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Dear Anthony

Project TransmiT: Impact Assessment of industry's proposals (CMP213) to change the electricity transmission charging methodology

EDF Energy is one of the UK's largest energy companies with activities throughout the energy chain. Our interests include nuclear, coal and gas-fired electricity generation, renewables, and energy supply to end users. We have over five million electricity and gas customer accounts in the UK, including residential and business users.

Thank you for the opportunity to respond to Ofgem's impact assessment on CMP 213.

Implementation of CMP213 should be delayed to April 2016. We strongly believe that April 2014 is too soon to bring in CMP213; this is not enough notice, and will be detrimental to consumers.

Concerns on the demand-side, of fast implementation of any charging changes, are more marked than for generation as has been recognised in Ofgem's own network charging volatility work. We have consistently argued that for material changes to network charges for the demand side, good notice is required to limit additional costs caused by uncertainty. The impact of any CMP213 variant on demand tariffs was said at the workgroup, and in both CUSC consultations, by NG to be of no (or limited) impact. However, as set out in the WACM2 tariffs released by National Grid on 10th September, in North Scotland, demand tariffs are set to increase if WACM2 is implemented, by 25%, whilst Southern Scotland sees an increase of 14%, and Northern England by 7% (demand tariffs in all other regions have decreased on average by 1%).

On the generation side, the new WACM2 tariffs that were released on 10th September, due to impacts on specific assets, show an unexpected further increase in the TNUoS bill for our fleet of +£12m a year.

While the charging method is based on SQSS, it is not a precise interpretation – it should be a fairly close proxy, but it must be sufficiently robust. The use of annual load factors in the charge application calculation is not sufficient to meet this criterion, and indeed, is not mentioned in SQSS itself in relation to system investment planning. We therefore

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welcome the approach to diversity, so as to at least apply the load factor charge dilution of the year-round charge element, in a less inappropriate manner. The question is around the detail of how to do this, and the balance between practicality, simplicity, and cost reflectivity. We still have serious reservation with diversity method 1 for the following reasons.

Looking at diversity method 1, we would expect real sharing to maximise in areas with a mix of carbon and low-carbon generation behind a boundary; where either type dominates the mix behind a boundary, sharing does not appear likely to be a real phenomenon, and we would not expect there to be any load factor dilution of the year round charge. By contrast, method 1 allows 100% load-factor-based dilution of the year-round charge element even where there is 100% carboniferous generation behind a boundary. Moreover, we would not expect load factor dilution of the year round charge to be anything like 100% (as per method 1), even when the mix of carbon and low carbon behind a boundary is even (50/50). No convincing evidence has been put forward to justify 100%. A significant proportion of the capacity of each new generator, of either type, would still need to be serviced in terms of new transmission, even at this point of 50/50 mix.

Diversity method 2 is better. The CMP213 variants featuring diversity methods 2 and 3 do not have the drawbacks of the variants of the original and the variants of method 1. They reflect what is intuitively obvious : that one would expect real sharing to maximise in areas with a mix of carbon and low-carbon generation behind a boundary; where either type dominates the mix behind a boundary, sharing does not appear likely to be a real phenomenon in transmission planning, and larger amounts of transmission infrastructure will be built. Moreover, they feature maximum charge dilution of 50%, where there is a 50/50 mix of generation types behind a boundary, reflecting what seems intuitively about right. There will not be 100% sharing, even for such a "perfect" mix; a significant proportion of the capacity of each new generator, of either type, will still need to be serviced in terms of new transmission and therefore a 50% limit provides a simple approximation for this.

Diversity method 3 while not being precisely aligned with the theoretical approach to planning new transmission investments in SQSS (in that it does not feature two backgrounds), is a sufficient proxy, and has a further number of advantages over Diversity method 2. We note that the year-round study element of CMP213 does itself include the time of peak demand. Because of this, and because the peak security tariffs under CMP213 tend to only amount to a small portion[1] of the year-round tariffs, we believe that there may be merit in – as in "diversity method 3" – not having the peak security charge at all. This makes the charge structure simpler; all other things being equal, simplicity

[1] Experience in operating SQSS GSR009, in planning alterations to the transmission system, shows that 80% of circuits are allocated to the year round study, and that the peak security charge element will be relatively small compared to the year round element.

does have its own merit. We believe that sharing arises from the combination of generation behind a boundary - but not from each plant's own load factor, which again suggests diversity method 3 as best. SQSS, the intended foundation stone for CMP213, makes no mention of individual load factors as a crude driver of new transmission investment.

Another reason why we support method 3 is it removes inherent issues with the use of ALF. There are some drawbacks from the approaches which entail reliance on each plant's load factor. These load factors for coal plant are inevitably likely to be in decline over time, although there was a recent uplift that would not have been forecastable. Gas plant load factors may decline or may not, dependent on factors that are very hard to forecast, but which boil down to the relative cost of delivered gas in GB compared to that of coal, after making allowance for carbon pricing and relative efficiencies. There seem to be some hazards in an approach that relies on specific plant's load factors.

Overall, taking all of the considerations above into account, we consider that both the variants based on method 2 and the variants based on method 3 better facilitate the charging CUSC objectives taken in span than baseline, but that the variants based on method 3, do so to the greatest extent.

We note that the modelling results indicate that Diversity Method 3 gives the greatest reduction in consumer bills over the period 2014-2020 – a £1.3b bigger total reduction in bills, than Diversity Method 1. This appears to represent a compelling advantage of method 3 compared with the alternatives.

Our responses to the questions in the impact assessment are set out in the attachment to this letter. Should you wish to discuss any of the issues raised in our response or have any queries, please contact Mark Cox on 01452 658415, or me.

I confirm that this letter and its attachment may be published on Ofgem's website.

Yours sincerely,

Angela Piearce
Corporate Policy and Regulation Director

Attachment

Project TransmiT: Impact Assessment of industry's proposals (CMP213) to change the electricity transmission charging methodology

EDF Energy's response to your questions

CHAPTER: Four

Q1. Do you think we have identified the relevant impacts from NGET's modelling and interpreted them appropriately?

We do believe that the modelling approach taken inevitably injects a lot of "noise" onto the results, due to the fact that so many fundamentals, including generation and transmission build as well as simplified capacity payments, are permitted to vary at once. It is our belief that a stable, uniform generation and transmission background for all CMP213 variants could have allowed greater confidence in comparing the modelled results, even if it meant that in some cases, some desired outcomes such as on generation margins, and renewable build, did not occur for some variants.

Q2. Do you have any further evidence of the impacts of the charging options not covered by NGET's analysis?

We have set out some considerations in our attached summary letter. If we could emphasise one point: the impact on demand tariffs was said by NG to be of no (or limited) impact, and in the impact assessment consultation (4.37), "Differences in demand TNUoS charges between Status Quo and the modelled alternatives are relatively minor….". In North Scotland, the new demand tariffs for 2014/15 released on 10th September, have increased by 25%, whilst Southern Scotland sees an increase of 14%, and Northern England by 7% (demand tariffs in all other regions have decreased on average by 1%). We suggest that based on this new evidence, if a decision on CMP213 is taken before Christmas, implementation should be on 1st April 2016 – the same notice period for the BSUoS change that is envisaged in CMP201.

CHAPTER: Five

Q3. Do you agree with our assessment of the options in terms of the strategic and sustainability impacts? In particular, are there any impacts that we have not identified?

We do not believe that it is the role of the charging regime to achieve political energy policies. If it is windier in one place than another, and the true additional transmission costs (if any) in that windier place, are less than the extra income from the additional generation, then it is a good place to build the generation. There may be considered by many to be a case, as a matter of politics, for additional subsidies to ensure build in that windier place, if not otherwise economic – but that is no matter for the economic regulator, or for the charging regime. We do believe that it would be potentially consistent with Ofgem's wider duties, for Ofgem as independent economic regulator to input with independent advice to the Government's development of an island renewables support scheme.

We have commented elsewhere on the difficulties of interpreting the modelling results given the number of things being varied at once (to meet various high level output constraints) in different CMP213 variants when modelling, including all the fundamentals.

We note that the modelling results indicate that *status quo* would lead to the highest deployment of renewables (figure 13, page 40, of the consultation document). However, this extra deployment comes after 2020, and there is no renewables target at this time, by when DECC has said the policy focus will be on low-carbon generation targets, to ameliorate climate change, rather than arbitrary renewables targets - so this is not necessarily a cost-minimiser, or social benefit.

Q4. Do you think that socialising some of the cost of HVDC converter stations could lead to other wider benefits, such as technology learning? If so, please provide further evidence in this area.

No, we do not believe it is possible to argue that socialising some of the cost of HVDC converter stations will lead to wider benefits. We are against cost socialisation as it logically, must lead to higher-cost solutions. We are in favour of cost-reflectivity. The way this question is put, is arguably very slightly tilted, as it implies that any HVDC converter cost removal must amount to "socialisation". In other words, the way the question is put is such as to imply that the only approach that is cost-reflective, is that in Ofgem's minded-to.

We understand Ofgem's concern in this area which is, in essence, that an AC substation (of which the costs are, and will continue under CMP213 to be, socialised in the model) may not otherwise have had to be built at all, had an AC approach been economically and technically feasible in place of a new HVDC line. Were Ofgem to be incorrect in this assumption – were it to be the case that an AC substation would have been built, had an AC line been able to be used technically and economically, then the appropriate portion o the converter cost should be stripped out of the expansion factor. It is hard for us to assess whether or not an AC substation would have been built, and we suggest that National Grid's evidence on this point, should be determinative as to the ideal approach, as only it really knows the answer to that question. On the continent one can see AC lines of span up to 500 km with no substation – but National Grid does often seem to exhibit a preference for extra switchgear, within an extra substation, often tieing-in with other lines.

CHAPTER: Six

Q5. Do you agree with our assessment of the options against the Relevant CUSC objectives? Please provide evidence to support any differing views.

We believe that a range of CMP213 variants do better meet the CUSC objectives overall than baseline, in part because baseline fails to reflect developments in transmission technology. Baseline will cease to function without further definition once the first HVDC lines to islands, and as "bootstraps", are constructed, as there is (under status quo) no valid impedance for the new lines, and no account is taken under baseline of non-redundancy of new island links. Correcting the charging method to take account of these new links strongly contributes to CUSC charging objective (c). However, we do not believe that diversity method one, taken in isolation of those other changes (which were vital anyway, and could have been taken forward on their own), better meets the CUSC charging objectives. In other words, the sharing treatment in diversity method one, doesn't have merit on its own. In contrast to the minded-to decision and the supporting views within the impact assessment, we do believe that the sharing treatment in diversity method two does, taken in isolation, better meet the CUSC charging objectives; and we believe this more strongly of the sharing treatment in diversity method three.

Q6. Do you agree with our assessment of the options against our statutory duties? Please provide evidence to support any differing views.

Consumer bill impacts are an increasing area of focus in national energy policy debates, and are the prime area for Ofgem to consider. Diversity method 3 gives the best reduction in consumer bills over the period 2014-2030 inclusive, according to the modelling. It gives a £1.3b bigger total reduction in bills, than Ofgem's preferred Diversity Method 1. This appears to represent a compelling advantage of method 3, as consumer bills are of strong relevance to Ofgem's statutory duties.

We agree that there is no discernible effect of CMP213 on health and safety.

Q7. Do you agree with our assessment that it is appropriate to implement WACM2 in April 2014? Please provide evidence to support any alternative implementation date.

We believe that April 2014 is too soon to bring in CMP213; there is insufficient notice, and insufficient certainty of its effects over the coming years (generation tariffs on the current, and future, 27-zone basis aren't even known beyond the year 2014/15).

When the first 27-zone generation TNUoS forecast under WACM2, for 2014/15 only, was released four weeks ago, it became apparent that the impact of WACM2 on our generation fleet's TNUoS costs, was £12m a year worse than we had expected.

Concerns on the demand-side, of fast implementation of any charging changes, are even more marked than for generation. The impact of any CMP213 variant on demand tariffs was said at the workgroup, and in both CUSC consultations, by NG to be of no (or limited) impact. In North Scotland, demand tariffs have increased by 25%, whilst Southern Scotland sees an increase of 14%, and Northern England by 7% (demand tariffs in all other regions have decreased on average by 1%). We suggest that if a decision on CMP213 is taken before Christmas, implementation should be on 1st April 2016 – the same notice period for the charging change that is envisaged in CMP201. We note also that up to 2020, all CMP213 variants tend to increase modelled consumer costs – the modelled benefits are all after 2020.

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