energygeneration INFRASTRUCTURE

RESPONSE TO CONSULTATION ON

‘CPM MEDIUM TERM REVIEW WORK PACKAGE 6 ONWARDS’ DISCUSSION PAPER SEM/11/019 OF 12TH APRIL 2011

Dated 1 July 2011

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On April 14th 2011 the Regulatory Authorities (RAs) published a paper which reviews work packages 6, 8, 9 and 10 of the Capacity Payment Mechanism (CPM) Medium Term Review. The RAs also published, as Appendices to the paper:

- a report by Poyry containing an evaluation of the CPM in 2008 and analyses of future impacts of a number of possible CPM reforms packages.
- A spreadsheet model of a possible ex-post CPM payment calculation.

The RAs have invited views regarding new ideas of good arguments pro or against the proposals put forward in the discussion paper.

This submission is the response of Energy Generation Infrastructure [EGI] to the RAs invitation. Our comments on each section of the Discussion Paper are as follows:

WORK PACKAGE 6 -TREATMENT OF GENERATOR TYPES IN CPM (WIND ETC)

All available generators receive equal capacity payments under the CPM. However, because 70% of capacity payment is decided ex-ante, capacity payments for particular trading periods can be above or below the payments that might be appropriate for those periods based on actual availability compared with actual demand. This can result in 'over-payment' of intermittent generators such as wind.

1. THE CAPACITY CREDIT SCENARIO

Analysis of market data from the first year of Single Electricity Market (SEM) suggested that wind received more capacity payments (and high merit plants such as hydro received lower capacity payments) under the CPM than if capacity payments were calculated based on the capacity credit contribution of each unit.

In our view, the CPM should equitably reward capacity in proportion to its actual contribution to security of supply. We favour rebalancing the CPM towards day-ahead and/or ex-post determination of capacity amounts based on day-ahead forecast and/or ex-post loss-of-load probability. This would maintain transparency, avoid complexity and reward available capacity proportionately with its usefulness. This approach would also be more compatible with day-ahead market coupling which will be required under EU legislation.

Our responses to the questions posed by the RAs in relation to the Capacity Payment Scenario are as follows:

Should the RAs look more closely at a Capacity Credit scenario for the payment of different generation types?

In our opinion, if the RAs are minded to retain the current overall CPM design, they should consider capacity credits which would reflect the contribution of each generation type to security of supply.

Is a Capacity Credit methodology appropriate for the CPM?

If the RAs are minded to retain the current overall CPM design, we favour the use of capacity credits as a basis for capacity payment under the CPM.

2. CAPACITY CREDIT OF WIND GENERATION – A VARIABLE ENERGY SOURCE

As more wind is added, the average capacity credit of wind reduces and the 'over-payment' of wind which has been identified in analyses of the CPM to date is likely to increase. In addition, increased wind capacity will depress average capacity payments under the current mechanism, which will affect existing generators and potential new entrants.

Our responses to the questions posed by the RAs in relation to capacity credits of wind generation are as follows:

Does the current mechanism fairly reward wind or does it need to be revised?

In our opinion, the CPM over-rewards wind generation and this over-payment will increase in future, to the detriment of existing generators and potential new entrants. We believe that the capacity payment mechanism should be modified to reward capacity (including wind) in relation to its actual contribution to security of supply.

Should there be a separate stream of capacity payments for wind?

We do not favour a separate stream of capacity payment for wind.

3. CPM IMPACT ON INTERCONNECTORS

The CPM and other aspects of the SEM are barriers to interconnector trade because they introduce trading risk, partly by virtue of the delay in final determination of prices in the SEM and also by application of capacity payments to interconnector energy flows.

Because market arrangements in Great Britain are under review, with the possible introduction of a capacity payment mechanism, it is difficult at this stage to develop proposals for the CPM in Ireland that would enhance interconnector trade.

Our view is that the CPM should be rebalanced to better reflect the actual contribution of capacity to security of supply, by relating capacity payments to day-ahead forecast and/or ex-post loss of load probability. This would give greater price certainty for interconnector traders and contribute to more effective regional market integration.

In principle, we believe that capacity payments should continue to be received / paid by interconnector traders.

Our response to the question posed by the RAs in relation to the CPM impact of interconnectors is as follows:

Should interconnector users' payments and charges be treated differently than under the current methodology in the CPM?

Until the Great Britain electricity market rules are developed, it would be inadvisable to change the CPM arrangements in relation to interconnectors.

4. ENERGY LIMITED UNITS

We favour retention of the existing arrangements for allocating Eligible Availability to energy-limited units.

Our response to the question posed by the RAs in relation to the energy limited units is as follows:

Should energy limited and pumped hydro storage units be treated differently to the current methodology in the CPM?

Pumped storage units have very high availability compared with other generator types. Winter availability of conventional plant is typically 80% to 90% whereas modern pumped storage can exceed 98%. The current methodology clearly does not reward this high level of performance.

In addition, pumped storage provides fast starting; fast load changing; demand side management when pumping; provision of reactive power and black starting. Advances in pumped storage technology with variable speed pumping and generating offer the features of instantaneous active power injection/absorption (thus enhancing frequency control) together with continuous power flow and voltage control during grid disturbances. Furthermore, pumped storage can be arranged to provide high inertia, a requirement that has been identified in studies of the system impacts of high wind. Pumped storage also reduces day-time prices and improves price stability while also providing a market and improving prices for wind power and other generators at night.

We believe that the current CPM methodology requires change in order to encourage new pumped storage into the market and provide this valuable, cost reducing capacity to the all island power system. This change could be non specific to pumped storage such as rebalancing, changes in the Flattening Power factor or capacity credits. Alternatively it could be specific to pumped storage such as classifying night time pumping as available capacity.

WORK PACKAGE 8 - INCENTIVES FOR GENERATORS

The CPM does not reward generator characteristics that would be helpful for system operation and security of supply, such as fast starting and operating flexibility. The RAs suggest that incentives for desirable generator characteristics can best be incentivised through Ancillary Services payments. The RAs point out that Ancillary Services payments are taken into account in deriving the annual cost of the Best New Entrant (BNE) peaker plant, which provides the basis for calculation of the Annual Capacity Payment Sum from which capacity payments are derived.

1. ANCILLARY SERVICES AND THE CPM

FLEXIBILITY PAYMENT SCENARIO

Poyry modelled a scenario in which 25% of the Annual Capacity Payment Sum was provided for flexibility payments (as with the other modelled scenarios, Poyry included other changes to the CPM so that the impact of each individual change is difficult to evaluate).

This scenario favours conventional and hydro plants (including pumped storage).

However, the RAs have decided not to actively pursue this option, suggesting that the Ancillary Services mechanism is more appropriate for flexibility payments.

NEW OR MODIFIED ANCILLARY SERVICES

The RAs believe that new or modified ancillary services will be required as the market matures and that these services will be delivered through appropriate incentives to generators via Ancillary Services payments. They suggest that possible increased Ancillary Services payments would reduce the BNE peaker cost, reducing the ACPS and (by implication) resulting in a limited impact on the cost of electricity.

The BNE peaker is projected to operate for a very short period each year. Most of its Ancillary Services payments are for static reserve. However, the type of ancillary service that will be required for the system in future will be low-cost fast capacity starting, provision of low-cost operating reserve, fast-acting active and reactive power resources, demand side management and inertia. The BNE peaker costs will not be impacted by provision or non-provision of these services and the ACPS will not change significantly. Therefore additional ancillary service funding to incentivise favourable generator characteristics is likely to result in an increased cost of electricity.

Our response to the question posed by the RAs in relation to ancillary services and the CPM is as follows:

The CPM and the AS revenue payment streams have two separate objectives and it is the RAs view that these should remain separate. Should the CPM offer payments for Flexibility?

We favour capacity payments for generator flexibility along the lines suggested in the Poyry flexibility payment scenario. The annual ancillary payments budget is a fraction of the Annual Capacity Payments Sum and is fully used for existing operational needs. As wind penetration increases there will be an increased need for generator flexibility in terms of fast starting and load changing, low starting cost and wide operating range. There will also be additional requirements that are not now supplied, such as for high inertia. The incentives that can be provided through ancillary services payments for these generator characteristics would be too low to attract them without a very significant increase in the ancillary services budget. The resulting increase in the cost of electricity would likely be politically unacceptable. On the other hand, setting aside part of the capacity payments to reward flexibility would not increase electricity prices but would likely reduce them by reducing constraint costs and attracting flexible plant to the market.

We request that the RAs reconsider the option of setting aside part of the ACPS to reward generator flexibility.

2 CAPACITY PENALTIES

The RAs suggest that there should be penalties for generators that fail to deliver capacity when required. Various options for application of such penalties are outlined.

Our response to the questions posed by the RAs in relation to capacity penalties are as follows:

Do respondents agree with the SEM Committee, that an appropriate mechanism for penalising generators for not providing capacity when they have declared that they would, would increase the incentive to encourage the availability of generators when actually needed?

We agree

Do respondents believe the Capacity Declaration Penalties (CDP) arrangement as described would fit the SEM CPM design?

A number of options are described for the CDP. We favour a CDP arrangement that would incentivise delivery of declared availability when required without being so onerous as to be a barrier to investment in new capacity.

What should an appeals process involve / include?

Legal advice should be sought on this issue. However, the CDP arrangement should be clear and unambiguous and the penalties should, as far as possible, be cost-reflective.

How should the proceeds from penalties be distributed?

We favour redistribution of the penalty proceeds to the generators that successfully provide capacity during the penalty period.

3. NEW ENTRANT SCENARIO

Poyry modelled the impact of setting aside a sum for new entrants that would provide guarantee capacity payments for five years (as with other scenarios, Poyry included other changes to the CPM with this option, making it difficult to isolate the sole impact of the new entrant set-aside).

The guaranteeing of payments would provide some certainty to new entrants, which should make funding easier. However, it would introduce discrimination between generators, reduce payments for existing generators, increase regulatory risk and require major changes in the Trading and Settlement Code.

The SEM is a small market and economically-sized new entrants have a market impact on prices. This results in high risk for investors, which is a significant barrier to new entrants. As a result of this barrier, worth-while investments that could result in a reduction in the price of electricity or to avoidance of transmission system investment could be foregone.

While acknowledging the problems that would arise from setting aside new entrant funding in the CPM, some mechanism should be available to ensure that worthwhile generation investments (in terms of electricity price reduction) are implemented.

Our response to the question posed by the RAs in relation to the new entrant scenario is as follows:

Should New Entrants be treated differently to incumbents in the CPM?

We understand the difficulties of providing special arrangements for new entrants in the CPM but we believe that some form of surety of income must be made available to ensure that worthwhile investments, which would reduce electricity prices, are implemented.

WORK PACKAGE 9 - TIMING & DISTRIBUTION OF CAPACITY PAYMENTS

The CPM uses a complex mix of ex-ante forecasts and ex-post analysis to allocate capacity payments for each period. Settlements under the CPM are monthly.

1., 2. and 3. CURRENT CAPACITY PAYMENT ARRANGEMENTS

We favour retention of the monthly capacity pot, distributed as at present. In our view, the CPM should be rebalanced towards day-ahead and/or ex-post determination of capacity amounts based on day-ahead forecast and/or ex-post loss-of-load probability.

Our response to the questions posed by the RAs in relation to the current capacity payment arrangements are as follows:

Should the design of the distribution allocations be changed?

We suggest that the current system of allocating monthly capacity pots be retained with further allocation of capacity pots for each day (on a month-ahead basis).

Should the current values be maintained?

We suggest that a 50:50 ex-ante/ex-post split for calculation of the capacity payment for each trading period, with day-ahead allocation for the ex-ante portion, based on forecast loss of load probability.

Should a Flattening Power Factor be applied within the CPM?

In the context of daily capacity pots, we suggest that the Flattening Power Factor be increased towards a value of 1 to encourage capacity availability in times of tight margin.

Should the current value be maintained or changed?

See previous answer.

If the mechanism moves to a heavier weighed ex-post payment will the FPF be as effective?

This requires analysis.

4. ALTERNATIVE APPROACHES TO THE DISTRIBUTION AND TIMING OF CAPACITY PAYMENTS

50/50 (ex-ante/ex-post)

We favour this split for capacity payment calculation, with the ex-ante payment based on daily capacity pots (allocated month-ahead) and forecast loss of load probability.

SOCAP model

The System Operator Capacity Allocation Model would be a 100% ex-post payment mechanism which would be calculated after the end of the year. A floor element (50% of the ACPS is suggested) would ensure a degree of certainty for capacity income. A sub-option would be to provide a higher 'floor' for new entrants.

There would be monthly provisional payments to generators but final settlement would only take place at year end. Various suggestions are put forward to deal with issues over- or under-payment of provisional amounts, errors in forecasting capacity over- and under- supply and other potential problems.

The major benefit of the proposed mechanism is that it aligns capacity payments with delivery of capacity when needed. It also gives the System Operators the ability to incentivise capacity adequacy and thus reduce the risk of load shedding. However, it would increase gaming opportunities and cost a lot to implement, requiring major changes in the Trading and Settlement Code.

A problem that is not mentioned by the RAs is that is would increase interconnector trading risk in that final determination of price and settlement could be more than one year after a trade takes place. It would seem to complicate planned regional market coupling which is to be based on day-ahead trading.

The RAs welcome comments on the feasibility of introducing a SOCAP Model.

We do not favour this proposed system. It would increase opacity, uncertainty, trading risk and market costs.

Specifically the RAs also welcome comment on:

The concept that the SO's would 'push money around' and signal need for capacity within-year.

We suggest that the current arrangements for trading be retained with cash flowing directly (through the market) from suppliers to generators, without SO intervention.

The value to the system of more explicitly incentivising capacity providers to make sure they will be available when the system will genuinely need them most.

We believe that providers should be incentivized to make capacity available when needed. This can be achieved by our suggested 50:50 payment mechanism with daily capacity pots and ex-ante/ex-post elements calculated based on loss of load probability, without the application of the Flattening Power Factor.

Whether a Floor; set high enough; is a sound tool for delivering revenue stability and lowering the cost of capital, and if not why not.

A revenue floor should help to reduce risk and the cost of capital. We believe that our suggestion of daily capacity pots with no Flattening Power Factor would provide a high level of income certainty for delivered capacity while providing incentives for capacity to be available when most needed.

The implications for Cash Flow and Credit for participants and operators.

As stated above, we favour cash flow directly (through the market) from suppliers to generators.

The RAs welcome alternative suggestions for allocating an effective distribution and timing payments system

As stated above, we favour day-ahead trading based on daily pots, with no Flattening Power Factor. This would allow faster settlement of capacity payments – within the same time-scale as energy payments, which would support market coupling and interconnector trading.

WORK PACKAGE 10 - IMPACT OF CPM ON SUPPLIERS

The RAs welcome comments from respondents / suppliers on options for shaping supplier Capacity Charges, in the context of the existing design and in the context of the other Capacity Payment proposals in this document.

We suggest that any market changes allow greater opportunities for both suppliers and pumped storage generators (when pumping) to provide demand side management.