Power Responsive

Snapshot on the impact of changes to Transmission & Distribution network charges on investment cases for demand side flexibility (DSF)

This snapshot reflects a wide-ranging discussion on Transmission and Distribution charging at the Power Responsive steering group meeting on 25 January 2017, held under Chatham House rule. The discussion focused on two main questions:

- *What are the potential impacts to those investing in demand side flexibility of short/longer term changes to network charging arrangements?*
- *What can we do as an electricity industry in practical terms to help alleviate these potential impacts on the case for investment?*

Two opening contributions were kindly made by colleagues from Cornwall Energy and KiWi Power.

Context for DSF and network charges

We have shifted away from an electricity system dominated by a few large suppliers and generators, with customers at the end, to a plethora of business models and more active customers. DSF is increasingly driven by technology innovation. Management of network charges has offered an entry point for many I&C customers to participate in DSF.

Historically, TRIADs have provided a strong signal for DSF, as a clear and straightforward mechanism that customers can understand and engage with. In winter 2015-16, National Grid witnessed up to 2GW non-dispatched load as a result of TRIAD avoidance activity during each event. Over the past five years, there has been a significant increase in the amount of winter peak-time load reduction in response to TRIADs. Customer avoidance activity is having a substantial impact on the shape of our winter system peaks. This means there are more TRIAD warnings, and it's harder to predict the three TRIAD periods.

TRIADs were not designed to provide a signal for DSF but have been effective at doing so among certain I&C customers. There has been a growth in response to TRIADs, and a reduction in ancillary services. There is increased recognition that a signal originally designed to avoid winter-peak transmission network use may no longer be the most appropriate signal to the wider market about bottle-necks on the transmission system, overall system operating costs, or, system peak. It is important to ensure Transmission charging is fit for the future. Reflecting costs and constraints on the system, which are locational, and not solely focused on winter peaks, but also on the impact of high renewable generation including during summer periods.

For Distribution Use of System (DUOS) Red Zone management, it is not known how far this signal in practice reaches customers (i.e. reflected in individual tariffs by suppliers or socialised across all customers) – or produces a response. It is unfortunate if peak costs are smeared across the day, as it is important long-term to have greater cost-reflectivity. It was noted that big historic regional differences in DUOS charges leads to many battery operators locating in certain locations. Underlying approaches to the charging methodologies between Distribution Network Operators (DNOs) are important.

Impacts of changes to network charges

There will be winners and losers as a result of changes in charging methodology. However, many demand side providers are agile enough to 'follow the money'. But, the changes will impact the investment cases for recent or new assets,– such as new diesel and battery storage. For Industrial and Commercial (I&C) customers, management of network charges was a simple route into DSF, so now those customers would need to engage with the more complex suite of products and contracts, or work via aggregators.

Ultimately, there was a sense that it may be too late. Once the embedded benefits review was announced, it began to impact investor confidence. It is important for network charges to be more cost reflective and also coherent across transmission and distribution. There will be short-term pain, but changes to charging methodologies are needed for the long-term. There was broad acceptance, and optimism expressed around the table that the changes need not derail current or future activity.

The effectiveness of TRIADs continues to demonstrate that there is value for market actors and demand side flexibility available from I&C customers. There is confidence that value will be there, but awareness that a revenue stream is disappearing and lack of clarity on what will replace it. Short-term uncertainty will impact 'sell-cycles'. But there are still opportunities in the contracted demand side markets. There may also be unintended consequences, such as a 'rush behind the meter'. And a shift of focus for distributed generation to respond to the capacity market recharge mechanism (where costs are recovered 4-7pm during winter).

Although DSF providers may be agile and able to follow changing revenue streams, it may be more challenging at the level of the individual I&C customer, who already sees the market as complex. The focus for I&C customers remains on their energy bills and reducing cost. Now the 'easy' entry point looks set to be taken away. It is important to start from a customer perspective, and look at what are the most straightforward ways customers can offer their flexibility to the system. Some feel this is through long-term contracts, others through greater liquidity and more frequent tendering. Its also important to consider and clarify which value streams are stackable.

Some DSF does not require capital investment, so changes only impact on the amount of revenue generated. But where upfront investment is required, this can be more difficult. Many of the same people who have invested in wind and solar – and there is concern about payback. Typical demand side investors are not pension pots with long term Power Purchase Agreements (PPAs) but venture capitalists. There has been a dramatic 'mind-shift' and investors are more willing to take risks. They are developing more sophisticated models and combining portfolios of DSF, supply, and generation to be 'virtually vertically integrated'.

Greater consideration will be needed on the impact of local market models and on households. Locational and peak avoidance signals will be important for these markets respectively in future.

Policy, regulatory and market actor steps

We need to get a better handle on what is driving cost on Transmission and Distribution systems, how to reflect these costs, and ensure fair allocation of cost recovery. There are choices to be made in what is or is not passed through and what the customer sees.

Uncertainty: there was strong agreement that the most important step is to reduce the period of uncertainty. The embedded benefit review started 15 months ago – and during that time, the market has accelerated. The market can bear a short period of uncertainty. Currently the process of designing and implementing change is slow and consultation heavy. By the time it has been implemented, the market has shifted again.

Resourcing for change: the vast majority of demand side participants do not have time to respond to the huge volume of consultations, let alone code modifications. Large companies also struggle to resource this, so it is even harder for small companies and customers. It is important to consider how new and smaller voices could be resourced and represented.

Market-wide approach: a holistic approach is needed. Currently changes are made in a piecemeal way, with different industry parties putting forward code modifications ad-hoc. A proper review is favoured by some – e.g. significant code review (SCR). Otherwise, there is a risk of pulling one lever to be more cost reflective, and having unintended consequences, so its less cost effective. We need to look at all levers together. However, it took a long time to develop both Transmit and the Common Charging Methodology.

Frameworks: need to be agile and responsive. There was a question as to how far the NETA change process (i.e. "self governance" principle) would remain fit for purpose. Therefore a question on whether it is better to look at everything in one go or in chunks – separating out the complex issues. Thinking is needed now on what features a future energy system might have – the broad structure and strategy. Ofgem is looking at this. It was suggested that we could then break the issues down into 'waves', setting out a clear timetable for addressing each issue.

Roles and responsibilities: clarity of roles and responsibilities will be important – both 'ownership' of issues and subsequent leadership. There is a high degree of commonality in the views of BEIS, Ofgem and the System Operator – due to collaborative working on the Call for Evidence and SO consultation – which is helpful. Ofgem is currently consulting on its forward plan, and BEIS is in the process of preparing a forward plan for parliament.

Conclusion - how we make change is as important as what we do

There was general agreement that it's not necessarily change itself, but the way change is made and implemented that has the biggest impact on market and customer confidence. The need for change is recognised across all actors. Network charging needs to be both fit for the future and reflective of costs.

There is confidence that flexibility will continue to have value, that value will be somewhere in the system and accessible through the markets. But we need to shorten the uncertainty period. There may be short-term pain, but overall there is opportunity for agile business models to respond.

It is critical for the review of charging to be done holistically, starting with principles, identifying all the changes required, prioritising these, and setting out a timetable for when each issue or batch of issues will be addressed.