SP Transmission & Distribution

Response to Ofgem Consultation Paper:

Transmission Price Control Review

Second Consultation

December 2005

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Members of the ScottishPower group

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1. Introduction

This response to Ofgem's December 2005 Second Consultation on the Transmission Price Control Review is submitted by SP Transmission, which is the Transmission Owner (TO) for central and southern Scotland.

Our key messages are:

- The TO price control must provide sufficient funding for the required increase in capital expenditure which the TO is already contracted to deliver;
- There are a number of alternatives to the proposed user commitment model, including development of the TIRG mechanism, a disaggregated revenue adjustment term and price control re-openers, which should be considered;
- The TO's funding should not be adversely affected if the user commitment model is adopted, even if there is a delay in its implementation;
- An industry working group should be established to develop the detail of the proposed user commitment model, if this approach is adopted by Ofgem;
- The respective roles and responsibilities of the TOs and the GBSO, under the proposed user commitment model, need to be clarified;
- We are concerned that the proposed user commitment model may not provide sufficient funding to meet our obligations under the GB SQSS;
- SP Transmission's depreciation "cliff edge" should be addressed by the standard approach that was developed for DNOs;
- The allowed cost of capital should reflect our increased risk exposure; and
- The continuing financeability of the transmission licensees must be assured.

Incentive options for electricity

The user commitment model should be subject to a full regulatory impact assessment, prior to adoption of that approach by Ofgem, which should consider alternative approaches and quantify the costs of implementation, as well as the benefits.

We encourage Ofgem to establish an industry working group to address the detailed design of the user commitment model. Implementing the user commitment model will be a complex and potentially lengthy process, involving several parties and modifications to industry agreements and codes. The roles and responsibilities of each of the parties need to be agreed and the scope of the project set out. We confirm that we wish to participate fully in that process as a member of the working group.

The TOs already have a licence obligation to plan and develop their transmission systems in accordance with the GB Security and Quality of Supply Standard (SQSS). We are concerned that the user commitment model would not fund all of our obligations arising from compliance with the GB SQSS.

In view of the need to modify the CUSC, NGET's charging methodology and other industry documents, we doubt that the user commitment model could be fully

implemented by 1 April 2007. However, by then we will have already contracted to deliver a substantial amount of additional capacity to connect renewable generation. The TO price control must provide sufficient funding for that capital expenditure. This could be achieved by including projects to which the TO has already committed in the baseline.

The base price control could then be supplemented by a disaggregated revenue adjustment term to accommodate any subsequent developments. However, there would still need to be a reconciliation to actual expenditure, at the end of the price control period. Otherwise, companies would be exposed to fluctuating rates of return on their investment. This approach would facilitate decoupling of the development of the detailed processes necessary to support the user commitment model from the price control mechanism.

Depreciation "cliff-edge" and financeability

During the next transmission price control period SP Transmission's pre-vesting assets will become fully depreciated in 2009/10. It will be essential for the management of cash flows that the impact of the "cliff edge" is minimised, by appropriate smoothing of regulatory depreciation allowances within income, once pre-vesting assets become fully depreciated. This was a major issue during DPCR4 for the DNOs in England and Wales. In DPCR4, the precedent for applying a smoothing mechanism, first established in DPCR3, was carried forward and we expect that this will now be applied to the TPCR.

More generally, financeability will be an important issue for the TPCR. We would expect that the financial ratios used to assess this would be those which the major credit rating agencies use for investor owned utilities.

Cost of capital

The introduction of incentives and the exposure to revenue adjustment mechanisms will increase the cost of capital. Adoption of the proposed user commitment model is likely to increase risk further, especially if transmission licensees become exposed to potential "buy-back" obligations.

This increase in risk takes place against a background of rising investment across the energy industry and other utility sectors. Therefore, our ability to attract and retain equity funding will be essential.

In considering the appropriate level of gearing, account must be taken of the impact of higher gearing increasing the cost of equity, as well as the direct effect on the weighted average cost of capital.

We support the post-tax approach to the cost of capital and the treatment of tax which was adopted in DPCR4.

2. Cost assessment

How should cost assessment take account of potential changes to SQSS – and in the absence of certainty as to when and how such changes might be implemented, what should Ofgem assume in estimating efficient future costs?

We envisage that changes to the SQSS would be preceded by a cost-benefit analysis which would justify the potential changes. This analysis would then form the basis for an adjustment to be incorporated in to the price control.

The SQSS could potentially be applied in a more flexible manner, which would allow for lower cost links to the main interconnected transmission system (MITS).

We would require a special condition of our licence which provided for changes in such costs, similar to that providing for the recovery of additional costs arising from changes to the ESQCR, in DNOs' licences.

How should Ofgem assess the need for additional capital expenditure allowances to provide flexibility in the availability of network capacity in advance of firm demands for capacity by network users?

As the uncertainty surrounding generation patterns and network flows increases, then a statistical modeling approach becomes necessary. By allowing for the uncertainty associated with the closure of existing generating plant, the connection of new generation and variations in demand growth, a probability distribution can be estimated for projected flows on the network.

For the TOs, funding is required for a realistic baseline which takes into account the latest available position on connection offers and the projected boundary flows. There are a number of alternatives to the user commitment model for adjusting TOs revenues, including development of the TIRG mechanism, a disaggregated revenue adjustment term, or reverting to deep connection charges. These are discussed in more detail in the "Incentive options" sections below.

What, if any, reasons might there be for consumers placing a higher (or lower) value on such network flexibility over the next price control period as compared to the current (or past) price control periods?

Network flexibility may be viewed as a form of real option which, in an uncertain environment, has a significant value. Real option theory has been developed to address investment decisions under uncertainty. The value of such an option rises as the degree of uncertainty increases.

Some degree of network flexibility can help to minimise costs to consumers. For example, flexibility in terms of spare network capacity can limit both operational and network expansion costs.

If the network is incapable of accommodating changes in the pattern of energy flows, including those arising from the growth in renewable generation, customers will bear the costs of an increase in constraints. In so far as renewable generation is constrained off and replaced by fossil fuel generation, then society would face a higher level of CO_2 and other emissions. In general, the costs of a small amount of spare network capacity are likely to be much less than the costs of a shortfall.

How should allowances be set for investment to support efficient system operation, and how, in the case of electricity transmission, should interactions between NGET and SPTL and SHETL be managed in this context?

These allowances should be set on the basis of a cost-benefit analysis, where the assumptions are consistent with those used elsewhere in setting the transmission price controls.

Although the incentives relating to system operation clearly should be placed on the GBSO, where the GBSO then requires additional investment by the TOs, over and above that required by the planning standards, the GBSO should pay the relevant TO for that work.

The baseline for each TO should, in addition to investment necessary to connect generation within its own area, also include infrastructure required to support projected boundary flows consistent with the generation connections projected for neighbouring TOs.

What areas, including those cited above and those discussed in Appendix 6, should the Authority focus on in the context of its environmental duties, in terms of analysis to support decisions as part of the TPCR? What specific measures should be developed and implemented in respect of any such areas?

Consideration should be given to the sustainability of an ageing network both in terms of the remediation of environmental issues such as noise pollution or contamination and the impact on amenity value. We are aware that, for various reasons, including perceived impact on amenity value, the acceptance of electricity infrastructure assets, such as towers, may be declining.

At a time of high stakeholder interest and public scrutiny, planning consent risk should be a key concern in the delivery of capital investment programmes. There is a greater need for recognizing the benefits of measures to reduce and offset any environmental impacts of major capital investment programmes.

In recent years, increased public resistance to the installation of transmission assets means that the least cost solution may no longer be acceptable to the planning authorities. This is particularly relevant to the replacement of ageing assets where urban areas have developed around existing infrastructure, which now requires replacement.

3. Form and structure of price controls

RPI-X

We agree that RPI-X is the preferred form of the basic price control, as it has proven incentive properties. However, in view of the considerable uncertainty surrounding the volume, location and timing of renewable generation, especially in Scotland, there will need to be a supplementary component to the price control which will allow revenue to be adjusted in an appropriate manner.

Revenue Drivers

We recognize the potential benefits of an automatic revenue adjustment which would adjust allowed revenue to reflect changes in circumstances from those assumed in the projections underlying the price control. However, development of an appropriate mechanism will require detailed analysis of relevant cost drivers, which we would like to work with Ofgem to develop.

How can Ofgem minimise the adverse consequences of price control re-openers if they prove to be unavoidable – even in the context of more sophisticated mechanisms for adjusting revenues automatically within the price control period?

We note Ofgem's aim to minimise the extent of price control re-openers. Nevertheless, circumstances will arise which have not been anticipated. It should be possible to address such events, in a way which would maintain the incentives for efficiency and alleviate fears of perceived opportunities for gaming. This could be achieved by adjusting the price control in advance of the expenditure being incurred and linking this to the delivery of relevant output measures. This approach would maintain the incentive to limit the increase in expenditure to no more than the revised allowance while ensuring provision of the desired outputs. The strength of the incentive could be increased by incorporation of a suitable rolling mechanism. This would overcome the potential reduction in the strength of the incentive for efficiency which may otherwise result from the shortening of the retention period for cost savings.

How should the information on NGET's and National Grid NTS's performance under their current SO incentives, as set out in the report compiled by National Grid, be interpreted by Ofgem in developing an appropriate regulatory regime for these activities from 1 April 2007 onwards?

Given the separate TO and SO price controls, Ofgem need to be clear to avoid interactions between the price controls. For example, were either National Grid or the TOs to make investments, which were paid for via the respective TO price controls,

that reduced the cost of system operation then, in setting the SO incentive parameters, it must be clear that these investments would then have been already accounted for.

It should be clear which output measures the SO is responsible for and, if the SO requires the TO to undertake expenditure, then the SO should pay the TO for that work. Again, for example, if the SO requires the TO to invest in transmission equipment, above what is required to meet the planning criteria, the SO should pay the TO for this investment.

How might the differences between transmission and distribution, discussed [in section 5 of the Consultation document], influence the design of information quality and rolling incentives as part of the TPCR?

As it is more difficult to establish a meaningful benchmark for transmission licensees which is not dependent on information provided by the licensees themselves, any information quality incentive should be designed to improve the accuracy of the licensees' capital expenditure forecasts.

A rolling mechanism should be designed to reduce the periodicity which may otherwise be introduced by a fixed term price control period. However, the introduction of a revenue adjustment term (such as G_t in National Grid's price control) into a rolling mechanism for capital expenditure is likely to lead to a complex calculation.

In practice, the lag used in a rolling mechanism needs to be longer than the price control period. Otherwise, complex adjustments would be required to take into account the actual expenditure for 2011/12 which would not be known when the price control from April 2012 is set.

How might any additional reporting arrangements (or financial incentives) in respect of environmental impacts be framed, and are such arrangements an appropriate element of the overall regulatory regime given the wider legal framework within which the transmission licensees operate?

As well as complying with various statutory duties, SP Transmission already voluntarily reports on a number of environmental topics. These are included in ScottishPower's Environmental Report.

We continue to believe that it is unnecessary for companies to report environmental performance to Ofgem as this would involve duplication of effort. We would add that financial incentives will not be appropriate at any time as this could lead to companies being exposed to double jeopardy, given the financial penalties that can be imposed by other regulatory bodies in this area.

4. Price control design options - framework

Whether respondents agree that Ofgem's focus on 'user commitment' options is appropriate, or whether they consider that there are other traditional price control options (or de-regulated revenue options) that might better meet Ofgem's objectives for the TPCR, and more generally the Authority's statutory and other legal duties?

There are at least three basic approaches which could be adopted for the price control framework:

1) Development of the methodology used for Transmission Investment for Renewable Generation (TIRG);
2) Refinement of the revenue adjustment term, G_t; or
3) Implementation of the proposed user commitment model.

However, these are not necessarily mutually exclusive alternatives. It would be possible to develop a hybrid approach which incorporated aspects of each of the above.

Another alternative would be to revert to the connection arrangements in place prior to BETTA, based on deeper connections, which would lead to more cost effective links to the main interconnected transmission system and also limit speculative requests for connection offers. Although one of the criticisms of a deep connection policy is that it may be viewed as a barrier to entry, the user commitment approach may also be perceived as a barrier to entry.

The user commitment model should be subject to a full regulatory impact assessment, which should consider alternative approaches and quantify the costs of implementation, as well as the benefits.

Although Ofgem would like a "minimal change" approach, in view of the need to modify the CUSC, NGET's charging methodology and other industry documents and then enter into appropriate contractual arrangements with the various industry participants, we doubt that the user commitment model can be fully implemented by 1 April 2007. However, by then we will have already contracted to deliver a substantial amount of additional capacity to connect renewable generation. The TO price control must provide sufficient funding for that capital expenditure. This could be achieved by including projects to which the TO has already committed in the baseline.

The base price control could then be supplemented by a disaggregated revenue adjustment term to accommodate any subsequent developments. This approach would facilitate the decoupling of the commercial framework for the user commitment model from the price control mechanism.

What is the appropriate allocation of investment risk between network users (both generally and at specific locations), transmission companies, and consumers, during the different phases of investment development, e.g. planning and design, construction, and operation?

We believe that the present arrangements under the CUSC and the SO-TO Code provide an acceptable allocation of risk during the different phases of investment development.

If more risk were to be transferred to the transmission companies, then this would lead to a requirement for a higher rate of return.

5. Incentive options - electricity

Has Ofgem focused on the appropriate issues to be addressed in the light of operation of the current price controls?

Recent experience has highlighted the need to address the considerable uncertainty associated with volume, location and timing of renewable generation connections in Scotland. The Scottish Executive's and the UK Government's desire to meet climate change targets suggest that many of these projects will proceed. However, the exact number is uncertain since some of these will be postponed or cancelled due to external factors, especially difficulties in gaining planning consents.

The next five year price control period will be characterised by a requirement for capital investment on a scale that is unprecedented in recent years, which will need to be funded through the price control.

The transmission price controls must be developed so as to take into account the relationship between the GBSO and the TOs and their respective responsibilities under BETTA.

Is it appropriate to develop more sophisticated revenue drivers under a 'status quo' option – and if so, what designs of revenue driver might be considered to be most appropriate and worthy of further detailed analysis and quantification?

Account must be taken of the substantial but uncertain amount of renewable generation which will require to be connected during the forthcoming price control period. In Scotland, applications have been received for the connection of 15 GW of renewable generation, of which we expect over 5GW will have connected by 2012.

The approach developed for Transmission Investment for Renewable Generation (TIRG) is applicable for major projects which can be identified in advance, at the time of the TPCR. We support the range of output measures and incentives which were developed for the additional capacity to be delivered by TIRG projects. These provide incentives to avoid delays and to reduce costs in the pre-construction and construction stages, while reducing the exposure to the risk of delays due to the planning process.

However, the cost per MW of renewable generation connected can vary substantially, reflecting:

- Voltage of connection;
- Length of circuit;
- Proportion of circuit laid underground or undersea;
- Topography of route;
- Degree of clustering.

The base price control could be supplemented by a disaggregated revenue adjustment term to accommodate any subsequent developments. However, there would still need to be a reconciliation to actual expenditure, at the end of the price control period. Otherwise, companies would be exposed to fluctuating rates of return on their investment.

Moreover, the resulting variation in costs can be substantial across projects within a licensee's area. At this stage, it is not possible to predict accurately which renewable generation projects will connect by 2012. Therefore, it is necessary to develop a more sophisticated revenue driver which reflects the above factors. We envisage that this could take the form of a more disaggregated version of the revenue adjustment term, G_t, in NGET's current price control. SP Transmission would wish to be involved in the analysis and development of an appropriate revenue driver and would encourage Ofgem to establish a joint working group to address this important issue.

We do not consider boundary flows to be an adequate overall revenue driver as they do not take into account the clustering of windfarms and shallow reinforcement which will require major investment within our boundaries. Also, flows of electricity on our network are multi-directional and vary considerably through the year. In particular, substantial winter exports from our area can be reversed in the summer to become significant imports into our area. In any case, flows that are estimated from a simplified model which are based on one particular set of assumptions would not adequately reflect the complex reality, nor the potential developments in a dynamic environment. Nevertheless, assessment of boundary flows could have a useful role in establishing the requirement for and triggering the funding of specific projects which will be required to relieve boundary constraints.

What are the advantages and disadvantages of user commitment models, as characterised [in section 8 of the Consultation document], in the context of electricity transmission?

The user commitment model would provide a framework for the more efficient allocation of resources. In particular, it should reduce the risk of assets becoming stranded in the medium term.

However, there may be a significant risk of unintended consequences and that the expected benefits may not be attained fully. For example, it appears that the return on investment to provide additional gas entry capacity may have fallen below the cost of capital, as a result of the bidding strategies adopted by users.

Some potential users perceive the present arrangements under the CUSC, which impose"final sums" liability, as a barrier to entry. The user commitment model would place an additional burden on users, by requiring long term contractual commitment.

Furthermore, implementing the user commitment model would be a complex and potentially lengthy process, involving several parties and modifications to industry agreements and codes. We anticipate that there would be major legal and commercial

implications if existing TECs were withdrawn or places in the queue for generation connection were lost.

What do respondents consider to be the most appropriate answers to the detailed design questions highlighted above for user commitment models? Are there any further questions that should be added to the list?

Ofgem should establish an industry working group, comprised of itself, the TOs and the GBSO, to address the detailed design of the user commitment model. A number of commercial agreements and technical standards need to be considered, including the CUSC and bi-lateral agreements, the SO-TO code, the Grid Code and the GB Security and Quality of Supply Standard (SQSS). We recommend that Ofgem also consult extensively with users.

It is also necessary to address the relationship between and the respective responsibilities of the GBSO and the Scottish TOs under the user commitment model.

The role of the GB SQSS, which will remain as a licence obligation for the TOs, alongside the user commitment model, needs to be clarified. We are concerned that the user commitment model may not provide sufficient funding to meet our obligations under the SQSS.

What is the appropriate means of managing a process to develop user commitment model options given the interactions with the revenue restriction, Connection and Use of System Code (CUSC), charging methodologies and other codes and documents? What role should Ofgem adopt in this process? What role should NGET take, given its role of GB System Operator and its obligations in respect of charging methodologies?

In view of the need to modify the CUSC, NGET's charging methodology and other industry documents, we doubt that the user commitment model could be fully implemented by 1 April 2007. However, by then we will have already contracted to deliver a substantial amount of additional capacity to connect renewable generation. The TO price control must provide sufficient funding for that capital expenditure. This could be achieved by including projects to which the TO has already committed in the baseline.

The current structure of industry governance does not provide for an efficient, consistent or holistic approach to change management. This is particularly relevant for changes such as the introduction of user commitment models which will require changes to a range of industry codes, including the CUSC, the charging methodologies, the STC and, potentially, also the GB SQSS. At present, the only party who can practically propose changes across all these codes is National Grid. However any changes that are proposed to the CUSC, for example, can only be tested within the applicable CUSC objectives – without consideration of the wider issues raised by the complementary changes.

Given the potentially wide-ranging impact of the introduction of user commitment model, as previously stated, we propose that an industry working group, comprising Ofgem, the TOs and the GBSO, is established. Further consultation with users, on the outputs from that group, would then be necessary. This would facilitate consideration of issues which span the various codes, undertake a rigorous impact assessment, including a cost-benefit analysis, and consider transitional and timing issues.

We continue to support the role of the Scottish TOs as agreed under the BETTA arrangements and implemented through the SO-TO Code (STC). This includes the TO's role in investment planning which recognises that we have considerable influence over the design of our network.

What are the advantages and disadvantages of more extensive system reliability and performance reporting – and how might such metrics be linked to financial incentives?

We consider that Ofgem already has sufficient access to information to perform its duties. We would be concerned if reporting were to become significantly more burdensome. We would encourage consolidation of disparate reports and information requests into a periodic structured report, possibly as a supplement to an annual regulatory reporting pack.

We are firmly opposed to a "penalty only" scheme, as incentive mechanisms should offer equal opportunity of rewards, as well as penalties.

The development of performance incentives should be consistent with customers' willingness to pay for improvements and take into account the respective responsibilities of the GBSO and the Scottish TOs. In particular, the duration of interruptions to supply is largely outside the control of the Scottish TOs. We would also caution against the development of overly complex incentive mechanisms as they risk having unintended consequences and are difficult for stakeholders to understand fully.

6. Financial issues

Whether the level and trend of key financial indicators consistent with a credit rating that is comfortably within investment grade provides the most appropriate approach to assessing the ability of the licensee to finance its regulated business.

A sufficient and stable return is required to attract and retain funds from capital markets. We are of the view that key financial indicators consistent with an investment grade credit rating remain an appropriate approach to this end. We would expect that the financial ratios used to assess this would be those which the major credit rating agencies use for investor owned utilities. We would welcome the opportunity to take part in any industry or other workshops which are arranged to discuss the model.

We note that an initial joint report on financeability from Ofgem and Ofwat is due to be published in early 2006 and we look forward to considering any alternative approaches.

The financing of the asset replacement cycle (timing of a 5-year cash flow allowance versus longlife investment cycle).

We consider that the current, five-year time frame, approach to be suitable. We believe that mechanisms such as the rolling capital expenditure mechanism can be used to ensure that actual cash flows and allowances can be synchronised.

Whether an ex-ante approach to setting tax allowances (with an ex-post adjustment for gearing and interest expense where relevant) is still appropriate.

As stated in our September 2005 response to Ofgem's initial consultation on the TPCR, we believe that it is appropriate for the approach adopted under DPCR4 to be applied to the TPCR.

Gearing issues, including:

> ***whether a common assumed level of gearing should be adopted for transmission companies, or***
> ***whether company-specific gearing assumptions should be adopted, and***
> ***what levels of gearing may be appropriate,***

It is unlikely that the Scottish TOs will be able to sustain as high a level of gearing as National Grid, while maintaining an investment grade credit rating.

As stated previously, companies must be able to attract and retain funds. All other factors being equal, an increase in the level of gearing assumed in setting the cost of capital would appear to reduce the allowed cost of capital at a time when a considerable increase in investment is required and where the timing and certainty of this investment is not entirely predictable. However, we would expect any increase in

gearing to result in a higher beta factor (i.e. the systematic risk component within the capital asset pricing model) within the calculation of the cost of equity.

The principles that should apply for assessing the past capital expenditure in excess of allowances.

Ofgem has previously set out its thoughts on the treatment of capital expenditure overspends for gas and electricity distribution which support the presumption that all capital expenditure will be included in the RAV unless there is clear evidence of wasteful and unnecessary spending.

As a matter of regulatory principle, where investment has been efficiently incurred and can be justified in terms of planning or security standards, safety or other legitimate driver then that investment must be allowed into the RAV.

The cessation of pre-vesting regulatory depreciation for electricity transmission companies.

During the next transmission price control period, SP Transmission's pre-vesting assets will become fully depreciated in 2009/10. It will be essential for the management of cash flows that the impact of the 'cliff edge' is minimised by appropriate smoothing of regulatory depreciation allowances once pre-vesting assets become fully depreciated. This was a major issue during DPCR4 for DNOs in England and Wales. We note the precedent for applying a smoothing mechanism, first established in DPCR3, was carried forward in DPCR4 and would expect that the same mechanism will be applied to transmission in this review.

Pensions issues, including:

the valuation and funding of pension schemes under new pensions regulation arrangements;

We would highlight that the impacts of the Pensions Act 2004 will lead to increased pension contributions and accelerated reparation of pension deficits. It is our expectation that Ofgem will take this into consideration in setting pension allowances.

the allocation between price-controlled and non-price-controlled activities;

We accept the stated objectives in making this distinction and we welcome Ofgem's intention to continue to take a proportionate and pragmatic approach to the application of this and the other stated principles.

It should be noted that many of the complexities that have been acknowledged to exist in the case of National Grid Gas are shared by SP Transmission and whilst we accept that the separate allocation of pension scheme assets and liabilities would indeed constitute a more accurate approach than that adopted at DPCR4

this may prove to be impractical and cost-prohibitive given the complexities involved. We will of course work with Ofgem to achieve an optimal approach.

the options in relation to the treatment of over/under funding;

Once again, we accept the stated objective on this issue, although it is possible that the issues surrounding the identification of implicit allowances for pension costs in the previous price control may prove to be a limiting factor. Of the options set out in DPCR4 our view was, and remains that the most equitable and pragmatic approach would be to assume that the allowance for the prior price control period, in this case including the roll over period, was equal to the actual contribution actually made. We believe that attempting to apply this principle to any periods prior to that would significantly increase the complexity of the exercise and the degree of retrospection required.

the treatment of early retirement deficiency costs;

We believe that, as a minimum, deficit repair costs associated with ERDCs should be recoverable on the grounds that this is consistent with the fact that consumers have benefited in the past from the associated historical savings.

A more detailed regulatory reporting requirement in accordance with regulatory reporting guidelines.

We are surprised by the statement that the regulatory accounts of the Transmission licensees vary considerably in terms of content and completeness. SP Transmission's regulatory accounts are produced in accordance with our electricity Transmission Licence and in accordance with applicable accounting standards. Our accounts are audited in this context by PricewaterhouseCoopers LLP. In our view, the regulatory accounts are a good vehicle for presenting reliable, consistent, comparable financial information which is both auditable and suitable for publication.

Nevertheless, we accept that Ofgem are committed to a more detailed annual reporting pack and we will cooperate fully in its development in order that it optimally meets Ofgem's objectives. We believe that these objectives can be achieved via an abbreviated form of the reporting which is being developed for Distribution.

Publication of the full, populated financial model

Ofgem should carefully consider its position on this issue in the context of, in particular, the Utilities Act 2000 Section 105 and other relevant legislation. We will normally object to the disclosure of information that we consider to have been provided to Ofgem in confidence.

7. Impact assessment approach

The use of IAs as part of the price control process, including whether Option A, Option B or a different option should be adopted.

It would be helpful if relevant impact assessments (IAs) were prepared at an early stage in the decision making process. Otherwise, they are unlikely to have a significant effect on the corresponding proposals.

Undertaking a separate IA for each significant issue would facilitate this. It is important that each major new initiative is subject to an appropriate impact assessment which assesses realistic alternative proposals and takes into account potential costs, as well as perceived benefits.

We recognise that some stakeholders may value the presentation of information in alternative ways but this can be accommodated by other means than relying on an overall IA, at the end of the process. By then, no meaningful consideration of alternatives could be undertaken, as policy decisions would already have been made.

8. Environmental considerations

How is transmission investment facilitating the expansion of renewable generation?

Investment in transmission infrastructure has been and will continue to be fundamental to supporting the development of renewable energy in line with government policy objectives. This was recognised by Malcolm Wicks, Energy Minister in a statement to the House of Commons on 21st July 2005. This is particularly the case in areas, such as Scotland and the North of England, that are rich in renewable resource but relatively sparse in terms of major transmission infrastructure.

The dominant renewable technology to date has been wind. Developments in both onshore and offshore wind have and will continue to be facilitated by transmission infrastructure investments. However, as time progresses and emerging technologies such as wave and tidal become commercially viable then these will also require to be supported by further investment in transmission infrastructure.

To date, over 600MW of renewable wind and biomass generation are operational in Scotland, with a further 1.2GW either under construction or with planning consent. The total activity in terms of terms of connection applications is of the order of 15GW. Our own FBPQ submission assumed that over 2GW of wind generation would connect in our licensed area by 2012.

How might changes in locational patterns of generation affect the volume of transmission losses?

Transmission losses are the result of the flow of power across the transmission network and are made up of variable and “fixed” losses.

Fixed losses are inherent in the equipment and cannot be avoided. Any increase in the quantity of transmission overhead line or transformers increases fixed losses regardless of location of the asset. The location of wind generation is, in the main, remote from existing substations and overhead lines and connection requires new assets to be installed with the inherent increase in losses. However, fixed losses are only a small percentage of the total losses, so the effect would be limited.

Variable losses are a function of the power flows through the network and vary throughout the day and across the year. In general, locating generation in high demand areas will have the effect of reducing power flows across the interconnected transmission system and therefore reduce losses. However, the location of wind generation is mostly in areas with low demand, resulting in increased power flows and hence increased losses within that area. In some circumstances, connection of generation requires an existing line to be uprated to a higher voltage to provide increased capacity. In these circumstances there may be a decrease in losses.

How might changes in locational patterns of generation and the associated need for transmission reinforcement impact on the environment in general, and on visual amenity in particular?

Changes in the locational patterns of generation which require new transmission connections will have certain impacts on the environment. New patterns of generation will create the need to relocate or provide additional infrastructure. The current proliferation of renewable wind development proposals will require significant infrastructure reinforcement, ultimately having a certain amount of environmental impact, primarily landscape and visual. By the very nature of wind developments they are generally located far from centres of population, where existing infrastructure does not exist, and in areas not conducive to the routeing of transmission infrastructure. Locations such as these often impact on rural and remote landscapes, which are presently free from network infrastructure, making visual amenity a key issue in the development of transmission infrastructure proposals.

What are the relative costs and benefits (both financial, and in terms of operational efficiency) of different forms of transmission investment which might be considered to have a lower visual impact on the landscape (e.g. underground cables, low visual impact substation designs, noise reduction measures)? How, if at all, can consumers (or other relevant stakeholders) express their willingness to pay? In the absence of direct mechanisms, how might the value to consumers' of any such additional costs be estimated?

There is already a mechanism for third parties to fund the deviation of licensee assets and the licensee may carry out these requests as an "Excluded Service".

Also, where new connections are provided (e.g. an overhead line construction to connect a windfarm), the user may elect for a cable connection and pay the difference in costs between an overhead line and cable as a capital contribution. This is known as "One off works" in CUSC terminology.

The survey of customers that was undertaken during the recent Distribution Price Control Review indicated that customers are willing to pay to enhance amenity value.

There is mounting evidence of growing resistance to the installation of transmission assets, such as towers, and it is increasingly likely that planning consent will require more expensive alternatives, such as undergrounding, to mitigate the perceived impact on amenity value. The additional cost of such measures provides one measure of the amenity value.

How might the generation market be affected by the EU Emissions Trading Scheme (EU ETS) and other policy initiative (such as the Large Coal Plant Directive), and how might this impact on the need for transmission investment? What different scenarios should be analysed?

Experience since the introduction of BETTA has, unsurprisingly, shown significant changes in the operating regime of plant in Scotland. This has resulted in swings between substantial levels of exports and imports depending on the plant that is operating in Scotland. We believe that this pattern will continue but it is very difficult to predict the generation background that will exist going forward.

If existing coal plant opts out of the LCPD requirements then this is likely to result in radical changes to the operating regime of this plant due to the limited operating hours permitted for opt-out plant. We consider that such a scenario, coupled with increases in renewables and potential closure of other major plants, would exacerbate the issue of swings between substantial exports and imports compared to experience to date under BETTA.

To reflect the need to support increased levels of imports into Scotland, our FBPQ submission includes provision for investment to increase the import capability to 2GW.

How should demand forecasts be adjusted to reflect the success or otherwise of measures designed to promote energy efficiency? What specific factors might be expected to be most significant in reducing demand for energy – and thereby influencing the need for transmission capacity?

The maximum demand for electricity in SP Transmission's area has remained remarkably constant over the last 20 years, although energy consumption has increased significantly. Under BETTA, SP Transmission now relies on demand information provided by NGET for future system planning studies.

What are the current levels of emissions associated with the operation of the gas and electricity transmission systems?

During 2004/05, around 1 tonne of SF_6 was released from SP Transmission's infrastructure equipment.

What are the costs and benefits of reducing emissions from the transmission systems (e.g. in respect of SF_6 leakage from transformers and switchgear, methane from the gas transmission network, NOx and CO2 from compressor stations)?

Costs involved in reducing emissions include the management, direct labour and equipment to undertake such remedial works on any leaking plant. Operational implications of undertaking such work and associated outage costs are an important factor. Costs associated with the recovery and recycling of gas from end of life plant should also be considered. Future capital investment programmes should be supportive of the search for SF_6 substitutes.

What is the interaction between these costs and benefits and the EU ETS?

The ETS will place values on emissions which will facilitate cost-benefit analysis of potential measures to reduce emissions.

Are additional reporting requirements appropriate in respect of emissions from the transmission system, and if so, then what form should the reporting take? Should levels of emissions be included as a performance indicator with associated financial incentives attached to performance?

We believe that it is unnecessary for companies to report environmental performance to Ofgem as this would involve duplication of effort. We would add that financial incentives will not be appropriate at any time as this could lead to companies being exposed to double jeopardy, given the financial penalties that can be imposed by other regulatory bodies in this area.

As well as complying with various statutory duties, SP Transmission already voluntarily reports on a number of environmental topics.

What is the current legacy of contaminated sites related to the operation of the gas and electricity transmission system? What additional measures, if any, should be introduced to affect how the transmission companies deal with any such issues?

The current legacy of contaminated sites related to the operation of the electricity transmission system can be split into two categories:

> contamination as a result of the operation of an electrical asset; and
> contamination due to the historical land use prior to the installation of the asset.

The second results in significant remedial action that costs in the region of £200-300k per site.

Consideration must also be given to existing assets and their potential to cause pollution.

In order to address the above, consideration should be given to the funding of capital investment on necessary environmental works.

How does efficient system operation impact on environmental considerations, such as transmission losses?

Transmission losses vary throughout the day and across the year and the exact losses at any time are influenced by the demand and generation pattern. The system operator has responsibility for matching generation to demand and has the ability to minimise losses through effective management of power flows across the transmission network. The extent to which this is achieved will be influenced by factors within the control of the system operator (e.g. outage planning and network availability) and factors outside their control (e.g. weather conditions and availability of generation).

How should any costs or revenues for the transmission licensees under EU ETS be treated for the purposes of setting the transmission price controls?

Load related network investment is triggered by the need to comply with the GB SQSS. If the EU ETS lead to changes which result in an SQSS non-compliance, it should be treated in the same way as any other system non-compliance.

What should the formal reporting arrangements be for transmission companies in respect of the impact of their actions on the environment?
What specific measures should form part of any revised reporting arrangements?

We believe that it is unnecessary for companies to report environmental performance to Ofgem as this would involve duplication of effort, as we already provide such information to other regulatory bodies.