National Grid - Operating the Electricity Transmission Networks in 2020 - Initial Consultation June 2009

Response by E.ON UK

Please note that our distribution business, Central Networks, is responding separately, and the two responses are intended to complement each other.

Responses to specific questions

Question 1: How do National Grid's observations align with your experience or modelling of wind generation?

From our experience, 10% of capacity is not unrealistic as an estimate of rms (root mean square) error in forecasting wind output four hours ahead. However, our experience is on much lower capacity of wind generation. We do not see the measure of error changing significantly with higher wind speeds, except during the ramp periods, and are investing in systems which we expect to reduce rms error significantly. We also believe there are improvements to be made in wind forecasting services by bodies such as the Met Office, which will reduce the error experienced.

National Grid uses a normal distribution to model the wind generation forecasting error but our analysis showed a much better fit to a Laplace distribution. As this has a greater probability of large variations, a higher multiple of rms error is needed in estimating reserve requirements to achieve the same system reliability. This raises additional reserve requirements to cover intermittent wind generation by about 30%.

In paragraph 2.22 National Grid says that greater interconnection with northern Europe will assist management of wind intermittency. We have looked at the effect that integration with Germany could have, and the result was to reduce reserve requirements in the UK by up to 30%, largely because wind in Germany is less variable. We do not have any hard evidence but are doubtful that much further benefit can be achieved.

Question 2: Are we correct in assuming that wind generation is controllable enough to assist in operating the networks?

Wind generation can be designed to provide good levels of voltage control and reactive power capability. This may entail the installation of compensation devices such as static var compensators (SVCs), either as a supplement to the limited capability provided by some wind turbine designs, or because wind turbines may be located in remote locations (e.g. offshore) and compensation is needed at the onshore connection point. SVCs are a more expensive means of providing voltage control or reactive power capability compared to synchronous machines in conventional power stations. It is also worth noting that wind generation designed to Grid Code requirements has less

reactive power capability than synchronous machines. As voltage control and reactive power provision are important on a regional basis, it is conceivable that there could be insufficient capability at times when a region has a lot of wind generation in operation with most of the synchronous plant displaced. This is likely to increase the requirement for other reactive compensation plant.

The capability of wind generation to control active power and provide frequency response in practice is less certain. Although current wind farms are being designed according to Grid Code requirements and can demonstrate a degree of capability during the compliance testing phase, the capability is not fully proven in real operation on a prolonged or continuous basis. There are uncertainties regarding the effect on the wear and life of wind turbines and developers may be reluctant to provide this service until these issues are resolved, or without full support of manufacturers. We are not able to confirm National Grid's view of the short frequency response dead time, but this seems to be inconsistent with the longer delays that have been discussed at the frequency response industry working group.

Question 3: Should National Grid assume that Supercritical Coal generators will provide some flexibility in operation which will assist in operating the networks?

We envisage that over the timescales for high volumes of wind generation discussed here, any supercritical units are likely to be fitted with CCS. A key issue therefore will be whether CCS will affect flexibility of operation (see our response to question 5). However, it is likely that supercritical coal stations will be able to offer some flexibility.

Question 4: Should we assume that Nuclear generators will continue to concentrate on base-load operation?

Our modelling suggests that with low to moderate penetration of wind there should still be sufficient space for nuclear generators to perform a baseload role, which means that there should be little requirement for them to offer flexibility. However, when intermittent generation exceeds 25% there will be some requirement for nominally baseload plant to offer flexibility and possibly ancillary services. In addition, whilst the new generation of PWR plants may be capable of providing some flexibility, their technical and commercial drivers are likely to mean that they will want to operate at baseload. This will of course be a decision for their operators.

Question 5: Is it likely that Carbon Capture plant will impose material restrictions on the operation of electricity generating plant?

Our expectation is that CCS will not materially impact on the operation of coal plant to the detriment of the electricity grid, but it is important to note that the technology is not designed to offer two-shifting capability, so operating in a flexible way will incur additional costs. However, the CCS

component could be switched off and the plant allowed to run unabated on a temporary basis in response to a shortage of generating capacity, which would provide approximately 30% more capacity, although the economics of doing so are unlikely to be attractive to the operator except when power prices are high as additional costs will be incurred associated with carbon emissions, either under the EU ETS or any government support mechanism. The CCS component could also be shut down to provide rapid frequency response if required.

As National Grid's consultation acknowledges, CCS has not been demonstrated at full power plant scale yet so practical experience will be required to validate these views.

Question 6: Are there other aspects of tidal or marine technologies that we should consider further at this stage?

The impact of tidal and marine technologies is small at present, and we believe National Grid has captured the key issues. However, as these technologies develop, they may have a more significant effect.

Ensuring that marine technologies are easily able to connect to the grid will remove a key barrier to their deployment, which should in turn encourage the further development of these technologies.

Question 7: Are there other restrictions we should consider in developing a view on gas fired generator flexibility?

National Grid seems to have considered the key areas.

Question 8: What is your view of future electricity demand growth and how would you quantify any uncertainty around this?

National Grid's view is broadly consistent with our own.

Question 9: Are there other developments which will change the way that electricity will be consumed in 2020 that we should consider?

An increase in distributed generation (DG) could lead to greater uncertainty over the outturn of demand, and the stability and reliability of DG and DG operating practices may need to be considered when thinking about reserve and response requirements. Consumer use of switched-mode power supplies, which draw constant power over a wide voltage range, may also change the response of the demand side if voltage control measures are used.

Also, heat pumps have been omitted from the modelling and we believe they could create additional electrical demand for heating.

Question 10: Do you share our view that distribution companies, suppliers, aggregators and ourselves will all value and compete for demand side services?

We do see the benefit of demand side management in terms of helping the UK meet its low carbon targets. However, the extent to which active demand side management will be economical for the consumer is as yet unproven and in some cases the financial incentives that might be payable to the demand owner may be too small to make participation in load shifting worthwhile.

The roles and responsibilities of DSOs and the TSO will need to be clearly defined to avoid any potential overlap or confusion, as each will want to optimise its own assets and systems.

Question 11: Are our assumptions around the number of electric vehicles in 2020 reasonable?

See response to question 13.

Question 12: Is it valid to assume that electric vehicle charging will be co-ordinated via a smart grid or something similar and will react to price signals?

The appropriate tariffs, metering and settlement processes will need to be in place to provide the right incentives, but it is likely to be in the interests of most stakeholders to ensure that this happens, in order to accommodate large numbers of vehicles at the lowest overall cost to the system and therefore to consumers. However, in order for the smart grid to materialise there will need to be considerable investment in information and communication technology (ICT) infrastructure, and a managed approach is needed to ensure a coordinated solution.

See also response to question 13.

Question 13: Do you foresee a greater or lesser role from embedded and distributed generation than we have assumed?

National Grid's assumptions are not unreasonable, although the cost of decentralised generation is still too high for many consumers and the forecast of 15GW of embedded generation by 2020 is high compared to our own view. However, it should be remembered that these assumptions represent only one possible outcome among many, and planning, both of the system and of markets and mechanisms, must be robust to alternative outcomes.

There are a number of UK and EU initiatives that are likely to have an impact on this area, including the Zero Carbon Buildings agenda in the UK (starting with Zero Carbon Homes in 2016) and the Energy Performance of Buildings Directive. It would also be prudent to look further ahead and consider a scenario with more nuclear and tidal power.

Question 14: Is our anticipated improvement in wind forecasting performance at 4 hours ahead achievable?

The assumptions made here are not unreasonable; although we do see some high covariances across the fleet, suggesting that a more geographic dispersion may not be as beneficial as first thought. Ultimately the error four hours out will be dependent on the quality of wind forecasting, and there are three major uncertainties in the industry's ability to forecast wind generation at the operational time scale:

- How will improved forecasting techniques reduce forecasting errors? Some of these improvements may be achieved by the Met Office, and it may be unnecessary for several different market participants to make their own separate forecasts. The Intermittent Generation Working Group set up under the Grid Code is looking at this issue.
- What will be the effect of including a high level of offshore wind generation into the current portfolio? Data is currently very limited as to the characteristics of offshore wind and the degree to which its variation is correlated with onshore wind.
- Will the future portfolio of wind farms be dominated by one or two major offshore clusters so that the dispersion effect is weakened?

Nevertheless, a 6% rms error is likely to be achievable on average.

Question 15: Do you have any views on our projected Short Term Operating Reserve requirement under 'Gone Green'?

Further work is needed to understand the correlations of errors across the wind fleet before we can assume geographic dispersion will help to minimise the amount of operating reserve. However, we feel that National Grid's central view of additional STORR may be too low because it assumes that variability of wind generation over four hours follows a normal distribution, and our analysis indicates that this may not be the case (see response to question 1).

National Grid notes in paragraph 6.9 that greater reserve will be required at times because of the risk of turbines shutting down in very high winds. Our analysis suggests this is not a material issue – such events are rare and unlikely to occur simultaneously at widely dispersed locations. Of more significance is the fact that the theoretically calculated additional reserve requirement will at times be greater than the total generation from wind, which is clearly a nonsensical situation and reserve requirements should be reduced in such situations; it is unclear if this effect is included in National Grid's analysis.

Thus we agree that reserve requirements will vary across the day and, furthermore, they will vary at relatively short notice. This will pose challenges for the way in which reserve is managed and procured by National Grid.

Question 16: Do you have any views on our projected volumes, prices and costs for STORR under 'Gone Green'?

With a higher requirement for operating reserve and higher ramping rates for fossil plant balancing changing wind conditions (discussed in paragraphs 7.24-33) it is possible that National Grid will need to take more action to ensure plant is in a position to provide reserve. These actions will include start-up and warming of plant and using bid-offer acceptances to reduce generation to make way. The driver for the increased activity is a greater divergence between a schedule of plant to meet demand alone at least cost and a schedule to meet demand but also provide reserve requirements. It is also possible that generation asset owners will take this action themselves for their own purposes in which case National Grid would need to do less.

The determining factor here is whether balancing actions are predominantly provided by the asset owners (self-hedging) or by the system operator. One problem in provision of balancing power to cover a drop in wind generation by the market is that the major generators are all likely to be experiencing the drop in wind generation at the same time, dependent on the degree to which wind portfolios are similarly dispersed geographically. The same is true now of change in demand due to weather but there is generally more warning of this, giving time to start additional units.

We note that costs of providing STORR via flexible demand are not included in National Grid's assessment. Providing STORR by flexing demand could be lower cost because little additional fuel is used. However, accessing small scale demand response may be more expensive than large scale because of the costs of the technology associated with controlling, measuring and aggregating many small scale actions, especially if smart metering is inadequate for instructing or measuring the demand response.

Question 17: Is National Grid's current view that 'low wind' events across Great Britain need to be considered when evaluating electricity operating margins reasonable?

Yes. National Grid should consider all relevant factors when setting margins, and we agree that periods of low wind speeds across Britain at times of high electricity demand are sufficiently frequent to require consideration in their own right. Failure to do so would risk seriously reducing the security of electricity supply. If decarbonising heat supply leads to greater use of electricity either for direct heating or heat pumps then the effect could be magnified.

The 95% confidence level for wind output (5% probability of being worse) is a reasonable reference point for assessing capacity credit as it puts wind on a similar footing to thermal plant, which

achieves reliability at around that level over winter peak periods. However, this value must be considered across the entire portfolio, because unlike thermal plant there is a strong correlation of wind output from different sites. Also, the estimate of the level of wind output that can be relied upon with that degree of confidence is much lower than the 15% quoted from the SKM report. National Grid should also consider the 10% and 5% cases as these are likely in the winter, when it is possible to see peak demand coincide with minimal wind generation (very cold, still days).

Question 18: Are our generator availability assumptions reasonable for application to analysis of future operating margins?

The figures quoted for offshore and biomass are consistent with our operating history. However, we believe a more realistic assumption for onshore availability of 92.5% should be factored into the equation. Under more extreme weather conditions, this is likely to have an impact on availability and hence we believe the report's initial conclusions are at the optimistic end of expectations rather than at the p-50 level.

In addition, availability for wind generators cannot be treated in the same way as availability for conventional sets. An assessment of availability traditionally assumes that a unit will run if the price is high enough, but this is not the case with wind farms, as no price will make the wind blow. Alternative approaches could be considered, including treating wind farm generation as a negative demand forecast rather than a supply side concern.

Question 19: We would welcome comments from market participants on how they expect to manage periods of low wind generation output and whether this is an important consideration for them.

It is a consideration but not a primary one. Given the likely low load factor of wind there is an asymmetric view of risk dealing with high wind scenarios rather than low wind scenarios, so it is likely that companies will deal with the uncertainty in the same way that they deal with demand variability now, but with a higher gearing ratio.

However, low wind conditions and a potential shortfall in supply will send signals to suppliers in the form of wholesale price volatility. Demand side measures that can be considered at times of low wind could include dynamic tariffs that are responsive on the timescales of wind forecasting (e.g. day ahead tariffs), which would incentivise load reduction and shifting by consumers, and direct load control of high power appliances with the owner's consent, such as commercial air conditioning. In both cases, cost effective market structures for metering and settlement of the alteration in demand will be needed, particularly in the case of small scale participants, where it is imperative that the value of demand management provided is not outweighed by aggregation and settlement costs. Tariff based systems are likely to alter suppliers' energy wholesale activity, whilst more reactive demand response measures will need appropriately designed markets in which the demand response service can be traded.

Demand side management, provision of back up capacity as well as potential interconnection are all likely to be useful in managing periods of low wind generation, but companies will of course have their own strategies for managing their portfolios.

Question 20: Are we correct to highlight the importance of wider European issues in electricity operating margin analysis?

Interconnectors will have a role to play, if there is a consistent approach across the whole of western Europe, and they could be helpful in dealing with at least some degree of wind intermittency and fast moving low pressure systems crossing the region. However, care needs to be taken in crediting interconnection with continental European and other neighbouring electricity systems with a role in meeting annual peak demands, as the British system will experience greatest stress during cold, windless periods which are often associated with anticyclones extending over much of western Europe.

Question 21: Are there further technical solutions for maintaining operating margins which we have not mentioned here?

In a future with much greater electrification of the heat and transport sectors, wind variation could perhaps be supported on the demand side, by switching electric heat and transport into fossil or biofuels. However, this would require appropriate dynamic tariffs and pricing signals to incentivise this switching/arbitrage behaviour and cost effective bivalent heating systems. Hybrid electric vehicles will be dual-fuel by definition and could have this capability added at low marginal cost.

Question 22: Do you think National Grid's view of future operating margins is useful and do you have views on how this should be presented?

See response to question 18 on the treatment of wind generation.

The view is very useful. It would be good to see the other types of reserve and response mapped onto the same graph.

Also, we believe that the increase in intermittent wind generation highlights the need for a continuing role for flexible gas or coal-fired plant able to respond to unpredictable, varying system requirements. The market will need to be able to incentivise operators to make this type of plant available.

Question 23: Are our assumptions regarding the level of electricity demand during the minimum demand periods reasonable?

This will be related to the level of embedded generation – see response to question 13.

Question 24: Are our generation availability assumptions for minimum demand periods reasonable?

National Grid's assumptions for the availability of gas and pumped storage generation look reasonable. EdF has suggested that there will be new nuclear in the UK by the end of 2017, so it is possible that there will be additional nuclear capacity on stream by 2020, in which case availability in minimum demand periods may be higher than the quoted 60%. If no new nuclear plants are constructed by then, 20% of nuclear capacity will be from PWR rather than AGR plant, and PWR design is less flexible and may not be able to operate at the 60% availability. It may be better therefore to model nuclear availability by plant type (AGR/PWR) rather than as generic nuclear.

The chapter also states that plant with CCS will be shut down overnight during periods of minimum demand. Although this may be feasible there are obviously costs associated with operating the plant in this way, and there may also be restrictions on CCS plant associated with any government subsidy that it may receive which could call for the plant to run. These restrictions will have costs associated with them, and may affect availability.

The suggestion that wind farms may bid in to the balancing mechanism to recover the cost of a ROC should they be constrained off is correct, although there may also be further costs associated with this should a CfD element be introduced.

Question 25: Is our central assumption regarding wind generation bid prices related to ROCs reasonable?

The assumption looks reasonable, but it should be remembered that there could be additional risk factors involved, most of which are unknown at this stage. The sites most likely to participate are the large offshore parks which may be eligible for more than one ROC, and it seems unlikely that the price will just cover the pure cost of the lost ROCs, as suppliers will also want to recoup the energy price of the curtailment as well as a recycled benefit. All of this will inflate the cost base assumptions used. Any revenue stabilisation mechanism may have the effect of increasing the level of negative prices that wind generators are prepared to bid into the market.

Question 26: Is it reasonable to assume that minimum demand periods will be managed using Interconnectors and Wind Generation in preference to the curtailment of Nuclear Generation?

Yes. However, this assumes that wind assets can be operated (and operating parameters altered) remotely and in time, and the ability to respond quickly for multiple turbines may require additional investment from generators. Also, once the curtailment period has passed, there is likely to be increased uncertainty regarding generation volumes as parameters are restored.

However, while the current nuclear fleet is deemed to be inflexible, the new generation of nuclear stations may be more flexible, but the technical and economic drivers on the plant are likely to mean it will still want to run at base load. Ultimately, it will be for market participants to make their own

technical and commercial decisions on which of their plant to run to meet the needs of their customers.

Question 27: Do you agree with National Grid's view of increased balancing activity in the future due to variation in market length?

As noted earlier, the variability of wind over a short period follows a Laplace distribution much more closely than a normal distribution. The implication in the context of section 7 is that occasions on which an unusually high number of instructions have to be issued will be more numerous than would be expected purely from the increase in standard deviation of NIV.

There is considerable uncertainty around the estimate of 5% rms error in NIV arising from wind volatility. As a whole portfolio, a lower error rate should be achievable, perhaps as low as 3%, but asset owners will each be making their own decisions on output from their smaller portfolios which, by virtue of being smaller, benefit less from dispersion.

However, it is clear that a significantly increased level of balancing activity should be expected.

Question 28: Do you agree with National Grid's view that ramping effects will impact on operation of the networks?

We agree that high levels of wind generation on the system will lead to more frequent instances of high rates of ramping of controllable generation, and more extreme rates of ramping being required on occasion. If the Severn Barrage is constructed (although this will not be possible by 2020), then the ramping rates will be even higher at times when the end of a period of tidal generation coincides with a fall off in wind generation, especially if this is during the morning demand pick up. If several tidal schemes of similar size are constructed then the impact would be lessened as the timing of tides will be slightly different at each.

Question 29: Do you believe that a new approach is required in the development of System Operator to generation or demand control point interfaces for 2020?

We would be happy to consider proposals for changes to the approach and provide National Grid with comments. We believe that distribution system operators will play a more significant role in future, and E.ON UK's distribution business, Central Networks, addresses this issue in more detail in its own response to the consultation.

Question 30: Are there any specific factors which suggest that adequate flexibility will not be available to National Grid for use in operating the networks in 2020?

Consumers' reluctance to embrace demand side management within their homes and a lack of incentives for consumers to change behaviours might be factors preventing National Grid, DNOs or suppliers from having access to additional flexibility. The implementation of smart metering will

help overcome these constraints but more work is needed to establish a framework to encourage demand side response. These issues are considered in the Government's recent call for evidence on delivering secure low carbon electricity.

Also, the uncertainties about delivery of the reforms introduced under the 2008 Planning Act, the impact of the recession and the associated restriction in the availability of funding to even the largest players, are all factors which will affect the UK's future generation portfolio and therefore the generation available to provide the necessary flexibility.

Question 31: The combined challenge of:

a) ensuring the networks are operated safely and securely against a background of generation variability; whilst

b) getting more from existing infrastructure;

suggests to us that control, communication and information systems have a greater part to play in controlling flows across the transmission networks.

Are there alternative approaches which should be considered?

Centralised control over aggregated demand has been envisaged for the future. Centralised control of the dispatch of DG could also be envisaged, although this may have to be at a lower system level in order to reduce complexity. Voltage support via reactive power is best deployed locally, and DG could be used to provide it.

Question 32: What criteria should National Grid use in developing any requirements for information regarding embedded generators? Are there other ways of obtaining this information?

There are three main criteria that National Grid will need to consider when gathering information on DG: technology (e.g. wind, solar, CHP etc.), scale (large numbers of small scale generation through to a smaller number of larger generators connected to the distribution network) and owner (householders, utility companies, community projects etc.).

We believe that distribution businesses are best placed to deal with information relating to generators connected to their networks, and they could then provide this data in an appropriate form to National Grid.

Question 33: Are there additional options that National Grid should consider to maintain a Black Start capability?

Whilst it is probably not feasible for embedded generation to assist a black start directly, demand side management could perhaps be used to reduce the level of immediate demand experienced as the System Operator brings the system back online. A combination of embedded generation and

storage (particularly at the domestic and community level) could allow buildings or communities to run in an 'islanded' mode, isolated from the local networks temporarily. Not only would this assist black start, but it could also be used during interruptions caused by local issues. This demonstrates another advantage of locating energy storage on the demand side (see our response to Q38).

Question 34: Are we correct in assuming that new interconnectors will be able to meet some of our Balancing Services requirement?

Reserving capacity for balancing is inefficient – market participants should be able to use any available capacity on the interconnectors to correct their own positions – but after intraday gate closure, any capacity that is made available by netting final nominations or that is not used by market participants, should be available to National Grid for balancing.

Question 35: What is your view on the potential of electric vehicles to provide balancing and other energy services?

This looks limited in the period covered by the consultation, but electric vehicles show significant levels of potential as a means of demand rescheduling in the longer term, provided there are suitable incentives to encourage consumers to recharge their vehicles at off peak times. Additionally, batteries could be used as a means of power within the home, but this potential is as yet uncertain. A critical issue around electric vehicles is obviously that there is a lack of operational experience, and solutions to many of the challenges around advanced charging have not been conclusively demonstrated.

Cars are a very large capital purchase for the majority of owners, and are probably only in use for around 400 hours a year, whilst charging for perhaps a further 1000-2000. EVs may therefore be available to participate in balancing for a number of hours per day. Therefore, a balancing market application that can improve the asset utilisation ratio is attractive at a fundamental economic level, provided that the following conditions are met:

- The value of the service (i.e. power prices) must provide an economic return to the service provider (battery owner) plus any aggregator, taking into account the technical means for auctioning or instructing demand, metering and settling this value, and the economic cost if participation significantly reduces battery lifetime or capability;
- That the balancing capability is not restricted by constraints on local distribution networks;
- That the value is greater than the value to the consumer of self-balancing to avoid exposure to peak prices in time of use tariffs;
- The battery owner makes rational economic decisions.

At this stage, it appears probable that the third condition will be met, although the sheer number of EVs that might be grid connected may flood balancing markets with capacity, destroying value and disincentivising new entrants. It may also be the case that only certain users will be interested in offering balancing services, with companies with large fleets probably more likely to participate than individuals, as it will be easier for them to address the issues of aggregation and scale, and to deal with any settlement process. These company owners may also have more predictable usage patterns, and will take a more rational economic viewpoint.

Question 36: How much of the electricity demand in Great Britain do you think could be regarded as discretionary or deferrable and hence available for use as a Balancing Service or other energy service?

Currently, very little. In our experience, financial incentives tend to be the only way to get active demand side management (for example, TRIAD charges). Our experience suggests that commercial services tend not to be particularly attractive to customers and differential pricing in the retail sector is extremely hard. However, in the longer term we do recognise that there will be value in demand side management as a means of coping with peak demand, provided an appropriate framework is developed.

Question 37: What specific actions should National Grid take to facilitate Balancing Services from demand-side providers while maintaining the required quality and volume of service?

As we said in our response to question 36, it is not easy to encourage demand side actions, and it may be that only rule or legislative changes will make this happen to the extent required. However, there could be value in DSM as a means of coping with peak demand in the longer term, given the right market framework.

Much of the potential for demand side activity is likely to be at lower voltages, and therefore involve customers connected to distribution networks. The DSO is therefore likely to have an increased role in the management of demand side activity in the future.

Question 38: Are there further aspects of storage or other storage technologies we should consider when looking forward to 2020?

Vanadium redox flow batteries could be considered, and thermal storage could also play an important part in load shifting in future.

Also, National Grid appears to be only considering the role of storage from a TSO's perspective. Distributed storage (at individual building or community level) may be able to provide flexibility and support system operations, but also support local distribution networks, allow 'islanded' operation in the event of a power failure, or allow customers to arbitrage across time of use tariffs.

Question 39: What are the prospects for the provision of Balancing Services from new OCGTs or other 'Back-Up' generation?

It is likely that such services would only be offered under contract, with appropriate incentives in order to make the build viable. Without the right market conditions, such units will not be built or made available for balancing.

Question 40: Is our mapping of technology to Balancing Services reasonable?

The mapping looks reasonable, although the table misses out aggregated controlled demand management.

Question 41: Is a statement of National Grid's view of its long term Balancing Services requirement useful to industry stakeholders?

Yes. It provides a degree of market certainty.

Question 42: What period should a long term Balancing Services Requirement statement cover?

A balance needs to be found between providing a view over as long a period as possible to enable generators to respond and the likely accuracy of the available data. Ten years may be a reasonable period to cover.

Question 43: What changes to the current reserve products would better encourage the provision of reserve services?

It is important that appropriate arrangements are in place to ensure sufficient reserve is available. We are considering a variety of possible options, and would be happy to share our views with National Grid once our work is more developed.

Question 44: What actions would ensure that procurement of reserve services does not impact adversely on the efficient operation of the wholesale energy markets?

Generators make commercial decisions to make plant available for providing reserve, and by doing so forego being able to use that plant to manage their own position or to benefit from price fluctuations in the market. More reserve capacity is going to be needed in a world with more wind generation, so any mechanism must be able to incentivise generators to make plant available. This is not straightforward, and trading and interference by the Grid Operator before real time disrupts the wholesale market as it sends inefficient price signals.

E.ON UK

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