SP Transmission

Response to Ofgem Consultation

Transmission Price Control Review: Initial Proposals

June 2006

Members of the ScottishPower group

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SP Transmission Limited

Response to June 2006 Ofgem Consultation

This response to Ofgem's Consultation on Initial Proposals for the Transmission Price Control Review is submitted by SP Transmission Limited.

We welcome the form of the Consultation paper. However the short response period provides insufficient time for as thorough an assessment as we would have chosen particularly as information was initially lacking on the proposed changes to our capital and operating expenditure plans. More recently, we have received Ofgem's consultant's reports which we will respond to following our evaluation of the detail.

Our main issues are:

- We believe that the allowed cost of capital is below the level required to finance a capital programme of £800m to £1000m, given the relatively small scale of SP Transmission. Our investors and advisors have equally expressed their concern in the strongest of terms.

- The non-load related capex and opex proposals significantly impact on the risk of our business over this review period and over subsequent review periods, and

- Although some progress has been made, more needs to be done on funding for load related expenditure

These are serious issues for SP Transmission and significant movement is required before any final proposals could be considered acceptable.

1. Summary of Issues

1.1 Financial

- We are very concerned by the allowed return indicated in these initial proposals for SP Transmission. We would emphasise that in our view this would be below the level required to adequately finance our activities and would therefore be unacceptable.

- Specific issues relating to the scale and operations of the Scottish companies have not been recognised in the cost of capital

- The requirement to maintain financeability has not been adequately addressed.

1.2 Non-Load Related Capital Expenditure

- The reductions in our non-load related capex allowance will lead to reduced safety and integrity of our network as our asset base deteriorates with age

- The proposed reduction in funding at Dewar Place creates an unacceptable risk

1.3 Load Related Capital Expenditure

- We welcome the inclusion of the load related baseline however thorough modelling is required to assess its adequacy

- It remains to be seen how the commercial implications of the reduction for “efficient connection design” will be resolved

1.4 Input Prices

- A common theme of all three licensee’s submissions is their issue over rising input prices and we are disappointed that no indication has been given as to how this will be resolved

1.5 Revenue Drivers

- Careful design of revenue drivers is required to avoid any adverse impact on financeability and undue discrimination between transmission licensees

- It is not possible to develop generic revenue drivers for deeper system reinforcements that provide an acceptable degree of accuracy

1.6 Operating Expenditure

- We are disappointed that even though being assessed at the "upper quartile benchmark" Ofgem proposes to make significant operating cost reductions at a time in the asset life cycle when this investment is so critical

- We disagree with Ofgem's view that non-operational capital expenditure should be treated as operating expenditure

1.7 Network Incentives

- The move to a 'penalties only' networks incentive scheme is disappointing

2. Recommendations

2.1 Cost of Capital

The cost of capital must take account of the considerable risk facing our industry including the particular impact of the scale and operation of the Scottish businesses.

We have separately submitted a report on cost of capital which concludes that ***the minimum acceptable allowed return will be 4.8% post tax real*** (assuming a vanilla equivalent for discounting purposes of 5.5%). Including an allowance for issuance costs, and taking account of other factors, could require a return of up to 5.4% fully post tax.

2.2 Non-Load Related Investment

Dewar Place

In order to limit fire and environmental risks, our replacement plans for Dewar Place are based on higher-cost SF6 equipment. In our view, the proposed reduction in funding to make use of oil-based equipment on this site leads to unacceptable risk. Use of oil filled transformers and reactors presents a significant explosion, fire safety and environmental hazard. This is supported by several independent experts including Professor Allan an acknowledged leader in the field of explosion and fire safety hazards associated with transmission plant. We have previously provided Ofgem with a copy of Professor Allan's report into safety hazards associated with equipment at this site. ***We recommend that full funding be provided for SF6 equipment at Dewar Place.***

Transformers

We have a particular make of 275/33kV transformer manufactured in the 1960s which, out of an initial population of twenty-three, have experienced five failures over recent years. This is due to a manufacturing defect. ***We believe that our evidence clearly demonstrates a type fault and we strongly recommend that full funding be provided to address this issue.***

Overhead Line Refurbishment

We believe that our justification for our overhead line refurbishment programme is very robust and we are disappointed at the reduction in the proposed overhead line allowance. Not only are our refurbishment works justified, but it is important to recognise that the consequence of delays will be a major, and potentially unmanageable, workload for the next price control period. This approach to this investment is also inefficient.

BT 21st Century

Although we would have preferred funding that addresses the BT21st Century issue to form part of the baseline, we believe the principle of a re-opener could work and look forward to discussing the detailed arrangements with Ofgem.

2.3 Load Related Baseline Allowance

We note and accept that Ofgem's proposals include a baseline allowance for load related investment. However this baseline may be too low because insufficient funding has been provided for local infrastructure for new connections, and for load growth in Glasgow.

Efficient Connection Design

Ofgem has made a reduction of £20m for "efficient connection design" for connections under 100MW. This reduction is not due to misinterpretation of the GB SQSS but as a result of the shallow connection policy introduced through BETTA which gives developers no incentive to accept lower-security, lower-cost connections. Ofgem proposes to address this by developing charging incentives that encourage generators to accept more economic and efficient, but less secure, connection designs (although, in some instances, overall costs may rise when account is taken of the cost of constraints).

If the "efficient connection design" reduction goes ahead as proposed, it will lead to major commercial impacts for SP Transmission, NGET (as GBSO), and users and will also create quality of supply and environmental issues. ***We believe that the right approach is to restore the £20m reduction for "efficient connection design" and establish arrangements that adjust our allowance down as and when generators select more economic and efficient connection designs***. We intend to write to Ofgem separately on this matter.

Load Growth in Glasgow

We do not agree with the consultant's view that the need for the Glasgow Riverside reinforcement is not sufficiently imminent to warrant the full project expenditure. A number of city centre substations (Partick, Charlotte Street, and Govan) will be overloaded by the end of the price control period and further opportunities for re-distribution of load are very limited. ***We recommend that full funding be provided for the Glasgow Riverside reinforcement during this price review period.***

Boundary B5 Transfer Capacity

Ofgem has removed the project to increase the transfer capacity across the central belt of Scotland (Boundary B5). The increased capacity across this boundary will be required once the Beauly-Denny TIRG baseline project is completed and so ***we recommend that an allowance for the Boundary B5 project is provided contingent on planning approval being given for Beauly-Denny.***

2.4 Input Prices

Our recent tenders, supported by NGET's similar experience, highlight the very high price rises being faced by the industry. We recommend that:

i) We review the basis for "efficient unit costs", and

ii) Rising input prices should be addressed through an ex ante allowance

2.5 Revenue Drivers

We recognise that cost reflective revenue drivers can help to mitigate the impact of uncertainty surrounding future requirements. However, whilst accurate and robust revenue drivers may provide protection to consumers, revenue drivers that are not cost-reflective may represent greater risk to customers than a fixed allowance. Consequently any revenue driver implemented must have a high likelihood of delivering appropriate revenues for all probable scenarios.

It is essential that any revenue drivers developed are equally suitable for all the transmission licensees and do not inadvertently discriminate against any Licensee. There is a significant difference in the nature and consequently cost of the projects that each Licensee currently faces. Hence it is important that the revenue drivers developed should be robust enough to satisfy the requirements of all Licensees and recognise the full range of projects that the Licensees may be required to deliver.

Local Works

Whilst the 'formula' approach revenue driver model discussed in the Initial Proposals is more accurate than the simpler £ / MW model, there is still an unacceptably wide dispersion between calculated revenues and required revenues for either model. We have derived a four-part revenue-driver model which is more cost-reflective and hence more appropriate for the range and mix of projects that we will have to undertake. Our proposal is simple, transparent and cost reflective and represents the solution that presents least risk to both consumers and transmission companies. Further, we believe we have the widest and most diverse range of projects and, consequently, an approach that adequately fits our data should also be applicable to both SSE and National Grid.

Deeper System Infrastructure

Transmission infrastructure investment is lumpy in nature with the released capacity and cost having a non-linear relationship. Consequently, it is not possible to develop generic revenue drivers for deeper system reinforcement that provide an acceptable degree of accuracy. Deeper system projects are relatively small in number and can be economically assessed against the constraint costs of not providing capacity with revenue for these projects awarded in a phased approach similar to TIRG.

Access Reform

Any Access Reform needs to recognise that there are significant factors outwith the TO's control that impact on the delivery of transmission access capacity. Ideally revenue drivers need to be independent of access reform.

There is a clear interaction between access reform and the Initial Proposals for revenue drivers, and the TPCR4 settlement. Price control re-openers may be needed if access reform significantly changes timings of investment and associated revenues or the balance of risk.

A detailed outline of our analysis on revenue drivers is given in Appendix 2. In summary, we recommend that:

i) Our proposed generic revenue driver for local connection works, rather than the option detailed in this Consultation, is implemented,

ii) Deep system reinforcements should be funded on a similar basis to TIRG with a return for investment during the construction phase and full capital funding on project completion, and

iii) The design of revenue drivers must avoid any adverse impact on financeability by ensuring that funding is provided in line with investment

2.6 Operating Costs

We are disappointed that although being assessed as around the "upper quartile benchmark" Ofgem proposes significant operating cost reductions.

On the basis that we are deemed efficient, our interpretation of the "efficiency adjustments" detailed in Table 5.6 is that adjustments primarily cover the removal of costs for tower painting and plant maintenance against a base in which there are no tower painting costs whatsoever. We must stress that these maintenance activities must be undertaken if we are to sustain the present level of network security over the medium to long term. ***We therefore require our operating cost allowance to include,***

in full, the costs associated with tower painting and plant maintenance. This allowance is critically important at this time in our asset business life cycle.

2.7 Network Incentives

Although the detail of a "wider package" of incentives is not present, the move to a minimum standard reliability incentive, i.e. a 'penalties only' scheme, is disappointing and not a true incentive. ***We recommend that any network incentives should be symmetric i.e. penalties and rewards, and entirely within the control of the TO with observable metrics.***

2.8 Non-Operational Capital Expenditure

We disagree with Ofgem's view that non-operational capital expenditure should be treated as operating expenditure. ***Consistent with the treatment in DPCR4, non-operational capex should be separately identified and included in the RAV***. In order to increase the transparency of regulation, we believe that there is a strong argument to, as closely as possible, align RAV additions with fixed asset additions as required by applicable accounting standards and reported within the Statutory and Regulatory Accounts. Any published performance comparatives will lose credibility if an opex variance is attributed to, for example, unanticipated IT investment or depot refurbishment. Asset lives should be 5 to 7 years as this capex relates predominantly to short life IT expenditure.

2.9 Links to the Scottish Islands

We are fully supportive of extending competition to these connections and would be very interested in participating in a competitive process.

2.10 Innovation Funding

We would welcome an introduction of an IFI mechanism for use on the transmission networks. We would comment that a "pot of funding" of up to 0.5% of TO allowed revenue is insufficient for transmission and ***recommend that this funding limit is increased to 1% of allowed revenue***.

2.11 Procurement Efficiency

We note that the "procurement efficiency" for our business is still under consideration. As we outlined in our FBPQ and have discussed with Ofgem and their consultants, our procurement strategy has been developed to help deliver our intensive capital investment programme. Central to this strategy is our partnership approach developed over the last five to six years with key strategic suppliers and contractors. This includes framework agreements for both the purchase of equipment and the provision of contractors to deliver turnkey construction solutions. It also involves standardising our requirements and developing new sources of supply and products.

Also, as a matter of course, we go to international markets to achieve best value for money and can cite examples of contracts placed with international suppliers.

2.12 Summary

Our main issues are:

- ***We believe that the allowed cost of capital is below the level required to finance a capital programme of £800m to £1000m, given the relatively small scale of SP Transmission. Our investors and advisors have equally expressed their concern in the strongest of terms.***

- ***The non-load related capex and opex proposals significantly impact on the risk of our business over this review period and over subsequent review periods, and***

- ***Although some progress has been made, more needs to be done on funding for load related expenditure***

These are serious issues for SP Transmission and significant movement is required before any final proposals could be considered acceptable.

Appendix 1 Financial

Cost of capital

We have separately submitted a report on cost of capital which concludes that the minimum acceptable allowed return will be 4.8% post tax real (assuming a vanilla equivalent for discounting purposes of 5.5%). Including an allowance for issuance costs, and taking account of other factors, could require a return of up to 5.4% fully post tax.

Financeability

Cost of equity

It is essential that transmission licensees are able to raise new equity to help to finance the substantial investment programme which is required. We are therefore concerned that the proposed cost of equity is insufficient to persuade investors to bear the risks of investing in transmission electricity infrastructure when significantly higher returns are available in, for example, the water and transport sectors.

Furthermore, allowance needs to be made for the costs of raising new equity. Analysis of the recent rights issue by United Utilities indicates that the associated costs amounted to 9% of the value of the issue. Based on UU's dividend yield of 8.2%, as at the announcement date of its rights issue, this translates into an upward adjustment to the cost of equity of 81 basis points[1].

Financial ratios

As regards debt, we agree that transmission licensees should be able to maintain a credit rating comfortably within investment grade. However, we are concerned that Ofgem appear to have relaxed significantly the critical financial ratios from those which were used in DPCR4 and would not allow SP Transmission to maintain it's A- credit rating. In particular, we would expect that the ratio of funds from operations to interest payable should be maintained above three. Furthermore, Ofgem should stress test the behaviour of financial ratios under adverse shocks.

Additionally, it is clear that the rating agencies are now placing more emphasis on a broader range of financial ratios than Ofgem have traditionally used. For example, in a recent report[2] Moody's states:

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[1] For issue costs of 9%, with a dividend yield of 8.2%, the adjustment to the cost of equity is [0.082/(1-0.09) – 0.082] = 0.0081

[2] UK Independent Gas Distribution Companies: Similar Fundamentals to Regulated Water at Slightly Lower Leverage, Moody's Investor Service, March 2004

> "For regulated utilities in the UK, the two most important measures that we utilize in assessing the financial strength are the adjusted interest cover ratio (after deducting from post-tax cash flows the capex spend required to maintain the RAV) and the ratio of the debt to the RAV."

Also, in a Special Report[3] following DPCR4, FitchRatings commented:

> "Fitch analysis currently focuses on EBITDA rather than FFO."
>
> and
>
> "Net debt/RAV is the key measure of gearing for regulated utilities and the best cross-DNO or cross-industry indicator of leverage. However, it is not a good early indicator of problems in a company or misalignment versus the regulatory template and EBITDA-based measures are much better for the early identification of a trend."

The lower the level of a company's current credit rating then the higher the probability that it could be downgraded to below investment grade, at some future date. If the majority of ratings were BBB there would be a significant risk that one or more companies would fall below investment grade, in the event of future downgrades. Furthermore, in view of the higher debt premia which are required by investors on the debt of companies with lower ratings, it is unlikely that lowering ratings to BBB would reduce the weighted average cost of capital (WACC). The average debt premium for BBB graded debt is 40 basis points above that for A graded.

In addition to debt related financial ratios, we believe that Ofgem should also consider equity related ones. In particular, the dividend cover ratio should be adequate and the prospective dividend yield and growth should be consistent with the return required by shareholders.

We welcome the opportunity to continue to work with Ofgem to develop further the financial model which will be used for assessing the effect of the revised price control on the financeability requirements of the licensees.

Tax

We agree that the ex ante approach to tax which was adopted for DPCR4 should be applied to the TPCR. However, we do not agree that it is necessary to put companies on a common starting gearing position. Each company should start from its actual gearing position. Moreover, we note that the gearing assumptions used for the

[3] No Shocks – The UK Electricity Distribution 2005-2010 Price Review, Fitch Ratings Ltd, December 2004

previous price controls were different for the Scottish transmission companies, Transco and NGC. Therefore, there is no basis on which to determine a common starting gearing position, as it would be inconsistent with the assumptions on which some of the previous price controls were set.

Regulatory Risk

At the moment regulatory actions are highly significant. Eighteen months ago Ofgem set a cost of capital of 4.8% (pre tax, real) for the DNOs recognising the need to fund significant investment. Eighteen months on, the TO companies, which are smaller scale overall and, in our view, more risky, face relatively higher investment. However Ofgem proposes a reduction in the post-tax cost of capital of 60 basis points.

We believe the market reacts to such decisions. Broker's comments on the Initial Proposals for the TPCR clearly show that the proposed cost of capital and capex allowances were lower than analysts expected and that they believe that Ofgem will moderate its stance between now and December. The share price movements on the day of publication (Monday, 26 June 2006) confirmed this negative reaction when all three groups with transmission licences suffered significant falls in their share prices, well beyond the market movement. This is particularly concerning, as the transmission businesses constitute only a minority of the groups' total activities.

Share price movements on 26 June 2006

	SPT	SSE	NG	FTSE All-Share	FTSE 100
Change 26/06/06	-1.29%	-1.15%	-0.58%	-0.17%	-0.19%

Source: FT.com

What is required is consistent behaviour. The lack of consistency between DPCR4 and the current TPCR has clearly unsettled investors, at a time when Ofgem's own financial modelling assumes that the Transmission licensees will have to raise new equity.

A long-term approach to investment cycles would lead to fewer surprises.

Pensions

Past over or under funding

As noted in Ofgem's second consultation paper in December 2005 the pension component of allowances given to SP Transmission was not explicit in either TPCR3 or the two year roll forward to 31 March 2007. Consistent with the conclusion reached in DPCR4 we believe that the most equitable and pragmatic approach would be to assume that the pension cost allowance for the prior price control period, including the roll over period, was equal to the actual normal contributions made (i.e. excluding any contributions made in respect of early retirement) and therefore the over or under funding principle should not apply in respect of periods up to and including 2006/07.

Treatment of ERDC's

As stated above we believe that the circumstances in SP Transmission are no different to that facing the DNOs during DPCR4. [We agree with the principle that early retirement deficiency costs arising from redundancy and re-organisation that have not already been matched by additional employer contributions should not be included in the allowances. However this principle can only apply from the first price control period that pension allowances are specified and the assumptions and components of the allowances have been clearly stated.] Adopting the pragmatic approach above that there is no over or under funding of past **normal** pension costs would mean that any ERDCs arising up to and including 31 March 2007 have not been funded in the past and should therefore be recognised as part of the pension cost allowances in the 2007-08 to 2011-12 price control period. This is consistent with the approach adopted in DPCR4.

Funding of deficits

The initial proposals correctly record the fact that Scottish Power have and will be making further payments to reduce the deficits in its schemes. We would expect the element of these deficits that is attributable to SP Transmission to be fully funded.

Depreciation

We support your intention to use tilted depreciation to bring forward depreciation funding as adopted in DPCR3 and DPCR4. This will ensure price stability over the price control period and beyond, and will mitigate against the short-term financial impact on companies that would otherwise result.

In order to ensure that companies are neutral to this switch in NPV terms it is also necessary to make an adjustment for the different values implied by the different lives. The difference between asset values using the existing asset lives and the accelerated asset lives should be calculated and the difference would be added to depreciation in equal instalments over the next 15 years. If accelerated asset lives of 20 years are combined with the smoothing of the differences over 15 years, the resulting "cliff face" percentage drop in depreciation is consistent with the equivalent precedent drop in the Distribution Price Control Review.

Regulatory Reporting

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. However the regulatory workload burden arising from the enhanced regulatory reporting needs to be proportionate to allow Ofgem to meet their regulatory duties. We believe this can be achieved via an abbreviated form of the reporting in Distribution. To ensure consistency of reporting by all Licensees, prior to implementation we will require full instructions and guidelines similar to Distribution.

Appendix 2 Adjustment Mechanisms and Incentives: Electricity

Revenue Driver Design

We recognise that cost reflective revenue drivers can help to mitigate the impact of uncertainty surrounding future requirements. However, whilst accurate and robust revenue drivers may provide protection to consumers, revenue drivers that do not have these characteristics may represent greater risk to customers than a fixed allowance. Consequently any revenue driver implemented must have a high likelihood of delivering appropriate revenues for all probable scenarios.

It is essential that any revenue drivers that are developed are equally suitable for all the transmission licensees and do not inadvertently discriminate against any licensee.

There is a significant difference in the nature and consequently cost of the projects that each of the Licensees currently face. The revenue drivers developed should be robust enough to satisfy the requirements for appropriate revenues for all licensees and recognise the full range of projects that they may be required to deliver.

The arrangements must facilitate strategic investment decisions for situations where it is not economic merely to build to current commitments, if the economic solution is to build spare capacity then this should be funded.

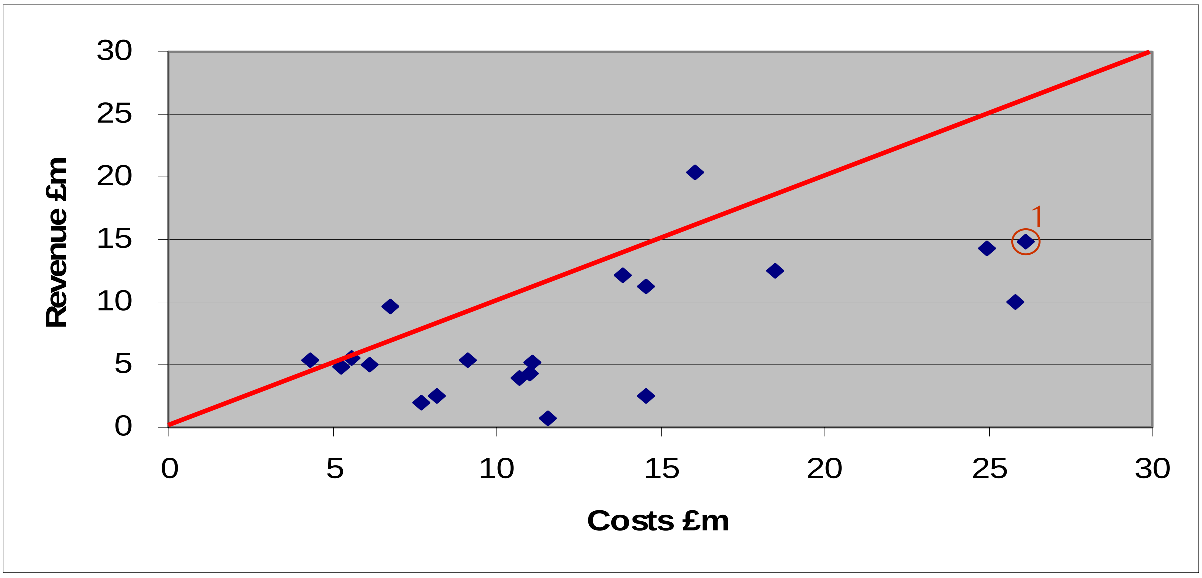
Whilst there is intent to deliver access reform in parallel to the TPCR4, there is significant uncertainty in relation to the outputs of access reform that are likely to interact with revenue drivers. Consequently any revenue drivers should ideally be fashioned in such a manner that, in so far as possible, revenue triggers relative to investment commitments and risk profile are unchanged by the access regime.

Local Connections Works – Method

The value of revenue drivers must meet the test of being sufficiently accurate to provide an acceptable degree of risk that is symmetrical to both users and companies under all probable scenarios. We have applied the formula approach in Ofgem's Initial Proposals to our own data and have also considered a simple average £/MW model with a degree of pass through.

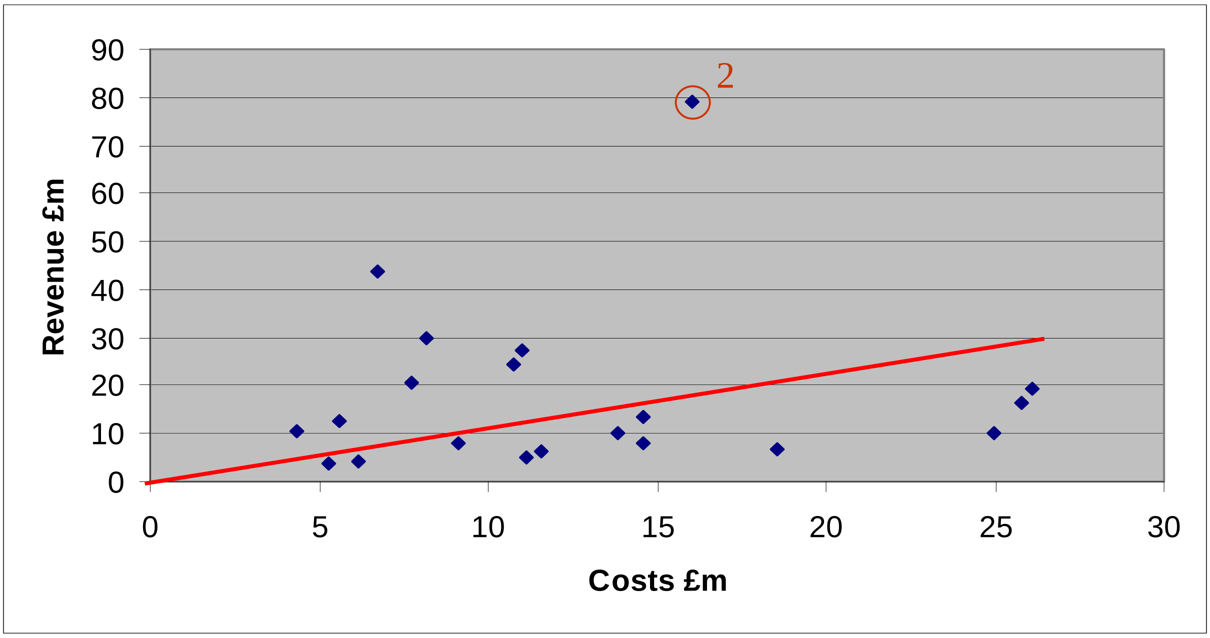
The scatter plot below shows capital cost for each connection and the associated capital expenditure that the revenue driver would fund. This demonstrates the poor correlation of the formula approach in the Initial Proposal to our data, e.g. Project 1 (circled) has a capital cost of circa. £26m, whilst this revenue driver would provide revenues appropriate for capital expenditure of circa £15m.

It is important to note that correlation is significantly worse if all potential projects are considered.



The alternative approach suggested in the Initial Proposals for a revenue driver based on cost pass through of a proportion of costs complemented by a £/MW driver for the remainder, may provide a simpler and more transparent solution. However it will still require to be constructed in such a manner that it delivers an acceptable degree of risk to consumers and transmission companies.

The scatter plot below demonstrates the poor correlation of a simple average £/MW driver for our data, e.g. Project 2 (circled) has a capital cost of circa. £16m, whilst this revenue driver would provide revenues appropriate for capital expenditure of circa £80m.



Whilst the range of risk can be mitigated by applying a proportion of cost pass through, the degree of suitability of a model with a proportion of cost pass through complemented with a £/MW is highly dependent on the proportion of cost pass through. Given the poor correlation between a simple £/MW driver and project costs, our analysis has shown that the pass through proportion would need to be significantly higher than that used for the DG mechanism to present consumers and companies a reasonable degree of risk.

The proportion of pass through in the DG mechanism is 80%, whilst our analysis has shown that a pass through greater than 90% would be required to provide sufficient accuracy. Given the high degree of pass through necessary we do not currently believe that Ofgem should consider this to be a viable alternative.

Whilst the model highlighted in Ofgem's Initial Proposals is substantially more accurate than a simple £ / MW model, it is clear that there is an unacceptably wide dispersion of our costs around the calculated revenue for either model. Our analysis indicates that a more cost-reflective form of revenue driver would be more appropriate for the range and mix of projects that we will have to undertake. This has been derived from a number of building blocks, which forms a four part model of the form:

T + D + C + A

Where:

T the cost of substation connection to existing Transmission System or appropriate H1 Collector, comprising:

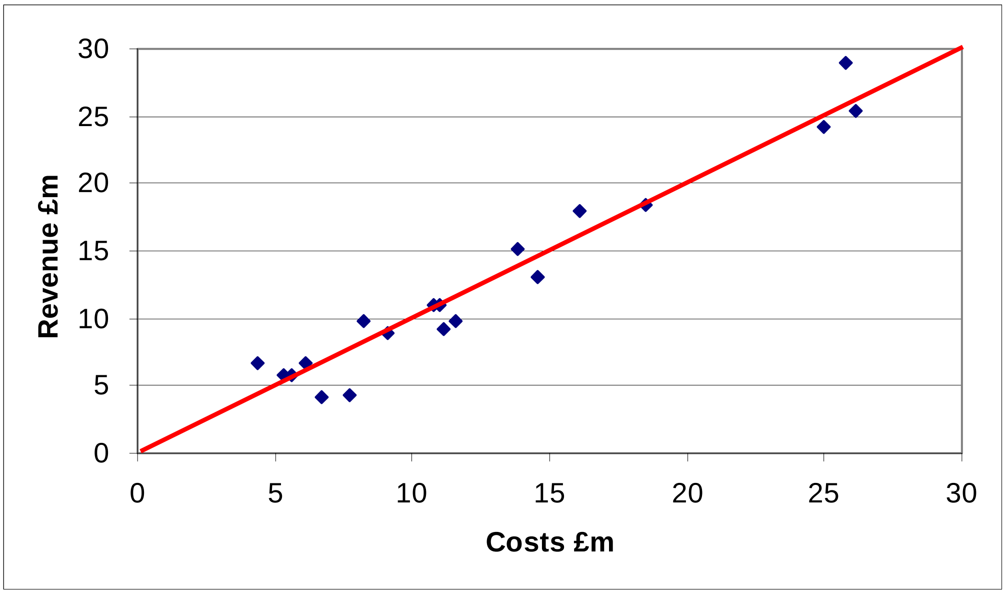
(i) T connection off a line
(ii) Simple – eg single switch
(iii) Bays into an existing (or H1 shared) substation
(iv) Intermediate [1½ switch]
(v) Double bus

D £/km of overhead line

C the cost of local infrastructure assets, comprising:

(i) Simple connection (e.g. disconnector)
(ii) Double bus
Double bus 33kV (which includes 132-33kV transformation)
Double bus 132kV
Double bus 400kV

A additional £/km for cable



As can be seen from the above plot this approach provides a much better fit to our data.

We believe that our proposal is simple, transparent and cost reflective and represents the solution that presents least risk to both consumers and transmission companies. Further, we believe we have the widest and most diverse range of projects and, consequently, an approach that adequately fits our data should also be applicable to both SSE and National Grid.

Importantly, the nature of our proposed model is such that it is also robust to significant changes in the mix of projects that progress, whilst the accuracy of the alternative models can be significantly deteriorated if alternative projects progress than anticipated.

The table below shows the results of this analysis as relative correlation coefficient that describes the relative ability of each revenue driver to deliver revenues that accurately match the actual cost. A value of unity describes a perfect solution:

Correlation Coefficients	
Simple £/MW	0.0518
Formula approach	0.6297
SPT proposal	0.9700

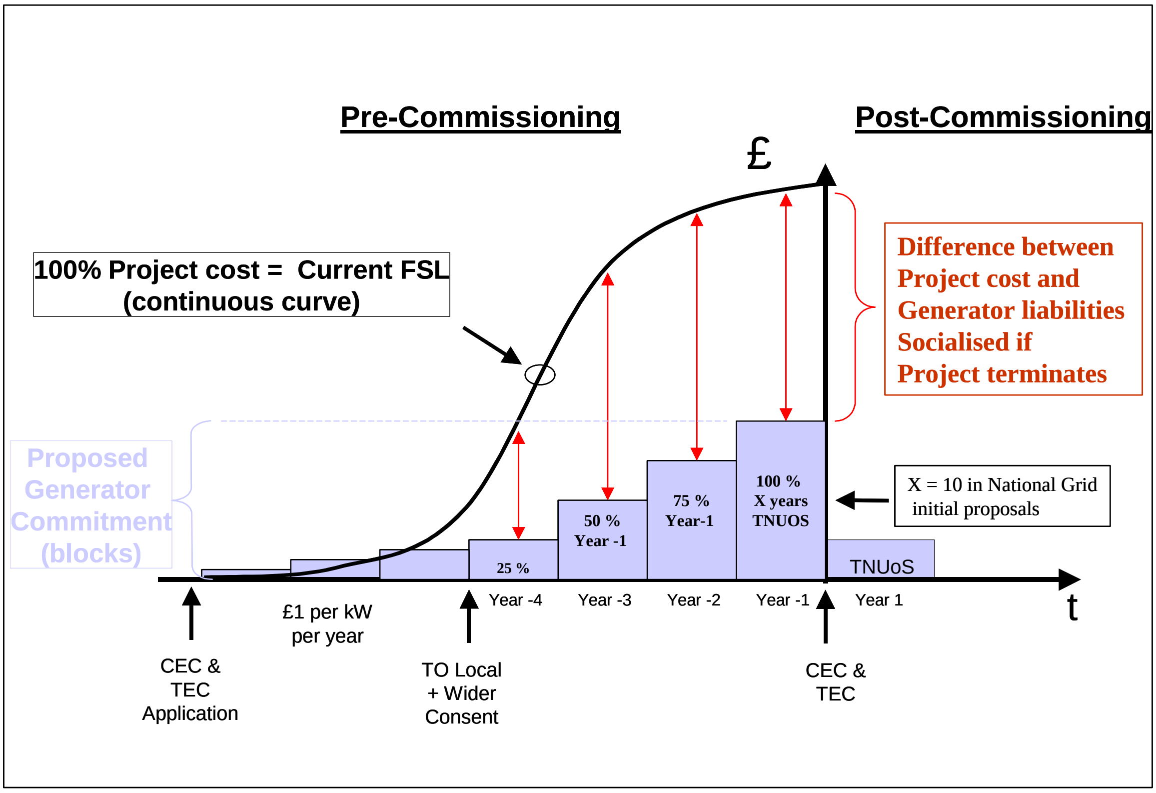
Local Revenue Driver Triggers

The timing of revenues in relation to costs is a significant question that remains to be answered as it has the potential to materially affect the transmission company's financeability even if the revenue driver is accurate. Revenues triggering on physical completion of generator connections (as per DG mechanism) is inappropriate in the context of transmission connections for a number of financeability reasons:

- Level of capex relative to RAV is much greater
- Construction periods are substantially longer – typically 3 years or upwards versus within year for DG
- SO-TO interface and charging mechanisms have an inherent delay on revenues

The suggested option in the Initial Proposals for revenues to trigger on a substantial commitment from a generator is more sensible. The suggested trigger of 30% of project costs, whilst possibly a useful trigger point under the current access regime, is subject to significant interaction with proposals on access reform and is a potentially meaningless threshold under the new proposals.

The current National Grid proposals for access reform propose to change generators financial commitments / liabilities from being directly related to project cost to a generic commitment (based around a £/MW initial commitment and a later TNUOS commitment) and are summarised below:



This proposed generic generator commitment bears no direct relation to the associated project costs, and for many projects will represent a significantly lower commitment for generators. It is possible that a 30% of project cost trigger point could fail to be met for a significant number of projects, and this becomes more probable in direct relation to how expensive a project is.

Ideally any revenue drivers implemented need to be independent of access reform in order to minimise the likelihood of TPCR4 re-openers.

To ensure the financeability of transmission licensees revenues should closely track costs as far as possible. In addition the inherent delays in revenues in relation to the charging mechanisms may require to be addressed.

A further consequence of reducing liabilities of new generators is that there is an increased likelihood of assets being constructed unnecessarily that are not fully underwritten by new generators. As a result the revenue driver mechanism will also need to trigger socialisation and associated revenue rights on the event of project termination to cover any shortfall between network investment and costs underwritten by generators.

Whilst the detail and timescales of access reform remain uncertain there will remain some risk of a requirement for a price control re-opener in relation to timing of investment and revenues and the risk associated with stranded assets.

Baseline

Whilst the Initial Proposals suggest a baseline case supplemented by revenue drivers, the Proposals do not provide sufficient information on the potential interactions of the baseline case and revenue drivers to properly assess the implications.

Further, the baseline proposed has been developed from the BPQ submissions to reflect a particular range of project scenarios. Whilst clearly the interaction between the baseline and revenue driver shall need to reflect the full range of probable scenarios faced by the licensees.

Deeper System Reinforcement

Transmission infrastructure investment is lumpy in nature with the released capacity and cost having a non-linear relationship. Consequently it is not possible to develop generic revenue drivers that will provide an acceptable degree of accuracy. We believe that a strategic approach is the most appropriate for deeper infrastructure assets. The small number of projects and timescales involved allows them to be assessed individually and these projects should then be included in the baseline capital expenditure allowance.

The Initial Proposals recognise that it can be efficient for transmission companies to respond to the need for additional capacity by investing in a way which ‘over provides’ capacity in the first instance. In situations where the economic solution is to build spare capacity, rather than merely to build to current commitments, then this should be funded.

However, the Initial Proposals are unclear on both investment and revenue triggers in relation to deeper system reinforcement. Whilst they recognise the need to reflect a wider range of influences, they suggest that revenue drivers may be sufficiently informed by generation net of peak demand in a transmission zone.

However, investment decisions in the deeper system are a function of the requirement for a stable and secure network, and must take cognizance of a number of factors such as closure of existing plant, voltage support and export/import requirements from adjacent zones.

Consequently, whilst generation net of peak demand in a transmission zone should be a consideration in these investment decisions it cannot be the only factor considered and cannot reasonably serve as a revenue trigger.

Boundary Transfer Assets (H2 assets)

Reinforcements of the main transmission system are required to partially alleviate constraints associated with the B5 and B6 boundaries. The main driver for this investment is compliance with the GB Security and Quality of Supply Standard. We believe that cost benefit analysis will support the economics of this investment and we are confident that such an analysis will demonstrate clear economic justification for these reinforcements. If there is clear justification then the TO should be provided with a return on its investment during the construction phase and be incentivised to deliver timely and cost-efficient works by receiving full capital funding (i.e. including depreciation) on project completion.

Infrastructure - Shared Use Assets (H1 shared use)

In view of the strategic nature of investment necessary to provide infrastructure to meet government energy targets, we have proposed ‘collector systems’ which extend the existing network towards geographic clusters of windfarms. These collector networks (i.e. shared used infrastructure assets) are designed to accommodate connections in the most efficient way overall, by facilitating the expansion of capacity to accommodate further connections, as required, without stranding the original assets. As with boundary transfer investment, we recommend that the TO should be provided with a return for its investment during the construction phase and be incentivised to deliver timely and cost-efficient works by receiving full capital funding (i.e. including depreciation) on project completion.

Access Reform

There is a clear interaction between access reform and the Initial Proposals for revenue drivers, and the TPCR4 settlement. Price control re-openers may be needed if access reform significantly changes timings of investment and associated revenues or the balance of risk.

The current access reform proposals from National Grid appear sound in principle and have delivery timetable proposed in line with TPCR 4. Whilst it would seem sensible to develop TPCR4 proposals based on the National Grid access reform proposals this creates a number of concerns.

Through the code governance mechanisms other parties can raise alternative proposals or propose alterations to National Grid's proposals. As a consequence there is a risk that enduring solution is not the same as the interim and could change a number of significant factors including:

- Timing of investments and revenue triggers
- Timing of revenues (cash flow)
- Risk profile
- Cost of capital
- Financeability

Ideally any revenue drivers implemented need to be independent of access reform in order to minimise the likelihood of TPCR4 re-openers. One possible solution would be to relate the revenue triggers to the current National Grid access reform proposals, or preferably to develop generic triggers that will be unaffected by access reform.

A further consequence of reducing liabilities of new generators is that there is an increased likelihood of assets being constructed unnecessarily that are not fully underwritten by new generators. As a result the revenue driver mechanism will also need to trigger asset socialisation and associated revenue rights on the event of generation project termination to cover any shortfall between the network investments and level underwritten by generators.

Any Access Reform also needs to recognise that there are significant factors out with transmission Company's control that impact on the delivery of Transmission Access Capacity, including:

- Planning and landowner consents
- BETTA transitional arrangements
- Boundary B6 below required capacity

Appendix 3 Responses to Specific Ofgem Questions

Section 7 Price control cost assessment and general policy issues

Question 7.1: Do you agree with Ofgem's proposed treatment of non-operational capex and 'quasi capex'?

Non-Operational Capex
In clause 7.24 Ofgem note that their proposal for treatment of non-operational capex is consistent with DPCR4. This is not the case as this expenditure is treated as capital expenditure for DNO's, albeit it is depreciated on a 40 to 45 year basis for revenue purposes.

We disagree with Ofgem's view that non-operational capex should be treated as opex. Ofgem appear to recognise that there are ongoing benefits from this type of investment and that such benefits should reflect the actual (shorter) life of these assets. However, the monitoring of this would be complicated and it is this aspect that has prompted Ofgem to propose an allowance under operational expenditure. There is a need for consistency in treatment of this category of expenditure for the regulated utilities that Ofgem must address. We believe non-operational capex should be treated as capex with the remuneration of this type of expenditure reflecting the period of time over which the benefits are realised.

Consistent with the treatment in DPCR4 non-operational capex should be separately identified and included in the RAV. In order to increase the transparency of regulation and to more intuitively understand the RAV, we believe that there is a strong argument to, as closely as possible, align RAV additions with fixed asset additions as required by applicable accounting standards and reported within the Statutory and Regulatory Accounts. Any published performance comparatives will lose credibility if an opex variance is attributed to, for example, unanticipated IT investment. Asset lives should be 5 to 7 years as this capex relates predominantly to short life IT expenditure.

Ofgem Question 7.2: Do you agree with Ofgem's proposed approach to future input price changes and indexation? Is our assumption of a 1.5% annual efficiency saving for opex realistic and appropriate?

Ofgem have applied an ongoing efficiency assumption of 1.5% based on benchmarking and adjusting NGET's costs to the upper quartile. Ofgem also state that both Scottish companies' costs were found to be around the upper quartile indicating that we are already operating at or near the frontier. We consider that the scope for further cost reductions in future years is extremely limited and consider 1.5% p.a. extremely challenging without impacting on the performance of the network.

Ofgem Question 7.3: Is Ofgem's assumption on efficient connection design for wind generation, and the associated reduction to some of the company cost forecasts, appropriate?

Ofgem has made a reduction of £20m for "efficient connection design" for connections under 100MW. This reduction is not due to misinterpretation of the GB SQSS but as a result of the shallow connection policy introduced through BETTA which gives developers no incentive to accept lower-security, lower-cost connections. Ofgem proposes to address this by developing charging incentives that encourage generators to accept more economic and efficient, but less secure, connection designs (although, in some instances, overall costs may rise when account is taken of the cost of constraints).

If the "efficient connection design" reduction goes ahead as proposed, it will lead to major commercial impacts for SP Transmission, NGET (as GBSO), and users and will also create quality of supply and environmental issues. We believe that the right approach is to restore the £20m reduction for "efficient connection design" and establish arrangements that adjust our allowance down as and when generators select more economic and efficient connection designs. We intend to write to Ofgem separately on this matter.

Ofgem Question 7.4: Do you think that Ofgem need to allow explicitly for the possibility of reopening the price controls for specified single events where the timing and level of costs is uncertain and driven by third party decisions? If so, what might such events be and why?

Ofgem need to explicitly allow for the possibility of price control re-openers to cater for single events, which may be unforeseen, and which are outside the control of the transmission companies. Without the opportunity to reopen, events that could incur significant cost would present an unacceptably high risk to the transmission companies.

BT 21st Century
Although we would have preferred funding that addresses the BT21st Century issue to form part of the baseline, we believe the principle of a re-opener could work and look forward to discussing the detailed arrangements with Ofgem.

Ofgem Question 7.5: What do you think of the proposed options for setting incentives for efficient capital expenditure?

Rolling Incentives

In principle, we support the use of an incentive mechanism which ensures consistent strength of the incentive to make efficiency savings throughout the price control period. However, care is needed in its design, so that it can be put into practice using data which will be available at the time required. In particular, if a shortened lag were to be implemented then the adjustment would need to be made prior to the next price control review, which would require more detailed annual reporting. Otherwise, it would be easier to implement a modified adjustment, which took account of the delayed timing, during or after the next price control review, when more data had been collated. Also, a rolling incentive should be implemented in a way which is consistent with any other incentive mechanisms which will be implemented.

We agree that, in view of the uncertainty surrounding the investment programme and the upward cost pressures from rising commodity prices, equipment costs and contractors' rates, that the incentive rate should be reduced to around 20%, especially if it will be applied to load related capex.

Information Quality Incentive

In principle, we support the introduction of an information quality incentive which is designed to improve the accuracy of the licensees' non-load related capital expenditure forecasts and allows companies to choose their preferred risk profile. The sliding scale mechanism, which was developed for DPCR4, can be improved, so as to provide an "information quality incentive mechanism" for non-load related capital expenditure for transmission. In particular, the incentive mechanism should be calibrated so as to avoid penalising a company that accurately forecasts its capital expenditure requirements.

However, for such a mechanism to work effectively, companies must have the opportunity to re-forecast their capital expenditure requirements after the detailed mechanism and associated parameters are established. We are now, therefore, doubtful that there is sufficient time remaining to develop a satisfactory mechanism and to communicate its details to the licensees in time for them to re-submit their forecasts, having taken account of the workings of such a mechanism. We, therefore, suggest that a lower incentive rate, of around 20%, should be set for all licensees through the implementation of the rolling incentive mechanism, as discussed in the previous section.

We agree that, in view of the uncertainty surrounding the investment programme and the upward cost pressures from rising commodity prices, equipment costs and contractors' rates, that the incentive rate should be reduced to around 20%, especially if it will be applied to load related capex.

Section 8 Financial Issues

Question 8.1: Should the licensees' revenue allowances for tax payments be set to avoid any need for ex post adjustments?

We support the ex ante approach to tax which was adopted for DPCR4. However, we would expect significant changes in tax law or applicable tax rates or allowances to be taken into account, if and when they occur.

Question 8.2: Are there any other measures which could be taken to reduce perceptions of Regulatory risk and what level of risk do these regulated utilities carry relative to other plc's?

At the moment regulatory actions are highly significant. Eighteen months ago Ofgem set a cost of capital of 4.8% (pre tax, real) for the DNOs recognising the need to fund significant investment. Eighteen months on, the TO companies, which are smaller scale overall and, in our view, more risky, face relatively higher investment. However Ofgem proposes a reduction in the post-tax cost of capital of 60 basis points.

We believe the market reacts to such decisions. Broker's comments on the Initial Proposals for the TPCR clearly show that the proposed cost of capital and capex allowances were lower than analysts expected and that they believe that Ofgem will moderate its stance between now and December. The share price movements on the day of publication (Monday, 26 June 2006) confirmed this negative reaction when all three groups with transmission licences suffered significant falls in their share prices, well beyond the market movement. This is particularly concerning, as the transmission businesses constitute only a minority of the groups' total activities.

Share price movements on 26 June 2006

	SPT	SSE	NG	FTSE All-Share	FTSE 100
Change 26/06/06	-1.29%	-1.15%	-0.58%	-0.17%	-0.19%

Source: FT.com

What is required is consistent behaviour. The lack of consistency between DPCR4 and the current TPCR has clearly unsettled investors, at a time when Ofgem's own financial modelling assumes that the Transmission licensees will have to raise new equity.

A long-term approach to investment cycles would lead to fewer surprises.

Section 10 Adjustment Mechanisms and incentives: electricity

Question 10.1: Is Ofgem's proposed two-part revenue driver design appropriate and proportionate to the issue it is seeking to address?

We recognise that cost reflective revenue drivers can help to mitigate the impact of uncertainty surrounding future requirements. However, whilst accurate and robust revenue drivers may provide protection to consumers, revenue drivers that are not cost-reflective may represent greater risk to customers than a fixed allowance. Consequently any revenue driver implemented must have a high likelihood of delivering appropriate revenues for all probable scenarios.

It is essential that any revenue drivers that are developed are equally suitable for all the transmission licensees and do not inadvertently discriminate against any licensee. There is a significant difference in the nature and consequently cost of the projects that each Licensee currently face. Hence it is important that the revenue drivers developed should be robust enough to satisfy the requirements of all Licensees and recognise the full range of projects that the Licensees may be required to deliver.

Local Works

Whilst the 'formula' approach revenue driver model discussed in the Initial Proposals is more accurate than the simpler £ / MW model, there is still an unacceptably wide dispersion between calculated revenues and required revenues for either model. We have derived a four-part revenue-driver model which is more cost-reflective and hence more appropriate for the range and mix of projects that we will have to undertake. Our proposal is simple, transparent and cost reflective and represents the solution that presents least risk to both consumers and transmission companies. Further, we believe we have the widest and most diverse range of projects and, consequently, an approach that adequately fits our data should also be applicable to both SSE and National Grid.

Deeper System Infrastructure

Transmission infrastructure investment is lumpy in nature with the released capacity and cost having a non-linear relationship. Consequently, it is not possible to develop generic revenue drivers for deeper system reinforcement that provide an acceptable degree of accuracy. Deeper system projects are relatively small in number and can be economically assessed against the constraint costs of not providing capacity with revenue for these projects awarded in a phased approach similar to TIRG.

A detailed outline of our analysis on revenue drivers is given in Appendix 2. In summary, we recommend that:

i) Our proposed generic revenue driver for local connection works, rather than the proposals detailed in this Consultation is implemented,

ii) A revenue driver for deep system reinforcements is inappropriate. Deep system reinforcements should be funded through a return for investment during the construction phase with full capital funding on project completion, and

iii) The design of revenue drivers must avoid any adverse impact on financeability by ensuring that funding is provided in line with investment

Question 10.2: What are the costs and benefits of seeking to facilitate greater competition between providers of transmission services, in respect of the prospective transmission links to the Scottish Islands?

We are fully supportive of extending competition to these connections and would be very interested in participating in a competitive process.

We believe that there are strong parallels between issues around determining efficient designs and costs for these large extensions on the periphery of the existing system, and the associated regulatory framework, and those being dealt with on the offshore transmission project. As such, we consider that there may be merit in extending the scope of the offshore transmission project to cover island connections. This might also go some way towards addressing the concerns of those stakeholders who believe that island connection issues are not currently being progressed.

We note in the case of island connections in the north of Scotland that SHETL has, to date, taken a very active role in developing potential solutions. In the interests of encouraging competition, and perhaps encouraging others to develop alternative solutions, it will be necessary for the information that is currently available to be published. There is also likely to be an important ongoing role for SHETL, as host TO, in engaging with various stakeholders and identifying high-level requirements and potential solutions. If this is the case then it would be reasonable for the efficient costs associated with this activity to be funded via its price control.

Question 10.3: Is Ofgem's proposed approach to funding for innovation appropriate and necessary?

We have found that the increase in innovation following the introduction of the Innovation Funding Incentive (IFI) for the distribution licensees is showing to be giving a much needed lift to development activities across the sector. Within the DNOs the mechanism is providing both short-term benefits and is changing the approach to risk. Externally, there are benefits to R&D establishments - with additional funding, improved steer on projects and re-energisation of academic activities, essential in educating and inspiring the next generation of developments (i.e. its technology and electrical engineers). If a consistent mechanism were to be in place across both distribution and transmission networks, it is clear that synergies may be possible.

To this end, SPT would welcome an introduction of an IFI mechanism for use on the transmission networks. We would comment that a “pot of funding” of up to 0.5% of TO allowed revenue is insufficient for transmission and recommend that this funding limit is increased to 1% of allowed revenue.

Questions 10.4: Is Ofgem’s proposal to extend the existing performance incentive scheme appropriate?

We are not of the opinion that Ofgem’s proposal of extending the existing performance incentive scheme is appropriate. We continue to believe that network incentives should be symmetric i.e. penalties and rewards, and entirely within the control of the TO with observable metrics.

Albeit the detail of a “wider package” of incentives is not present in the initial proposals, the move towards re-categorisation of a minimum standard reliability incentive, i.e. a ‘penalties only’ scheme, is a disappointing strategy to begin a more extensive regime, especially in the area of system performance. By design, a penalties only scheme is not symmetric, an extension of the existing scheme continues to remain largely outwith the TO’s direct control. It is our opinion that a ‘penalty only’ scheme may well distort decisions regarding discretionary expenditure, as any available expenditure would be diverted to areas where there is the opportunity to earn a reward. The potential here could easily have an adverse effect by reducing the current levels of reliability.

We agree that levels of system reliability must be consistent with the needs of consumers and that the development of performance incentives should correspondingly be consistent with customers’ willingness to pay for improvements. Although we recognise the need to investigate other areas of output measures to allow other areas of incentivisation to be examined, Ofgem must avoid the introduction of incentives for incentives sake. Proposals to introduce new output measures clearly indicate that the existing metrics, however extensive, are insufficient to generate further suitable incentivisation mechanisms.

Section 12 Environmental considerations

Question 12.1: Do you agree with Ofgem's assessment of the main impacts of the transmission system? What are the most important impacts from the perspective of consumers?

We acknowledge that the broad types of environmental impacts set out by Ofgem are emissions, losses, visual amenity and noise. Our experience is that visual amenity is the most important impact from a customer's perspective.

Although we have a licence obligation to plan and develop our transmission network in accordance with the GB SQSS, we take considerable care to take into account the customer perspective. This is demonstrated by our approach, working with the GBSO, in making offers for connections to our network.

Question 12.2: Should emissions of SF6 be subject to a separate incentive scheme, given that they are currently outside the scope of the European Emission Trading Scheme (EU-ETS)

Ofgem must avoid the introduction of incentives for incentives sake.

Emissions such as SF6 are an important matter that we take very seriously. However the introduction of an incentive regime for SF6 would be complex and difficult to administer and audit. We therefore recommend that SF6 emissions should not be subject to a separate incentive scheme.

Question12.3: Should there be additional measures to promote innovation in support of environmental benefits, either as part of the proposed incentive scheme for innovation for NGET, SPT and SHET or as a separate measure?

We recommend that any innovation in support of environmental benefits should be addressed through the proposed IFI mechanism for transmission networks.