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Dear Alistair,

PROJECT DISCOVERY – comments on behalf of Durham Energy Institute

Thank you for requesting comments on the Project Discovery report. I've read it with great interest and I broadly support the Project's analysis and conclusions. However I would like to make some specific comments and recommendations. Our comments are restricted to the electricity part of the Project as this is where our main expertise lies. In writing this response I have drawn on work and comments by Dr Chris Dent of Durham Energy Institute, Mr Dan Eager of the University of Edinburgh, and Mr Colin Gibson, former Power Network Director of National Grid.

Chapter 3: GB energy market arrangements, para 3.47.
One characteristic and rather unusual feature of GB electricity market is the lack of any capacity payments which were scrapped following bad experience with the old Pool. Capacity payments are used widely in the world and serve well the purpose of ensuring that peaking generation capacity is provided and that generation investment cycles are properly damped. Hence there is a wealth of experience to draw on in ensuring that "sufficient peak thermal capacity remains on the system, and/or that increased investment in demand side response occurs" (para 3.47). I would like to point out that the success of Spain in accommodating 50% of energy being produced by renewable generation is based on a large hydro storage capacity and a capacity payments mechanism. We have neither. A widely reported success of Denmark has been achieved on the back of strong interconnection with Europe which provides a necessary backup for wind. Our connection with France, and in future with the Netherlands, is relatively weak and cannot be used for similar purposes.

I would also like to add that we see the danger of underinvestment more generally in that insufficient peak thermal capacity will generate high prices which in turn will attract more investment causing the prices to collapse. This is a well known boom-and-bust cycle which have already witnessed in GB. We have attempted to model this mechanism in a work that is funded by UK Energy Research Centre. Our aim is to model explicitly the mechanism by which generation investment cycles are created, i.e. the combination of uncertainty about price and investment with long investment time lags. Uncertainty and time lags are well recognised in control engineering as responsible for worsening system stability and creation of undamped oscillations. Hence our approach is to model the generation investment market as a dynamic negative feedback process with price driven by the system generation margin. This pricing mechanism is somewhat similar to your modelling (para 2.64) but with the main difference that our model is dynamic, i.e. current prices and their predictions are fed back daily to the investment block hence modifying the investment behaviour. The resulting investment decisions are then fed back to the pricing mechanism so closing the loop. First preliminary results validating the model have showed excellent agreement with the actual market behaviour in years 2001-2008. Our ultimate goal will be to assess whether or not excessive investment and price cycles will occur in GB in future years and if so, design an appropriate damping mechanism, e.g. capacity payments. As we have an extensive experience in designing engineering damping controllers, we intend to draw on this to design economic damping controllers. We would be more than happy to share our experience and results with Ofgem.

Influence of network constraints on energy market

This is an issue which we believe is very important but which has not been dealt with in the Project report. The whole Project analysis deals with the energy market neglecting the profound influence of network constraints on the energy market. We believe that the results of such analysis could be overly simplified. The painful experience of flawed early market designs in California, Texas and PJM showed clearly the danger of failing to take into account properly the influence of network constraints. In all those cases the early market design had to be quickly corrected.

Historically the cost of transmission constraints in GB was relatively small, mainly because Scottish generators were not allowed to contract exports to England above the level of Interconnector constraint. Hence it has been acceptable for the cost of congestion management to be socialised (shared) among the market participants. However with BETTA in place, the Interconnector has become just another internal GB line with no special treatment in operational practice and the cost of constraints has been rapidly increasing year-on-year. This is expected to continue as more wind generation is added in Scotland. Even if the planned network reinforcements are implemented in time, it is still expected that the network will be heavily constrained at times of high wind. Otherwise the network would not be optimally designed – the incidences of high wind are relatively rare and it does not make economic sense to design a network which would serve rare events. One cannot plan a network which would rarely constrain the peak generation capacity of about 100 GW (Fig. 3.8) when the peak demand is expected to be only 61-71 GW.

This issue is being dealt with by the industry in Transmission Access Review but the progress has been painfully slow. We are worried that unless Ofgem takes decisive action, we will sleep-walk into a new world of high penetration of renewables with outdated market arrangements and the consequences could be very unpleasant indeed. We suggest again to draw on the wealth of worldwide experience which suggests that the only efficient way of dealing with a highly-constrained network is to apply so-called Locational Marginal Pricing (LMP) in a similar way as it is done by PJM, NYISO and others. Obviously the transition from the current market, when all the generators enjoy firm access to the network and therefore receive compensation if they are constrained, to a new regime with un-firm access and no compensations is heavily opposed by the incumbents. Hence the emphasis should be on how to engineer a transition to a new LMP-based regime in such a way that the incumbents are not financially disadvantaged (at least in the short or medium term) and will therefore accept the change.

Chapter 3: GB electricity derated capacity margins.

Questions 7: Do you agree with our methodology of modelling gas and electricity supply/demand balances

We fully support Ofgem's approach of choosing a capacity value figure based on study of a range of studies; differently from the capacity factor which may be measured directly, there can be no one definitive figure for the capacity credit of wind generation due to the range of definitions and underlying assumptions in use. Moreover, limited data on renewable resource availability at times of absolute peak demand (particularly for offshore wind) can result in substantial uncertainty in capacity credit results, even assuming that the model structure is ideal.

We would be delighted to discuss with Ofgem our work with National Grid on robust capacity credit calculation, including modelling the relationship between resource availability and demand, and also the use of whole-peak-season calculations (as opposed to annual peak) to give a more complete picture of system adequacy risk.

Presentation of results

We would like to make a small but we believe important recommendation about presentation of results. Currently almost all the graphs show simulation results starting from year 2008 or 2009. This makes it difficult to assess whether things are getting better or worse by comparing with the past. We would like to suggest that all the graphs start from say year 2000 showing the actual outcomes until 2008/9 and simulation results thereafter.

Chapter 3: Wholesale electricity prices

We believe that the graph of wholesale electricity prices (Fig. 3.19) may be somewhat deceiving by showing annual averages and masking out short-term volatility. It is expected that high penetration of wind will lead to highly volatile daily and hourly electricity prices. In times of high wind the price may become negative when there is a surplus of wind (with respect to demand or export capability in a given transmission-constrained area). On the other hand at times of low wind the prices are expected to reach very high values as thermal peaking units will be trying to recover their investment costs while operating at low load factors (para 3.47).

There is already experience of negative energy prices in Texas due to wind generators located behind a transmission constraint. They may take advantage of wind price subsidies only when they generate hence they tend to bid a negative marginal price equal to the subsidy. This behaviour is likely to be reproduced in GB.

The consequences of high price volatility may be profound for the market by undermining the confidence of investors unless effective hedges are developed. Implementation of proposed capacity signals (please see discussion above) would also have the effect of damping price oscillations.

May I also take this opportunity to draw your attention to our work on developing optimal bidding strategies for wind. We have derived a closed-form solution by taking into account probability distribution of wind and market prices. This may help to give insights into the future market and model the behaviour of market participants.

I hope you will find our comments useful and we would be happy to discuss them in detail.

Yours sincerely,