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Transmission Investment for Renewable Generation
A Response to Ofgem's 2nd Consultation of May 2004

Dear Jonas,

The following comments are made on behalf of RWE Trading GMBh, RWE Innogy plc, Innogy Cogen Ltd., Innogy Cogen Trading Ltd., npower Ltd., npower direct Ltd, npower Northern Supply Ltd., npower Yorkshire Supply Ltd, npower Northern Ltd, npower Yorkshire Ltd, National Wind Power Ltd

RWE Innogy welcomes the opportunity to comment on the issues contained within the OFGEM consultation on transmission investment for renewable generation published in May 2004.

The consultation document assumes that an adjustment to the existing price controls is appropriate to deal with the impact of the forecast expansion of renewable generation on transmission costs. RWE Innogy is not persuaded of the necessity to adjust the current Price Controls at this stage on the basis of the anticipated transmission investment that might be needed to accommodate new renewable generation.

Some transmission investment will be needed to connect new renewable generation to the transmission system, although much of this should be funded by connection charges even under a more shallow connection policy. The economic case for investment in the transmission infrastructure will depend, at least in part, on the congestion that may emerge as a result of the additional generating capacity that is connected. The uncertainty of the output from renewable sources, coupled with the unknown response of existing generation to the extension of a system of transmission charging to GB that provides economic signals for siting and closure, makes the level of these congestion costs equally unpredictable.

The economic case for investment in new network assets will also suffer from this uncertainty. The associated risks of stranded investment could be mitigated by permitting the SO to incur somewhat higher congestion costs for a period until the need for infrastructure investment became more clear. Commercial inter-trip schemes may provide a further practical way of limiting these risks in the short term until the uncertainty of the forecast need had diminished.

Adjusting the Price Control - Views invited

- *Whether the revenue deriving from the adjustment mechanism should be based on the funding costs of projections of investment over the period 2004/05 to 2006/07.*

- *Whether outputs should be identified to assist in establishing whether licensees have delivered investment that is fit for purpose, and any suggestions as to what sort of outputs would be most appropriate*

- *Whether there is a mechanism that could be adopted that would deal with the uncertainties created by the requirements on licensees to obtain planning consents for new investment.*

- *Whether the cost of capital should be consistent with that in setting the main price controls*

- *Whether it would be appropriate to identify revenue drivers to determine the level of revenue that a licensee would be entitled to each year.*

Broadly we would support the conclusion that if there is to be an adjustment mechanism to the price control then it should be based on investment drivers that can reflect the generating capacity that is added to the system and the additional transmission capacity that is provided. Given the uncertainties attached to the renewable programmes, and the wide range of likely costs for connecting schemes at different locations, a lump sum allowance would be inappropriate. As the consultation notes a cost pass through approach would lack any incentive properties for encouraging economic efficiency in the development of the transmission system.

Although an approach based on revenue drivers would seem to offer the best prospect for encouraging efficient development of the system such drivers would need to be reasonably sophisticated if they are to be effective. A simple £/kW of connected capacity would be too blunt an instrument to discriminate between the competing schemes with dramatically varying potential impacts on the transmission network. Furthermore the regulatory framework should also accord with the charging arrangements that should be seeking to encourage economic efficiency by providing locational signals for the siting of new plant and the closure of uneconomic capacity. Indeed it would be preferable for the charge out arrangements to be established first such that developers could appropriately site new schemes before any investment in the transmission system were contemplated.

As we have noted above the risks of stranded assets in transmission investment are significant. These risks can be reduced if the SO tolerates a certain level of congestion cost before any investment is contemplated by the TOs. It may be more economic for the SO to find ways of reducing congestion costs by "buying back" access capacity from established generators rather than encouraging new investment in network assets.

These considerations suggest that a revenue adjusting mechanism based on the projections of investment over the remaining period of the price control would be far too simplistic. A zonal or nodal revenue driver that could reflect the location of new schemes should be one ingredient, but it should be applied on a non-discriminatory basis to *all* additional connections, rather than solely to renewable generation. It should also be applied consistently in the subsequent Price Controls of all three TOs.

Assessing the avoidance of congestion costs might then test the efficacy of any investment undertaken. In such an approach it would be necessary to recognise the economic worth of commercial inter-trip schemes that might provide an alternative to transmission investment for a period. Such an approach would have the added merit of delaying the activation of the revenue adjusting mechanism until the outcome of aspects such as planning consents were known. Since the risks of under utilised investment would be much diminished the cost of the capital could be kept consistent with that for the main price control.

As is noted in the consultation, the decision on whether to adjust the Price Controls should depend on an assessment of the magnitude of the relevant risks. These will include the risk of stranded transmission assets, the risk of large constraint payments and the risk of renewable generation developments not being connected within an efficient timeframe.

Determining the efficient level of investment – Views invited

- *What are the best approaches and sources of information on the likely level and pattern of renewable generation*
- *Assumptions that should be made about the operation of existing conventional plant particularly in Scotland.*
- *Assumptions that should be made about the operation of existing conventional plant in Scotland.*
- *The assessment of whether transmission upgrades are economic on the basis of assessing the expected difference in the annual costs of constraints that are likely to occur with and without the network upgrade (assuming broadly cost reflective transmission charging) against the annual cost of financing and maintaining the transmission system upgrades.*
- *The best approach to assessing the expected costs of reinforcement schemes'*

Generally we would support the use of independent consultants to audit the costs of schemes and evaluate whether such investment should be economic. Such evaluations will need to be against a judgement of the likely merit order for conventional generation. The evaluation should take account of the likely response of conventional generation to the application of a consistent transmission charging arrangement across all of GB.

Contractual and charging arrangements – Views invited

- *What changes if any might be appropriate to NGC's charging methods to take account of the increasing levels of renewable generation.*
- *Whether generators that trigger significant investment in the transmission system should be required to commit to longer-term access arrangements to reduce the chance of assets being stranded.*
- *Should access rights be allocated on a first come first served basis or whether all generators should be treated consistently.*
- *Whether transmission access rights should be tradeable and whether this would assist generators and network operators in efficiently resolving tradeoffs between network constraints and investment.*
- *How to ensure that distribution connected generators exporting energy and/or increasing flows on transmission networks make an appropriate contribution toward the cost of transmission networks.*

The uniform scaling method used in the current E&W TNUoS methodology produces nodal generation values that are not reflective of peak conditions. We support the application of scaling factors for all injection points, including interconnectors, approximating the peak merit order. This would produce generation capacities, particularly for wind generation, that are more representative of peak conditions, The resultant

tariffs would therefore more accurately reflect the investment required to transport peak flows on the system.

Subjecting generators to either longer-term arrangements or requiring the provision of financial security appears an attractive method for reducing the risk of stranded assets. However, such arrangements may not be enforceable especially if the generator in question has gone into receivership. For this reason we believe it better to mitigate the stranded asset risk by delaying network investment and relying on operational methods for reducing any subsequent constraints until the new renewable generation schemes have been proven.

Allocating transmission capacity on a first come, first served basis would seem the only pragmatic approach although there should be some test of a scheme's viability before a connection offer is made. However, establishing a mechanism whereby capacity can be traded, perhaps along the lines of that envisaged by CAP068, would contribute significantly to ensuring the most economic schemes proceed first. Such an arrangement is also crucial if unneeded access capacity is to be released in an efficient manner.

Generators should be liable for the costs of the transmission system to the extent that they impose cost upon it. This principle should apply irrespective of the size of a generator or its voltage of connection. It is for this reason we favour the extension of the ICRP approach to network pricing that is used for transmission voltages to distribution connected generation. The extension of the DCLF model to distribution voltages presents an opportunity to create an economic basis for charges to generators of less than 100 MW both in terms of the costs they impose on the transmission system, and the benefits they may bring to distribution systems.