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The Regulatory Assistance Project's (RAP) and ClientEarth's Concerns with UK Capacity Mechanism's State Aid Conformity

The Regulatory Assistance Project (RAP) and ClientEarth are both organizations that are using their power market and regulation (RAP) and legal (ClientEarth) expertise to contribute to achievement of a sustainable, decarbonized and competitive energy market. We are concerned that the mechanism the United Kingdom proposes to introduce to solve its alleged generation¹ adequacy problem will harm competition more than necessary.

Below we will provide you with arguments why the UK's analysis of its generation adequacy problem is probably incorrect; why, ongoing balancing market reform discussions in the UK might put the UK's need for a capacity mechanism into question; why the capacity mechanism does not do enough to avoid major undue distortion of competition; and, why the UK could, and should, use a more appropriate measure to address its alleged adequacy problem.

1. Analysis of the UK's generation adequacy problem

In making the case for the introduction of a Capacity Market, DECC points to declining future plant margins brought about by the decommissioning of conventional generation due to emissions legislation and a challenging investment environment associated. However, while plant margins are likely to deteriorate in the immediate years ahead, DECC's analysis of how far they will deteriorate and the assumptions underpinning that analysis, can be challenged.

The question whether the UK's analysis of its generation adequacy problem is correct, contains two parts: Does the UK make correct assumptions with regard to the capacity that is, and will be, available to meet its reliability standard? Is the UK's proposed use of the reliability standard as a mandatory minimum and the translation of that standard into an implied target resource margin reasonable?

Adequacy problem analysis

¹ In order to avoid confusion, we will follow the language used in the EEAG, however, we believe that it is more appropriate to use the term „resource adequacy“. “Generation adequacy” tends to put an emphasis on supply-side resources, while it is generally recognized that the achievement of adequacy depends, by far, not only on the availability of supply-side resources.

We have yet to see National Grid's advice (as the CM Delivery Body) to Ministers concerning the capacity to be tendered for in the first capacity auction. However, based on previous analysis by National Grid, Ofgem and DECC's consultants, it is difficult to avoid the conclusion that the outcome will be overly conservative. This is due to demonstrably pessimistic assumptions made about peak season generation availability, support via interconnectors, the range of events considered "lost load" in the assessment of loss of load probability, and the potential contribution of demand response.

Generator availability. In estimating plant availability, National Grid rely on "commercial" data provided by generators for the core winter months since 2000. While this data may reflect plant availability over the winter period as a whole during this period, it arguably under-estimates availability during the two or three week period when peak demands invariably occur. For example, winter availability for coal-fired plant was assumed by National Grid in their 2013 winter assessment to be 85%, while actual availability over the two recent winter peaks was 92%². As importantly, and as noted in the report to DECC by the Expert Panel in July 2013³, the selection of the period since 2000 corresponds, intentionally or otherwise, with a period during which generators had no commercial incentive to maximize peak season availability. International experience with peak season availability in markets where such commercial incentives exist demonstrates the ability of generation owners to deliver dramatically higher peak season plant availability than what has been assumed in the current assessment. As an example, the most recent information available indicates an assumption of peak season availability for CCGT plants of 85%; in the PJM market, where strong incentives drive generation owners to seek to maximize peak season availability, the comparable figure for CCGT plants is over 96%. A very comparable difference can be seen across all technologies. The performance of the UK fleet prior to 2000, when stronger incentives were in place, substantiate the fact that there is no good reason to assume that British plant owners are incapable of delivering comparable performance. It is likely to be the case that as plant margins tighten, the prospect of higher energy prices, the incentives included in a properly designed capacity mechanism, and reputational issues will all tend to increase outturn availability to within the range typically found in other markets. The Expert Panel's second report in December 2013⁴ noted that DECC and National Grid had declared their intent to commission an independent study of this issue and therefore "closed" that recommendation. However the results of that study have not been made available, nor have the input assumptions, nor is it clear whether or not the current recommendations reflect an improved set of availability assumptions as strongly indicated by the Expert Panel's review.

Interconnector support. In recent assessments, no imports over winter peak are assumed from continental Europe, despite recent and projected increases in interconnector capacity and the

² Winter Consultation Report, 2013. National Grid.

<http://www.nationalgrid.com/NR/rdonlyres/D03C2CD6-D81E-4751-AD0A-D4EDF155FE1F/61304/WinterConsultationReport201314FINAL2.pdf>

³³ Consultation on the draft EMR Delivery Plan, July 2013; Annex F: EMR Panel of Technical Experts Final Report to DECC

https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/223656/emr_consultation_annex_f.pdf

⁴ Capacity Market De-rating Methodology – CMEG32.03. Report to DECC by the EMR Capacity Market Expert Group

https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/266011/cmeg31_17_dec_2013.zip

existence of emergency support arrangements with neighbouring TSOs. The interconnection with Ireland is assumed to be exporting at full capacity, an assumption that is simply not credible given a capacity deficit in GB, unless of course GB generation was contracted to the Irish Capacity Market.

With the introduction of market coupling, flows to and from continental Europe will become more volatile and dependent on price differentials. In the event of a genuine capacity shortage in GB, wholesale prices would rise and energy would be imported. However the overly conservative position adopted By National Grid and DECC reflects a fear that a GB capacity deficit could coincide with similar conditions on the continent and that no support would be available on the day. While this is a possibility and emergency support arrangements are not firm, a probabilistic approach suggests that at least some discounted interconnector contribution should be assumed. To assume no contribution is inconsistent with the probabilistic approach adopted in calculating LOLE⁵. The proper coupling of intra-day and balancing markets, as mandated by the Third Energy Package, will only increase the statistical contribution to resource adequacy by cross-border interconnectors. Furthermore, the concern motivating the current assumption is precisely why ENTSO-E, ACER and the Commission are currently working toward regional resource adequacy assessments, an effort that (if they are genuinely concerned about this) National Grid, DECC and Ofgem should be enthusiastically supporting. If the region within which interconnectors operate is adequately supplied with resources to a standard comparable to what has been utilized for the GB market, there is no rational basis for the concerns expressed. To sum up, in effect the current contribution from interconnectors assumes that the proper coupling of day-ahead, intra-day and balancing markets does not happen, that resource adequacy continues to be assessed on a strictly MS-by-MS basis such that the availability of adequate resources on the other side of the interconnectors cannot be relied upon, and that there is literally zero probability in any case that the interconnector would ever make a contribution to reliability during scarcity events. These assumptions, individually and taken together, simply cannot be justified on a purely rational basis.

Demand response. The estimated demand side contribution to meeting winter peak demand seems very conservative, with Ofgem assuming between 200 & 400 MW in recent assessments. However, National Grid is tendering for a new DSB service for the coming winter and has already received expressions of interest totalling some 1GW. Given the steps that are being taken to encourage demand side participation over the coming years, a higher demand side contribution seems appropriate. Ample experience in other markets demonstrates that demand response is capable of delivering as much as 10% of all capacity requirements at a far lower cost than new generation and at least as reliably⁶.

Application of the reliability standard

DECC have introduced a reliability standard against which the amount of capacity to be tendered will be assessed. With a target of no more than 3 hours of LOLE expectation per year, the standard is high compared with those adopted by some Member States, but not excessively so. For example, it is considerably higher than the Irish reliability standard of 8 hours, but the same as that adopted by

⁵ An estimate of LOLE is given by the overlapping tails of the distributions around central estimates of demand and supply. To simply assume a central (zero) estimate of interconnector flow with no associated distribution makes no sense

⁶ See Synapse 2013, [“Demand Response as a Power System Resource: Program designs, performance and lessons learned in the United States”](#)

France. (See discussion below about the distinction between a target and a mandatory minimum LOLP, which is directly relevant to this point.)

Security of supply standards are a matter for individual MS and therefore difficult to challenge from a European point of view. However, the method of application can be challenged as being overly-conservative. For example, while LOLE counts periods when demand exceeds supply and where it is necessary to restrict demand, the application of the GB standard will not take account of measures that increase supply and avoid the need to restrict demand, such as instructing “maximum generation” or invoking emergency support from neighbouring systems. The current application also assumes that the deployment of voltage reductions count to loss of load, which is not consistent with international practice and introduces yet another layer of questionable conservatism into the assessment. As applied, the GB reliability standard will therefore be considerably tighter than appears at first sight.

2. Undue distortion of competition

As mentioned earlier, ample experience with capacity markets in other markets demonstrates that demand response is capable of delivering as much as 10% of all capacity requirements at a far lower cost than new generation and at least as reliably, yet the proposed design for initial capacity auction seems almost deliberately to be designed to foreclose this as a practical possibility, despite the stated objective of including demand response in the mechanism in subsequent years. Demand response is not slated to participate in the auction proposed for late 2014, with discussion of a set-aside of between 400 and 900 MW to be filled by demand response in subsequent stages of the mechanism. Given that the level of capacity procured via this auction will therefore be set assuming a contribution to resource adequacy by demand response of only about 1% of peak demand, and given that the new capacity procured is set to receive contracts for 15 years, the result will be that any potential for competitive and qualified demand response resources above 1% of peak demand will be effectively foreclosed for the foreseeable future. Given international experience indicating that low-cost demand response resources could meet as much as 10% of peak demand, this implies that UK consumers will be locked into as much as 4,000 MW of unnecessary new power plant investments. Furthermore, since the proposed mechanism is a market-wide capacity market, the exclusion of up to 4,000 MW of low-cost demand response potential implies that UK consumers will be locked into paying all installed capacity far more than would otherwise be the case. As an example, in the PJM auction for the 2012/2013 commitment year demand response constituted a third of all resources cleared and resulted in the clearing price being reduced by 90% from the expected price of \$179/MW-day to \$16.46/MW day. In other words, the extra costs imposed on the UK economy as a result of the current approach could well be very large.

3. Existence of more appropriate measure

A Market-wide or targeted Capacity Mechanism?

DECC initially favoured a strategic reserve rather than a market-wide Capacity Mechanism (CM). Its decision to move away from this option can be challenged, both on need and the detrimental impact on customers.

In their original consultation, DECC indicated that they preferred a targeted Capacity Mechanism rather than the market-wide arrangements now proposed. Their original preference was based on analysis carried out by Redpoint, who concluded that although the risks to security were material, they were uncertain that a targeted Capacity Mechanism was the most appropriate and cost reflective “insurance policy”⁷. This conclusion was reached despite some assumptions that clearly favoured a market-wide Capacity Mechanism, such as an assumption that all scarcity pricing would disappear from energy prices.

In their analysis, Redpoint compared “packages” of low-carbon support and security of supply options and demonstrated that the cost implications of low-carbon support outweighed those of security of supply. However, it is clear from their analysis that, for DECC’s preferred CfD-feed in tariff low-carbon support option, the costs of a market-wide Capacity Margin are higher than those of a strategic reserve and have a greater impact on consumer bills. This is in spite of the favourable assumptions referred to above.

DECC’s eventual decision to opt for a market-wide capacity mechanism is not therefore supported by the analysis carried out by their consultants. It is also pertinent to note that the decision to change course followed extensive lobbying by industry.

The choice of a market-wide capacity market is also challengeable by reference to the analysis of value of lost load and loss of load probability conducted in the course of the consultation. Without going into the detailed analysis (which can be provided separately) the claim that a market wide capacity market is either warranted or economically efficient may well be fundamentally flawed. The analysis of the value of lost load, while reasonable, leaves open the question of whether the selected standard of 3 hours should be treated in the administrative mechanism as the mandatory minimum or rather as a target; the similar historical standard was in practice not an absolute minimum but rather was the target upon which long-term planning was based, with margins consciously expected to fluctuate above and, occasionally, below the target. The analysis in the consultation points instead to the possibility that the mandatory minimum, on the basis of which binding commitments will be made, should be closer to the 5-6 hour level cited in that analysis. Furthermore, the translation of the 3-hour standard into an actual resource margin in practice warrants closer scrutiny, for all of the reasons cited above as well as for other reasons. As an example, in the recent and very lengthy proceeding conducted by the Public Utility Commission of Texas regarding resource adequacy, Brattle Group were retained by the PUCT to examine the analytical and practical implications of proceeding with or without the adoption of a capacity market. As part of that analysis Brattle analysed (1) what resource margin would be efficient given an expert analysis of the value of lost load, (2) what resource margin a properly functioning energy market would actually produce, and (3) what resource margin was implied by the Texas standard of 2.4 hours per year (in other words, slightly *more* conservative than the proposed GB standard) based on a conventional statistical analysis of loss of load probability. The results are particularly instructive for the GB case given that the size of the ERCOT market is very similar to the size of the GB market, the penetration of wind generation in ERCOT is and is expected to be very similar to the GB market, and the ERCOT market is

⁷ Electricity Market Reform, Analysis of policy options. A report by Redpoint Energy in association with Trilemma UK, December 2010
https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/42638/1043-emr-analysis-policy-options.pdf

connected to neighbouring markets only by a small quantity of HVDC interconnectors. Brattle's analysis concluded that the efficient resource margin above peak is 10.2%, a properly functioning energy market would deliver a resource margin of 11.1%, and the resource margin implied by the Texas standard is 14.5%. This points to two possible conclusions in the GB context. First, the target GB resource margin, which is currently pegged at 17%,⁸ is materially above what it seems one could expect from a proper statistical assessment of resource performance (see above comments regarding the assumed peak season performance of GB resources). Second, the failure of the energy market to deliver even a 14.5% resource margin, much less the higher margin apparently being sought the current proposal, cannot be taken as evidence that the market has failed. It is rather simply the result of a target reserve margin that is beyond what an efficient market outcome would produce. The point is not necessarily that a 14.5%, or even a 16% or 20% resource margin cannot be justified – that is in the end a political decision – but that there is no theoretical or practical justification for employing a market-wide capacity market to deliver it. The result of doing so would seem inevitably to lead to institutionalized surplus capacity participating in the energy and balancing services markets, permanently suppressing the necessary price signals expected from those markets, and to the imposition of an unnecessary transfer of wealth from consumers to generators in the form of a higher clearing price paid to all generation clearing in the capacity auction. As the Expert Panel stated at page 14 of their December 2013 report, regarding the cost of the CfD instrument, "...higher capacity margins that depress wholesale prices will raise the subsidy required, all other things being equal." For these and other reasons the original recommendation by Redpoint of a target strategic reserve solution, with the assets in the strategic reserve prohibited from participating in the day-to-day energy and balancing services markets, continues to be the most sensible solution for UK electricity consumers.

A mechanism that includes imports

Although DECC recognise the value of allowing non-GB generation to participate in a Capacity Market, they have been unable to identify an acceptable model that would allow this to happen. Their primary concerns are that any contracted imports could be swamped by outflows resulting from energy price differentials in a market coupling setting, and difficulties in validating the availability and output of non-GB generation.

The outflow concern is not valid. If price differentials cause flows out of GB, then GB does not have a capacity problem. The existence of a Capacity Market may exacerbate energy price differentials and increase outflows causing prices to rise higher than would otherwise be the case, but there would not be a capacity deficit. If a GB capacity shortage did exist, energy prices would rise and energy would be imported as described above. In this case, contracting non-GB resource is effectively an unused insurance policy, as market coupling will have "done the job".

Where contracting for non-GB resource would be of most value is when a capacity deficit exists at both ends of the interconnector. In this case energy price differentials may be insufficient to fully utilise interconnector capacity as prices would be very high at both ends of the interconnector. However, as the non-GB generation effectively becomes part of the GB market and the donor system has to replace that generation (if necessary by demand reduction), interconnector flows should be

⁸ We have endeavored to use comparable metrics between the two markets; the numbers quoted should both correspond roughly to what in the GB market is referred to as the "de-rated capacity margin."

assured. Even in a fully interconnected continental AC system, provided all other MS systems are balanced, the energy should find its way from the donor to the recipient system. In fact, the issue is much simpler for GB, which is interconnected only by dispatchable HVDC circuits.

DECC's concern about validating the availability and output of non-GB generation also seems misplaced. As any contracted non-GB resource would effectively become part of the GB system (e.g. its metering would need to be transferred once a scarcity event had been declared), monitoring availability and output should be simple.

4. Necessity of the capacity mechanism

Measures are in train that undermine the need for a market-wide Capacity Mechanism. Ofgem intends radical reform of the GB Balancing Mechanism⁹ that appears to undermine the need for market-wide capacity payments. This reform will ensure that cash-out prices reflect the marginal cost of balancing incurred by the TSO, including the cost to consumers of voltage reduction or disconnection. As a capacity deficit situation implies that some market participants will be seriously imbalanced, they could face charges that ultimately reflect VOLL. Charges of this magnitude will represent a powerful economic signal to procure adequate capacity cover in the form of generation or DSR. Similar measures adopted for the ERCOT market, including an operating reserve demand curve, were deemed sufficient by the Public Utility Commission of Texas to obviate the need for or value of a market-wide capacity market.

The introduction of Ofgem's measures will address the principal deficiency in the existing energy market that drives the need for market-wide capacity support, ie the fact that energy prices do not reflect the real cost of loss of supply seen by customers. Given these measures, the case for a targeted strategic reserve, designed not to dilute energy prices when capacity is scarce, seems far more appropriate than a market-wide Capacity Mechanism. In fact DECC's proposals seem at odds with Ofgem's Balancing Mechanism reform; the former designed to remove scarcity pricing from energy pricing, while the latter is designed to sharpen energy prices when capacity is scarce.

Conclusions

This note outlines a number of concerns over DECC's decision to opt for a market-wide Capacity Mechanism rather than a strategic reserve and suggests that they have compounded the potential harm from this decision by proposing to lock in the results of the first auction – almost exclusively reserved for generation – with 15 year contracts. No planning process is perfect and that is not the standard to which we are proposing the UK government be held. However capacity mechanisms in comparable competitive electricity markets have been designed and successfully executed with much shorter commitment periods – typically no longer than one year – precisely to allow for this type of uncertainty and to avoid undue distortion of competitive markets. No such caution has been shown here. Some of our concerns may turn out to be over-stated, but there are probably many other issues that we have overlooked due to a lack of time. Overall, we believe that DECC have made the wrong choice and that the decision to introduce a market-wide Capacity Mechanism which will commit electricity consumers to underwrite 15-year capacity contracts for capacity, is simply not supported by the available evidence.

⁹ <https://www.ofgem.gov.uk/ofgem-publications/87782/electricitybalancingsignificantcodereview-finalpolicydecision.pdf>