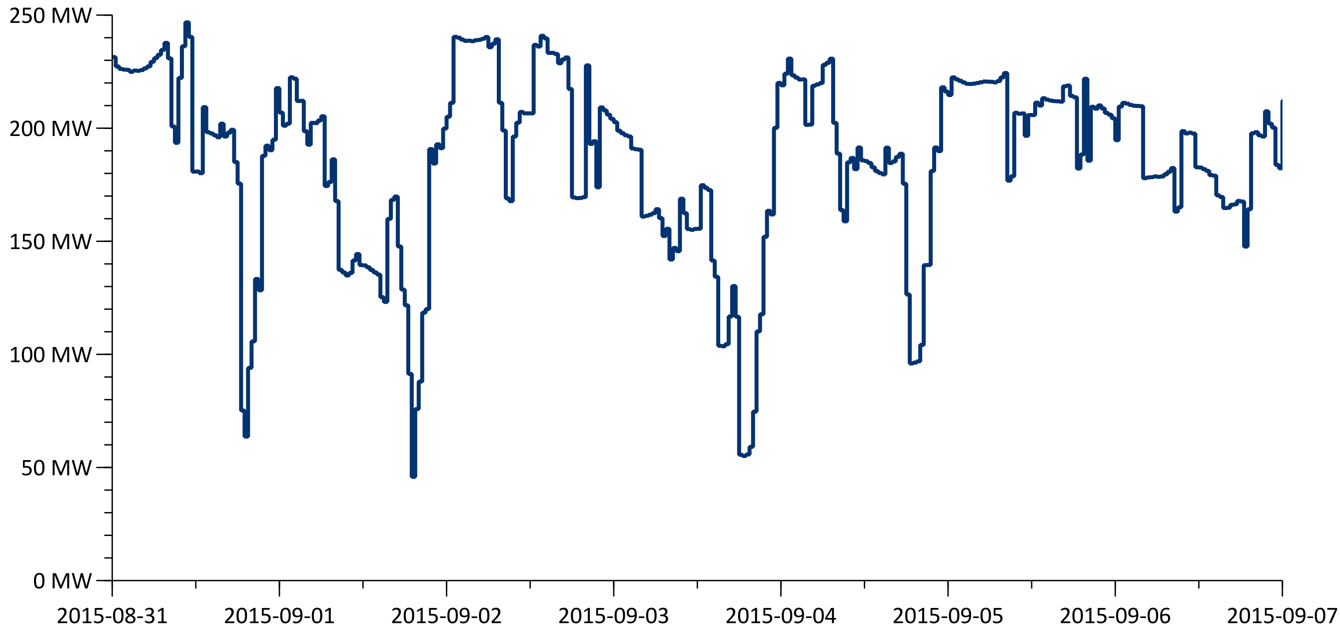

Figure 1: Total volume offered in each trading interval by Interruptible Load resources into New Zealand's North Island Fast Instantaneous Reserves market.

[4] It is worth noting that this is a great deal larger than the volume of frequency response PA Consulting found was offered from DSR in the GB market, despite the North Island of New Zealand having a power system roughly a seventh of the size of the GB one.

- *Overlapping products.* The technology-specific, rather than needs-based, nature of the balancing services leads to National Grid having a choice of multiple different products for addressing particular system need. This makes it very hard for participants to predict the value of providing a particular service in future years. Starting from first principles – that a certain amount of a particular type of response will be required to maintain system stability – doesn't help if that type of response might be provided by an entirely different service procured in a different way.

- *Lack of transparency in procurement.* There are no organised markets for balancing services. Rather, everything is at the whim of National Grid, with the hope that the financial incentives in their regulatory framework will lead to them making optimal choices. In addition to tendering for a large range of overlapping and varying products through rather opaque pay-as-bid tenders, National Grid also do bilateral deals, sometimes for quite similar products, on which very little information is available. This approach would be normal in a jurisdiction that has not liberalised its electricity sector, and so retains vertically-integrated, regulated monopoly utilities, but seems incongruous for a jurisdiction that has otherwise embraced competitive markets.[5] The unpredictability of the arrangements makes the provision of balancing services seem much more risky than in other jurisdictions – providers have little comfort that the opportunity will persist beyond the end of their contract – which will tend to increase the prices demanded.

Balancing mechanism and wholesale markets

Independent aggregators have no access to the balancing mechanism, and hence also have no access to the wholesale markets. This issue is not unique to GB: it has arisen and is being addressed in many markets. In Europe, France and Switzerland have already addressed it fully, Belgium and Germany are part way through the process, and other markets will be required to address it as part of the implementation of the recent winter package.

The supplier-aggregator model does not work

The problem is not that an aggregator would need to hold a supply licence or become a supplier[6] to offer flexibility into the balancing mechanism or wholesale markets: that would be a surmountable barrier. The problem is that they need to be **the** one and only supplier for all of the customer load from which they are

[5] As part of its reform programme, Japan is currently moving away from a National Grid-like approach to ancillary services procurement towards open, competitive markets. The organised US markets, most of continental Europe, New Zealand, and the National Electricity Market in Australia have more transparent, structured ancillary services markets. Even California (which retains a lot of vertical integration and traditional regulation) has open ancillary services markets. See, Argonne National Laboratory, *Survey of US Ancillary Services Markets*, ANL/ESD-16/1, January 2016, for examples of the structured approaches in US markets.

[6] Call for evidence, p. 39, para 48 and p. 42, para. 59.

sourcing the flexibility. Not just a supplier, but one that can successfully compete for all those customers' retail business.

From the customer's point of view, this is a forced bundling of two very different services. They are not allowed to choose one company from whom to buy electricity and another to whom they'll sell flexibility for balancing mechanism or intra-day market purposes. When forced to choose one party, it makes sense that the customer would prioritise the retail deal, as this is typically of much greater value to them than anything they can earn from offering flexibility: it is better for the consumer to have a fractionally cheaper retail deal even if it means forfeiting the ability to offer flexibility.

Tempus Energy tried very hard to be a supplier-aggregator, but failed, providing evidence that this model doesn't work. To be a successful supplier to large commercial and industrial customers requires a very different skill-set and balance sheet to being an effective aggregator.

Bilateral deals are often unachievable; retail competition doesn't help

The overwhelming importance of the retail deal also means that there is very little competitive pressure for a supplier to engage with an independent aggregator who is seeking access to their customers' flexibility through a bilateral deal. This is something that suppliers are often unwilling to do, for a variety of reasons, such as:

- Simply not wanting their customers to be involved with any other energy businesses.
- Having a vague intention of setting up an aggregation business at some point in the future.
- Having supply-side assets which compete in the same markets as the aggregator.

In short, what's good for the customer, or for consumers in general, is not necessarily good for the supplier.

Our experience in Germany[7] shows that, despite a fairly competitive retail market for industrial customers, suppliers are able to draw out negotiations for very long periods, and feel little pressure to agree reasonable terms.

The dynamic of the negotiation is quite predictable: the supplier is the monopoly provider of access to the customer's flexibility; the only restraint on their behaviour is the possibility that the aggregator could use it to convince the customer to switch to another supplier. Given the much greater value of the retail contract, this would be like the tail wagging the dog.

[7] In Germany, before an independent aggregator can offer a customer's load into any of the TSOs' reserves markets, they need a bilateral deal with the customer's retailer. The German government has recognised that this does not work and causes consumer harm by suppressing the participation of customer load, and so has encouraged the development of a standardised framework to remove the need for any negotiation or prior consent.

Drawing out negotiations is a particularly effective tactic for preventing independent aggregation, as it makes the "time to value" of the customer proposition long and uncertain, as well as increasing the transaction costs for the aggregator. With some suppliers, the process has taken more than a year, or failed altogether because the customer has lost patience.[8]

In short, this form of regulatory bundling of flexibility with retail services allows suppliers to exploit their position in the retail market to exercise market power in the aggregation market. This harms competition and leads to lower levels of customer participation.

Forced bundling and short retail contracts combine to make participation by small customers uneconomical

Offering flexibility from customer load is often rather a long-term business, and the smaller the customer, the longer term it has to be.

The aggregator incurs significant up-front costs in finding the customer, persuading them that they can provide flexibility, contracting with them, and installing the necessary control and monitoring equipment. For very large customers, these costs may not be material, but with smaller customers it can take several years to recoup these costs from the aggregator's share of the resulting market revenue, so aggregators will typically seek 4-5 year contracts with customers, as well as hoping to renew.

If the aggregator's ability to offer the customer's flexibility is dependent on their relationship with the customer's supplier, then when the customer changes retailer, the aggregator is back to square one. This means that the aggregator can only count on the customer remaining available for the remainder of their retail contract.

Retail contracts tend to be much shorter than aggregator contracts. Amongst the UK customers for whom we have data, they are typically 2 or 3 years. This means that, when an aggregator approaches a customer, they will have on average 12-18 months remaining on their retail contract.

This problem doesn't only affect aggregators: exactly the same effect hurts any retailers who are dealing with customer flexibility in a market which enforces bundling. We have experience of this where retailers have outsourced dealing with customer flexibility to us.[9] In one market, if you ignored retail contract durations, it made economic sense to enrol customers who could provide 100 kW or more of flexibility. However, since it was a very competitive retail market, retail contracts were short, such that it became impossible to justify enrolling customers below 1 MW.

8 In some cases, customers have signed up to provide flexibility directly to the obstructive supplier, rewarding them for their obstruction.

9 Experience shows that this is not a model that leads to large-scale provision of flexibility by customer loads: in the absence of pressure from independent aggregators, typically only a few niche retailers will seriously engage with customer flexibility.

The more competitive the retail market, the shorter retail contracts tend to be, which exacerbates this effect.

Other market barriers

The Triad regime is an issue here. We discuss this in our responses to Q11-Q14.

Consumer protection

We do not consider consumer protection (or lack thereof) to be a significant barrier. We discuss this further in our response to Q40.

Q7B Do you have evidence of the benefits that could accrue to consumers from removing or reducing these barriers?

Going by PA Consulting's findings, there is a low level of participation of customer flexibility in balancing services – maybe 0.5% of system peak, at most – and essentially none in the balancing mechanism and wholesale markets. Suppliers just don't seem to be interested in offering this service.

Other jurisdictions manage to have much higher levels of participation, which bring benefits both to participating customers and to customers as a whole. For example:

- In New Zealand, around 7% of North Island customer load is offered into the instantaneous reserves markets.[10] This is a lower cost source of frequency response than generation, and so makes the instantaneous reserves markets more competitive and frees up generation resources that don't clear for frequency response to compete in the energy market.
- In PJM, there was 3.5 GW of Economic DR (i.e. DR participating in the energy market, rather than the capacity market) available at the start of 2016: around 2% of peak demand.[11] PJM has calculated that reductions in wholesale prices due to demand response during a particular week-long heatwave reduced total system costs by $650m.[12]
- In Belgium, data from Elia shows that participation of demand-side flexibility in balancing and ancillary services markets[13] reached 520 MW in 2016: around 4% of peak demand.

We cannot prove that removing the identified barriers would bring UK participation all the way up to these best-practice levels. But we are quite sure that not removing them would prevent any significant improvements in participation. In particular, we are not aware of any market that has achieved a

[10] EnerNOC analysis of public offer data for 22 Jul to 19 Oct 2015: the maximum offers from interruptible load resources were for 261 MW of fast and 339 MW of sustained reserves.

[11] PJM, *2016 Demand Response Operations Markets Activity Report*, December 2016, fig. 21.

[12] PJM, *Demand Response Fact Sheet,* 6 May 2008.

[13] i.e. excluding strategic reserves.

meaningful level of demand-side flexibility while retaining forced bundling between flexibility and retail energy supply.

PA Consulting suggests that the balancing mechanism's energy-only payment structure may not be attractive to aggregators.[14] We agree that availability payments are important to customers and aggregators. This means that participation in the balancing mechanism alone may not be particularly appealing. However, the interaction with other markets is very important:

- Access to the balancing mechanism would allow access to wholesale markets – especially the intra-day market – in which it could be attractive either to trade when prices exceed customers' curtailment costs, or to back the sale of hedges, bringing new competition to either the intra-day or the hedge markets.
- In the capacity market, independently aggregated DR is the only resource that has no access to energy payments. This is a very unusual design: in most capacity markets, all resources have equal access to energy payments.[15] There is great uncertainty about the number of hours of dispatch that will be required in any year. During dispatches, generators may make a profit from energy sales, or at least offset much of their running costs. In contrast, independent aggregators have to make provision for all of their running costs when determining their capacity offer price: there are energy revenues during dispatches, but they accrue to the customer's supplier, rather than to the customer or the aggregator. Fixing this would allow DR aggregators to offer more competitively, and so allow more demand-side flexibility to clear.

Also, in balancing services, in addition to the cross-party impacts mentioned in the call for evidence, the segregation into BM and non-BM services (e.g. for STOR) distorts the merit order for balancing service dispatch.[16] Fixing this by removing the artificial distinction may not necessarily benefit aggregators, but it should certainly improve economic efficiency.

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14 PA Consulting, *op. cit.*, p. 32.

15 For example, in PJM, demand-side resources receive energy payments whenever they are dispatched for capacity market purposes, without any need for them to register and submit offers as Economic DR resources. The 2% of demand which makes itself available for Economic DR there is load which wants to be able to submit offers and be dispatched under circumstances other than capacity market dispatches – i.e. more often. If the GB balancing mechanism were opened up to demand-side participation and was the only means for demand-side capacity resources to receive energy payments, it would be reasonable to expect most DSR CMUs to participate in the balancing mechanism, in addition to any loads seeking more dispatch opportunities (like the 2% in PJM).

16 Non-BM STOR spill payments were the subject of a heated debate hosted by National Grid on 1 Nov 2016, which seems likely to lead to a messy fix being applied that only addresses the worst symptoms in the STOR market, rather than the real underlying issue of lack of access to the BM.

Finally, the size of the distortions caused by lack of balancing mechanism access are likely to increase markedly over the next few years due to:

- The completion of the reforms resulting from the Electricity Balancing Significant Code Review, further doubling the price cap of the balancing mechanism to £6,000/MWh.
- The increasingly inflexible and variable nature of the generation fleet.

Even if the distortions do not seem material now, they are likely to become so in future.

Q8 What are your views on these different approaches to dealing with the barriers set out above?

The prohibition on participation by independent aggregators in the balancing mechanism and wholesale markets will not go away by itself. Hence merely continuing to monitor the absence of consumer participation will achieve nothing.

Continued inaction would also be inconsistent with:

- Article 15.8 of the 2012 Energy Efficiency Directive, which requires "national regulatory authorities [...] in close cooperation with demand service providers and consumers, to define technical modalities for participation in [balancing] markets on the basis of the technical requirements of these markets and the capabilities of Demand Response. Such specifications shall include the participation of aggregators."
- Articles 17 and 13 of the proposed directive on common rules for the internal market in electricity, published by the European Commission on 30 November 2016 as part of their "Clean Energy for All Europeans" winter package.
- The requirement to implement Project TERRE.[17]

Reform to remove this barrier could be implemented through the BSC modification process, or through changes to licence obligations: the outcome is more important than the process.

We would not characterise the "regulator steps in" approach as increased intervention. There is nothing natural about the current design of the balancing mechanism: it is an entirely artificial construct resulting from the existing licence conditions. It happens to have a design flaw, in that it restricts competition by forcibly bundling the procurement of flexibility with retail supply. It is quite reasonable for the regulator to change conditions to remove such a flaw now that it has come to light.

[17] In principle, cross-party issues for Project TERRE could be addressed in a stand-alone manner just for that service. However, since this would probably involve almost all of the complexity and cost of fixing the underlying issue of access to the balancing mechanism, this would seem a wasteful approach.

Since this is, at heart, a competition issue, it may be unrealistic to expect an industry-led process – i.e. one dominated by parties that benefit from the continued existence of the resulting barriers – to address it. We note that the development of a mechanism for the provision of balancing reserves by independent aggregators in Germany was "industry-led", in that the work was done by the trade associations representing the incumbents and the new entrants. However, the process was initiated by the regulator, who also made it clear that they would impose a solution if the industry failed to reach agreement by a particular date.

The issue has also been resolved in France and Switzerland, is being resolved in Belgium, and will be resolved across Europe as part of the implementation of the winter package. It is not unique to GB, and it would be odd for GB to decide to be the one market not to address it.

Q9 What are your views on the pros and cons of the options outlined in Table 5?

The key requirement is to allow the customer to choose how (and whether) to offer flexibility into the balancing mechanism separately from choosing a retail supply deal. This means that it must be possible for them to interact with two Balancing Responsible Parties: their supplier during normal circumstances, and an aggregator when they are delivering flexibility to them.

It is not reasonable for the supplier's balancing position to be affected by the actions of an independent aggregator. To prevent this, it is necessary to correct the supplier's balancing position to remove the effect of the DR dispatch. A similar correction already takes place when BMUs are dispatched for balancing services, and it may be possible to use the same mechanism. However, there are two differences:

1. Since the supplier is not involved in the provision of the flexibility, they should be held harmless from any imbalances resulting from under- or over-provision of the flexibility. Imbalances due to under- or over-delivery should be a matter for the aggregator. Hence the supplier's balancing position should be corrected to remove the actual DR delivered, measured relative to a baseline, rather than the volume that was intended to be dispatched.[18]

2. The supplier has no way to anticipate the dispatch – it is not their decision – and so will have procured energy in the expectation that the customer will continue with their normal consumption patterns. This means that there is a good case to be made that the supplier should be compensated

[18] This means that, during a DR dispatch, the supplier is responsible for energy to meet the customer's baseline consumption profile. This should be very close to what the supplier was expecting the customer to consume on average, but with much lower variance – essentially, it's the central estimate. This means that the imbalance risk faced by the supplier will be considerably lower during third-party DR dispatches than under normal circumstances.

so that their financial position is similar to how it would have been if the DR had not been dispatched.

The correct level of compensation is an oddly fraught issue. This seems to be because for some aggregator business models – ones that involve dispatches for hundreds of hours in the year – the level (or existence) of the payment can make a crucial difference. We consider that most of the potential value of DR arises from relatively rare, extreme circumstances – it is essentially an insurance product. In these situations, the retailer's sourcing cost is likely to be tiny compared to the value of the flexibility, so the level of compensation does not matter much. The most important thing is to avoid the need for any negotiation with the supplier, as this inhibits participation.

The most generous possible approach for compensating suppliers would be for them to earn the same amount that they would have earned if they had supplied the energy to the customer – i.e. for them to be compensated at whatever retail price applies between that retailer and that customer (less levies and network charges, since the retailer will not be incurring these costs for energy not supplied). This should be uncontroversial, because the supplier was clearly willing to supply the energy to the customer at that price: in fact, they were expecting to do so. It is also easy to calculate, because the relevant numbers are either public information, or appear on the customer's bill.

Compensating suppliers at this level would arguably be overcompensation, as it compensates them both for their sourcing cost and their retail margin. If the customer's consumption is shifted in time, rather than completely forgone,[19] then the retailer gets to make their profit margin twice.

This is the approach proposed in Germany. Clearly, the French approach (a regulated price), or the default approach proposed in the Winter Package (no compensation) would be more favourable for aggregators, including us. Nevertheless, we are willing to accept the more generous approach, because it should be uncontroversial and hence allow market access, without the need for negotiation, to be achieved sooner.

The process could be implemented through standardised bilateral arrangements, or through modifications to central settlement. The latter ought to be more efficient, as it would avoid duplication of effort, but it may be that Elexon has particularly high change costs, in which case changes to their systems could be minimised by working around them.

Requiring aggregators to become BSC participants or obtain supply licences should not present an insurmountable barrier, although it is likely that many of the supply licence conditions will not be relevant.

19 For example, if the customer interrupted production to reduce their consumption, and hence made 1,000 fewer widgets over the course of the week, you would expect them to make 1,000 more widgets in some future week. On the other hand, if they reduced consumption by dimming lights or turning off a decorative fountain, then that forgone energy consumption will never be made up.

We are cautious about the idea of reforming balancing services to provide an alternative to the balancing mechanism. We can see the appeal: it avoids the need to change much in the balancing mechanism, and yet could solve the problem of the lack of energy payments to demand-side resources in the capacity market, and potentially address cross-party effects from balancing services and capacity market participation. We think it would be difficult for this approach to enable wholesale market access. However, our main reasons for caution come from historical experience with attempts at "equivalent but different" treatment of demand- and supply-side resources.[20] Direct competition in the same market seems a simpler and more permanent approach.

Q10 Do you agree with our assessment of the risks to system stability if aggregators' systems are not robust and secure? Do you have views on the tools outlined to mitigate this risk?

The main system stability issue raised in the call for evidence is not about the security of aggregators' systems, but rather about the effect of simultaneous switching of many customer loads.

The GB system has quite high inertia[21] and maintains a lot of reserves to deal with the sudden loss of large generators or transmission assets. We are a long way away from any aggregator controlling so much demand-side flexibility that it could pose a risk to system stability – it would be a good problem to have!

In our experience, the response from a large portfolio of commercial and industrial customer loads in most DR programmes tends to be more like a ramp than a sudden switch. This is because sudden switching on or off of load tends to be disruptive for customers. Unless the programme requires a very fast response,[22] there is often a step requiring manual confirmation of participation from each customer, which tends to splay response times.

This could be a more pressing issue with technologies that don't have a natural dispersion of response times, such as battery storage.

If aggregated portfolios became so large that this was a real threat to stability, then it could be addressed by issuing dispatch instructions in a staggered manner, rather than requiring the portfolio to deliver its entire capacity at a particular time.[23]

[20] In particular, the lesson from SBR and DSBR is that initial intentions to allow competition between supply- and demand-side resources eventually gave way to tenders run only for supply-side resources, procuring services priced higher than demand-side resources were even allowed to offer.

[21] Notwithstanding National Grid's concern about falling levels of inertia, it is still much higher in the GB system than in many other systems worldwide, and will not fall into uncharted territory in the foreseeable future.

[22] Fast response is required for frequency response ancillary services – e.g. 200 ms in Alberta, 1 s in New Zealand, or 2 s in FCDM. With the exception of the Alberta programme, even for frequency response we tend to work through customers' process control systems rather than directly triggering circuit breakers, so the response time varies between sites, and load restoration often requires local approval.

[23] National Grid can do this already for balancing services and the balancing mechanism, but not for the capacity market. Unlike most explicit DR programs, the capacity market currently does not have any provision for dispatch instructions. It instead requires all participants to monitor published reserve margin

Note that this remedy is difficult to apply to implicit DR – i.e. where customers are responding to a price signal in their network tariff, or to wholesale prices. If there is a step change in price from below a customer's marginal value of consumption to above it, then the customer derives optimal benefit by adjusting their consumption as close as possible to the time of the price change. In the 2016 System Operability Framework, National Grid refers to this as "herding behaviour". Customers will not deliberately respond sooner or later without some incentive to do so.

The SMETS2 smart metering standard avoids herding around time-of-use band switching times: the switching of any loads and the corresponding change-over between meter registers are delayed by a randomised offset.

Note, however, that this does nothing to address price signals which are applied on the basis of half-hourly consumption data, rather than the finite number of time-of-use bands supported by the meter. The most obvious current example of this is Triads: these are imposed on all customers at exactly the same time. To the extent that the Triad periods are predictable, customers can be expected to herd around them. Similar issues could arise from customer exposure to wholesale prices.

On the issue of cyber-security, aggregators' potential liability to their customers in the event of mishaps when controlling their loads forces them to pay attention to the security and robustness of their systems. We note that some aggregators (including EnerNOC) have formal security programmes based on standards such as ISO 27001.

Aggregators are probably a smaller risk than smart meters, because they cover less of the system's load, they have more diverse systems, and they don't always have direct control of the loads. In contrast, the fleet of smart meters is likely to be quite homogenous. Every meter will include a load switch, and the only safeguards against simultaneous switching are in software.

5 System value pricing

Q11 What types of enablers do you think could make accessing flexibility, and seeing a benefit from offering it, easier in future?

As discussed on p. 3, we consider that the current design of many balancing services, where constant quantities need to be offered throughout long time windows, with the quantities having to be finalised days or weeks ahead, hampers participation by many customers. Moving to more dynamic markets would allow

data to decide whether to respond after a capacity market notice has been issued. This could cause herding behaviour leading to system stability threats. These could be prevented by issuing specific dispatch instructions to particular resources in merit order, rather than publishing general notices and waiting for the herd to respond.

many more customer loads to participate, and to offer a greater proportion of their capabilities.

Such a reform would also facilitate participation in multiple markets: rather than having to commit to provide a particular form of flexibility a long way ahead of time, resources could offer whichever service is the most valuable at the time. In extremis, this becomes near-real-time cooptimisation of the services – something that is already practiced in many markets in the US and in Australasia.

Q12 If you are a potential or existing provider of flexibility could you provide evidence on the extent to which you are currently able to access and combine different revenue streams? Where do you see the most attractive opportunities for combining revenues and what do you see as the main barriers preventing you from doing so?

We agree that stacking of revenue streams should be encouraged in all cases where there is no conflict between the services. For example, it should be possible for the same customer load to participate in the capacity market while also being available in the balancing mechanism or enabled for frequency response. Where there is a conflict between services – e.g. if a customer has reduced their consumption due to a balancing mechanism dispatch, that reduction is not also available to respond to a coincidental frequency event – having shorter-term (e.g. half-hourly, rather than monthly) markets for the balancing services will allow flexible resources to offer the services that are of the most value to the system at the time.

We consider the conflict between Triad avoidance and every other programme to be a major barrier.

Triad avoidance is the most rewarding thing that any customer can do, even though it is likely to be of much less benefit to the system than providing a firm, dispatchable resource, or providing frequency response. As a result, customers are only willing to provide these more useful services to the extent that it doesn't undermine their ability to avoid Triads.

This leads to strange balancing services product designs – defining availability windows that allow the exclusion of likely Triad periods – and to capacity market portfolios having to account for the effect of baseline erosion from customers' Triad avoidance actions.[24]

In short, overpaying for the Triad market drains participation from all other markets. The charging regime should be reformed so that the price signals are no greater than the marginal costs imposed by consumption at those times. That way, they would only incentivise response to the extent that it is efficient.

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[24] Note that this is only an issue for DSR CMUs. Distribution-connected generating CMUs can earn revenue by running during Triads without it interfering with their availability to discharge their capacity market obligations. This is yet another way in which generation CMUs are advantaged in the design of the capacity market.

Q13 If you are a potential or existing provider of flexibility are there benefits of your technology which are not currently remunerated or are undervalued? What is preventing you from capturing the full value of these benefits?

Customer load can be used to provide flexibility for many purposes. However, the areas in which it has the greatest cost advantages are as an emergency resource and providing fast frequency response.

DR as an emergency resource

Some customers may incur relatively low short-run marginal costs (SRMC) of curtailment, and hence be willing to curtail frequently. Such customers would sit amongst supply-side peaking resources in the system's merit order. However, those customers are a small minority. There is a much larger volume of customer load that either incurs significant costs when curtailed, or whose costs increase sharply with the number of hours of curtailment.

Such resources can be highly cost-effective as an emergency resource – the "last cab off the rank" after all supply-side resources have been deployed. However, if the only route to market for flexibility is one that may require many hours of dispatch, these emergency resources will be expensive, or customers may choose not to participate at all.

This type of customer makes up the majority of demand-side participation in most capacity markets, but is relatively underdeveloped in the UK.[25]

The current capacity market design does not accommodate emergency DR well:

- It has no merit order – so high-SMRC resources are likely to be dispatched just as much as low-SRMC ones.
- It requires a lot of testing – four times per year, compared to once or twice in most other capacity markets.

This results in potential emergency DR resources being reluctant to participate in the capacity market, or incurring unnecessary costs to do so.

DR for fast frequency response

Fast static frequency response is very effective at managing the sudden loss of large generators or interconnectors in low inertia systems. It is used very successfully for this purpose in the New Zealand and Alberta systems. It is a great deal more cost-effective than dynamic response for managing large, rare contingencies, because customer loads can be ready to provide it without incurring significant ongoing operating costs. However, it does require ancillary

[25] Historically, there has been no route to market for such resources in GB: STOR was the only option, and it tended to require large numbers of dispatches to earn any worthwhile revenue. The GB demand-side aggregation industry has been shaped by this history, leading to many of the aggregators having expertise mainly with generators, rather than load curtailment.

services to be dispatched in a fairly dynamic manner, rather than for fixed volumes for long periods of time.

National Grid does not procure fast static frequency response: they have not defined it as a product. Instead, they use a combination of fast dynamic response from batteries (EFR) and slow static response (FFR and FCDM), and are considering procuring an inertia service. This might allow them to avoid moving to a more dynamic approach to balancing services dispatch, but is likely to be a great deal more expensive than the fast static alternative.

Q14 Can you provide evidence to support changes to market and regulatory arrangements that would allow the efficient use of flexibility and what might be the Government's, Ofgem's, and System Operator's role in making these changes?

We would consider investment in the GB market to be less risky if there were less political involvement in the energy system. It is clearly tempting to pick winners, and bias markets to favour those technologies, but the tendency for this to happen makes all potential participants nervous.

We believe that the System Operator intends to do the right thing when reforming balancing services. However, as discussed on p. 4, the level of discretion National Grid has over what they procure, and when and how they procure it, is striking. This is very different from most liberalised markets, and again leads participants to consider participation risky.

We would therefore consider a stronger role for Ofgem to be likely to lead to greater confidence in the market arrangements, which should encourage greater investment from aggregators and other new entrants.

6 Tariffs

Q18 Do you recognise the reasons we have identified for why suppliers may not offer or why larger non-domestic consumers may not take up, smart tariffs?

Consumer preferences for simpler tariffs may be entirely rational. It is not just that simpler tariffs are easier to compare. The problem is that highly-variable tariffs make budgeting much harder and less accurate, consuming valuable management time. For huge, energy-intensive industrial loads, the benefits are large enough to justify the effort required. For many other customers, even quite large ones, this is not the case.

Rather than attempting to force customers onto more complex tariffs in the hope that this will lead to flexibility (through "implicit DR"), it may be better to focus on ways to allow customers to retain the comfort and predictability of a simple tariff without this choice precluding the provision of flexibility. They can do this by combining a simple retail tariff with separate arrangements through which they are paid for the flexibility they are able to provide (“explicit DR”).

7 Other government policies

Q26 What changes to CM application/verification processes could reduce barriers to flexibility in the near term, and what longer term evolutions within/alongside the CM might be needed to enable newer forms of flexibility (such as storage and DSR) to contribute in light of future smart system developments?

It is not the capacity market’s job to drive flexibility. The incentives to provide flexibility come from the balancing mechanism, intra-day market, and balancing services. It is therefore important to allow access to those markets.

The capacity market should work alongside these to ensure supply adequacy at least cost. It might be helpful to reappraise the capacity market in this light: it is not a government intervention or a subsidy scheme, but an open market in the commodity of supply adequacy.

The following reforms would make participation by customer load less costly, and place it on a more level playing field with supply-side resources:

1. *Equal contract durations.* At present, new-build generation and storage receives higher value from the capacity market than new-build demand-side flexibility, in the form of 15 years of revenue certainty, rather than just 1 year.

2. *Portfolio management.* Unlike all other resources, demand-side flexibility does not involve dedicated assets. Instead, it relies on customers’ behaviour. Customers may replace equipment, move, or go out of business. Aggregators cannot prevent such changes, but they can manage their effects, by replacing customers when necessary to maintain reliable performance. This essential activity is analogous to a generator owner performing routine maintenance, but it is currently prohibited by the capacity market rules: once a CMU has been assembled and tested, it becomes immutable. This restriction increases costs and reduces reliability. Ofgem has received multiple rule change proposals to fix this, and has said that it intends to do so. However, there are worrying signs that this may not happen in time for the start of the 2017/18 delivery year, in part because the Government’s contract with Elexon apparently makes no provision for changes to settlement systems.

3. *Less expensive metering.* At the moment the cost of “bespoke metering” – both installing it and managing its certification and testing – is prohibitive for all but the largest resources. This prevents participation by customers whose sites cannot be covered by supplier metering – e.g. because they

happen to have some rooftop solar panels. Rule changes to simplify the metering arrangements should be progressed.

4. *Less expensive testing.* As mentioned on p. 15, the capacity market requires DSR CMUs to be tested four times each year: one pre-season DSR Test and three "satisfactory performance days". Most other capacity markets find that one annual test, or one summer and one winter test, suffices. Excessive testing is expensive and disruptive for emergency DR resources, and deters participation. We note that Ofgem has received multiple rule change proposals from generators suggesting that the satisfactory performance days should be lengthened. Their intent is to deter participation by battery storage, but the effect on DSR of some of these proposals would be devastating: they would further increase costs and greatly deter participation. This would be the wrong direction of travel.

5. *Dispatch signal.* At present the GB capacity market seems to be unique amongst the world's capacity markets in that it does not provide a dispatch signal, and instead issues vague capacity market notices, potentially very often, and only announces afterwards whether a dispatch was really required. For supply-side resources, with relatively low SRMCs, this approach poses little problem. For demand-side resources, however, it greatly increases the expected number of hours of dispatch, deterring participation by emergency DR. It may also lead to herding behaviour, as discussed on p. 12, which could be avoided by issuing explicit dispatch instructions.

6. *Merit order.* As mentioned on p. 15, the current design of the capacity market leads to high-SRMC resources having to be dispatched just as often as low-SRMC ones. This is economically wasteful, and deters participation by emergency DR resources.

7. *Heavier penalties, allowing less bureaucracy.* The penalty regime in the capacity market is weak: penalties are capped at 100% of annual revenues, and further restricted by monthly caps. This tends to undervalue reliable resources – such as batteries and well aggregated emergency DR – which seems the wrong thing to do in a market whose job is to ensure security of supply. A more serious impact on DR aggregators comes from the complex and burdensome prequalification, testing, and other paperwork requirements. These seem to have been imposed to gain political comfort about the resources being offered, in an attempt to make up for the weak financial incentives for reliability. They make the market more costly to administer and more costly for all participants, but they have a particularly damaging effect on aggregators, because they have to deal with paperwork for hundreds of customer sites. Increasing the strength of the penalties and removing the arbitrary hoop-

jumping would lead to a cheaper, more reliable system that would be more attractive to reliable DR providers.[26]

Of these, items 2, 4, 5, and 6 are particularly pertinent to "true DSR".

8 Consumer engagement with DSR

Q36 Can you provide any evidence demonstrating how large non-domestic consumers currently find out about and provide DSR services?

Except for the very largest customers, who have dedicated energy teams, most customers find out about DSR opportunities by being approached by aggregators.

Despite being one of the most prominent demand-side aggregators, only around 5% of customers we deal with approach us. 95% of our customer relationships in GB come from us approaching them. Around half of the customers we approach are aware of demand response as a concept.

Q37 Do you recognise the barriers we have identified to large non-domestic customers providing DSR? Can you provide evidence of additional barriers that we have not identified?

Yes. Many of the issues listed are valid concerns. However, some caution is needed in interpreting the survey results.

Overcoming these issues is what aggregators are good at. Customers come up with all sorts of reasons why that cannot provide flexibility. Many of these are due to lack of information, understanding, or analysis, and can be worked through. An aggregator does this, to find out what the customer is really able and willing to do.

The remaining risk-related issues, and some of the technical ones, can then be overcome through participation in a suitably balanced portfolio.

Q38 Do you think that existing initiatives are the best way to engage large non-domestic consumers with DSR? If not, what else do you think we should be doing?

We do not see a pressing need for further public outreach campaigns. They have probably already reached all energy managers, and have little hope of reaching many of the smaller customers who don't have energy managers.

From the point of view of an aggregator, probably the most useful initiative is to have authoritative yet comprehensible online resources available that a customer can consult after they have been approached by an aggregator – to confirm that it is a genuine opportunity.

[26] Note that allowing DSR CMUs to participate in the balancing mechanism will expose them to much stronger penalties for underperformance than in the capacity market, as imbalance prices will be high during system stress events.

The best use of regulatory effort would be to work on opening the remaining flexibility markets to access by independent aggregators, simplifying balancing services products, and improving the capacity market along the lines suggested in our response to Q26.

9 Consumer protection

Q40 Please provide views on what interventions might be necessary to ensure consumer protection in the following areas: social impacts, data and privacy, informed consumers, preventing abuses, other

We support the work by the Association for Decentralised Energy to develop a code of conduct for aggregators of commercial and industrial load, as it would be good to have a mechanism to restrain potential bad actors from misleading customers.

Consumer protection would be more important for residential customers. However, their involvement seems still to be quite a long way off.

For all classes of customer, it is important to bear in mind that most consumer protection initiatives have arisen from the behaviour of retailers and brokers, whereas the relationship an aggregator has with a customer is very different:

- A customer buys an essential service from a retailer. The retailer might claim that the customer owes them a lot of money. In the event of difficulty, the customer may be concerned that their supply could be cut off.
- In contrast, an aggregator buys a service from the customer, and has no special power to enforce anything. On the contrary, the aggregator has typically made commitments to provide services based on the customer's expected performance. If the customer withholds their services, it is the aggregator that suffers both financial penalties and damage to their reputation.

Hence we would expect a proportionate consumer protection regime for customers of aggregators to be rather lighter than the equivalents for retail supply.

Q41 Can you provide evidence demonstrating how smart technologies (domestic or industrial/commercial) could compromise the energy system and how likely this is?

We have addressed this in our response to Q10.

10 The roles of different parties in the system and network operation

Q45 With regard to the need for immediate action: (a) Do you agree with the proposed roles of DSOs and the need for increased coordination between DSOs, the SO and TOs in delivering efficient network planning and local/system-wide use of resources? (b) How could industry best carry these activities forward? Do you agree the further progress we describe is both necessary and possible over the coming year? (c) Are there any legal or regulatory barriers (e.g. including appropriate incentives), to the immediate actions we identify as necessary? If so, please state and prioritise them.

One issue to be wary of is the potential for DNOs/DSOs to erect unnecessary barriers to the provision of flexibility by customers. We have not yet come across any examples of this in GB, but thought it might be helpful to highlight some examples from other jurisdictions:

- Some German network tariffs include substantial discounts for customers who have a flat load profile. Providing flexibility to the system operator or wholesale markets by varying consumption levels has the potential to cause the customer to lose their discount. The customer is often better off forgoing the opportunity to provide flexibility, so they can be sure of retaining their discount. If the network tariff were genuinely cost-reflective, this might be efficient. But this does not appear to be the case: a customer who occasionally reduces their consumption is no more expensive for a DNO to serve than one who doesn't.

- In Northern Ireland, the DNO initially took a position of demanding a veto over the provision of flexibility by customers. To date, no information has been published about how often they have used this veto, but its existence is enough to discourage investment in flexibility in the region. Their argument was that it was possible that load reductions could lead to reverse power flow in parts of their network.[27] This initiative seems to have been linked to other negotiations with the regulator about funding to support connection of renewable generation to their network and increased behind-the-meter generation – customer DR participation was just an innocent bystander. However, similar issues can occur for other reasons: if a DNO has no incentive to allow flexibility, and is given an unfettered ability to stop it, then they may choose to stop it just because it leads to an easier life. This is easily resolved by requiring DSOs to compensate customers whenever they prevent them from offering flexibility. An approach along these lines[28] is described in Article 12 of the internal electricity market regulation proposed by the European Commission on 30 November 2016.

27 In reality, this seems to have been only a theoretical possibility. It would have required customers to be dispatched to reduce demand at times when the system was already at minimum demand and embedded wind generators had high output. In such circumstances, demand-side flexibility would only be dispatched to increase demand, reducing the likelihood of reverse power flows compared to the status quo.

28 … although with arguably inadequate compensation.

Q46 With regard to further future changes to arrangements: (b) What are your views on the different models, including: i. whether the models presented illustrate the right range of potential arrangements to act as a basis for further thinking and analysis?

Open markets seem by far the preferable approach. Note, however, that this does not mean that all flexibility should be procured through “implicit DR” – i.e. customers taking action to avoid high costs. We consider that there is great potential for competitive markets to procure flexibility from both supply- and demand-side flexibility providers on an equal footing.

We are wary of devolving to DSOs the procurement of services that could be procured centrally,[29] because dealing with multiple DSOs’ procurement processes will increase overheads for market participants. This hurts smaller players – such as demand-side aggregators – more than the major suppliers.

I would be happy to provide further detail on these comments, if that would be helpful.

Yours faithfully,

Dr Paul Troughton
Senior Director of Regulatory Affairs

[29] We are also puzzled by the suggestion that frequency management services might be procured by DSOs, as frequency management is the epitome of a system-level service.