Evidence

National Infrastructure Commission call for evidence - Electricity interconnection and storage

EDF Energy's response to your questions

Q1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

Market framework and investment challenge

The generation mix will have a significant impact on the costs of operating the system. This is shown clearly in National Grid's recent System Operability Framework (SOF) publications which highlight the differences in system costs arising from different generation mixes. Although it may be possible to mitigate these cost impacts to some extent through storage, demand response and interconnection, we believe that an important first step is to ensure that there is a sensible generation mix. Government should regularly publish and consult on its view of the key constraints and parameters for the generation mix, taking account of deliverability, whole system costs and operability, including the implications for transmission infrastructure; it should take this analysis into account in the design of support schemes.

The Electricity Market Reform (EMR) package has provided the right framework to deliver the transition to a low carbon generation mix and to maintain security of supply at an affordable cost to consumers. Key elements of EMR are the Carbon Price Floor to provide an appropriate carbon price signal to electricity generators, a market-wide technology neutral Capacity Market to support investment in new and existing capacity to safeguard security of electricity supply and the Contracts for Difference (CfD) mechanism to support investment in new low carbon generation.

However, further evolution of the market framework is required to address outstanding challenges, both in the short and longer term. The UK needs to replace and upgrade energy infrastructure. Specifically in power generation, over 40% of the capacity operating in 2012 will have closed by 2030, falling into three main categories:

- Around 8 GW of coal-fired plant has closed since 2012 driven by restrictions imposed by the Large Combustion Plant Directive with the remaining 18 GW expected to close before 2025, some of it imminently, due to further environmental limitations coming from the Industrial Emissions Directive and the Government's intention to close all remaining coal generation by 2025;
- Moreover, over 6 GW of older less efficient gas-fired plant has closed since 2012 with further plants at risk of closure in the next few years;
- Over 7 GW of EDF Energy's Advanced Gas Cooled Reactor (AGR) nuclear plant is expected to close as it reaches the end of its scheduled life by 2030.

We need to replace this capacity to deliver a balanced energy mix that will include new and existing nuclear, gas-fired plants (replacing coal generation as it closes) and renewables, each of which has different characteristics. We must achieve the required scale of investment, delivered when needed through a combination of extension of existing asset lives and

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construction of new capacity. This investment challenge is exacerbated by low commodity prices making investment in low carbon generation uneconomic. CfDs provide the right mechanism to support investment in new low carbon generation. Investment in existing low carbon generation is also required; EDF Energy invests £600m per annum in its existing nuclear stations, including in , life extension and outages. It is important that this is supported by access to capacity market revenues and strong carbon price support.

The capacity market provides the right framework to support investment to ensure security of supply; it must remain technology neutral to deliver the best value for consumers. It has been widely commented on that first two capacity market auctions have not delivered new CCGTs. This is unsurprising as we have been coming out of a period of over-capacity. However, we are reaching a time when new gas-fired generation will soon be needed, but the clearing price for the first two auctions would not deliver new capacity. Some further development of the capacity market is necessary including:

- Measures to ensure that new assets securing capacity agreements are delivered, including effective pre-auction checks on project financing (DECC has recently consulted on this issue);
- Ensuring that adequate capacity is procured in T-4 auctions through prudent assessment of capacity requirements, and a review of volumes set aside for procurement in T-1 auctions;
- Consistent methodologies to calculate de-rated capacity provision.

In addition, action should be taken to address market distortions arising from embedded benefits that do not reflect the costs and benefits arising from embedded generation. These embedded benefits are currently distorting outcomes in the capacity market by giving an unjustifiable cost advantage to embedded generation compared with transmission-connected generation, such as CCGTs.

National Grid is right to use Supplemental Balancing Reserve (SBR) as an interim measure until 2018. It is important to ensure that it continues to provide consumers with value for money during this period. SBR will not provide signals for new investment and therefore must stop when the CM becomes operational in 2018.

Efficient price signals
The development of an efficient system, where supply and demand can be balanced cost effectively, relies on efficient price signals. There are three areas where this needs to be addressed: carbon pricing; pricing intermittency and network charging.

<u>Carbon pricing:</u>
It is important to maintain strong carbon pricing to provide the right economic signals to meet decarbonisation goals. This would ideally be achieved through the European Emissions Trading Scheme (EU ETS). However, to date this has failed to provide the price signals necessary to support investment in low carbon generation. Until it does so, it is vital that the UK continues to maintain a strong UK-wide Carbon Price Floor through the 2020s. Continuation of the Carbon Price Floor at a level which stabilises the current level of wholesale price impact will provide a clear price signal to encourage investment in decarbonisation and a source of tax revenue to the Government and will support decarbonisation at least cost to consumers. More specifically, it will support the Government's objective of phasing out coal

generation and replacing it with new, efficient gas-fired plants and it will also support the refurbishment and life extension of existing low carbon generation, including existing nuclear power stations.

<u>Pricing intermittency:</u>
Intermittent plant imposes additional costs on the system because it requires additional capacity to provide back-up when it is not available at peak demand times, it leads to additional investment requirements on the transmission system and, as the volume of intermittent generation grows, it will increasingly result in the production of surplus wasted energy at times of low demand. Therefore, intermittent plant should bear the cost it imposes on the system; it is important to develop clearly agreed solutions to deliver this.

There are two possible approaches which may not be mutually exclusive. One would be to make changes to market rules and charging arrangements. The other approach would be to provide clearer incentives to intermittent generators through two changes to the design of the CfD mechanism.

- Firstly, new CfDs for intermittent generation could be struck against the baseload reference price: this would greatly improve incentives for market-supportive outage planning, as well as more accurately allocating at least some elements of the costs created by intermittency.
- Secondly, paying CfDs on the basis of availability rather than output would remove incentives to generate when not needed and help to avoid distortions to near-term wholesale and balancing markets, and consequential distortions to incentives for investment. In our modelling we have quantified the additional cost of suboptimal dispatch introduced by this distortion as being in excess of 20% of the total cost of providing response, or around £65m a year. We are happy to share this modelling with the National Infrastructure Commission.

<u>Network charging:</u>
A comprehensive review of networking charging arrangements is required to ensure that they remain fit for purpose and effective in promoting economic outcomes to ensure that the energy system develops at least cost to consumers. A significant example of concern is the favourable treatment of embedded generation through the transmission charging regime; this has contributed to the success of embedded generation in the Capacity Market auctions at the expense of transmission-connected capacity (e.g. new CCGTs) for reasons that do not reflect economic fundamentals.

Embedded generation gets a double benefit from the transmission charging regime because, firstly, it does not pay for generators' Transmission Network Use of System (TNUoS) charges and, secondly, it derives a benefit because suppliers can net embedded generation off their TNUoS charges. This approach had some justification in the past when transmission charges were largely driven by the need for investment to meet increases in demand and the relatively small volume of embedded generation served to reduce the need for this transmission investment. However, transmission investment is now largely driven by changes in the generation mix, not by demand growth, and new embedded generation will bring little or no benefit to the transmission system.

There is a similar charging treatment of Balancing Services Use of System (BSUoS) charges which means that, for example, although embedded solar photovoltaic (PV) generation requires National Grid to hold more reserve to cover rapid changes in its output, it pays nothing towards the cost of this reserve but instead derives a benefit through an offset against charges on suppliers.

It will often be the case that solar PV on a consumer's premises will make no contribution to reducing the peak capacity requirement driving the need for distribution network investment but it will reduce the distribution charges paid by the consumer. Other charges, e.g. for the capacity market, are also levied on net demand volumes. With increasing embedded generation this needs to be reconsidered.

Demand Side Response (DSR) and Embedded Generation

Existing market arrangements provide price signals that indicate to consumers when electricity is most costly to provide and when it is cheapest, and we support the continuing development of these signals.

- Two-thirds of electricity consumption is settled on the basis of half-hourly meter readings and so exposed to the wholesale market time-of-use signal. This provides an incentive for large business consumers to shift their load to periods when it is cheaper.
- Charging for access to the transmission and distribution networks is on the basis of consumption during winter peak hours that signals the additional cost of meeting peak demand through investment in new network capacity. This provides an incentive for large business consumers to avoid consumption when overall electricity demand is highest[1].
- For the domestic residential sector and the smallest commercial premises, historically the only significant flexible load has been electrical heating. The various Economy 7 tariffs have been effective at providing an incentive to take this demand overnight.
- Smart metering will enable these consumers to be settled on the basis of half-hourly meter readings, along with existing half-hourly meters. This means the entire market will be half-hourly settled, and exposed to time-of-use incentives.

Therefore, the arrangements for DSR participation in the wholesale market already exist, and the smart metering programme is completing the picture. It is right to ensure that the market framework does not impede the development of cost-effective DSR. At the same time, efforts to stimulate artificially a "market" for DSR outside the wholesale market would risk undermining the economic efficiency of these arrangements.

There are circumstances in which it is appropriate for the SO (for the transmission network, and, potentially, in the future, for distribution networks) to procure DSR outside the wholesale market, as it does with generation: within half-hourly periods; in specific geographical locations; or with specific technical characteristics (inertia, reactive power provision etc.) Where a demand-side provider can offer these services most cost-effectively then that is to the benefit of all consumers. Equally clearly, it is not to the benefit of all consumers that the SO should pay "over the odds" for demand-side services – there is no additional social benefit that would justify this.

[1] This is known as "TRIAD avoidance".

Modelling work was undertaken in DECC / Ofgem's Smart Grid Forum[2] workstream on the 2030 distribution networks, to analyse the potential for DSR to be used outside the wholesale market for management of the local network. The results show that "smart solutions" may help to postpone necessary reinforcement work, and are relatively quick to deploy, but cannot avoid indefinitely the need to put new distribution infrastructure in the ground. Based on this and similar analysis, we consider that the most cost-effective application of DSR is through the wholesale market, not via network operators. Therefore, we would like to emphasise the importance of having a clear route to market for DSR, to enable all consumers to satisfy their consumption needs at least cost. The current proliferation of overlapping special and one-off schemes obscures the opportunity rather than stimulating it.

In parallel with consideration of the market arrangements for DSR, we are also keen to counter the frequent exaggeration of the potential volume of domestic residential DSR. A mistaken sense of the ease with which the load curve could be "flattened", and the value of a flat load curve compared with a peaky one, has fuelled inappropriate refinements to the market arrangements.

Since 2010, we have undertaken detailed modelling to create an hour-by-hour breakdown of electrical load by application. We have used this breakdown to assess the potential for flexibility of DSR, and used our fundamental dispatch models to determine the value of enhanced flexibility across a range of scenarios. The modelling approach complements the experimental approach undertaken in a series of trials by the distribution networks, in which we have also been involved, funded under Ofgem's Low Carbon Networks Fund (LCNF)[3]. Together, these trials create a valuable resource of data on the real-world reaction of domestic and other consumers to incentives for load shedding and shifting.

Based on our modelling (which we are happy to share with the National Infrastructure Commission on request) and LCNF trial results, evidence is accumulating that there is little value creation resulting from shifting the volume of load that is flexible in typical household consumption. Frontier Economics' analysis of Northern Powergrid's Customer-Led Network Revolution[4] trial shows the *annual* value of interrupting tumble dryer load is up to £4 for a typical household. Other (smaller) loads, including washing machines and dishwashers offer around half that potential. Larger value, up to £15, is available for households with electrical heating – though the number of these households is small, as the majority of electrically-heated homes already utilise night storage heaters (to benefit from Economy 7 tariffs).

In our modelling we have also reviewed scenarios for future changes in load, especially resulting from the electrification of heating and transport, driven by cutting carbon emissions in these sectors. It is clear that electric vehicles (EV) in particular could dramatically increase peak load, assuming consumers recharge their vehicles on arriving home in the early evening. Projections for the speed and extent of EV roll-out vary widely, but we calculate savings from flexible EV charging could be significantly higher, around £150 for the first mover (i.e. assuming all other consumers charge their EV as they wish, there is a saving of £150 available for anyone willing to be flexible; though as more consumers shift their consumption to take

[2] UK Smart Grid Forum Portal: http://uksmartgrid.org/
[3] LCNF: https://www.ofgem.gov.uk/electricity/distribution-networks/network-innovation/low-carbon-networks-fund
[4] Northern Power Grid: http://www.networkrevolution.co.uk/

advantage of the saving, the saving will fall to around £90). For this reason, we believe the assessment of the benefit of half-hourly settlement for smart meters should take note of the latest projections for EV uptake.

Finally, we would like to emphasise that a distinction should properly be made between genuine load-shifting / shedding and embedded generation. The capacity market design does not distinguish between "true" DSR and "behind the meter" embedded generation; we believe that there are essential differences. Embedded generation can provide an appropriate response at peak times in the same way as DSR but it has impacts on carbon and other emissions and so it is important that the right controls are in place to manage any consequential environmental damage. Therefore, in the interests of transparency and to assist future policy development, the operation of the capacity market and the procurement of flexibility products should identify clearly whether providers are providing DSR or embedded generation.

Independent System Operator

The System Operator (SO) has a key role to play in ensuring that the system is balanced cost effectively both short- and long-term. National Grid's role is evolving as it enhances its SO function by acquiring greater responsibility in system planning. We do not believe that the case has yet been made for a fully independent SO and there are risks that need to be carefully considered if such a proposal is implemented. However, we believe that it is appropriate for there to be a review its role, which should encompass SO incentives, National Grid's role in providing visibility on system costs, and potential conflicts of interests, particularly in relation to National Grid's interconnection business.

<u>SO incentives</u>

Ofgem sets a range of incentives on National Grid that are designed to deliver financial benefits to the industry and ultimately consumers by reducing the cost and minimising the risks of balancing the system. The SO incentives are generally set over short time periods (1 or 2 years) and partly due to uncertain future projections of costs, and so focus on minimising short-term costs. With an evolving, fast-changing energy mix and the need to develop innovative solutions to address new or growing issues, a different incentive framework is needed. Developers of new services need longer-term certainty to allow investment. Whole system costs also need to be considered which go beyond the current artificial transmission/ distribution boundary. Incentives are needed to ensure that processes and systems are developed to plug this potential gap.

We believe there is scope to set more effective SO incentives for National Grid that could minimise cost to consumers over the longer-term while balancing the need to keep short-term costs and risks low. This is important area needs significant attention during 2016.

<u>System costs</u>

It would be helpful if National Grid could do more to provide visibility of the system-related costs of different generation mixes. We believe this could be achieved through further development of their Future Energy Scenarios (FES). The status of the FES has increased over recent years. They are now used across the industry to determine capacity requirements, allocation of CfDs under the EMR framework, as well as the general development of longer term energy policy. Given their elevated status it is important to review the checks and balances in place to minimise conflicts of interest and ensure that these FES represent an independent assessment of the potential range of future outcomes. The FES forms the basis of the System Operability Framework (SOF). It would be helpful if National Grid could do more in the FES to provide evidence of the likely costs of operating the system under different future energy mix scenarios.

Conflicts of interest

Finally, we believe it is important to ensure there is no conflict of interest between National Grid's SO role and its ownership of a commercial interconnection business. There is a risk that National Grid's ownership of an interconnector business could compromise its ability to provide independent advice in its role in supporting Ofgem's interconnector cap and floor assessments. It is important that the SO can make an objective assessment of more interconnection, and take that into account in its views about system development. We recognise that National Grid has put some measures in place to manage potential conflict. We believe it would be valuable to review whether these measures are sufficient to ensure that no conflict of interest could arise.

Balancing Market

We do not see a need for further reform of the balancing market itself at this stage. The outcome of Ofgem's Electricity Balancing Significant Code Review to address long-standing concerns on electricity balancing arrangements[5] began to be implemented in late 2015. It is important that these changes are given time to have effect. In parallel, European Market initiatives to harmonise markets are in development which may lead to further reform of the GB balancing market and lead to a broader balancing market.

One area where development is needed is ensuring that the balancing market arrangements are applied effectively to all parties who may be responsible for energy balancing. There are already new market participants getting involved in providing balancing services, e.g. aggregators, and the potential for further innovative business models. With increasing innovation it is important that imbalance arrangements cater for new types of parties to ensure incentives to balance are maintained.

Q2. What are the barriers to the deployment of energy storage capacity?

Energy storage plays a huge role in GB's energy infrastructure at present. Coal is stockpiled at power stations; petrol is stored in quantity throughout the supply chain; and natural gas is injected throughout the summer into vast underground caverns, and withdrawn to fuel consumption in winter. Fossil fuels are cheap to store. The challenge for a low-carbon energy mix is to replicate the flexibility that this storage provides, without the fossil fuels. The most significant barrier to using electricity storage to provide this flexibility is simply its much higher cost per unit of energy.

Due to the high capital costs, to date electricity storage has only been economically viable with pumped hydro, which can cycle on a daily basis. Through technological innovation, the costs of battery storage are decreasing rapidly, and are no longer orders of magnitude higher than pumped storage. It is therefore becoming commercially viable to deploy batteries for applications with very high frequency of cycling, e.g. for second-to-second management of the transmission grid; and as costs continue to fall, we expect these applications to become

[5] Concerns included cash-out prices not creating the correct signals for the market to balance, which could increase the risks to future electricity security of supply and undermine balancing efficiency, unnecessarily increasing costs

broader, to include other reserve services (requiring longer response duration) and potentially playing a daily cycling role similar to pumped storage. At residential scale, for example, this would enable daytime solar generation to be used in the evening. On a transmission-level scale, daily cycling of storage could help to accommodate intermittent wind generation; on the distribution level, storage with reliable daily cycling potential can help provide security of supply to the local DNO.

These applications are dependent on continued strong cost reduction, by perhaps as much as an order of magnitude, which is not guaranteed. Moreover it is inconceivable that costs could fall to the point where batteries (or any other electricity storage) could play a role in accommodating seasonal variation in demand or supply. So a "solar plus storage" model will only work in GB in the summer months to utilise daytime solar power in the evening. It does not have the same potential in GB as in other parts of the world, for example California, where hours of sunshine are more evenly distributed through the year.
It will be important to support further cost reduction in storage via R&D as this is the key barrier to its deployment. In addition, addressing some of the distortions in the market already mentioned will help to facilitate storage development by ensuring there are efficient price signals. This includes National Grid providing more visibility about the system costs of different generation mixes, and the future value of balancing services and flexibility.

Q3. What level of electricity interconnection is likely to be in the best interests of consumers?

Interconnection has a valuable role to play in an efficient European electricity market, and EDF Energy supports increasing the current level of interconnection. We believe that there are clear long-term benefits from increased interconnection such as lower GB consumer prices, a wider pool of electricity balancing providers, diverse contribution to security of supply and efficient use of European resources. However, we believe there are also implications for the GB market that need to be considered further; there could be conflicts of interests with National Grid's interconnector business that need to be reviewed.

We do not agree that there is a case for building interconnection out to a greater capacity or more rapidly than the current 'cap and floor' regime would allow beyond 2020. We consider that the current cap and floor regime has flaws both in design and implementation that risk over-supply of interconnection.

The "cap and floor" regime sets a floor on returns at the cost of debt. We consider that this is too generous such that it minimises risk to investors. In addition the floor protects the developer from technical risk, e.g. continued availability of the interconnector, as well as market risk. For longer interconnectors with challenging sea bed conditions where risk of cable failures may be higher, ultimately this risk is being covered by consumers.

Given the regime is developer-led; it is likely to lead to projects coming forward that are not necessarily optimal. There is no check as to whether these are the best interconnectors and this is an area where a demand led approach may lead to inefficient outcomes. While in the short run new interconnection reduces consumer costs due to market differentials, in the long-run, it will increase costs for consumers as such projects will deter capacity that could have come forward at lower cost. Lowering the floor would expose the equity providers to appropriate market risk and is likely to optimise the level, location and design of new interconnection.

In Ofgem's assessment of the case for a cap and floor regime, they do not consider all the costs that will be incurred by GB consumers and they base their analysis on the market differentials rather than the long-term fundamentals. For example, lower GB wholesale prices due to a new interconnector will increase CfD payments which are ultimately recovered from consumers. Ofgem do not assess this impact which will become material during the 2020s. In addition, the current large price differential between the GB and European market is largely driven by Member State policy interventions, e.g. renewable support schemes in Europe or the Carbon Price Floor in the UK. It is not clear that these differentials will endure through the 2020s as there is likely to be a convergence with time, e.g. strengthening carbon price via the EU ETS and potentially with the introduction of carbon price floors in other member states. Furthermore, if differentials between Member States reduce faster than expected, consumers may be exposed to the costs for stranded assets under Ofgem's cap and floor approach. Therefore, it is important that Ofgem's assessment is based on long-term fundamentals to avoid the risk of future stranded assets and increased costs to consumers.

Q4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

There are two French initiatives which have sought to adopt changes in energy technology when planning to balance supply and demand.

The first initiative seeks to encourage storage technology in order to manage intermittent renewables and balance supply and demand. The French regulator CRE is organising tenders in order to grant feed in tariffs to renewable energy providers in the "non-interconnected zones" typically in the French islands. The successful projects need to be compliant with a set of rules in term of output. Mainly, the generated power needs to be "smoothed" reducing its variability and enhancing its forecast. This is usually met by adding storage technologies to the project. This scheme contributes to "facilitate" supply and demand balance end hence better integration of intermittent renewable technologies into the mix. At this stage it cannot be applied to GB as the current subsidies regime does not take into account the variability and the predictability of the generated power. However, this initiative should be consider if the UK Government were to review further the subsidies for intermittent generation.

The second initiative is a DSR scheme for residential consumers; France has a high proportion of homes with direct electrical heating. Management of peak load has been an important feature of residential tariff design for many years. Consumers on the Tempo tariff[6], for example, are notified day-ahead of up to 22 peak days – designated "red" days, on which the rate charged is a 5-fold multiple of the average annual price. In return, the rate charged on normal "blue" days is around 12% cheaper than the average price. This achieves a peak demand reduction on red days of around 200 MW, compared with normal "blue" days.

[6] Tempo is a demand response option of a regulated tariff for residential customers with a minimum contract of 9kVA. It is based on a horo-seasonal pricing method: the day is split in peak and off-peak hours (10pm – 6am); the year is split in blue, white and red days (from the cheapest to the most expensive tariff).

This initiative suggests that DSR from the residential domestic sector in GB may not be great. The magnitude of the incentive (i.e. the ratio of peak to normal prices) needs to be very high to achieve consumer engagement; it is difficult to believe that such ratios are cost-reflective in GB. The achieved response is a small fraction of France's 75,000 MW peak, even in circumstances in which direct electrical heating is widespread. By contrast the majority of electrically-heated homes in GB have night storage heaters.

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