

# **BWEA response to the consultation “Reform of the Renewables Obligation” Appendix B: Assessment of the Ernst & Young and Oxera reports**

## **Ernst & Young**

### *Onshore wind*

In general, the figures quoted by E&Y for onshore wind costs appear appropriate given the recent rises in the capital cost of wind turbines. The current excess of demand over supply globally appears set to continue to about 2010, driving some further increase in cost. Beyond that time we would hope to see the situation reverse and bring a return to innovation-driven reductions in costs. The deployment figures that E&Y have produced are credible in broad-brush terms, though we would hope that the work that Government has in hand on planning, and grid access and management, will allow higher build rates beyond 2010.

### *Offshore wind*

Similarly, the costs for offshore wind follow the trajectory that we would expect up to 2015, but we are somewhat puzzled by the flat line for capital costs from there to 2020. We surmise that E&Y have translated their expectation of limited delivery in that period into stagnation in cost reduction – this is based on an assumption that there is no more offshore wind development in the UK beyond Round Two. BWEA is working with Government to bring forward new site awards so that there will be cumulative delivery of perhaps 20GW by 2020. Delivery on that scale should bring economies of scale and increased competition and innovation, so we would expect some cost reduction in this period, despite the need for deeper water sites further from shore to deliver this higher capacity. In the short term, however, prices from recent projects (Lynn/Inner Dowsing, Robin Rigg, Gunfleet Sands and Rhyl Flat) indicate that costs are tending towards the High capital cost figures rather than the Medium one presented by E&Y. We are reasonably confident that the High figure captures the range, net of grid costs.

The deployment figure for 2010 appears to be somewhat optimistic, with the figure of 8.3TWh generated in that year translating into 2.7GW at a load factor of 35%. BWEA expects approximately 1.5GW of offshore capacity to be operating by 2010.

The operating costs for offshore wind depend on the assumptions used for transmission use of system charges. These are still uncertain since the

regulatory regime is still being determined. We would hope for a result from this process which keeps the TNUoS charges down as this would improve the economics of offshore wind projects, maximising delivery of marginal projects, of which there will still be some even with a multiple of 1.5ROC/MWh. We have tested the optimistic case in the analysis presented in Appendix A that TNUoS charges are £15,000/MW/yr, which improves project IRR by 0.4% compared to £22,000/MW/yr, the bottom of the range used by E&Y.

### *Wave and tidal stream*

Our assessment of wave and tidal stream deployment is that the figures presented by E&Y are pessimistic: we would expect perhaps 50% more capacity for each, with appropriate policy in place. The levels assumed are not unreasonable, however. When assessing cost development for these technologies, there is inevitably a level of speculation involved given the embryonic state of the sector. However, we consider the cost reductions that E&Y show to be too pessimistic: the steepest part of the cost reduction curve is at the start, when the largest gains in efficiency are made.

### **Oxera**

The modelling approach taken by Oxera in this report was to create a number of different banding scenarios and compare their results with a base case (no banding) scenario. These banding scenarios are 'static', ie there is no change in the multiples (apart from co-firing) and the allocation of technologies to bands for the duration of the RO. This means that any effect on investor sentiment that the uncertainty inherent in the review process brings is left unmodelled. However, since the focus is on delivery to 2015, this may not introduce too much inaccuracy to the results.

The focus on 2015 is stated to be because power, carbon and technology costs are all highly uncertain after that date, and thus any modelling after that date can only be speculative – though of course investments made up to 2015 will be highly dependent on views of these key variables. The modelling is still undertaken to 2027, however, and clearly shows the effect of the RO's end, with investment starting to tail off before 2015 and dropping to nothing after 2020 in all scenarios.

One factor left unmodelled is the variation in output of wind and hydro from year to year, which introduces the risk that the headroom could be breached, with a subsequent impact on investment. The analysis we have undertaken (see Appendix A) indicates that headroom should be set higher than 6%, and should be at least 8%, though preferably 10%. This will have a small positive impact on project economics as the expected recycle value will be increased slightly.

Three revenue sources are assumed for projects: ROCs, LECs and power. Power and LECs are assumed to be variables outside the model: LECs are assumed to provide £4.30/MWh in real terms indefinitely. Whether the continued existence of LEC income beyond 2012 is a warranted assumption is questionable, and certainly banks would not be providing finance on this basis.

Maximum build rates were imposed by Oxera on wind build, with up to 300MW/yr allowed for onshore, high wind sites (31% load factor), 400MW/yr of onshore, low wind sites (26% load factor) and 1,000MW/yr for all offshore. These numbers are important since in the base case, the onshore limits are hit in the first three years of the next decade, and thus the resulting modelled delivery of onshore in 2015 is considerably lower than it could otherwise have been. The claimed improvement in delivery under the banding scenarios is arguably overstating the case, therefore.

A number of metrics are used by Oxera to assess how well each approach modelled performs against certain criteria. These metrics would appear to have some considerable issues in being realistic reflections of the costs and benefits.

- Resource cost – £37.40/MWh would appear to slightly understate the avoided cost of power: the central price forecast used in the modelling is £40/MWh or slightly less. If the avoided cost were assumed to be higher then the resource cost of renewables would be lower.
- Carbon savings – 0.351tCO<sub>2</sub>/MWh is not a realistic avoided carbon rate. It assumes that renewables displace new CCGT capacity with an efficiency of about 55%, whereas the average electricity mix emits about 0.45tCO<sub>2</sub>/MWh. Since renewables will never displace nuclear generation, they will in fact be displacing a mix of coal and gas, which will have a higher factor still – in 2006 the average fossil-fuelled electricity emission factor was 0.63tCO<sub>2</sub>/MWh<sup>1</sup>. The base assumption therefore understates the carbon savings by 30-70%.
- Social value of carbon saved – This depends on the carbon savings, and thus will also be understated.
- Net benefit – This should be carbon value less resource cost, not generation cost. This is because the cost of the carbon reduction is the **extra** you pay for the low-carbon option over what you would have paid for the carbon-emitting one. This is acknowledged indirectly in the calculation of the deadweight cost.
- Cost-effectiveness – This should go beyond £/tCO<sub>2</sub> saved and at least nod towards gas import avoidance (and hence reduction in foreign exchange costs) and perhaps the effect that low marginal cost, must run renewables have of lowering wholesale power prices overall. To

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<sup>1</sup> Digest of UK Energy Statistics 2007

([www.berr.gov.uk/energy/statistics/publications/dukes/page39771.html](http://www.berr.gov.uk/energy/statistics/publications/dukes/page39771.html)), Table 5C, p120. The figure of 172tC/GWh is quoted there, which is multiplied by (44/12)/1,000 to convert into tCO<sub>2</sub>/MWh.

measure cost effectiveness in terms of carbon only is to ignore the other benefits that renewables bring. In any case, changing the other metrics in the way indicated above will considerably lower the calculated £/tCO<sub>2</sub> figures.

Oxera also measures three forms of cost for each scenario:

- *Cost to Exchequer*: Foregone CCL receipts plus value of capital grants. Any CCL revenue should be regarded as money Treasury should not have expected to receive and so to regard this as a 'loss' is misleading. The definition also assumes that CCL continues indefinitely when its existence is questionable due to the EU ETS and other possible carbon trading schemes. Should Government wish at this time to confirm the indefinite life of the CCL, we would be very happy, but to calculate 'costs' on the assumption of its continuation is not helpful.
- *Cost to firms*: Cost to generators and suppliers without considering pass-through to consumers – this appears a strange thing to measure when the cost is indeed passed on.
- *Cost to consumer*: Obligation size times buy-out price (or out-turn ROC price if ski-slope invoked, though the ski-slope does not appear to be modelled).

Regarding the actual modelling results, we believe them to be a realistic reflection of the input assumptions, so where we regard those to be appropriate, so should the results be. The out-turn for onshore wind in the base case scenario is overly constrained in our view and so we believe the results underplay delivery by an unchanged RO to some extent.

We would particularly point to the 'net banding position' results for almost all of the scenarios, which are in the range 1.1-1.2. Government needs to make clear that such a result is consistent with the position of net neutrality as a broad guiding principle.

We strongly support the message of Figure 5.15 of the Oxera report, which clearly shows how the end of the RO in 2027 affects investment in new generating capacity. We hope that Government takes note of this result and puts in place arrangements to remove the negative impact of the end of the policy.