NIE Energy Limited
Power Procurement Business (PPB)

Electricity Market Reform

DECC Consultation Paper

Response by NIE Energy (PPB)

10 March 2011.

Introduction

NIE Energy – Power Procurement Business (“PPB”) welcomes the opportunity to respond to the consultation by DECC on the Government’s Electricity Market Reform proposals.

PPB is a participant in the Single Electricity Market (SEM) which is the all-island, cross jurisdictional, wholesale electricity market within which all generators in Northern Ireland and the Republic of Ireland (RoI) with capacity in excess of 10MW must participate. The SEM is a gross mandatory pool into which all generators must sell their output and are required to bid to generate on the basis of their short run marginal costs. These bids enable the Transmission System Operators (TSOs) to establish a merit order which they then use to schedule generation on a least cost basis to meet customer demand on the Island of Ireland. The obligations to make bids into the SEM are set out in the relevant Licence documents, further supplemented by a Bidding code of Practice. All suppliers must buy their electricity out of the pool at a common clearing price (System Marginal Price – SMP). Northern Ireland generation and demand represents c25% of the all-island wholesale market.

PPB is not a generator but was established as part of the 1992 privatisation arrangements in Northern Ireland as the counter-party to long term power purchase agreements (PPAs) with the power stations that were sold by the UK Government by way of a trade sale. While some of the original generating units have retired or are no longer under contract, PPB continues to contract with eight generating units with capacity totalling c1,000MW and pays for capacity and energy in accordance with the contract terms. PPB is a regulated business and its obligations are set out in the NIE Energy Supply Licence.

PPB manages the PPAs on behalf of Northern Ireland customers and as well as managing the portfolio of contracts, is responsible for trading the generating units in the SEM. The effect of this arrangement is that the contracted generators continue to enjoy the rights and obligations as set out in the PPAs and PPB bears all market risks on behalf of Northern Ireland customers. The PPAs were established by Government in 1992 and include provisions in respect of Changes in Law that allow any change in a generator’s costs, arising from any change in law, to be passed through to PPB under the terms of the contract such as to hold the generator financially neutral. The implementation of the EU ETS was one such change in law and the Government’s proposals in relation to a Carbon Price Floor are likely to also be a change in law and hence any additional costs will be passed through by the generators under the PPAs to PPB and will ultimately be borne by Northern Ireland customers.

It is also important to take cognisance of the carbon reductions that have already been realised in the electricity industry in Northern Ireland. It is important that these significant reductions, which have been the result of considerable investment, are recognised.

Year	CO_2 Emissions	Reduction	Source
1990/91	5.98 mtes		*PPB estimate based on fuel consumed*
2006 2008	5.745 mtes 4.831 mtes	4% 19.2%	*Verified emissions published on the EU Website*

It is within this context and from this perspective that PPB provides comments on the Government's Electricity Market Reform Proposals. PPB has already replied to the HMT consultation on the Carbon Price Support and we attach a copy of that response for your information.

<u>Specific Comments</u>

Questions 1 and 2 on the current market arrangements.

The discussion on the current market arrangements in Chapter 2 describe the GB market and do not reflect the Northern Ireland market arrangements. While having some common elements (e.g. network separation, EUETS, RO, etc.), the wholesale electricity market is part of an all-island market that operates on the basis of a mandatory gross pool.

The technology mix in Northern Ireland (and Ireland) is also very different as there is no nuclear generation and hence fossil fuel generators tend to operate at higher load factors than equivalent generating units in GB. The market is also much smaller and generating unit sizes also reflect that and as a consequence of all these features, NI has higher average carbon intensity per unit of electricity produced than in GB, notwithstanding that, as shown in the table above, actual emissions have reduced by just under 40% since 1990, which is also noteworthy given that electricity production increased by c40% between 1990 and 2009.

We do agree that similar to the GB market, the Irish market will need flexible generation to supplement and complement the ongoing expansion of wind generation and there may need to be further revision to the SEM to ensure such non-wind generation is able to earn a reasonable return to support investment.

Feed-in Tariffs

Question 3 : Do you agree with the Government's assessment of the pros and cons of each of the models of feed-in tariff (FIT)?

In general PPB agrees with the Government's assessment although there are a few areas that we consider are unclear and some elements that would be different for Northern Ireland given that the wholesale market is Ireland is a pool. For example, the paper indicates that that a fixed FIT would remove the market price incentive to dispatch electricity efficiently. However, in the case of wind generation, "dispatch" is generally meaningless and if nuclear is similarly inflexible then the scope for efficiency would appear to be limited.

In the context of the SEM, all generation with capacity in excess of 10MW is mandated to sell their output into the pool and all generation receives the same price (SMP). Hence for the SEM, generators have no choice in relation to selling electricity and hence a Fixed FIT and a FIT with CfD would effectively be identical (the short-term electricity price risk is removed assuming the reference price index for the CfD is the SEM SMPs).

Question 4 : Do you agree with the Government's preferred policy of introducing a contract for difference based feed-in tariff (FIT with CfD)?

We consider this is an appropriate approach. However, we recognise that such a decision is a devolved matter for Northern Ireland and analysis of the impact for Northern Ireland should be concluded separately since all the analysis completed by Redpoint relates to the GB market. If the FIT with CfD is to be adopted in Northern Ireland, it would need to be a modified version of the GB contract such that it aligns with the SEM market. This would require that the reference price used is the SEM SMP and that an additional adjustment is required to take account of the capacity payments that would be earned in the SEM.

Question 5 : What do you see as the advantages and disadvantages of transferring different risks from the generator or the supplier to the Government? In particular, what are the implications of removing the (long-term) electricity price risk from generators under the CfD model?

Firstly, we consider that the transfer of risks is from generators to customers and hence Government are not the recipient under any risk transfer. The main advantage of transferring risks, over which generators have little control, is that it should result in lower overall prices for consumers.

Question 6 : What are the efficient operational decisions that the price signal incentivises? How important are these for the market to function properly? How would they be affected by the proposed policy?

In the SEM nearly all renewable generators are price-taking units and the market design means that those that are not would be centrally despatched by the TSOs on a merit order basis. This means that despatch should always be economic, particularly given that all generators are obligated under their licences to bid on the basis of their short-run marginal costs, which is further overseen by the regulatory authorities through the guise of the Market Monitoring Unit.

This means that the main area of concern within the SEM may be around outage/maintenance planning which would be a discretionary decision for the owner, but is one that should be incentivised to minimise the cost to consumers. This could be addressed as part of the detailed design of the contract.

Question 7 : Do you agree with the Government's assessment of the impact of the different models of FITs on the cost of capital for low-carbon generators?

We agree with the general assessment that the cost of capital will reduce as revenue certainty increases although it is difficult to comment on the detailed impacts shown by the modelling.

Question 8 : What impact do you think the different models of FITs will have on the availability of finance for low-carbon electricity generation investments from both new investors and the existing investor base?

Contractual arrangements that have reduced political risk should intuitively be more attractive to potential investors.

Question 9 : What impact do you think the different models of FITs will have on different types of generators (vertically integrated utilities, existing independent gas, wind or biomass generators and new entrant generators)? How would different models impact on contract negotiations/relationships with electricity suppliers?

The impact on the various type of generators is difficult to predict and is likely to be different in the GB bilateral market to that under a pool arrangement such as the SEM. In SEM, generators sell their output into the pool and hence have predictable counter-party arrangements. The outcome in GB is less obvious as the removal (or grand-fathering) of a supplier obligation may mean they have less interest in contracting for small variable volumes. This could make it more difficult for small independent generators to find an electricity off-take counter-party or it may reduce the competition for such contracts, thereby increasing supplier buying power to the disadvantage of generators.

Question 10 : How important do you think greater liquidity in the wholesale market is to the effective operation of the FIT with CfD model? What reference price or index should be used?

The underlying principle must be that the reference price should reflect the prices reasonably obtainable by generators when they sell their electricity. In relation to Northern Ireland generators participating in the SEM, the reference price should be the outturn SMP in the SEM, adjusted accordingly, depending on how capacity payments are included in the contract.

Question 11 : Should the FIT be paid on availability or output?

The decision on whether to pay based on availability or output has different merits depending on the low carbon technology involved. In the case of wind, availability normally equates to output but as the installed wind capacity increases there may be occasions where the TSOs may need to curtail the output from windfarms. Such events are outside the control of an investor and hence if the lowest cost of capital is required, such risks may best be managed by paying on the basis of the availability (i.e. adjusting output by any curtailment).

Where the generator is not intermittent and is capable of despatch, then the decision depends on what provides the most efficient outcome for customers. Paying on the basis of output would incentivise the generator to maximise its output even where that is not efficient for the overall system. Alternatively, paying based on availability may not be appropriate in the GB bilateral market as it may distort the decisions of a generator in terms of actually operating and will not properly account for avoided costs. In the SEM, all generators must declare their availability to run and are scheduled by the TSOs and hence it would be possible to base FIT payments for Northern Ireland generators on the generator availability.

Questions 12 to 18 : Emissions Performance Standards

As is noted in the consultation paper, energy is a devolved matter in Northern Ireland and therefore any Emissions Performance Standard proposals for NI should be consulted upon along with a detailed impact assessment.

Notwithstanding this would need to be considered in an Northern Ireland context, it is also worth noting that Northern Ireland power stations are generally much smaller than GB power stations because of the smaller size of the NI market and therefore generating units must be smaller such that the loss of a single unit does not compromise security of supply. Consequently, the cost of CCS for smaller units in NI will be proportionally higher on a per MW basis and is therefore unlikely to be an efficient approach, neither for NI nor for the UK as a whole, to help minimise CO_2 emissions at least overall cost.

Questions 19 to 25 : Options for Market Efficiency and Security of Supply

The proposals in the consultation paper relate to reforms proposed for the GB market. As we have previously noted, Northern Ireland generators are obligated by their licences to participate in the All-Island Single Electricity Market and this market includes an inherent capacity payment mechanism.

Questions 26 to 29 : Analysis of Packages

None of the packages analysed reflect any that would be appropriate for Northern Ireland. In our view, the only component that has the potential to be implemented (with suitable adjustments to reflect the SEM) is the FIT with CfD that could replace the existing Northern Ireland Renewables Obligation and ensure alignment of renewable support mechanisms across the UK.

In this context, Northern Ireland has very good renewable resources and could leverage this resource to help the UK meet its renewable and carbon targets. A key issue to address is how any such costs, that help deliver the Government's objectives at least overall cost, is re-allocated and recovered from GB customers.

Implementation Issues

Question 30 : What do you think are the main implementation risks for the Government's preferred package? Are these risks different for the other packages being considered?

The main risks relate to the interactions between each of the elements and also the requirements for adjustments to existing arrangements (e.g. if CPS is introduced, does the RO need to be revised to maintain the same level of support? And does it need to be revised again from 2017 once the RO enters its run-off phase?).

Question 31 : Do you have views on the role that auctions or tenders can play in setting the price for feed-in tariffs, compared to administratively determined support levels?

We consider that auctions/tenders will provide more transparent exposure of the underlying support required by various technologies and by setting the volume required to meet targets will deliver that at least cost. We expect it would be virtually impossible for Government to determine contract prices that strike a balance such that customers do not over-pay, yet if the price is too low, investment will be frustrated and delayed to the extent that renewable and carbon reduction targets will not be met.

In relation to new and emerging technologies, it is not clear why Government would be better placed to determine the appropriate price than a potential investor/developer.

We consider that it may be appropriate to hold separate auctions/tenders for different technologies as that would provide flexibility to allow more expensive technologies, in an earlier stage of development, to be supported. The basic structure of the NFFO tender approach may provide a suitable base model, enhanced to reflect on experiences gained. It is also fair to say that during NFFO, the renewables market was at an early stage of development and hence some of the concerns raised (e.g. optimistic bidding) may no longer be such an issue as potential developers have much more solid experience and benchmarks to rely upon. It would also allow for some discretion should prices turn out higher than expected, e.g. a maximum strike price could be identified for any given technology.

Question 32 : What changes do you think would be necessary to the institutional arrangements in the electricity sector to support these market reforms?

The package of reforms will necessarily be different in GB than they will be in Northern Ireland and what is appropriate for Northern Ireland should be assessed as part of the consultation and impact assessment carried out under NI's devolved powers. We would highlight that PPB was originally established to contract will all generation in Northern Ireland and it was PPB who conducted the NFFO tendering process in Northern Ireland in close co-operation with DETI and the Utility Regulator. PPB would be well placed to perform a similar role in relation to FIT CfDs for Northern Ireland and the licencing arrangements already exist that would allow the costs of such support to be recovered through tariffs from customers.

Question 33 : Do you have any view on how market distortion and any other unintended consequences of a FIT or a targeted capacity mechanism can be minimised?

The targeted capacity mechanism is not relevant for Northern Ireland given that the SEM includes a universal capacity mechanism. However, these capacity payments are relevant in the context of a FIT in Northern Ireland as, unlike in GB where the wholesale market is currently "energy only", the separate capacity payment revenue stream would have to be taken into account in the contractual arrangements and hence the applicable contract for Northern Ireland will be different to the GB contracts because it will need to seamlessly interface and interact with the underlying wholesale market.

Questions 34 to 38 : Renewables - transition during the implementation of the new market arrangements

It will be important to ensure the change process does not generate uncertainty such as to encourage investors to delay their investment which may create later bottlenecks (e.g. creating a log-jam for network connection).

In terms of the options for calculating a post-2017 obligation, a twenty year run-off is significant, not least in terms of its administration, and therefore a pragmatic approach must be found to minimise the burden on stakeholders while ensuring generators are in no worse a position and are held harmless. The fixed ROC system appears to produce what is effectively a Premium FIT and the key factor to be determined would be the premium required, noting that, for example, the value of the underlying energy would increase if the carbon price support proposals are implemented.

Conclusions

The Northern Ireland wholesale electricity market is very different to the rest of the UK electricity market as a consequence of it being part of a cross jurisdictional All-Ireland market. The size of both the Northern Ireland and All Ireland markets is small in comparison to the GB and European markets and the capacity of interconnectors is such that, while small in a UK context, it equates to a significant proportion of peak demand in Ireland (for example the maximum change of flow on the interconnectors will be c2,000MW, compared to a peak demand of c6,500MW).

<u>Carbon Price Support</u>

The impact of the carbon price support proposals applying to Northern Ireland generation will be to increase its costs in the SEM relative to RoI based generators, thereby distorting the functioning of the SEM on an ongoing basis and also discouraging any medium to long term investment in new generation in Northern Ireland which will naturally seek to locate in RoI, creating risks to the long term security of supply in Northern Ireland. The knock-on effect of reduced scheduling in respect of the generating capacity contracted to PPB will be to increase costs for Northern Ireland customers to offset the reduced contribution from sales to the SEM.

The only way to avoid distorting the ongoing functioning and competition in the SEM is to provide an exemption for generation in Northern Ireland from the CCL and oil duty rates, thereby enabling Northern Ireland generators to continue to compete on a equitable basis in the All-Ireland market. This would also create a more level playing field in the competition for new generation investment in Ireland.

<u>Supporting Renewables</u>

We consider a FIT with CfD and Fixed FIT are identical in the context of the SEM because all electricity is sold through the pool at a single clearing price (SMP).

It would be possible to implement a FIT with CfD in Northern Ireland that largely mirrors the GB contracts but it would require a few variations to ensure alignment with the SEM through which energy revenues will be earned. The appropriate electricity price index for Northern Ireland, against which the strike price would be settled, would be the SEM System Marginal Price although further adjustments would be required to take account of revenues earned under the SEM Capacity Payment Mechanism.

Northern Ireland has good renewable resource potential and therefore could make a larger than target regional contribution to helping meet UK targets. This could help minimise the overall UK cost of meeting its carbon and renewables targets but it would be unfair if the costs were concentrated solely on Northern Ireland customers. Hence an arrangement would be required, e.g. through a financial reconciliation between GB customers and NI customers, to fund leveraged utilisation of the renewable resources in Northern Ireland to meet UK wide targets.