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Dear Robert,

Transmission Price Control Review 2007-12: Third Consultation

Thank you for the opportunity to comment on the third Transmission Price Control Review consultation document. This response is submitted on behalf of International Power's operating companies in the UK: First Hydro Company; Rugeley Power Ltd; Deeside Power Development Company Ltd; and Saltend Cogeneration Company Ltd.

We have split our response into two sections. The first section covers electricity whilst the second covers gas form, structure and incentives primarily relating to offtake arrangements.

1) Electricity

Form and Structure of the Price Control

We believe that the current structure of the price control continues to be appropriate with an RPI – X framework backed up by licence obligations. The next few years will test this framework as the TOs enter a period of significant asset replacement and potential reinforcement to allow connection of potentially high levels of new generation capacity.

Given the level of asset replacement (non-load related) that the TOs are indicating going forward, it is important to ensure that asset replacement takes place only where an engineering/safety need is identified. When designing the non-load related element of the incentive the TOs should not have a financial incentive to replace assets simply because they have reached a nominal asset life.

The treatment of load-related capex needs more detailed consideration and we currently would not support a zonal allowance where the TOs received a location based allowance when connecting new generation. We believe that it would be difficult to arrive

at a meaningful value for the locational allowance given the information asymmetry that would inevitably exist and it could encourage the TOs to favour generation connecting in locations where the highest immediate revenues are available.

If the location related capex were to be based on increase in boundary flows we would have concerns as to how a differential price could be established for different boundaries, how the baseline flows are established and whether in fact this necessarily justifies the investment taking place. With significant information asymmetry in this area also, we believe that it would be difficult to protect customers interests.

The current system of a flat rate (£/kw) for new capacity with later adjustments for actual cost at the end of the price control period (all subject to an economic test) provides the correct signal for the TOs to invest in assets only when they can be justified on economic grounds.

This does put the emphasis on the regulator to be involved in reviewing investments at the end of a price control period and further regulatory involvement during price control periods for significant investment above the baseline. We do not believe that the regulator should, in effect, abdicate this responsibility by mean of a locational or zonal incentive that would provide an automatic increase in the TO allowable revenue based on a set of factors.

Impact on user cost

Although the consultation document contains details of the proposed capital programmes of the various TOs, the financial impact on customers is not derived. In order for the user community to assess the cost implications of such a significant increase in non-load related CAPEX in particular, it would be useful if subsequent consultations could detail the range of effects on demand and generation users over the timescale of the charging. Without this the impact on users cannot be fully assessed

New Connection Issues

The significant number of new connection applications in the Scottish TO regions has two root causes: firstly the BETTA arrangements created a situation where the timing of applications prior to BETTA gave greater certainty of an early connection date; and secondly the current access arrangements encourage applicants to be first in the queue.

We understand that many of the applications (although there is no transparency of these) are small in size and do not have the benefit of planning or other consents. We believe that the unique set of circumstances created by the current Scottish queue are unlikely to be repeated and we have concerns a solution the Scottish queue issue may be sought that is not appropriate for enduring arrangements.

We believe that a sensible way forward for the queue would be to allow new connection to be relieved of the obligation of providing final sums for infrastructure work after they have received local planning permission and to fix the liability for aborted local works at the point an offer is made. This will encourage new entrants to get through the significant hurdle of planning at an early stage (or hold off applying until planning is obtained) but help share the risk of infrastructure work with the community once planning is obtained.

User Commitment

We believe that there should be no additional commitment on existing generators to provide security for TEC in future years. One of the reasons put forward for enhanced user commitment is that it would provide the TO with additional information relating to use of the network.

However, an additional commitment would be seen as a sunk cost for the generator and would affect the closure economics. Rather than close a station to release capacity (either short or long term) the generator would be faced with a sub-optimal decision to continue to hold capacity whilst the short run economics may indicate closure. This could therefore constrain efficient market exit - generation can currently withdraw from the market (mothball) and release capacity for use by others. With enhanced user commitment, short or medium term withdrawal would no longer be possible leading to additional cost for customers as uneconomic plant continues to operate.

There would also be a significant additional burden on independent and small generators, who do not meet the TO credit rating requirements, through the costly provision of security. This could divert credit allocation from the traded markets, impacting further on liquidity. Both of these security related issues would increase the market risks for independent players, and potentially lead to additional cost for consumers.

Legacy arrangements

Any change to the existing arrangements would need to be sensitive to the legacy issue that may be created. Existing power stations have been constructed and operated under the current arrangements providing final sums for new connections. If the burden for new entrants was eased whilst imposing additional burdens on existing generators, existing generators would be seen to suffer the worst of both worlds, adding to the already heavy burden of regulatory risk that is ultimately borne by the consumer.

2) Gas

Form and Structure

We believe that the current structure of the price control continues to be appropriate with an RPI – X framework backed up by licence obligations. This is particularly true for small generators such as Deeside Power Development Company Limited, who are particularly sensitive to market and regulatory change. Adopting a User Commitment Approach to charging, could have a fundamental effect on the continued operation of independent generators.

However, in Consultation 3 the use of a User Commitment Model appears to be a given, and structured questions on this regime have been provided. Therefore, the following comments address these questions in that context.

Gas Offtake Transitional regime

International Power believes that the proposed approach for the Transitional Period is appropriate, as the mechanism proposed means that NG is not remunerated for providing capacity on a firm basis that already exists within the network (and therefore for which it does not need to make any investment) Therefore setting baselines on a practical maximum physical is appropriate. Furthermore, setting baselines on a nodal basis will provide the clearest information to connectees.

With respect to interruptible capacity, we agree it is not necessary to provide baselines for interruptibles, as no investment is required to provide the interruption. We also agree with use of revenue drivers commencing from the Transitional Period, although we envisage scenarios where investment is required that may not be linked to a specific user. However, the methodology for setting such drivers will be critical, if they are to incentivise the delivery of capacity long-term.

We concur that the Charges Foregone and Exit Investment incentive should not be part of the next price control, as the incentive provided loses impact due to the reduced cap (£1M). Furthermore, we support the use of the Constrained LNG Incentive and Buyback Incentive in principle, although little information is available on the former. Finally we agree that in principle the 15 Day Incentive should be retained to minimise interruption of NTS sites. However this incentive may have limited application and thus NG may simply create additional cost to customers.

Gas Offtake Enduring Regime

In the event that a change from the current model is deemed necessary, International Power supports the establishment of a prevailing rights regime as in the Third Consultation rather than the finite rights regime previously suggested in the Second Consultation. However, neither NG nor Ofgem have currently presented any information on the extent of stranded assets, and so it is currently difficult to quantify the requirement for a user commitment model.

The applicability of any User Commitment Model will depend on the compatibility of investment timescales between NG, a distribution network operator, power station developer or storage operator. The relationship between these parties will determine whether there are efficient investment signals and potentially reduce stranded assets. Any mismatch in timescales could potentially lead to CCGT developers committing to capacity on purely the possibility that it may be required. Therefore it would seem appropriate that there be a mechanism to review any capacity application before final investment of all parties. Further to this, for the first year of operation of a new facility, "partial year" applications for capacity should be considered to facilitate commissioning and start-up which follow normal economic drivers. Additionally, we do not agree with the 2.5 year lead-time for reductions in capacity levels. Any extension of the commitment beyond current timescales will introduce additional complexity.

International Power agrees in principle with some of the high level options set out in the second consultation, in particular that the use of baselines on a zonal or global basis

would add complexity, reduce transparency and would not provide locational specific investment signals to incentivise security of supply. Similarly, we agree that nodal products and nodal baselines do provide locational specific investment signals. However before commenting further, we would require more information on the “rating” of individual offtakes and more detail on their treatment in the nodal model.

Our preliminary view is that capacity should be delivered before NG is remunerated, but it is unclear how such investment will be financed. We are concerned that there may be a cost impact.

We can also envisage scenarios where a more efficient outcome may be achieved if NG were to tender for either a) long term buyback or b) prevailing rights surrender (including baseline) or c) interruptible contracts at offtakes close to that requiring incremental capacity prior to committing to undertake incremental investment. We note that this could lead to a cycling effect on the availability of interruptible capacity as these proposed reforms would essentially ‘force’ current interruptibles to go firm, but new connections or sites close to them may be offered interruptible terms, potentially creating a new generation of interruptible offtakes at least until the next set of reforms!

With regard to baselines, International Power agrees that setting these on a practical maximum physical basis rather than a theoretical maximum, best identifies incremental investment costs which require funding. Our view is that static baselines are appropriate in particular for offtakes serving CCGTs, since any incremental requirements will be sizable rather than marginal. Furthermore, we agree that the revenue drivers approach has merits and is potentially an appropriate way of remunerating incremental investment.

We agree that buybacks relating to investment should be excluded from any incentive so that NG faces the costs of any delays for which it is responsible. The issue of buybacks for maintenance has yet to be discussed.

We trust you find these comments useful.

Yours sincerely,

Kevin Dibble
Regulation Manager