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Response to Ofgem's open letter: 'Charging arrangements for embedded generation'

Vattenfall is the Swedish state-owned utility and one of Europe's largest generators of electricity and heat and the second largest player in the global offshore sector.

We have invested nearly £3bn in the UK in onshore and offshore wind since 2008. We will operate nearly 1GW of capacity by 2017 and recently announced plans to invest £5bn in renewables, mainly offshore wind, in Northern Europe by 2020. It is our ambition that the UK will continue to be a growth market for Vattenfall.

Our over-riding objective in responding to this letter is to help industry and Government develop a grid charging regime which is stable, predictable, fair, and provides efficient investment signals to demand customers and generators with a long-term view of society's needs.

Our existing portfolio includes assets which are both transmission and distribution connected and we are actively developing new projects which would be connected at the distribution level. Some of our assets receive 'embedded benefits' and others do not and we are therefore well positioned to provide input on both sides of the embedded benefits debate due to the risks and opportunities for our business in the UK.

Firstly, we agree with Ofgem's view that changing BSUoS charging arrangement is not a priority and support this by noting that embedded BSUoS benefits, unlike the TRIAD element, turn negative in areas of high penetration of embedded generation. This is increasing prevalent in the Northern Scotland GSP Group, acting to mitigate the regional embedded benefit.

With respect to TRIAD benefits we agree, on balance, that there are exceptional factors accelerating the growth of TNUoS demand residual tariffs and associated TRIAD benefits that are not efficient. This growth is increasing discrepancies between charges for transmission and distribution-connected generation and likely excessively incentivising flexible embedded generation and demand-side response. We also accept that these factors may not reflect increasing value of these beneficiaries either to the network or to the system as a whole and that this defect indicates the need for analysis and long-term reform.

TRIADs were established in 1990 and are generally accepted as having been successful in improving efficiency by incentivising mitigation of winter peak power flows across the transmission network. These arrangements have also, we believe, contributed to securing the system and reducing energy price excursions by providing a targeted incentive for balancing generation and demand during periods of greatest stress. A key strength of the TRIAD arrangements is that generator and demand-side (including generation behind the meter) response are treated equally, thereby increasing competition across a level playing field to deliver a reduction in peak net demand. However, we accept that changes in the system since 1990 and the recent and forecast increases in the TNUoS residual element may cause distortion and merit long-term reform.

Given the historic benefit of TRIADs to network efficiency and system security we believe that the impact and risks of radical change implemented to the timescales proposed in CMP264 and Ofgem's letter merit detailed and careful analysis. Alongside this analysis, any decisions taken should take into account that investment decisions have been taken on the basis of a long-standing charging regime and sudden changes to this may manifest themselves in decreased confidence and, therefore, higher costs of capital.

We are particularly concerned about the potential for piecemeal and disjointed reform leading to significant unintended and inefficient consequences and damage to investor confidence. Furthermore, we do not believe the current evidence put forward by Ofgem or the CUSC Modification Working Group has effectively made the case for, or addressed the risk of, change. We are not convinced the analysis presented publically has considered in sufficient detail the financial impact on existing and future generators, the risks of unintended consequences, or the impacts on security of supply; neither has it assessed in adequate detail the benefits of distributed generation to the system.

Ofgem's decision not to undertake a Significant Code Review and to rely on CUSC modification instead underlines a recent trend in energy policy towards unpredictable, significant, and fast-paced change arguably conducted without full understanding of the costs and benefits. Our perception of the policy and regulatory risks of the UK market is rising and proposals like these may well have a significant impact on investor confidence, particularly when considered cumulatively with other policy and market changes.

We do believe that there is now an excellent opportunity to fully and independently assess the costs and benefits of distributed generation, on-site generation and demand-side response, and the extent to which this should be reflected in the charging methodology. A consultation that allows industry to engage effectively, conducted in a joined-up manner with full sight of National Grid's developing Transmission Charging Review would seem the right time to settle long-term change using a process with which investors can have confidence.

Although we urge Ofgem not to enact piecemeal change of this scale through the CUSC process and note that both CUSC modifications CMP 264 and CMP 265 will have significant consequences for the sector and consumers, it is our view that the CMP 265 is more targeted and is therefore likely to have comparatively less impact on the energy system than the alternative. We do not support CMP 264 and its proposal to create an increasingly un-level playing where some projects receive access to embedded benefits and others do not. We would also be extremely concerned by any decision to remove embedded benefits for all generators with immediate effect.

A fuller response is supplied in the attached annex. My colleague Matthew Bacon would be pleased to discuss. He can be reached at matthew.bacon@vattenfall.com or on 0203 301 9103.

Yours sincerely



Piers Guy
UK Country Manager

Annex – Charging arrangements for embedded benefits

This annex lays out our views on embedded benefits, Ofgem’s open letter, and the CUSC modification proposals in more detail. Supporting information of a commercially sensitive nature is located in a separate confidential annex.

We have grouped this response into a number of topics.

1) Impact on security of supply

The only detailed analyses conducted so far on the impact of change to the embedded benefits system has highlighted significant short-term security of supply concerns as some plant suddenly finds itself uneconomic and exits the market. KPMG and Cornwall Energy separately have estimated this impact around 2.1-3.6GW of embedded generation exiting the system, which would otherwise be present at winter peak.¹ Careful thought should be given to the corresponding impacts on security of supply and what will replace this capacity in the short-term.

2) Financial impact on existing generators

Investment decisions have been taken on the basis of a legitimate expectation of the longevity of the current charging regime and it is of great concern that Ofgem may enact change which curtails a significant part of project revenue on which investment decisions have been based (i.e. change which goes beyond the remit of the current CUSC proposals or follows on from it).

It is particularly concerning that change may lack a sufficient lead-in time given the scale of value at stake and knock-on impact to the electricity system. Although signalled in Ofgem’s forward workplan for 16/17, analysis and proposals have been brought forward at an accelerated pace and could go from proposal to implementation over the course of just one year, following consultation on CUSC proposals amounting to 16 working days over August. We think this is problematic considering that investors take a long-term view of revenues and costs and their development at the point of Final Investment Decision (20 years for onshore wind and 25 years for offshore wind).

It is our interpretation of Ofgem’s letter and BEIS’s May consultation on the Capacity Market that there is a perception that the proposed changes to the charging regime are likely to be less problematic for wind generators than dispatchable power (and are therefore attractive in that they fix a perceived problem in the Capacity Market whilst minimising impact elsewhere). Whilst dispatchable power is likely to feel the impact

¹ Cornwall Energy, *A Review of the embedded benefits accruing to distribution connected generation in GB*, pp.27-31; KPMG, *The effects of changes to embedded benefits on the energy trilemma – executive summary*, pp.3-4.

more than wind generation, there is likely significant value at stake for wind generators outlined in Figure 4.

3) Impact on the investment case for viability of embedded wind

Analysis by Bloomberg New Energy Finance suggests that onshore wind is now the cheapest form of new build electricity generation in the UK at around \$85/MWh in terms of the levelised costs of energy (LCOE) compared to \$88/MWh for new-build CCGT.² This position is likely to entrench and widen as technological development continues to drive down the costs of wind compared to gas (which is likely at a low ebb now in terms of LCOE thanks to currently low wholesale gas prices).

However, all forms of new-build power generation remain un-investable on their own basis against current wholesale electricity prices (around \$50/MWh in Q1 2016). This is likely to remain the case out to 2035 based on the central scenario of wholesale electricity price projections produced by the Department of Business, Energy, and Industrial Strategy.³

Developers are currently working hard to reduce the LCOE of new-build wind, but cost reductions in the region of 50% that would allow projects to come forward under the wholesale price alone are clearly challenging, especially for smaller-scale distribution-connected projects. Removal of the TRIAD residual element of embedded benefits makes this objective harder still for smaller projects.

Within this context, we find CMP 264 particularly problematic as it creates a ‘twin track’ system where new distribution connected generation is discriminated against when compared to existing incumbents. Whilst a discriminatory element is also true of CMP 265, in CMP 265 the discrimination is limited to those that also access revenue support through Capacity Market payments and this is also a more limited number of technologies and parties.

Removing the TRIAD residual could therefore have a knock-on impact on the amount of embedded onshore wind which can be constructed in the future. We are aware that consumers ultimately pay for embedded benefits through energy bills. However, as the CUSC Modifications and Ofgem’s letter suggest the counterfactual of removing the TRIAD residual may not be lower bills for consumers, if the effect of embedded benefit change manifests in higher clearing prices for the Capacity Market and potentially increased wholesale electricity prices. If this happens, it would amount to a transfer of value from distributed generators, many of which are small innovative businesses, new market entrants and/or renewable generators, to a small number of large incumbent power generators operating ageing carbon-emitting assets with little net change to the

² Bloomberg New Energy Finance, *H1 2016 EMEA LCOE Outlook* (April 2016).

³ BEIS, *Updated Energy and Emissions Projections 2015*.

ability to meet peak power demand (as there would be ‘re-procurement’ of capacity already ‘bought’ once under previous auctions). We believe that this is not in the overall interests of existing or future energy consumers.

We would also like to take this opportunity to address an assertion in Ofgem’s *Open Letter* that embedded benefits are causing distortion in investment decisions between transmission and distribution connected capacity. Whilst there may be instances where embedded benefits have affected decisions around the size of distribution connected projects near the 100MW boundary for embedded benefit eligibility, we anticipate that the number and scale of these decisions is likely to be minimal.

This is because decisions around the size of an installation and whether to connect at the transmission or distribution level will be driven by many other factors besides embedded benefits, including: land availability; proximity to transmission/distribution infrastructure; transmission/distribution entry capacity availability; greater regulatory/administrative overheads of transmission connection; restrictions on size imposed through planning; and, until recently, the relative immaturity of the wind sector and technology which would incline developers towards smaller installations at the distribution level.

4) Regulatory risk and concern over due process

We have a number of concerns regarding the CUSC process in this instance. These all serve to increase our perception of the GB energy market as vulnerable to sudden, unpredictable and significant change in policy. Other examples of this include the early closure of the Renewables Obligation (RO), change in approach to onshore wind in planning and the Contracts for Difference (CFD) mechanism, capping of the Feed-in Tariff scheme, cancellation of the CCS programme, and removal of Levy Exemption Certificates, alongside the broader uncertainty created by the result of the EU referendum.

Although none of these have been caused by Ofgem, we hope Ofgem bears in mind the broader market context and impact on perceptions of regulatory risk, as it did in the decision not to re-open the RIIO methodology for transmission system regulated returns in the recent RIIO mid-point review. Below we highlight a number of concerns with the current process. We also note that many of these perceptions resonate with findings made by the CMA about adverse effects on competition in energy sector analysis and regulatory change.⁴

- i. We feel a change of this scale requires independent analysis led by the regulator or TSO acting on behalf of the sector as a whole, and not through industry-led processes where there is a significant risk of analysis and decisions being driven

⁴ CMA, *Energy Market Investigation – final report* (June 2016), pp.1219-1289.

by those with financial interests in a particular outcome. Whilst we appreciate Ofgem's willingness to engage pragmatically and quickly with perceived distortions in the sector, we do not think this should come at the expense of robust analysis and effective industry engagement.

- ii. In particular, Ofgem notes that the decision not to launch a Significant Code Review is due to lack of confidence in delivery of a timely response. In light of this view, we suggest the SCR process should be reformed to ensure Ofgem is capable of delivering industry change which balances the need to act with quality of analysis.
- iii. Furthermore, both modifications and publications from BEIS and Ofgem either implicitly or explicitly reference perceived problems with the Capacity Market in discussing embedded benefits and we do not think the charging methodology is an appropriate way to address policy concerns, which should instead be dealt with through the Capacity Market rules and regulations.
- iv. In our view, the complexity of analysis presented by the CUSC Modification panel is insufficient. We therefore think relying on this significantly increases the risks of unintended consequences, or basing decisions around flawed analysis or assumptions. We note that this runs counter to views expressed recently by the Competition and Markets Authority.⁵ Furthermore, the paucity of analysis so far is in part a product of the excessive speed with which these proposals have been developed, which has amounted to a consultation period on the proposals of 16 working days over August.

5) Flawed rationale for change

We have concerns about a number of the theories of harm put forward by Ofgem arising from views that embedded benefits:

- i. 'distort the outcome of the capacity market by holding down prices': our principle concern is that BEIS and Ofgem are conflating the primary objective of the Capacity Market (securing technology-neutral capacity at the lowest cost to consumers) with secondary objectives (incentivising new-build CCGT). The 2015 auction secured 46.4GW at a clearing price of

⁵ In particular, their statement that 'government policies and regulations have had a fundamental influence on the nature of competition in energy markets... to ensure [these policies] serve customers' needs, it is vital that policy decisions... are informed by robust analyses of their likely impact'. Furthermore, the CMA states 'it is our view that analysis and communication of the impact of government and regulatory policies on energy prices and bills... is insufficient; and there is a lack of relevant financial information, which is needed to provide clear and trusted assessment of outcomes in the GB energy markets, including an analysis of the forecast and actual impacts of regulations, and the trade-offs between policies'. CMA, *Energy Market Investigation – Final Report* (2016), p.1234.

£18/kW/year and a total cost to the consumer of £834mn.⁶ This is significantly lower than the estimates provided before the first auction (at an average of £33/kW/year between 2019-30).⁷ It therefore seems questionable to pursue a change which seeks to raise the clearing price of an auction mechanism which is already achieving its objectives at a lower cost to consumers than anticipated. This is particularly the case as analysis conducted by independent consultants proposes that the impact of removing embedded benefits would be to increase the clearing price in 2019/20 to c.£23.2/kW/year at an additional cost to consumers of £214mn and that this would still be significantly lower than the clearing price required to bring forward new CCGT capacity.⁸

- ii. 'lead to [transmission connected generation] exiting because it cannot compete': whilst embedded benefits are likely a factor in the comparative competitiveness of transmission vs. distribution connected generation, we note that there are broader fundamentals leading to the exit of transmission-connected capacity, including competition from interconnection (which receives favourable treatment in EU network codes with regards to TNUOS charges), over-capacity in conventional generation, competition from low-marginal cost renewables, and policy such as the Industrial Emissions Directive, which limits the running hours of coal. We note also that larger transmission-connected capacity also accesses benefits largely not available to distribution-connected capacity (including economies of scale and more favourable financing arrangements) which may counter-act any effect of embedded benefits.
- iii. 'lead to an inefficient mix of generation by encouraging investment in smaller distribution connected generation... over potentially more efficient larger transmission connected generators': this is a matter of interpretation that assumes bigger is better. An alternative interpretation could be that smaller plant designed to run for limited hours during periods of system peak is more efficient than larger power stations requiring larger grid connections etc. which are redundant for large parts of the year.
- iv. 'distort innovation in the market towards parties who can best capture this large payment': this is an assertion which needs evidence and further rationale to substantiate and develop. The counter-factual of this argument is also hard to follow, i.e. that it is pro-innovation to support large incumbents running traditional forms of large power stations.

⁶ National Grid, *Final Auction Results T-4 Capacity Market Auction for 2019/20*.

⁷ DECC, *Electricity Market Reform – Capacity Market Impact Assessment* (Sept, 2014), p.29.

⁸ Cornwall Energy, *A Review of the Embedded Benefits accruing to Distribution Connected Generation in GB* (May 2016).

6) Analysis suggests that the value of embedded wind generation to the system may actually be undervalued at present due to the impact of ‘TRIAD shifting’

In relation to their effect on the Triad, embedded generation can be divided into two types: controllable “Triad-chasing” generators such as diesel plants, and intermittent generators such as wind farms. Both types reduce Triad demand but, whereas the former tends to have a uniform effect across all potential Triad periods, the latter have a variable effect that depends on aggregate production during each settlement period.

Whereas the aggregate solar production during Triad periods, which consistently occur after sunset, is always zero, aggregate wind production can vary between zero and its annual maximum level depending on wind speeds. The effect of variable wind production on potential Triad periods is illustrated by the following example on consecutive days in February 2016.

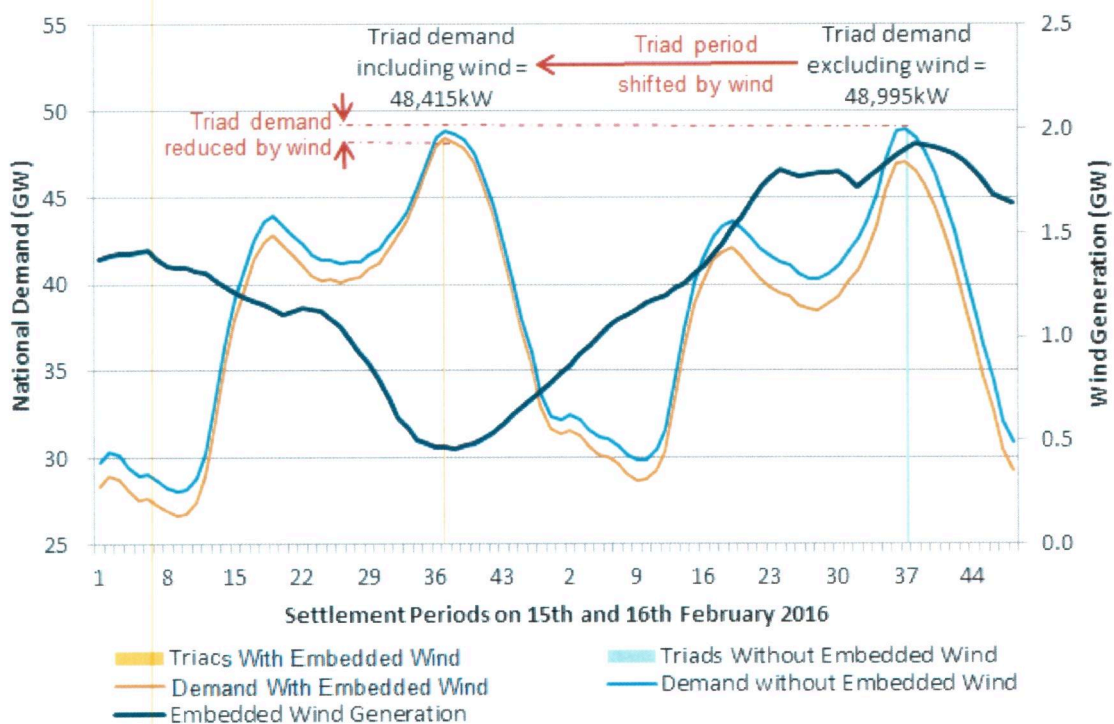


Figure 1 - Embedded wind effect on peak demand

The above chart shows that the third Triad period in winter 2015/16 was shifted by wind from 16th to 15th February, thereby reducing the Triad demand by 580MW and the aggregate embedded wind production during the Triad period by 1,430MW (i.e. 75% reduction). This example illustrates an underlying principle that embedded wind generation tends to reduce peak demand and shift Triads to periods of lower wind production, thereby reducing the aggregate Triad benefit for wind generators.

Further analysis of the last four years, summarised in Figure 2 below, illustrates the extent of Triad-shifting, with seven out of twelve Triads in that period shifted by embedded wind to different dates resulting in an average reduction in Triad demand of 858MW, representing 27% of the average embedded wind generation capacity in the same period.

Year	Triad no	Including Embedded Wind		Excluding Embedded Wind		Effect of Embedded Wind
		Demand (MW)	Triad Date	Demand (MW)	Triad Date	Demand reduction (MW)
2012 - 13	1	55751	12/12/2012	56068	12/12/2012	317
	2	55438	16/01/2013	55665	16/01/2013	227
	3	52941	28/11/2012	53997	28/01/2013	1056
	Average	54710	-	55243	-	533
2013 - 14	1	51738	03/12/2013	52796	05/12/2013	1058
	2	51333	19/11/2013	52104	12/02/2014	771
	3	50967	30/01/2014	52065	20/11/2013	1098
	Average	51346	-	52322	-	976
2014 - 15	1	52379	19/01/2015	53138	09/12/2014	759
	2	52020	02/02/2015	52925	20/01/2015	905
	3	50900	12/02/2015	52509	02/02/2015	1609
	Average	51766	-	52857	-	1091
2015 - 16	1	50965	18/01/2016	51419	18/01/2016	454
	2	48781	23/11/2015	50241	23/11/2015	1460
	3	48415	15/02/2016	48995	16/02/2016	580
	Average	49387	-	50218	-	831

Figure 2 - Effect of embedded wind generation on Triad demand and date (shifted Triad periods in red)

Triad-shifting also leads to a significant reduction in the average wind generation during Triad periods, as shown in Figure 3 below. The average reduction in embedded wind generation caused by this effect over the four-year period is 57%. **This reduction has a proportional effect on the aggregate Triad benefits that embedded wind farms received in the same period.**

Year	Embedded wind capacity (MW)	Average wind output during Triads including embedded wind		Average wind output during Triads excluding embedded wind		Resulting reduction in wind output & Triad benefits
		Wind generation (MW)	Wind capacity factor	Wind generation (MW)	Wind capacity factor	
2012 - 13	2085	370	20%	764	41%	52%
2013 - 14	2434	490	25%	1465	76%	67%
2014 - 15	4039	388	13%	1320	43%	71%
2015 - 16	4013	793	28%	1270	44%	38%
Average	-	-	22%	-	51%	57%

Figure 3 - Effect of Triad-shifting on aggregate embedded wind generation and associated embedded benefits

Furthermore, the results in Figure 3 indicate that the average wind capacity factor during Triads excluding the contribution of wind generation is 51%, significantly greater than the average annual capacity factor for embedded wind generation. The effect of Triad-shifting reduces this average capacity factor to 22%, which is lower than the average annual capacity factor but still a significant and continuing revenue stream for embedded wind farms, as indicated generically in Figure 4 below based on TNUoS data from selected Demand Zones, as published in the current NGET TNUoS Forecast Statement.

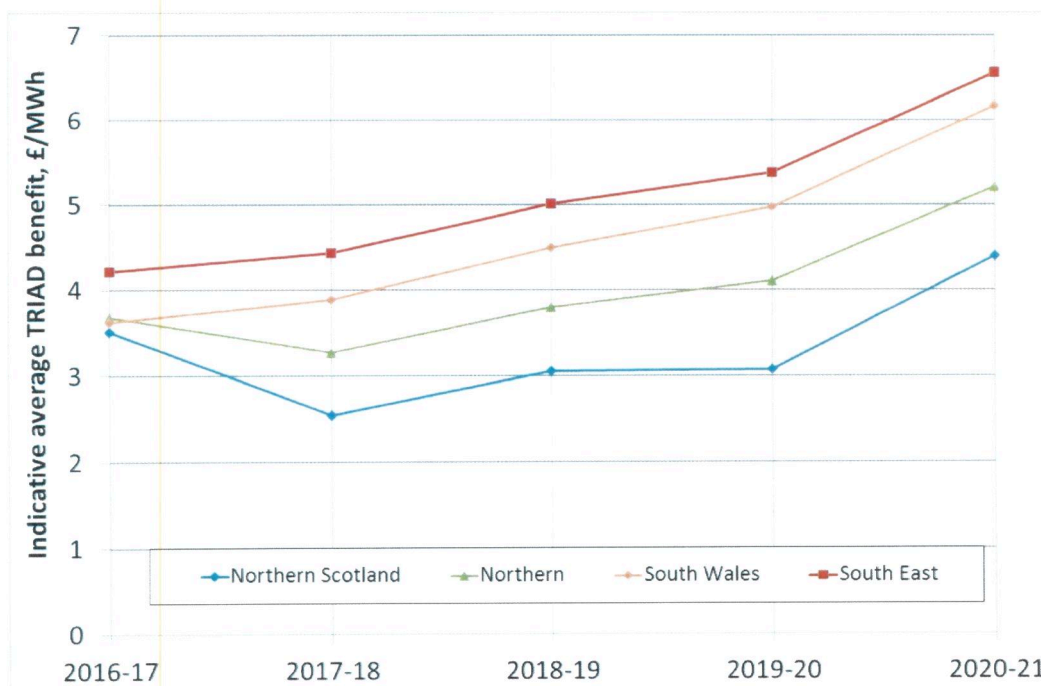


Figure 4 – Indicative Triad benefits for wind generation in four TNUoS demand zones assuming average output during Triad periods is equal to 75% of average annual output

It is important to note Vattenfall has undertaken this analysis using publically available data downloaded from National Grid's data explorer website, which does not reflect

precisely the demand data used to determine Triads. However, we believe it illustrates the principle and merits consideration and further analysis, possibly using data not available in the public domain.

The analysis was performed using historic half-hourly data downloaded from the National Grid website.⁹ The available demand dataset that most closely reflects that used by National Grid to determine Triads is *IO14 National Demand*, which is the sum of metered generation, excluding generation required to meet station load, pump storage pumping and interconnector exports. There is a small but material difference between this dataset and the one used to derive Triad periods which includes station loads and pumped storage. This discrepancy results in some differences between actual Triad periods and those derived from the analysis. Although those differences do not undermine the demonstration of principle, further detailed analysis should seek to fully align.

In order to demonstrate the principle illustrated above, half-hourly Embedded Wind Generation and *IO14 National Demand* datasets were summed to derive National Demand without embedded wind and used to determine windless Triads applying the methodology defined in CUSC. These windless Triads were compared to Triads determined directly from the *IO14 National Demand* dataset and the changes in their occurrence and magnitude were noted together with the differences in the average embedded wind generation for the Triad in each of the last four winters. Wind generation was expressed in MW and as a capacity factor using the installed wind capacity during each associated winter period, as estimated in the National Grid dataset.

It is important to note, as stated in the website dataset descriptions, that the true output of these (embedded wind) generators is not known so an estimate is provided based on National Grid's model. This estimate will inevitably result in residual errors in any Triad-shifting analysis which are unlikely to be eliminated in more comprehensive analysis, since accurate measurement of aggregate embedded generation is not available from any publically available source.

Alternative proposals

We note that the main problem with the TRIAD residual element of embedded benefits is that they are dominated by the network investment residual element and not the specific value of reducing peak network power flows and balancing demand in peak periods. The increasing network investment which is driving the increase in the residual element (and therefore the TRIAD benefits) is a function of a changing market which has seen large-scale retirement of ageing coal generation dispatched from the centre of the UK being replaced by new technologies based on the periphery of the UK with offshore wind and associated OFTO investment being a significant factor.

⁹ <http://www2.nationalgrid.com/UK/Industry-information/Electricity-transmission-operational-data/Data-Explorer/>

Within this context, in the short-term we note that CUSC working group proposals to 'pause' the TRIAD benefit at the current level may help to mitigate increases to TNUoS charges for consumers whilst balancing investor confidence or creating other unintended and inefficient outcomes.

It is our strong view that a full and independent assessment of the embedded benefit system should be completed alongside National Grid's charging review. We are aware of alternative approaches, such as changing the number of TRIAD periods (e.g. aligning TRIAD periods with the peak times of the Capacity Market) or applying a demand TNUoS charging methodology that is more closely related to the principles of GB SQSS (as already applied to generation TNUoS), which could be further developed as an industry with more time and visibility of the future network charging regime. We believe strongly this is an objective Ofgem and industry should be working towards.

