

Transmission Price Control Review Initial Consultation Response by Scottish and Southern Energy

The initial consultation document for the transmission price control review of the GB electricity and gas transmission licensees was published in July 2005. In that document, Ofgem raised a number of specific questions about the approach to the review. These questions are reproduced in *italics* below, together with SSE's detailed response.

How should Ofgem seek to address the external factors cited in paragraph 4.11 above in setting new price controls? Are there any other external factors that Ofgem should take into account?

The factors mentioned in paragraph 4.11 of the consultation will be key in setting the next price control.

The potential levels of renewable generation connecting to the system are a particular concern in terms of the uncertainty regarding the amount and timing of investment in transmission capacity that will be required to meet their demands. The current initiatives by Government to move towards a low carbon economy have resulted in an unprecedented number of applications from renewable generators for connection to the systems of all three transmission licensees. While it is unlikely that all of these projects will succeed in obtaining the necessary consents, significant investment will still be required to accommodate the successful projects.

While the necessary investment can be identified and linked to the generation projects, the total level of investment and its timing is dependent on the progress of these projects. NGET's previous five-year price control was set on the basis of a forecast level of load related expenditure with an incentive term (the Gt term) to set an incremental allowance dependent on the volume of new generation connecting. In our view, this is too blunt an instrument for setting an incremental adjustment to allowed revenue. We also do not believe the auction regimes and incentive arrangements introduced in the gas market have been successful and would not support their extension in to the electricity arrangements.

In contrast, the two-year extension to the Scottish licensees' price control had a new allowance for transmission investment for renewable generation (the TIRG term) for named major projects driven by renewable generation. We believe that this more sophisticated approach of linking allowed revenues to the actual construction programme for major projects is a significant step forward in dealing with uncertainty and should be further developed for the main review. We also believe that a development of this "TIRG" mechanism could address the wider issues of investment uncertainty.

In this model, specific large investments are identified, together with the triggers for the investment (i.e. the events which lead to each investment being considered an

economical and efficient development of the system). The TIRG mechanism also sets out the funding arrangements to give the licensee certainty of recovering its investment costs and the output measure in terms of what the investment delivers. Any investment identified under this arrangement and justified through the economic analysis is treated as baseline and is added to the RAV once completed. For some potential investments it is necessary to carry out preconstruction work to identify possible routes and carry out environmental assessments. Some of these projects will be classed as baseline because of the level of demand for new capacity. Others may not proceed because not economically justified or because the demand for the capacity is not confirmed. In these cases we believe the preconstruction costs should be recovered through the TIRG term or through a specific ex ante allowance under the core price control.

A further external factor that Ofgem should take into account in the price control is BT's proposal for major changes to the telecomms service. Transmission companies rely on high speed, high reliability telecommunications channels for protection signalling between substations for system protection and security of supply. Withdrawal of the service by BT would involve significant investment in alternative signalling methods.

Is the standard model of a five year control and RPI indexation still appropriate for the next transmission price controls? Are there any areas of activity which should be price-regulated differently, including any scope for de-regulation?

We believe that for most of the activities of the companies, a five year control and RPI indexation will continue to be appropriate. This should cover the core activities of operational expenditure and non-load related expenditure, i.e. expenditure to replace and refurbish plant due to age and/or condition. This core replacement expenditure should be capable of being forecast with a reasonable degree of accuracy based on age, condition and performance of the assets.

However, the capital investment required to respond to such external influences as described above is a key concern.

We believe that new connections, telecomms rental and outage rescheduling costs should continue to be treated as excluded services.

What particular areas of the licensees' activities should Ofgem focus on in this price control review?

This review will have a particular focus on capital investment for the reasons mentioned above.

Should incentives to reduce costs be strengthened or weakened?

We believe that incentives to reduce costs should be strengthened by reaffirming the principles of rolling incentives for capital and operating expenditure. These should also apply to savings made during the two-year rollover period to preserve incentives for efficiency.

Also, in our view, benchmarking should be considered even though there may be difficulties in interpreting the results given the small sample of companies and management teams.

How should the range of refinements to the basic RPI-X form of control be deployed by Ofgem in setting the next transmission price controls? Are there any refinements that should be used more or less than is currently the case?

We firmly believe that the basic well-established RPI-X methodology should form the basis for this review, supplemented by the rolling incentives as used in the distribution price control. There should continue to be a pass-through of rates costs and licence fees.

For operating expenditure we believe that Ofgem should attempt some form of benchmarking for controllable cost to establish the relative and absolute efficiencies of the licensees as mentioned above. We also believe that pension costs should be subject to the same approach as used in the electricity distribution price control review.

Capital expenditure should be based on an assessment of non-load related expenditure using the established processes of Ofgem's consultants. Load related expenditure should be based on a development of the TIRG mechanism

Depreciation should be set at a level which is sustainable from a cashflow perspective. Given the scale of the investment, this will need to be a particular focus.

Are rolling incentives appropriate for transmission, and if so how long should the retention periods be for efficiency savings? Should the rolling incentive approach adopted in gas for incremental entry capacity also be adopted in electricity?

We believe rolling incentives are appropriate and have already been introduced for the Scottish transmission two year extension. The same rolling incentive is also being developed for the TIRG investment with the same 5 year retention period. We therefore believe a five year retention period is appropriate.

Should Ofgem seek to ensure that the strength of incentives for efficiency in operating costs and capital expenditure is equalised?

The existing incentive framework has worked well hitherto and has delivered real benefits for customers. We are also not aware of any problems caused by the differing nature of capex and operating cost incentives. As a consequence, we do not believe it is necessary to align incentives for efficiency in operating and capital expenditure.

We would also be concerned if any reforms of the incentive framework weakened the incentives for either capex or operating efficiency.

Are Ofgem's objectives for the price control review appropriate and comprehensive? If not, how should the objectives be re-stated?

We believe the objectives are appropriate and do not need to be re-stated.

Assessing Costs

Capital expenditure:

What methods and models of capital expenditure cost assessment should Ofgem seek to use in the transmission price control review? What might an increasing importance of non-load related capital expenditure (as opposed to load related capital expenditure) mean for how Ofgem undertakes the price control review?

We believe that the methods adopted by Ofgem at the recent Distribution Price Control Review should be used. This involves a detailed review of non-load related capital expenditure using established models for estimating the need for and timing of replacement and/or refurbishment of plant. We are not clear why this should be of increasing importance, since it continues to be the case that the gas and electricity transmission systems must be maintained and refurbished to the requisite standards.

How, if at all, should Ofgem adapt its approach to assessing capital expenditure requirements related to growth in renewable and distributed generation and future plant closure? Does the model of assessment adopted for TIRG provide a useful model for the price control review?

We believe the growth of renewable generation will be a significant driver for transmission capital expenditure, and for the smaller licensees such as SHETL will far outweigh the non-load related expenditure. Indeed, the likely level of expenditure is many times the historic level raising questions about the financial ratios of the business going forward. We believe that flexible mechanisms to identify the funding requirements on a licensee specific basis will be required in this review. In particular, the mechanism already identified for the TIRG investments should be further developed to this end.

Operating costs

What particular areas of operating costs should Ofgem focus on in its assessment of the current and future efficiency of the transmission licensees?

It will be important to ensure that capitalisation policies and the treatment of shared costs are understood and netted out before any meaningful comparisons between the companies can be made. It will also be important to recognise the unique costs of servicing the Scottish Hydro-Electric territory, which accounts for 25% of the UK land mass but only 2% of the customers.

What approaches, other than those identified in this chapter, might be available to Ofgem in assessing the efficiency of each transmission licensee's operating costs?

We believe that there is such a discrepancy of scale between the licensees and the small number of comparators will rule out the type of benchmarking carried out between the 14 electricity distribution licensees in the recent review. However, this should not preclude an attempt at benchmarking operating costs.

Cost reporting

What form of cost reporting framework should Ofgem develop for each of the transmission licensees as a means of monitoring performance under the new price controls over time?

In our view, any cost reporting mechanism must be proportionate to the size of the organisation. It would be unacceptable to have a large regulatory burden on cost reporting on such a small organisation as SHETL's. We would support a proportionate "regulatory reporting pack" for monitoring performance over time based on the level of detail provided in the historic business plan questionnaire submitted as part of the price control review.

Incentives

How should Ofgem encourage users and potential users of the system to signal their future requirements and how should the licensees be incentivised to meet these requirements?

There are key differences in this problem for the gas as compared to the electricity market. In both markets, it is the production rather than consumption of the commodity that is likely to drive investment in the transmission networks. In electricity it is generation-led, whereas in gas, it is the shift in supply from North Sea fields to imports from mainland Europe. Electricity production is characterised by a large number of entry points (almost 100) to the transmission system with capacity contracted at each entry point to a single user. In gas there is only a handful of entry points and the capacity is contracted across a number of shippers. These differences drive different approaches to signalling capacity requirements.

As the commercial incentives for generation shift over time, so the generation mix changes resulting in different flow patterns across the electricity transmission system. Historically generation has located near its fuel source – coal fired adjacent to coal mines, oil fired near to docks for example. In the 1990s there was a growth in gas fired power stations located near the gas transmission system.

We are now seeing large scale development of renewable generation, which tends to be located where the renewable resource is greatest. This in turn means the more remote locations such as Scotland, where the transmission system is less robust than the heavily meshed network in the Midlands of England. There is also potential for offshore wind farms, which will need to connect into the system.

To avoid the risk of stranded transmission assets it is imperative that the system is developed in parallel with the new generation projects. The physical construction of a generating station is the ultimate demonstration of its requirements for transmission capacity. However, the generator will only be able to bring its project to fruition if all the financial constraints are managed. For example, the generator will require reasonable certainty on the level of access charges to the transmission system and the commercial framework within which he will be operating. Once these are in place, it would seem reasonable to seek a degree of underwriting of the transmission investment from the generator. This ensures that if the generator fails to complete the project, the costs of any nugatory work on the transmission system would fall on the generator rather than on customers as a whole.

In electricity it is clear that there should be a degree of underwriting of transmission investment by generation developers culminating in the physical construction of the generating station to secure the long term commitment. On this basis, we do not believe that any further incentive is required for transmission licensees to meet customers' requirement.

However, in gas transmission the problem is different in that a requirement for transmission capacity is not always reinforced by the construction of physical assets by the party requesting the capacity. As noted above a power station is a clear physical asset that signals a long-term requirement for transmission capacity. In electricity, it is the generator that pays for the connection to and use of the transmission system. However, in gas it is the gas shipper that pays for capacity. Shippers may not be the owners of the gas production facilities and are often unwilling to commit to long term contracts for capacity. This has been seen in the entry auctions for the past few years. The problem is exacerbated by the mechanism for setting reserve prices in the auctions which, in our view, is not reflective of the cost of additional capacity on the network. This has resulted in large swings in the cost recovery mechanism leading to unpredictable tariffs as the charges swing between capacity and commodity to correct for over or under recovery. Also, we are not convinced that the auctions have led to consolidated investment signals.

We therefore believe the gas capacity auction regime should be reviewed from first principles and would suggest a move towards a TIRG type funding arrangements for major investments in gas transmission. This planning based approach will lead to stability of charges and certainty for market participants in respect of their capacity requirements.

Is there a need for consistency between gas and electricity transmission and between arrangements for entry to and exit from the networks?

In our view, there is no pressing need for consistency between gas and electricity transmission for arrangements for entry and exit. As noted above the market arrangements and the products themselves are significantly different.

In particular, we would be firmly opposed to any extension of the gas entry regime into the electricity market. We do not believe that the gas entry auctions have

delivered the objectives of robust investment signals. That regime has, however, introduced substantial uncertainty into the gas market and a number of unintended consequences.

To what extent should new users of the networks be required to make a firm financial commitment before the Transmission licensee is required to make capacity available to them?

In electricity, the requirement for capacity is usually supported by the potential user constructing physical assets such as a generating station. The commitment should be made in the form of underwriting of a share of the investment in transmission capacity. Once constructed, the new user will be obliged to pay the relevant charges for use of the network.

However, the use of system charge under the prevailing methodology, which is intended to reflect the long term cost of capacity, is in our view disproportionate and can lead to inefficient outcomes. A shallow connection charge plus a proportionate use of system charge would lead to a more efficient investment decisions.

In gas, the mechanism would depend on the type of user requesting capacity. A gas distributor would only request additional capacity in order to fulfil its licence obligations to meet the demands of the customers on its network. We believe the most appropriate approach for such requirements is co-ordinated network planning between the licensees. This model is already used in electricity transmission where the three licensees meet to discuss the necessary reinforcements to the transmission system. However, if a single large user requests capacity as a commercial arrangement, then this should be subject to an ARCA type mechanism to avoid the possibility of stranded assets.

How should baseline outputs and incremental outputs be defined for (a) electricity transmission licensees, and (b) Transco NTS? Should the existing definitions be retained? If not, how should they change?

In electricity, specific major projects can be identified with predefined outputs. These projects would be triggered and underwritten by the generators driving the investment. This is broadly the mechanism for the TIRG investments already classified as baseline. We believe the TIRG mechanism should be further developed to deal with the future growth in renewable generation.

How should the provision of incremental outputs be remunerated? Should NGC have a similar incentive to Transco NTS in respect of incremental capacity, i.e. that it is rewarded for providing future capacity based on firm commitments by network users to pay? Is there a need for greater use of explicit output measures and performance indicators as part of the next price controls? If so, what areas should such new output measures focus on?

Our experience to date has been that once a user or group of users has committed to their requirements for capacity the most economic solution to provide for that incremental capacity can be determined. However, there is no straightforward formula to link incremental capacity requirement to incremental remuneration. Once

a solution to the user's capacity requirement has been identified, then we believe the most appropriate incentive is through a TIRG type funding arrangement.

In this arrangement, the most economic means of providing for the capacity requirement is identified and the cost, once consented, is incorporated into a licence term. The licensee then has certainty of funding for the project and is incentivised to construct this project at below the budgeted cost through a rolling incentive mechanism with retention of efficiency savings for five years before the project goes onto the RAV.

Within this framework, we do not believe that NGC (as the GB system operator) can or should have an incentive in respect of incremental capacity since the investment is carried out by the TO or NGC in its role as a TO. NGC in its role as a system operator could be incentivised through the SO incentive only to the extent that capacity can be provided by working the existing assets harder.

To what extent should Ofgem set price controls in the expectation that they will need to be re-opened in the light of future events, or should Ofgem as far as practicable seek to set price controls which adjust revenues automatically as circumstances change?

In general, it would be preferable to set price controls that adjust revenues automatically as circumstances change. However, it may not be possible to predefine the extent of any adjustments even if the circumstances that might lead to income adjustment can be predefined. For example, it is clear that investment in transmission networks is affected by the level of generation, particularly renewable, obtaining the necessary consents. NGC currently have an allowance (the Gt term) to provide an incremental allowance to income for every MW of generation connecting. However, such a simple revenue increment is in our view too blunt an instrument to deal with these circumstances. In particular, we believe that it would be very difficult to set unit cost allowances that would capture the range of possible projects. Also, given the nature of the likely investment, we believe that such a mechanism would involve excessive risks for the licensee.

The major constraint boundaries in the GB transmission system are identified in the transmission seven year statement, and the point at which it would be economic to upgrade the network (depending on the level of generation connecting) to relieve each boundary can be defined. The costs of these upgrades can also be estimated and the economic "break points" confirmed through independent analysis. The process described here is, in effect, the process leading up to the TIRG licence modifications already implemented for the electricity transmission licensees, and we believe such automatic income adjustments should be developed for all such major projects going forwards.

This mechanism can be successfully applied to the major investments necessary to accommodate groupings of applicants. A secondary level of uncertainty exists in relation to the more local infrastructure necessary to accommodate each individual generator. However, even this can be accommodated since the necessary local infrastructure is identified in the connection offer. Again, an allowance could be

made against the identified infrastructure work for the remainder of the price control, after which the investment would be added to the RAV.

Such mechanisms would minimise the likelihood of reopening the price control, and we believe they should be developed for foreseeable events. It is also worth noting that, given the small number of major transmission investment projects for renewable generation, the workload involved in a TIRG term would not be substantial.

Financial Issues

Should Ofgem's approach to cost of capital and tax under DPCR4 be adopted for the transmission price control review?

We believe that Ofgem should adopt a post-tax approach to the cost of capital with an ex ante company-specific allowance for tax, as in electricity distribution. In transmission, we believe this will result in a cost of capital in excess of 5% post tax, given the more capital-intensive nature of the transmission businesses. The tax funding would need to be specific to each company taking into account its forecast financial ratios.

What are the reasons why the cost of capital for a transmission business might be different to the cost of capital for a distribution business?

Cost of capital is the return required by the financial markets to provide capital to a firm. In the distribution review, because of the "investment focus" of the review, Ofgem concluded that an appropriate possible range would be from 4.2% to 5.0% post tax and finally adopted a figure of 4.8%. Given that transmission is a more capital-intensive activity than distribution and the significant investments required to cater for renewable generation, we believe that 4.8% would be too low a figure for transmission. In fact we believe an efficient company should be able to achieve post tax returns approaching 6%. This implies a cost of capital in excess of 5% assuming scope for outperformance.

What principles should Ofgem apply in rolling forward Regulatory Asset Values (RAVs), in particular in respect of capital expenditure in excess of past allowances, and in respect of changes to how costs are accounted?

We support Ofgem's commitment that "where a full review of past capital expenditure demonstrates that expenditure has been efficiently incurred, the additional funding... would be included as part of the revenue allowances for 2007/8 onwards". It is essential in terms of managing regulatory risk that efficient investment should be funded and added to the RAV. To do otherwise would increase the perceived risk of the companies and lead to more risk averse strategies going forward.

To this end, we believe it is important for Ofgem's consultants to reach a conclusion early on in the process regarding historical capital expenditure so that the starting RAV for the price control can be determined.

Are there any other factors which Ofgem should consider in assessing financial issues under this price control review?

It is clear that in this review, some licensees may be significantly cash negative due to the major capital investments required. It is essential that due consideration is given to financial ratios and financeability in such circumstances.