PROJECT TRANSMIT: CMP213

SCOTTISHPOWER MEMORANDUM TO OFGEM

INTRODUCTION

ScottishPower has reviewed the evidence presented by NERA Economic Consulting and Imperial College London on behalf of RWE npower dated 9 October 2013 'Project TransmiT: Modelling the Impact of the WACM2 Charging Model' ("the NERA paper"). We believe this analysis was intended to reverse Ofgem's minded to decision on how to implement the long running review of locational transmission charging for GB generators: CMP213.

We consider that this new evidence is unreliable in a number of material areas including the assumptions made around power purchase costs, plant closures, new generation build, carbon savings and the impacts on transmission system investment. On that basis we believe it should be given low weighting in Ofgem's final assessment on whether to implement CMP213.

We also consider that Ofgem should give a high weighting to the decision and advice of the CUSC Panel, which approved WACM2 and other alternatives. Those options are in line with Ofgem's direction following the TransmiT SCR. We do not consider that the NERA paper makes a persuasive case that WACM2 would operate against the customer interest. It certainly comes, in our view, nowhere near the high threshold of making it irrational for Ofgem to follow the decision of the Panel.

MERITS OF CMP213

We continue to believe that CMP213 is more cost-reflective than the existing charging methodology. The existing methodology scales all generation against peak demand and as such it does not take account of the changes in the way the transmission is planned under the SQSS since the introduction of GSR009.

In particular, the existing methodology does not take account of the fact that wind, wave, tidal generation and interconnectors are not assumed to contribute to the design of the system to meet demand security. Similarly, the existing methodology does not take account of the fact that, in planning for the Economy (Year Round) scenario, peaking plant should be excluded and other plant should be scaled according to an expected contribution to year round running.

The WACM2 methodology clearly takes account of both of the scenarios which could trigger transmission investment under the SQSS and determines which of them is more likely to drive further incremental investment. The proposed methodology thus appropriately derives the Peak Security and Year Round elements of the charges.

The SQSS uses fixed scaling factors in its approximation of plant running (Appendix E) which is applied to broad categories of generation type but does not take account of individual plant characteristics such as efficiency and short-run marginal costs. The WACM2 methodology uses historic plant running (as interpreted through ALF) as the best indication of the impact of individual plant characteristics on future running, thus further improving the cost reflectivity to individual generating plants.

OBSERVATIONS ON THE NERA AND IMPERIAL COLLEGE MODELLING

The NERA and Imperial College analysis included in the report "Modelling the Impact of the WACM 2 Charging Model" challenges the longer term benefits to consumers from implementation of CMP213. ScottishPower has reviewed the modelling assumptions, methodology, and outputs from that report.

It is noted that predicting the exact outcome of future market operation is inherently difficult, particularly at a time where the electricity industry is going through a significant period of change in terms of plant closures, new investment and changes to market design on a national and Europe wide scale.

Against this backdrop we have identified no supporting evidence to suggest that Ofgem's modelling of consumer benefits in the original CMP213 impact assessment was unreasonable. Indeed, when considering the new evidence provided by NERA / Imperial College, we consider the NERA paper to be unreliable in a number of important respects.

Power Purchase Costs

The main finding in the report in this area appears to be based on the premise that the power market will run at new entrant Long Run Marginal Cost (LRMC) for the most favourable location at all times, and that all wholesale costs will flow through perfectly to retail consumers. In our view this assumption does not appear at all likely, is inconsistent with current market dynamics and our understanding of how other market commentators expect the energy market to evolve.

This hypothesis is susceptible to a *reductio ad absurdum* test. Why stop at the current structure of transmission charges? Suppose locational charges were made more intense, such that there was a credit for power stations south of the Thames sufficient to remunerate the capital of a new CCGT (say £15/MWh), paid for by additional charges in all other locations. Since new stations south of the Thames would have their capital fully paid for, the LRMC would fall to SRMC, and all consumers would be £15/MWh better off. In this world, we would have invented the financial equivalent of a perpetual motion machine, which would build as much capacity as we need at no cost to consumers. It is of course not possible. The unsubsidised plants would seek to recover their higher fixed costs by charging more than the short run marginal costs, before eventually being forced out of business by the subsidised southern plants, which would then find there was nobody to pay the subsidy and they too would have to raise prices. There is no reason to believe that anything other than the cost reflective pricing regime will deliver sustained efficient and low prices to consumers.

To test the NERA paper's hypothesis further we have considered two time horizons. Firstly, from now until October 2018, prior to the introduction of the capacity mechanism, it is clear that available market sparks spreads are extremely low in comparison to those presented in that analysis. Over this time horizon we do not consider it at all likely that the market will operate anywhere near LRMC on average. To support this view it is important to reflect that the primary justification for the introduction of the capacity mechanism under the Electricity Market Reform proposals after all is to help address the "missing money" problem where generator returns fail to recover LRMC for new investments.

Secondly in the period beyond October 2018 we agree that, from a theoretical perspective, LRMC could be viewed as an acceptable modelling assumption, subject to appropriate treatment of the capacity mechanism. We would however note that it is not sensible to expect prices in the whole market to index directly to the level of transmission charges in the most favourable zones; there are many factors which will determine which sites are developed when including site characteristics, who owns the land (and who has the will to develop it) and competitive issues. Moreover, there are a number of market scenarios where generator returns are likely to fall below "theoretically perfect" expected return on their investments. Examples of such factors are numerous but could, for example, include new generator taxes, changes in the relative cost of input fuels, capital cost overruns or changes in plant specific operating costs.

Plant Closures and New Build Generation

ScottishPower does not believe that the level of imminent plant retirements in the NERA paper consistent with many other examples of similar industry analysis that has been undertaken. As a result, the plant retirement assumptions will drive the model to build plant at a level and a rate higher than is ever likely, and from our understanding of the modelling, would lead to additional consumer costs that in our view are extremely unlikely to materialise.

Similarly, based on our understanding of the analysis, it appears that the model chooses to build new plant at different locations to replace those facilities coming to the end of their economic life. Given the accepted future outlook of lower load factors for thermal generation, in practice many existing sites may be able to run beyond this period, or they could also be repowered. As the capital expenditure savings from use of existing infrastructure at many existing sites are likely to be significant, market participants are likely to choose repowering or longevity options, which would lead to consumer benefits through lower capacity mechanism clearing prices.

Carbon Savings

The model described in the NERA paper seems to build significant amounts of CCS or new nuclear power stations in particular locations, depending on relatively small differences in transmission charges. In our opinion it is highly unlikely that such differences will determine these kinds of investment, which are more likely to be determined by technical site factors, including in the case of CCS the availability of CO_2 routes to storage.

Similarly, the model builds much more wind in WACM2 than in the status quo. This appears to be assumed to be a source of additional consumer cost (because enough was built in the status quo case) and therefore a bad thing. An alternative and in our view much more likely outcome is that subsidy levels will be adjusted either administratively or through competition, so that WACM2 builds the same amount of wind but at a lower cost – or alternatively, if the levy control framework is the main driver, somewhat more wind at exactly the same cost. In either case, given the current focus on cutting back subsidy costs, we do not see how reducing the cost of renewables deployment is likely to increase costs for consumers. At the very least, given the nature of these technologies, the analysis should have explicitly identified any effect on the overall conclusions from holding the build assumptions for these technologies (and possibly biomass) constant in each scenario.

We also believe that the assumptions around renewables development in the analysis do not reflect the likely benefits to consumers of more onshore wind projects proceeding, leading to a lower reliance on offshore wind volumes to reach UK renewable energy and decarbonisation goals. In terms of final consumer costs the recent Oxera analysis[1] commissioned by ScottishPower highlighted the relative cost saving potential from developing 4TWh of onshore wind generation compared to an equivalent amount of offshore wind would be £164m (2009 prices).

Transmission Investment

We would question the outcome of the analysis as detailed in Figure 3.18 on Page 28. This analysis appears to suggest that there would be an immediate increase to the transmission construction capital plans and therefore annualised costs borne ultimately by consumers.

[1] https://www.ofgem.gov.uk/publications-and-updates/project-transmit-external-web-forum-paper-principles-and-priorities-transmission-charging-reform-oxera

In the first case, transmission projects are "lumpy" and will tend to cater for large amounts of generation. It is misleading to suggest that CMP213 will necessarily lead to major new transmission projects. In addition, previous work by Oxera for ScottishPower suggests that any additional transmission cost from building more wind in Scotland under Project Transmit, is more than offset by the savings from deploying the lower cost onshore wind rather than offshore.

In addition it is our experience that transmission upgrades are a slow and lengthy process, so any costs are unlikely to be felt immediately. As with power generation projects, the planning and consenting process for new transmission can be very lengthy and take considerably longer than construction and commissioning.

Constraint Costs and Transmission Build

We would highlight that the summary of findings in this section do not immediately appear to be consistent with the analysis presented elsewhere in the report (refer to Figure 3.19) which shows a favourable impact on expected constraint costs under WACM2.

We agree that constraint costs are likely to be lower under WACM2. Due to the asymmetric nature of transmission investment costs and constraint costs it should always be beneficial to "over build" the transmission system. However, TNUoS is charged on the basis of the TEC requested by the generator and not the size of the transmission line actually built. This will always be the case with the "lumpy" nature of transmission investment. The balance of the cost is recovered in the Residual element of the charge under both the existing and WACM2 methodology.

The generation outputs specified in Appendix E of the SQSS to be used in the Economy Background represent an approximation of a CBA e.g. the Wind output is set to 70% rather than 30% to reflect the fact that constraint costs associated with wind are higher than those associated with other generator types. Similarly Nuclear and CCS outputs are set at 85% as it is to be expected that these would be commissioned on the anticipation of near-baseload running.

WACM 2 uses the generator outputs from Appendices C and E of the SQSS to determine whether incremental transmission investment at each generation node would be driven by the Demand Security (Peak) or Economy (Year Round) Background planning requirements. Having derived both a Peak and Year Round tariff element, cost reflectivity is further improved by utilising factors which are more indicative of the contribution of each individual generator to future running on the transmission system (Annualised Load Factor) than the generic generator-type factors utilised in the SQSS. Utilising the factors in the SQSS Appendices would fail to reflect the different operating characteristics of each generating plant such as efficiency, operating cost structures and environmental constraints as reflected in the merit order and measured by load factor.

ScottishPower
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