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Dear Hannah

Consultation on strategy for the next transmission price control – RIIO-T1 (Document Reference – 159/10)

We welcome the opportunity to comment and provide views on the above consultation paper published on 17 December 2010. This response is written from SP Transmission Ltd (SPT), which as the regulated Transmission Owner (TO), owns and maintains the electricity transmission network in the south of Scotland.

At this stage in the RIIO-T1 review process it is not possible to quantify in detail the likely impacts of the review. Many of the key risk areas, for example surrounding financeability, have deliberately been left open by Ofgem with each of the companies being required to construct a holistic view of the price control package and submit these as part of their well justified business plans.

That said, we are concerned that much of the tone and thinking underpinning the consultation is similar to that observed at previous reviews. For example, there remains a focus upon historical data within Ofgem's early thinking and that of their advisors on allowed returns for the companies. There is acknowledgement that cross-checks to forward looking analysis, via for example Dividend Growth models, should form part of the debate but there has been little evidence of this is in practice.

At a time when the UK and indeed the global economy remains fragile, when we are seeing increased demand for finite capital resources and when as an industry we are seeking to play a full role in the delivery of a sustainable energy sector there are risks to achieving UK Government policy if we are to remain wedded to an econometric model which fails to fully reflect future economic and market conditions.

Recent decisions on allowed returns have seen the major industry players reconsider their desire to participate in Networks activities. Regulators must be confident that the right investors can continue to be attracted to the sector.

We welcome Ofgem's improved transparency in their thinking around financeability. This was lacking at DPCR5 and bringing this into focus early in the review process is helpful and will allow companies to manage investor expectations.

Financeability

SPT is part of Iberdrola Group which is an experienced industrial player world-wide with the capability and commitment to help fulfil the UK agenda in the electricity sector. Iberdrola has already shown a strong commitment to participate in the sizeable investments needed in the UK electricity sector in the next years. However RIIO-T1 represents a huge capex programme and SPT will have to fund close to £ 3B over the period of RIIO-T1.

Ofgem's proposals set out in this strategy consultation combine a low level of return with substantially increased risk on the transmission companies. The impact will be to discourage and suppress this unprecedented increase in investment that is necessary. We are concerned that Ofgem is failing to recognize the uncertainty and risk of investment going forward. This represents a major threat to the necessary investment, not least putting at risk some 3 to 6 GW of connected renewables. Indeed, investors, analysts and rating agencies have already warned about too low a level of return and increased risks. Ultimately the impact would be to affect customers and the overall economy by threatening jobs in a key sector and putting the UK at a competitive disadvantage. It is essential, therefore, that the cost of capital significantly increases above current levels and recent regulatory decisions such as DPCR5.

The change from a regulatory asset lives from 20 years to 45-55 years will have a significant impact on the network companies. Even with transitional mechanisms these radical changes will significantly impact financeability. They are certainly not, as Ofgem claims, 'NPV-neutral'.

We have already undertaken considerable investment, and entered into appropriate financing arrangements, under the current price control arrangements. The hastily implemented move to longer asset lives is inconsistent with better regulation principles of stability and predictability and will have a damaging effect upon prospective investors' assessment of the energy networks sector.

Outputs and Incentives

We support the development of outputs and broadly welcome Ofgem's dialogue in scoping these measures within the industry. Ofgem's guiding principle should be to ensure that outputs be within the control of the transmission company.

We believe that the development process has been too rushed. We completely accept that it is very important to involve industry stakeholders in the development of outputs. However, the consequence of this approach is that the outputs development meetings have devoted too little time to discussing the detail. In hindsight a process that combined stakeholder meetings and transmission licensee meetings only may have helped make more progress. Given the challenging timescales, progress has been made but there is a concern that the opportunity to agree the scope and principles underpinning many outputs may be compromised by Ofgem's deadlines for completing work prior to publishing their March final proposals on strategy. This short-notice is a concern, particularly given that the implementation of RIIO T1 is still more than two years away at April 2013.

Putting to one side the short time to define meaningful outputs, we have three main concerns. Firstly we are very concerned that incentives could be introduced for which we have little or no controls. Secondly, if we are to be incentivised then we must have full access to information on which the incentive is based. Finally, there must not be conflicting incentives. For example, the current high levels of asset replacement and refurbishment investment over the period of RIIO T1 mean that we require system access in line with the year-ahead outage plan. Any SO-TO incentive which aims to minimize constraint costs, for example by postponing outages or returning circuits to service before all works are complete, could compromise our asset replacement and refurbishment programme.

Stakeholder Engagement and Customer Satisfaction

We fully support Ofgem's approach under RIIO for stakeholders to have greater opportunity to influence both Ofgem's and our own decisions. We have therefore embraced the requirement for demonstrating that we engage with our stakeholders and have completed a stakeholder pre-consultation for RIIO-T1, and our full stakeholder consultation is now underway.

One of the key challenges we have in the stakeholder engagement field is to ensure that we communicate our plans and engage with as wide a range of stakeholders as possible. To this end we have tried to target our communication process by publishing our consultation documents on our website and providing facilities to give feedback on our website and also by having a face to face stakeholder engagement event.

We have directly contacted a very large number of stakeholders to participate in both our consultation and our stakeholder event. However take up has been poor for both methods of engagement; we received only five responses to our pre-consultation meeting which was electronic based, and only a limited number of stakeholders turned up to our stakeholder event. We believe that this may be due to a number of reasons including numerous other regulatory projects within the electricity industry and which stakeholders may believe are currently more important to them to engage with. Examples of such projects are Project TransmiT, Electricity Market Reform and the new Connect and Manage regime. There may also be an element that parties will only actively engage if they believe there is a major issue to be addressed and we therefore could acknowledge that generally our performance is to a high or at least acceptable standard.

We also need to acknowledge the structure of GB transmission with the different roles and responsibilities between a TO and the SO which were introduced under BETTA. For many customers, the distinction between the two different roles is unclear and can be become blurred, through the comparison with the set-up in England and Wales.

TOs have only one direct customer, which is the SO, and generally communications to customers must progress through them. However, we realise that the services we provide have a direct impact on end consumers and we will continue to engage with the widest possible range of stakeholders through individual bilateral meetings, industry meetings and other industry events.

Finally it is important that Ofgem understands that we already undertake considerable ongoing stakeholder engagement. We regularly meet with stakeholders such as National Grid, wind farm developers and industry parties such as DECC, Ofgem, Scottish Renewables Forum and Renewables UK. We also frequently present at industry conferences e.g. IEA July 2010, Scottish Construction Congress February 2011, Scottish Renewables Grid Conference February 2011, and are represented at industry forums such as the Grid Code Review Panel. Our experience in undertaking our stakeholder consultations for RIIO T1 suggests that the best approach for engaging stakeholders is to build on our current engagement approach.

Third Party Delivery

Ofgem is considering introducing competition such that third parties could construct and own assets on the onshore transmission system. Ofgem recently cited a major reinforcement in central Edinburgh as an example of such an approach. This example was completely inappropriate and raises a major concern for us as to Ofgem's thinking on this matter. This project is a major, complex strategic asset replacement project, involving new technology, major telecommunication infrastructure changes, and some of the most complex civil engineering challenges ever faced. This is absolutely not a project suitable for third party delivery.

The transmission companies are the only parties that have the overall skills, experience and capability to deliver major reinforcement and refurbishment projects. Our position on third party delivery is that may be a place for this model where it involves simple, new radial connections, and the current arrangements allow this to happen e.g. Hadyard Hill wind farm connection. But it must not cover projects which are more complex, and/or potentially have significant safety impacts, and/or could compromise security of supply.

In summary, we are very much of the view, as highlighted by Ofgem in Para 3.18 of the Impact Assessment that the impacts and risks surrounding RIIO-T1 are very much dependent on how the stated principles are interpreted and applied in practice.

Finally, I should comment that the consultation and its appendices amount to over seven hundred pages. In addition to the detail covered in this consultation, the transmission businesses have an unprecedented work load in other regulatory areas with Ofgem; including but not limited to the Adapted Roll-Over Project, Transmission Investment Incentives, Project Transmit, Transmission Unbundling, Connect and Manage transition, and Security Standard Derogations. Given this work load, and the consequential impact on our team, we may need to provide further comments on this consultation in the near future, if we deem this to be necessary.

Should you have any questions regarding any aspect of our submission, please do not hesitate to contact me by return.

Yours sincerely

Scott Mathieson

Scott Mathieson
Regulation & Commercial Director

Contents Summary

Appendix 1 RIIO-T1 and GD1 Financial Issues

Chapter 2 – Asset Lives & Depreciation

We consider it prudent to assume an average economic life for the purposes of depreciating the electricity transmission RAV of no more than 40 years.

Combination of split and stepped approach is required to ensure that Electricity Transmission NWOs are able to adequately finance the forthcoming significant investment in network assets whilst maintaining “comfortable investment grade” credit rating and equity metrics.

Regulatory certainty is paramount at any time but especially at a time of significant investment in network assets. Without this, equity/debt investors will not have the confidence that expected cash flows at the time of their investment will materialise; regulatory trust will be severely tarnished and as a result there is a significant risk that debt/equity investors will think twice before committing to future investment in regulatory assets.

Existing assets in the RAV at 31st March 2013 must continue to be depreciated over lives established in the current price control i.e. 20 years for Electricity Transmission NWOs.

The new longer lives should apply to new assets only i.e. additions to the RAV from 1st April 2013 onwards; the split approach. Ofgem have previously recognised the adverse impact on financeability which would arise from a step change in the allowance for depreciation.

Our initial financial modeling indicates that constraining the transition to the forthcoming price control period would result in an unacceptable deterioration in credit metrics. We will further develop our modeling in order to inform our FBPQ submission but initial indications are that the move to the longer lives (for post 1st April 2013 additions only) should be phased in over at least the next two price control periods and quite possibly longer (the stepped approach).

Asset lives of 45-55 years make little sense against the background of the acute uncertainties facing energy industries – not only those relating to the potential decline in the use of gas but also, in a world where energy has again become high on the political agenda, uncertainty about future changes in energy policy;

Especially without adequate transitional mechanisms it is implausible to contend that the changes to RAV capitalisation (in gas distribution) and regulatory asset lives (for electricity networks) as significant as those proposed by Ofgem will not significantly and adversely affect the cost of funding investment in energy networks – in other words, the proposals are not, as Ofgem claims, ‘NPV-neutral’;

- We have made substantial investments and financing arrangements have been entered into under Ofgem’s existing regime. We believe that, despite assertions to the contrary, Ofgem gave little warning of the changes in the financing arrangements that it is now proposing. We believe that this is inconsistent with better Regulation principles of stability and predictability and will have a damaging effect upon prospective investors' assessment of the energy networks sector.

Ofgem's proposals for transitional arrangements – including the proposal that any adjustment mechanism should only apply for one price control period – are inconsistent with the approach taken by DECC (in its proposals for electricity market reform) to minimise the regulatory risk facing energy market participants by ensuring that investment undertaken under one regulatory regime will not be exposed to a change of regime.

Against the background of the relatively modest impact of the proposed changes on network prices and the significant impact on energy network company cash flows, Ofgem would seem to be at odds with the principle proposed by The Department for Business Innovation & Skills (BIS) that 'the framework of economic regulation should not unreasonably unravel past decisions'. The proposed changes to capitalisation and to asset lives are likely to impact on future network funding costs not just through the direct impact on cash flows but also through increasing the perceived risk that Ofgem could, in future, change the existing regulatory regime in other equally fundamental ways and for equally little benefits to consumers.

In the rest of this response, we first summarise what we understand to be the core Ofgem proposition on capitalisation, asset lives, depreciation and financeability and, second, set out what we see as some of the problems with this proposition.

The Ofgem proposition on capitalisation, regulatory asset lives, depreciation and financeability has a number of elements, including the following.

- Regulatory asset lives should reflect (although, by implication, not necessarily equal) expected economic lives of the relevant network assets, not least to balance the interests of current and future consumers.[1]
- Taking account of this principle and the uncertainties which relate to the future of energy networks (and, in particular, gas distribution networks), Ofgem is suggesting economic asset lives of 45-55 years for electricity transmission and distribution assets and (as now) 45 years for post-2002 gas assets and no change for pre-2002 assets.[2]
- All future gas distribution repex will be capitalised into the RAV, as against the current practice of expensing 50% of the cost for revenue purposes.[3]
- There could be transitional arrangements but only if they were necessary to avoid an efficient company having financing difficulties[4] or cause 'excessive disruption to capital markets and/or raise concerns about financeability'.[5]

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[1] Ofgem (2010), 'Consultation on strategy for the next transmission and gas distribution price controls – RIIO-Ti and GD1 financial issues', December, para 2.2 – this paper hereafter referred to as 'Financial Issues'.
[2] Ibid., Figure 2.6, page 15.
[3] Ofgem (2010), 'RIIO-GD1 Overview paper', December – hereafter referred to as 'GD-1 Overview'.

- In the case of electricity networks, transition arrangement could include, among other options still to be discussed, either a ‘split’ arrangement – in which the proposed lives would apply only to future investment – or a ‘stepped’ implementation where the change to asset lives is made in a series of steps. Ofgem has re-stated its preference for transition arrangements working themselves through in one (eight-year) price control period – which would look to be inconsistent with the split approach.
- In the case of gas distribution, a stepped approach to implementing 100% capitalisation of repex is mooted[6]. Ofgem, however, suggests that its proposal to front-end load depreciation of new assets could partly offset the effects of the proposed change to capitalisation[7] (which, Ofgem accepts, ‘could have a material impact on GDNs’ cash flows’[8]).
- In any event, Ofgem does not believe that the resulting substantial lengthening of the duration of cash flows for gas distribution will significantly impact on the cost of financing energy networks, albeit that it is open to opposing arguments on this issue.[9]

The problems with the Ofgem approach are that:

- There is considerable uncertainty about the long-term future of energy networks, not least because of the exposure of those networks to future changes in government energy policy;
- Given this uncertainty, lengthening regulatory asset lives (either explicitly for electricity networks or through requiring all investment in gas distribution assets to be capitalised into RAV) will increase the risk associated with owning and investing in energy network assets which will, in turn, impact on the cost of finance;
- Ofgem’s proposed change of approach to duration of cash flows is inconsistent with the desirable requirement that network regulation should be predictable – which will compound the financing implications of increasing the duration of cash flows;
- The proposed approach to transitional arrangements further compounds the problems, whereas it could usefully look to the proposed transitional arrangements suggested (in relation to generators) by DECC in its proposals for electricity market reform.

Underlying Ofgem’s position on asset lives are two propositions.

- Regulatory asset lives should equal expected economic asset lives.
- Economic asset lives can be determined with an acceptable degree of certainty, even when the lives in question are judged to last for many decades hence.

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[4] ‘GD-1 Overview’, para 8.10.
[5] ‘Financial Issues’, para 2.40.
[6] ‘GD-1 Overview’, para 8.11
[7] Ibid.
[8] Ibid., para 8.5.
[9] Ofgem (2010), ‘Consultation on strategy for the next transmission price control – RIIO-T1 Overview paper’, December, para 8.18.

Taken by itself, the first proposition is not unreasonable. However, taking the proposition by itself is to ignore why the current regulatory regime includes 50% capitalisation of gas distribution repex and 20-year regulatory asset lives for electricity networks. Both of these positions were reached because of financeability concerns which arose not from actions by the energy networks themselves but because of changes in the environment in which they operate – first, the HSE requirement for comprehensive replacement of cast iron low pressure gas mains and, second, Offer's decision in the 1990s to adopt a rectangular depreciation profile for pre-privatisation electricity network assets. This policy background would suggest that, at the very least, Ofgem should adopt adequate transitional arrangements (covered below) – otherwise, Ofgem's proposed change of policy looks to be arbitrary and likely to create uncertainty about Ofgem's future decision making.

However, the problems with Ofgem's proposed asset lives (and, by extension its proposals for the capitalisation of gas distribution repex) are more fundamental than this and ignore the nature and extent of the uncertainty which surrounds the *expected* (i.e. mean) economic lives of energy network assets. Back in the 1980s and 1990s, the UK philosophy was for different energy sources to fight it out in a competitive market – to reverse the protection afforded to, for example, domestically produced coal. In this sort of world, there was plenty of uncertainty – viz. the persistent failure of fossil prices to track anywhere near virtually any forecasts.

However, the current position is much more uncertain than that. As is made very clear in DECC's consultation on electricity market reform[10], competition between energy sources will not be decided just by the market (which remains as uncertain as ever) but, to a very large extent, by government policy – with the current subsidy, market reform and regulatory proposals being based on, amongst other things, views on the role played by fossil fuels in climate change and on the importance of the UK and other European countries incurring substantial costs of investing in currently uncompetitive energy sources, regardless of the policies to be pursued in other countries.

Recent history suggests that views on climate change and the policies to deal with it do not have a life of 45-55 years. Thus, at a time of (arguably) unprecedented uncertainty about future energy markets, future energy technologies and future energy policies (all of which were, in effect, acknowledged by Ofgem as a large part of the reason for initiating its RPI-X@20 review), investors in energy networks are being asked to wait for 45-55 years to get a return on their investment, with the only qualification being an unspecified degree of front-end loading for the depreciation of gas distribution assets.
In its Financial Issues consultation paper (Figure 2.7), Ofgem further suggests that long regulatory asset lives are used in other jurisdictions, including:

- electricity distribution in Victoria, Australia;
- electricity transmission in the Republic of Ireland;
- electricity distribution in the Republic of Ireland;
- GB water industry.

[10] DECC (2010), 'Electricity Market Reform Consultation Document', December – hereafter referred to as 'Electricity Market Reform'.

The fact of these precedents does not, by itself, advance the argument without knowing other information about these industries but, in any event, at least the last three of these would not, in fact, seem relevant to Ofgem's position.

This is because:

- The electricity distribution and transmission networks in the Republic of Ireland are owned and operated by a state-owned company which, as such, is somewhat shielded from the capital market pressures which apply to privately owned regulated networks – the same effect in GB being observable in effect of the government guarantee of Network Rail's debt on the cost of that debt;
- The same applies to the water industry in Scotland;
- In addition for water, the risks of economic asset lives being less than technical lives – more specifically, the risk of the water industry ceasing to exist in something like its current form – would look to be significantly lower than for energy networks.

In an uncertain world where uncertainty tends to increase the further one looks into the future, the lengthening of average regulatory asset lives for gas distribution and for electricity transmission and distribution networks will inevitably expose equity and debt investors in those networks to greater risk.

Implications of this increased uncertainty for cost of financing

In its Financial Issues consultation, Ofgem says (para 3.54) that it remains open to arguments that increased duration of cash flows will increase perceptions of risk (and, therefore, the cost) of investing in energy networks. However, it also quotes Europe Economics' suggestion that the fact that the betas for the owners of electricity distribution networks did not react to the shortening of regulatory asset lives in DPCR3 suggests that there should not be any significant effect from the proposed lengthening.

Drawing this conclusion from the DPCR3 experience suggests a degree of misunderstanding of the historical context in which regulatory asset lives were shortened – and this applies to both the change for electricity distribution in DPCR3 and to the similar later change for electricity transmission. In both cases, Offer's earlier decision to apply a rectangular depreciation profile for pre-privatisation assets meant that the end of this profile implied a very substantial and sudden reduction in the cash flows to the businesses – cash flows which had been assumed in the setting of previous price controls.

As a result, there was a general expectation that Ofgem would act to mitigate the impact of the ending of depreciation revenue in respect of pre-privatisation assets, i.e. a general expectation that Ofgem would, in effect, act to maintain the status quo in terms of expected cash flows. This was indeed what Ofgem did and the lack of market reaction was exactly what would have been expected as a result of the status quo being maintained. Indeed, one might have expected rather significant negative share price reactions if Ofgem had failed to act in the way that it did.

Ofgem also quotes Europe Economics' analogous conclusions to the lack of reactions of various oil companies to changes in tax allowances in the North Sea. However, again, it is not clear that this demonstrates what Europe Economics seems to think that it does. Even leaving aside the question of the materiality of North Sea revenues to the companies in question, the more fundamental issue is that UK government changes in the North Sea tax regime have typically been designed to make *future* (i.e. marginal) investment more financially attractive. As such, the changes had little or no impact on the NPV of cash flows from past investment which would make up the bulk of the foreseeable cash flows for most companies (in other words, a version of grandfathering). To the extent that this was not the case (i.e. to the extent that changes affected past investment), it is arguable that the frequency of changes (Europe Economics highlights changes in 2002, 2004, 2006 and 2009) might lead investors to attribute little value to any particular change, not least on the basis that the change could itself re-occur.

Instead, and even if it is concluded that the technical corporate finance arguments (Brennan and Xia etc) have been, to date, somewhat inconclusive, one is still left with the question of whether investors, as a whole, would be indifferent as between cash flows accruing over a 20 year period and, with the same internal rate of return, over a 45-55 year period. Leaving the financial technicalities on one side, it is hard to believe that investors will exhibit such indifference. At the very least, indifference would require a high degree of certainty to attach to those longer term cash flows and, for both market and political reasons, this certainty does not exist for energy markets.

It is especially hard to believe that investors will be relaxed about the extra risks associated with longer duration uncertain cash flows if one assumes that 'risk-free' assets will, in the foreseeable future, again earn something closer to historically normal returns and thus reduce the ferocity of the 'search for yield' (and attendant yield compression) which has characterised a period of global savings glut – not just because of the unwinding of quantitative easing (whose likely effect is acknowledged by Europe Economics) but also because of the longer term forces in capital markets (in particular, the likely increase in global investment) described in a recent paper from the McKinsey Global Institute.[11] Especially in a world of longer duration price controls, such longer term issues can no longer be ignored.

The proposed changes to capitalisation and depreciation has implications for regulatory predictability. In its recent consultation on Principles for Economic Regulation, the Department for Business, Innovation & Skills (BIS) suggests that 'the framework of economic regulation should not unreasonably unravel past decisions'.[12] The underlying rationale for this is that lack of regulatory predictability will itself increase risks of investing. Thus, Ofgem risks compounding the effect of increased cash flow duration in a world of inherent uncertainty by increasing the uncertainties associated with its own future decision making. Ofgem either has defended itself or could defend itself against

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[11] McKinsey Global Institute (2010), 'Farewell to cheap capital? The implications of long-term shifts in global investment and saving', December.

[12] BIS (2011), 'Principles for Economic Regulation', January, page 5.

the accusation of unpredictable and unreasonable unraveling of past decisions in a number of ways.

- At least in relation to the proposed change in asset life for electricity network assets, it has suggested that it has not adversely affected the 'legitimate expectations of investors' because 'we have signaled for some time that the 20-year regulatory life was subject to review'.[13] In its recent Open Letter on regulatory asset lives, Ofgem has pointed to the regulatory life of assets being raised as an issue in its DPCR4 final proposals.[14]
- The changes could be defended on the basis of a strong consumer interest in the change.
- Ofgem could defend the changes on the basis that the changes which BIS had in mind were ones which affected rates of return – and that Ofgem is not proposing a change in rate of return but an 'NPV-neutral' re-profiling of revenue.

In our view, none of these arguments is sufficient.

- At best, the argument about reasonable warning have been given would apply only to new investment – which would point to the 'split' transitional arrangement (covered below under transitional arrangements), a linkage which Ofgem seems to recognise in the Open Letter. In addition, what was less obviously flagged up in earlier Ofgem publications was the changed approach to financeability itself (for companies to sort out through equity injection/ retention) which is what gives the change in asset lives its potential financial impact and which was not proposed until January 2010 in the paper 'Embedding financeability in a new regulatory framework'.
- The argument for a strong consumer interest in the change does not seem strong. First, Ofgem has a duty to balance the interests of existing and future consumers and it is not clear that existing consumers, already benefiting from the discount between net replacement cost and RAV incorporated into initial RAV valuations of pre-privatisation assets, have a strong case for further assistance at the expenses of future consumers. Second, the modeling carried out by CEPA et al in their paper on asset lives does not seem to suggest a great consumer benefit from the proposed changes.
- The argument that the changes are NPV-neutral is obviously one with which we disagree for the reasons given above in this response.

<u>Transitional Arrangements</u>

Ofgem accepts that there is a case for transitional arrangements to mitigate perceptions of increased regulatory risk. However, it has repeatedly suggested that any transitional arrangements should work themselves out within the next price control period. At the same time, it has acknowledged that the 'split' approach – in which the new asset lives would only apply to future investment – is a possible approach (and one which would clearly not work itself out in one price control period).

[13] 'Financial Issues', para 2.47.
[14] Ofgem (2010), 'Open letter consultation on the regulatory asset lives for electricity distribution assets', January 14th.

In our view, any transitional arrangements should start from the principles underlying a split approach – in other words, the desirability of 'grandfathering' regulatory arrangements in respect of investments which have been undertaken under an existing regime. A robust argument for adopting such an approach is indeed offered by DECC in its recent consultation on electricity market reform.

'Grandfathering: the Government recognises the importance of honouring commitments given to provide generators with a particular level of support, as part of maintaining investor confidence.'[15]

Thus, generating plant which has been built on the basis of the Renewables Obligation (and, indeed, plant which is being planned on this basis but not yet built) will continue to operate under the existing regime.

Similarly, in discussing the introduction of an Emission Performance Standard (EPS),

DECC states:

'One of the unavoidable risks in the energy sector is regulatory: at any point during the operating life of a power station, Government may change the regulatory environment and undermine the economics of a power station, forcing early closure with implications for the investor's finances. However investors will gauge the overall regulatory risk in the UK, based on Government behaviour and a series of discrete, individual decisions. Where investors perceive actions are taken against one set of generators, they will become increasingly nervous and might choose not to make new investments in the UK because of their perceptions of the regulatory risk. For example, decisions taken by the Spanish Government over summer 2010 to retrospectively reduce levels of renewable subsidies has affected levels of investor confidence in Spain and indeed across other European countries.

Another way of helping to ensure investor confidence in the UK energy sector would be to apply the principle of grandfathering, which is widely used in regulatory regimes, including the Renewables Obligation. In its simplest form, the principle of grandfathering, when applied to an EPS would mean that the level of the EPS in place at the point that a power station is consented remains the level which is relevant for the economic life of that power station, i.e. if Government decided to lower the level in the future, say to reflect advances in CCS technology, the EPS would only be at the lower level for plant consented after date of that decision. Without such protection in place, the regulatory risk around investing in new fossil-fuel power stations might prevent any new flexible plant being built, creating a risk to security of supply. The Government's initial view is, therefore, that the EPS be grandfathered, for a period linked to the period of time investors would expect to see a return on their capital investment.'[16]

Thus, DECC is trying to introduce regulatory safeguards into the relatively high-risk world of electricity generation just at the time that Ofgem is at least considering a rather more cavalier approach to supposedly low-risk energy networks.

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[15] 'Electricity Market Reform', page 122.
[16] Ibid., pages 72-73.

The grandfathering argument, when applied to assets, applies much more easily to the changes which are being proposed for electricity networks than to the changed approach to capitalisation being proposed for gas distribution networks. However, the principle of grandfathering is not just about assets, it is about 'arrangements' which have been entered into under a particular regulatory regime. Such arrangements could, in particular, include financing arrangements which have been entered into on the basis of a particular profile of expected future cash flows. At the very least, such considerations argue for transitional arrangements which substantially cushion gas distribution networks from the cash flow consequences of changes to repex capitalisation – and this would mean not limiting such arrangements to one price control period.

In summary:

- The financial framework which Ofgem is proposing (longer electricity asset lives, increased capitalisation of gas distribution repex, possible short-term transitional arrangements but lasting for only one price control period) would inevitably lead to increased financing costs for energy networks (both because of the direct impact on cash flows and because of the increased uncertainty which would be engendered in respect of future Ofgem decisions) and, therefore, to increased long-term costs for energy consumers - and should, therefore, not be implemented in the form proposed;

- Any material change in the existing regime should, at the very least, have transitional arrangements which are based on the principle of grandfathering of existing assets and take account of financing arrangements which have been rationally and efficiently entered into under the existing regime. Such arrangements should last longer than one price control period.

Question 1 – Do you agree with our proposed economic asset lives for gas and electricity transmission and gas distribution?

Ofgem's assessment of economic lives for electricity transmission has been unduly influenced by the perceived long technical lives. This fails to take into account the uncertainty surrounding future use, especially of individual assets in a particular location. For example, generation projections are typically assessed over an expected life of 15 to 20 years. Subsequent developments depend on technological developments, relative primary fuel price movements and future energy, environmental, climate change and planning policies.

The technical lives for electricity transmission themselves appear to have been skewed by the weighting given to National Grid's 275kv and 400kV assets which are not representative of the Scottish TO networks, which also include 132kV assets that are part of distribution systems in England and Wales. Furthermore, the MEAV weights give undue weight to tower foundations, which are assumed to have the longest technical lives. This distorts the calculation of the average technical life.

In view of the extreme uncertainty surrounding energy market developments and future government policies, it is not reasonable to assume economic lives of 45-55 years.

Individual circuits and plant items may be reinforced, modified, re-routed or removed well before they reach the end of their technical lives. Clearly, a significant proportion of assets are replaced or modified before the end of their technical life.

Ofgem's proposals are likely to result in future customers bearing the cost of both existing assets and their replacements. Furthermore, lowering the depreciation charge would result in a larger RAV and higher charges for future customers. This clearly would not be equitable, especially as real energy costs are expected to rise in future.

Moreover, Ofgem have also failed to take into account the effect of incorporating a proportion of operating costs into the value of the RAV, so as to equalise incentives. The value of the RAV no longer simply represents the undepreciated part of physical assets. It is clearly not appropriate to apply technical lives to a financial construct that has resulted from a series of regulatory decisions from privatisation onwards.

We therefore consider it prudent to assume an average economic life for purposes of depreciating the electricity transmission RAV of no more than 40 years.

Question 2 – Do you agree with our proposals for the depreciation profile?

We agree that a straight line is the most appropriate depreciation profile for electricity transmission. A back-loaded profile would result in future customers bearing a disproportionate share of costs of the assets installed for the benefit of current customers. This clearly would not be equitable.

Question 3 – We invite views on our proposed approach on transition?

<u>Existing Assets:</u>

Assets in the RAV at 31st March 2013 must continue to be depreciated at rates existing in the current price control for the remainder of their regulatory lives i.e. in the case of Electricity Transmission NWOs this would mean that post vesting assets should remain at 20 year lives until they become fully depreciated in March 2033.

As Ofgem acknowledges in paragraph 2.40: "We are committed to ensuring that efficient network companies are able to raise the finance they require, both debt and equity, in a timely manner". At a time of significant investment in the electricity industry to help foster a low carbon economy it is essential that investor confidence is maintained if NWOs are going to be able raise the debt/equity funding that will be required. One of the key principles that investors have relied upon when investing in the regulatory businesses is the certainty that their investments in respect of RAV additions to 31st

March 2013 will be repaid over 20 years (post vesting asset lives of 20 years for Electricity Transmission for RAV additions to 31st March 2013). If the regulator damages the principles of stability and predictability there is a significant risk that regulatory trust will be severely tarnished and as a result debt/equity investors will think twice before committing to future investment in regulatory assets. Ofgem are committed to ensuring that efficient network companies are able to raise the finance they require, both debt and equity, in a timely manner and we urge them not to change their commitment to funding over 20 years post vesting RAV additions in the period to 31st March 2013.

Future Assets:

Our initial financial modeling indicates that constraining the transition to the forthcoming price control period would result in an unacceptable deterioration in credit metrics. We will further develop our modeling in order to inform our FBPQ submission but initial indications are that the move to the longer lives (for post 1st April 2013 additions only) should be phased in over at least the next two price control periods and quite possibly longer (the stepped approach).

Chapter 3 – Allowed Return

Question 1 – Is our approach for setting the allowed return appropriate, particularly in the context of an eight-year price control?

The RIIO-T1 proposals will increase increased the cost of capital, whereas Ofgem proposes to reduce the allowed return. This is clearly an unacceptable combination for investors. Some companies will be cash negative throughout the price control period and will need to raise external finance.

The Capital Asset Pricing Model (CAPM) is a single period model and cannot be used to assess the impact of duration of cashflows on the expected return.

Ofgem have not checked their range for the cost of equity against the Dividend Discount Model, which shows that shareholders require a higher return.

The lower end of the WACC range is implausible. Ofgem's apparent consideration of such figures serves only to increase investors' perception of regulatory risk.

The problem of "time inconsistency" has been exacerbated, as TOs have to rely on the consistency of regulatory decisions over a longer period of time.

Question 2 – What impact do our proposals for RIIO-T1 and GD1 have on the companies' cashflow risk, and does this have a material impact on how the allowed return should be set?

The proposals for RIIO-T1 will significantly increase the duration of cashflows by extending depreciation lives for transmission assets and lengthening the period of the price control to eight years. The Capital Asset Pricing Model (CAPM) is a single period model and cannot be used to assess the impact of duration of cashflows on the expected return. Comparing the cost of capital for different profiles of cash flows over time is fundamentally a multi-period problem. There is a substantial literature on multi-period asset pricing models, which have become a well established part of finance theory.

Asset pricing models which have been developed to address the issue of duration, such as Brennan and Xia (2006), show how for lower (asset) beta companies the cost of equity increases with the duration of cashflows[17]. Bernardo et al. (2007) present evidence in support of a positive relationship between betas and the duration of cash flows. Their empirical findings support the view that the beta of growth opportunities is greater than the beta for existing assets. Moreover, the asset betas of firms with above average growth opportunities, which have longer duration cash flows, are higher than for firms with below average growth opportunities, within the same industry. They note:

"the failure to account for [the impact of duration] can lead to misestimating the cost of equity by as much as 3% depending on the industry."[18]

More recently, Da (2009) uses a two factor version of the consumption CAPM, which includes the duration of cash flows relative to the market portfolio[19]. The expected excess return increases with duration for assets with lower cash flow betas relative to the market portfolio. This model significantly outperforms the CAPM and the results are consistent with the framework of Brennan and Xia.

Moreover, there is widely recognised empirical support for movement of estimated beta towards unity over time. Clearly, with an eight year price control a raw beta estimate from a short period of data is inadequate and should be adjusted towards unity, using:

- The Blume adjustment (as used by a number of beta measurement services);
- Bayesian adjustment (as used by the LBS Risk Management Service);
- Upper confidence limit of beta estimate; or
- Zero-beta CAPM

In addition, there is increased risk of "time inconsistency" over time, as returns depend on regulatory decisions over a longer period of time. For example, as the saga of Heathrow Terminal 5 demonstrated, BAA could not rely on a continuation of the expected return beyond the current price control period.

The cull of non-departmental public bodies, commonly known as "quangos", following the General Election and the ongoing government reviews of the principles for economic regulation (by BIS) and regulatory authorities, including Ofgem (by DECC) and Ofwat (by Defra), demonstrate how it is extremely difficult for companies to rely upon regulatory consistency over long periods.

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[17] Brennan, M.J. and Xia, Y. (2006) "Risk and Valuation under an Intertemporal Capital Asset Pricing Model", Journal of Business, 79, 1-35
[18] Bernado, A.E., Chowdhry, B. And Goyal, A. (2007) "Growth Options, Beta, and the Cost of Capital", Financial Management, summer, p2
[19] Da, Z. (2009) "Cash Flow, Consumption Risk and Cross Section of Stock Returns", Journal of Finance, 64:2, April

Furthermore, the longer price control period means that the allowed return is locked in for more years, increasing the required return. In US regulation, an allowance is made for this through an additional "stay-out" premium.

Finally, dividend cuts will increase the cost of equity for the following reasons:

- **"Term Premium":** Investors prefer dividends as they are more certain than capital gains. Analysts attach a premium to utilities with stronger or more stable dividend yields.
- **"Clientele effects":** There are different "types" of investors with different preferences for income or capital gains. Our review of city analysts' reports strongly suggests that investors holding utility stocks expect current income, i.e. the marginal investor is likely to be an institutional pension fund.
- **"Agency costs":** Dividend policy is an effective mechanism for reducing monitoring costs. This is particularly so in a regulated context, where dividends are used to control regulatory behaviour. Many academic papers support this argument.

Question 3 – What considerations do we need to take into account when setting the notional gearing level?

Notional gearing for SPT should be set at 50%, which is consistent with an A credit rating, which would allow finance to be continued to be raised during periods of financial distress. A BBB rating would be sub-optimal and increase the overall WACC, as well as limit access to external finance during periods of capital market disruption.

We are concerned that, should there be another period of stress within the capital markets, for example, as a result of contagion from a sovereign debt crisis, refinancing will be available only to companies with higher investment grade credit ratings. This risk should be mitigated by the initial credit metrics and gearing assumption.

Furthermore, in view of recent criticisms of the rating agencies, their rating methodologies and criteria may be become more demanding in future, which is of particular concern in view of the long term nature of transmission projects.

We face higher equity risk than National Grid due to the combination of us having:

- Higher operating leverage than NGET due to its substantially higher capex to RAV ratio
- Less diverse operating activities and geographic spread
- A very much smaller RAV than NGET (£863m versus £6,474m) and thus higher equity costs associated with the empirically observed "small company" effect.

To place the difference in size between ourselves and NGET in context: NGET would be halfway down the FTSE 100 above International Power, whereas we would be halfway down the FTSE 250, alongside Taylor Wimpey. In other words, we would be ranked 175 places below NGET in the FTSE 350.

Since SPT is a materially higher risk business than NGET, this justifies a lower level of gearing.

Question 4 – Is our proposed approach to setting the notional equity wedge appropriate?

Ofgem's proposed approach is not sufficiently transparent to allow us to comment in detail.

In general, we would expect the notional equity wedge to be sufficient to absorb comfortably the volatility arising from revenue adjustments and unforeseen cost shocks, while maintaining adequate credit metrics.

Question 5 – Is our proposed mechanism for indexing the cost of debt assumption appropriate?

In our view, the proposed mechanism for indexing the cost of debt would not be consistent with Ofgem's financing duty.

The proposed ten-year trailing average, by construction, only adjusts to an increase in interest rates (e.g. when quantitative easing is reversed) over a subsequent ten year period. This leaves the company facing a shortfall in revenues to cover the increase in interest payments and would adversely impact interest coverage ratios.

Moreover, Ofgem's approach to calculating the real cost of debt fails to allow for the inflation risk premium which is incorporated into the nominal cost of debt.

Ofgem propose to rely on data from Bloomberg, whereas many practitioners are more familiar with iTraxx indices. More generally, the benchmark is sensitive to the particular index used and the maturities of the constituents. In particular, the proposed 10 year maturity is not representative of network operators' financing.

The proposed mechanism would therefore be unacceptable to us without an appropriate form of amelioration. We propose the use of a weighted average index which reflects our own debt issuance. A "one size fits all approach" is inappropriate, especially where capex programmes and debt issuance profiles vary across companies.

Furthermore, we require the index to respond more quickly to changes in interest rates, through the use of a shorter trailing average of not more than 5-years.

Question 6 – How should we account for the costs of issuing debt?

The published indices which Ofgem are considering are calculated from secondary yields observed in the market and do not include issuance costs and other transaction costs. To cover such costs, we propose that a minimum of 30bps are added to the yield that is indexed. However, these costs will be proportionately higher for smaller companies, including SPT.

Question 7 – Is our range for the equity beta appropriate for the network companies? What factors might mean that we should use different equity betas for the different sectors and/or companies within a sector?

As the equity beta cannot be determined without a gearing adjustment, it is not possible to determine the consistency with the underlying asset beta.

There is widely recognised empirical support for movement of estimated beta towards unity over time. Clearly, with an eight year price control a raw beta estimate from a short period of data is inadequate and should be adjusted towards unity, using:

- The Blume[20] adjustment (as used by a number of beta measurement services);
- Bayesian adjustment (as used by the LBS Risk Management Service);
- Upper confidence limit of beta estimate; or
- Zero-beta CAPM

Using the Blume adjustment and 5 years' data, NERA estimate an average asset beta of 0.41 for European network operators, which would imply an equity beta of 1.03 at 60% gearing.

However, betas which are estimated from historic data cannot take into account the increased volatility and dispersion of returns which will result from the incentive mechanisms and output requirements which will be implemented as part of RIIO. Also, the longer price control period will amplify the impact of any systematic risks that have a persistent effect on value. Forward looking betas will inevitably be higher.

Furthermore, the equity beta for SPT is higher than for NGET and water companies, as:

- Electricity consumption is more exposed to the business cycle than water
- SPT has higher operational gearing than NGET; and
- SPT is much smaller than NGET

[20] Blume, M. (1971) "On the assessment of risk", Journal of Finance, 26, pp 1-10

Question 8 – Does our overall range for the cost of equity capture probable range for RIIO-T1 and GD1?

The absence of clarity surrounding the assumed gearing makes it impossible to effectively assess the cost of equity. In any case, the lower end of the range is implausible and inconsistent with estimates for the cost of debt and observed dividend yields for network operators.

European and US regulators are setting the cost of equity at 7.5% to 8.5%, which is 30 to 130bps above the upper end of Ofgem's range.

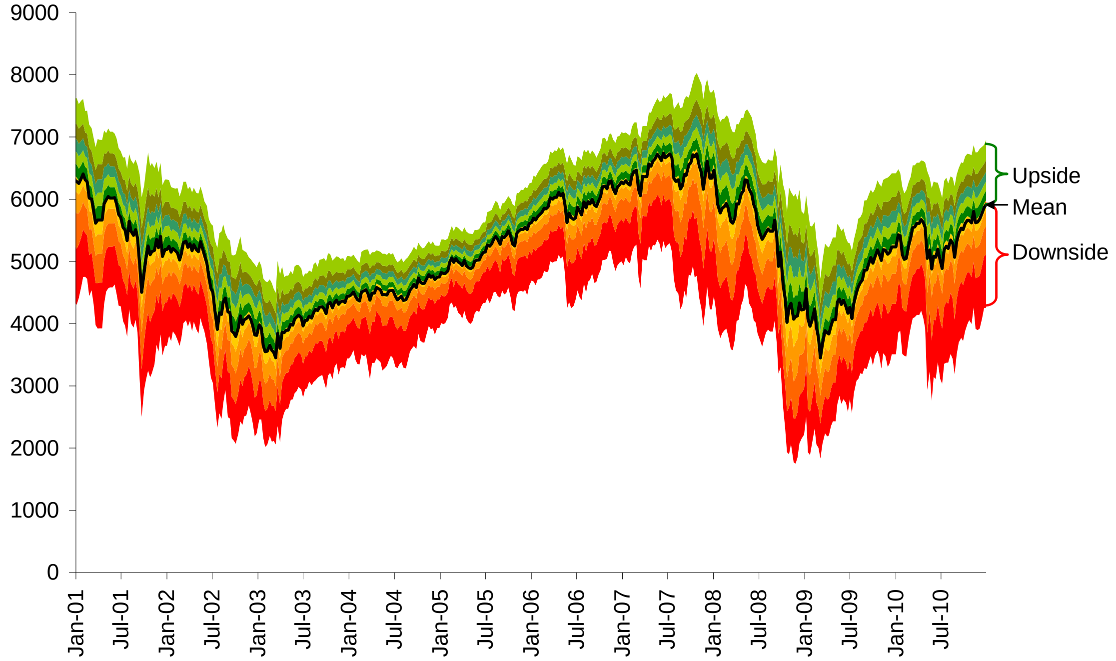
The upper end of the range for the cost of equity is below that derived from the Dividend Discount Model. Ofgem have not cross-checked their range with alternative approaches to estimating the cost of equity.

Furthermore, the CAPM estimates, which appear to underlie Ofgem's range do not allow for a higher forward looking risk premium which is higher than the historic average.

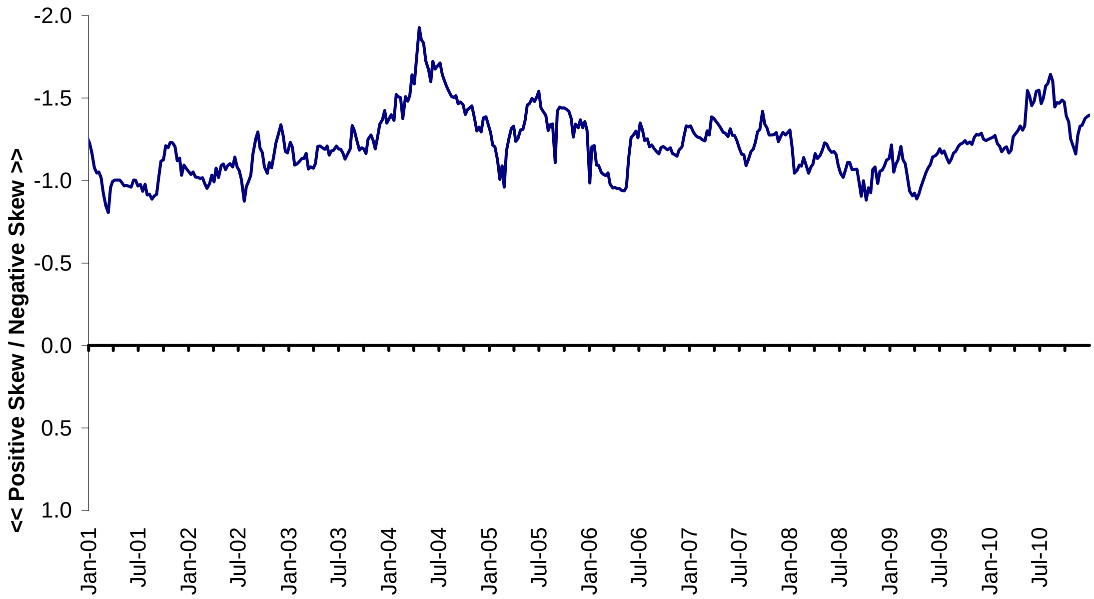
Ofgem's assertion than "normal" market conditions will prevail has no basis. Indeed, equity market volatility remains higher than when the price controls for TPCR4 and the GDPCR were set (in December 2006 and December 2007, respectively). The last ten years have seen three major crises (i.e. the burst of the dot-com bubble, the credit crisis and collapse of Lehman Brothers, and the sovereign debt crisis. The 10 year average which Ofgem use as a reference level cannot therefore be considered as a period of normality. Moreover, the allowed return must be robust in the event of major unforeseen financial turmoil.

In addition, data from option prices show that investors perceive greater downside risk in equity prices. However, the CAPM assumes a symmetric distribution of risk and return. Extensions of CAPM which account for skewness in returns, indicate a higher cost of equity for negative skew. To take account of this higher expected downside risk, the allowed return has to be set above the CAPM estimate, to offset downside skewness.

Option implied percentiles for FTSE 100 in 6 months' time



Option implied skewness of FTSE 100 returns in 6 months' time

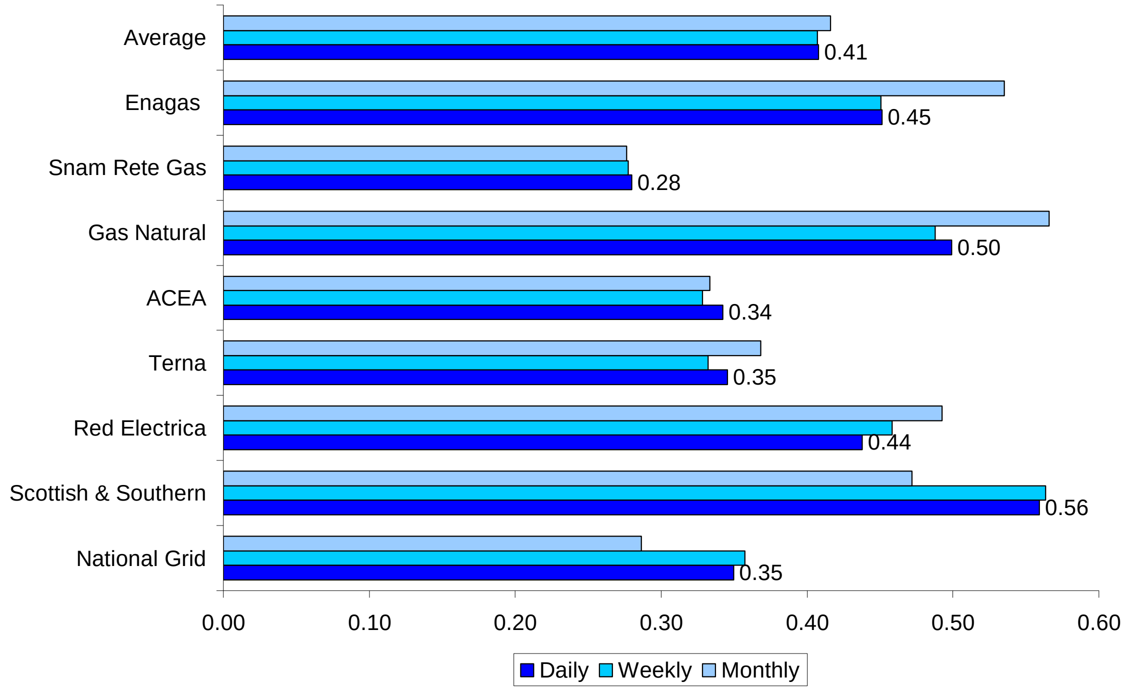


Global Investment Strategy
UK Equity Risk Premium

UBS' estimate of the UK equity risk premium increased again during 2010 and is at level which was only exceeded following the collapse of Lehman Brothers.

Moreover, Ofgem do not allow for an equity beta of unity or above, which would result from an asset beta of 0.4 or above with gearing of 60% or more.

5-year asset beta for European Network Operators



In addition, as the Scottish TOs are much smaller than NGET, they require a small company premium, as determined for small water companies.

Overall Ofgem's December range for the cost of equity appears arbitrary and fails to provide a sound basis on which to attract sufficient finance to fund the essential investment in the transmission system.

Taking into account the above, our investor tells us that the required return on equity for SPT is significantly above Ofgem's range and could be as high as 9.5%, at 50% gearing.

Question 9 – Is the ex ante approach to the cost of raising equity, with a true-up at the next price control review appropriate for RIIO-T1 and GD1?

In principle, we agree that the cost of raising equity can be set as an allowance in the financial model. We estimate the cost of raising equity to be at least 5%, although it would be higher for smaller amounts.

The true-up should take into account equity raised elsewhere in the Group, provided that it is for the benefit of SPT. For example, it is likely to be more cost effective to raise new equity for more than one network licensee in a group, at the same time.

The true-up should take place at the beginning of the next price control period, which allows the precise timing of an equity issuance to remain flexible. Clearly, the timing of any equity issuance would be dependent on market conditions, which can change rapidly.

Chapter 4 – Assessing Financeability

Question 1 – Have we identified the correct equity and credit metrics?

It appears that the major credit rating agencies focus on:

- Net Debt / RAV
- Post-maintenance Interest Cover Ratio (PMICR)
- Interest coverage ratio.

In particular, we are aware that not all credit rating agencies prefer PMICR to the unadjusted interest cover ratio.

Question 2 – Do the rating agency levels quoted provide the most appropriate levels?

In its Industry Outlook 2010 for EMEA electric and gas utilities, Moody's warn that:

"All other things being equal, to the extent that business risk increases, that will probably result in a tightening of guideline leverage ratios at the same rating level."

and

"the sheer size of the investment programmes, coupled with potentially tighter regulatory constraints in some regimes, could lead to rating pressure if tariff increases are insufficient or untimely, and capital structures become overburdened with debt."

In view of recent criticisms of the rating agencies, their rating methodologies and criteria may be become more demanding in future, which is of particular concern in view of the long term nature of transmission projects.

Typically, rating agencies have adopted a three year horizon for assessing financial ratios. However, the probability distribution of financial ratios widens with the time horizon. Consequently, the probability of financial distress increases over time. The proposed longer price control exposes SPT to higher cumulative risk. This increases the need for stress testing of financial ratios.

In its 2011 Outlook for UK utilities Fitch highlighted that:

"From a credit risk perspective particularly the downside risk is relevant for the analysis. If the price control cycle is extended and there are no other changes to the regulatory regime, then this clearly increases credit risk."

Question 3 – We invite views on the approach to assessing the appropriate level of notional gearing.

Credit metrics should be set at a level consistent with an A rating. For SPT, which faces a large increase in its capex programme, notional gearing should be set at 50%.

Chapter 5 – Taxation

Question 1 – Do you agree with modeling tax based on the proposals in the June 2010 Budget?

The impact of changes to tax legislation is totally outside the control of network operators. We do not agree with the Competition Commission's comments in their report on Bristol Water plc, that changes in the tax rate is a normal business risk. Normal businesses in a competitive (non regulatory price controlled) market are able to react to changes in tax legislation by adjusting prices if they wish; this option is not open to regulatory price controlled companies who have ex ante revenue allowances set by the regulator based on tax legislation in force at the time of the final proposals. We accept that the risk is partially mitigated by the tax trigger mechanism; we accept the principle of a tax trigger point to determine whether or not an adjustment should apply however we believe that once the tax trigger deadband threshold has been breached the whole impact should be reflected in the adjustment to revenue not just the excess over the trigger point.

In paragraph 2.18 of the Financial Issues paper reference is made to Ofgem's Long term Electricity Network Scenarios which result from consideration, inter alia, of either rapid or slow economic recovery. The pace of economic recovery applies equally to tax legislation and the flexibility of fiscal measures as one of the tools to manage economic growth. In times of economic uncertainty when there could be material changes in tax legislation both customers and network operators need to be fully protected against the impact of such tax changes. In paragraph 5.2 Ofgem have correctly recognised the conundrum of the winners/losers depending on whether or not the forecast changes are modeled and whether or not they ultimately materialise. Therefore we believe that a variant of option c in paragraph 5.3 is the fairest solution to modeling tax: "Use extant rates *as proposed in the most recent budget before final proposals (including any proposed future year changes signaled in that budget)* but automatically pass-through any changes to CT and CA rates without any dead-band. This has the benefit that both customers and licensees are fully shielded from any upside or downside exposure".

If, however, the decision is made to adopt Ofgem's preferred option a i.e. "Use June 2010 Budget tax rates *(reflecting any changes in subsequent budgets prior to final proposals that affect CT and CA rates)* with the DPCR5 type tax trigger and dead-band" we suggest that 8 years is too long for network operators/customers to be exposed to the full amount of any tax changes and suggest that the tax allowances should be reset after 4 years (via a mini reopener) to reflect the most up to date tax legislation.

The opening capital allowance pool balances need to be adjusted to remove the balances associated with TIRG, logged up costs and other incentive mechanisms (including projects associated with TO Incentives (ENSG). Shadow capital allowances calculations should be made for these categories so that their written down values can be added to the pools when these categories are included in the RAV.

Question 2 – Do you agree with modeling tax under UK GAAP pending adoption of IFRS reporting with any changes to be subject to the tax trigger?

Adoption of IFRS has been signaled and it is all but a fait accompli that IFRS will be in place for the majority of the 8 year RIIO-T1 price control. Therefore tax should be modeled under IFRS. If the decision is made to model tax under UK GAAP then any subsequent changes that would normally fall within the scope of the tax trigger should be automatically passed through without any dead-band.

Question 3 – We invite views on the size of the dead-band?

Consistent with the decision in DPCR5 the tax trigger should be calibrated around a one per cent change in the corporation tax rate.

Question 4 – Do you agree that clawback of the tax benefit of excess gearing in TPCR4 & GDPCR1 should be spread over the eight years of the RIIO price control? If not, which alternative option do you prefer?

Yes, we agree.

Question 5 – Do you agree that clawback of the tax benefit of excess gearing should be updated every three years during the price control period?

Yes, we agree.

Question 6 – Do you agree that the tax treatment of new incentives should be calculated using vanilla WACC?

Our preference is to retain the existing pre-tax WACC for new incentives because this is simple to apply.

If it is decided to adopt the vanilla WACC plus the estimated incremental tax effects for new incentives we think that detailed modeling should be applied to ensure that neither customers or network companies are penalised.

Chapter 6 – Pensions

Question 1 – Do you agree that the timing of true up adjustments for existing controls should be spread over the eight years of the RIIO price control? If not, which alternative option do you prefer?

Consistent with the principle established in DPCR5, the true up adjustments for existing controls should be funded in year one (in the case of Transmission this would be the 2012/13 rollover year).

Question 2 – Do you agree that updated valuations for non fast-tracked companies should be the same as fast-tracked companies, ie 31 March 2011 unless no network company is fast-tracked, in which case updated as at September 2012 in time for final proposals?

Consistent with the principle established in DPCR5 the most up to date data should be used for valuations regardless of whether the company is fast-track or non fast-track.

SP ENERGY NETWORKS

Question 3 – Do you agree that the deficit funding rate of return should be derived for the range of benchmarked pre-retirement real discount rates? If not, which alternative option do you prefer?

We think that a scheme specific rate (option e) should be used to ensure consistency with the approach used to agreeing the deficit contributions with the trustees. Use of a higher discount rate, for example, than the scheme specific rate might imply a riskier investment strategy which would be inconsistent with the rest of the triennial valuation.

If this does not prevail then our second preference would be to continue to derive the deficit funding rate of return from the range of benchmarked pre-retirement real discount rates (option a).

Question 4 – Do you agree that same rates should apply to the calculation of the net present value of the true up adjustments?

We agree that the same rate should apply to the calculation of the net present value of the ex post true up adjustments.

Question 5 – Do you agree that deficit funding allowances and the true up to date in a RIIO price control period should be every three years rather than truing up at the next eight-year price control?

We agree as this will tie in with the triennial valuations. To avoid duplication of effort the same three year true ups, valuations and associated efficiency reviews should be used for both the RIIO-T1 and other regulatory price controls e.g. Electricity Distribution price controls

Question 6 – Do you agree that PPF levies should be part of benchmarked total costs? If not, which should be the alternative option?

The future framework of the PPF levy is uncertain therefore a benchmarking approach to assessing the allowance could penalise both network companies and customers. Therefore full cost pass through, similar to business rates and the Ofgem licence fee, would seem to be the fairest approach.

Question 7 – We invite views on whether the revised guidance to our pension principles is comprehensive and adequate for licensees and stakeholders to understand how the principles will be applied in RIIO controls and for network companies to prepare their business plan?

The guidance on the pension principles is adequate.

SP ENERGY NETWORKS

Chapter 7 – Regulatory Asset Value

Question 1 – How should we calculate the percentage of totex allowed into RAV?

Whilst a blend of the approaches suggested by Ofgem merits further discussion, it is difficult for us to comment substantively this early in the process until the impact of other policy changes are more clearly understood.

Question 2 – The proposed totex approach includes repex, business support costs and non-operational capex as part of totex. Views are invited on whether totex should include (a) Repex; (b) Business support costs; (c) Non operational capex

In principle we would have no objection to including these items as part of totex although it is difficult to see how Business Support Costs and Non-operational Capex could be substituted to any significant degree with capex or operating costs

Question 3 – Should the definition of related parties include captive insurance companies?

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Question 4 – In GDPCR1, we allowed GDNs to retain the proceeds of asset disposals in RAV for five years to incentivise GDNs to dispose of assets at competitive prices. We invite views on whether we should now remove this treatment, or extend it to electricity distribution operators and transmission operators so that we deal with all licensees on a similar basis.

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Appendix 2 RIIO-T1 Outputs & Incentives

Chapter 1 – Introduction & Context

Question 1 – Do you have views on the approach we have undertaken in developing the outputs framework?

We support the development of outputs. However the process for has been far too rushed. Given the challenging timescales, progress has been made but there is a concern that the opportunity to agree the scope and principles underpinning many outputs may be compromised by Ofgem's deadlines for completing work prior to publishing their March final proposals on strategy. This short-notice is a concern, particularly given that the implementation of RIIO T1 is still more than two years away at April 2013.

We believe that a further 6 months is required to design and develop clear outputs. It is important that the strategy consultation outcome leaves open the opportunity to further refine outputs that meet Ofgem's requirements, and also provides the right risk / reward balance for the transmission companies.

Question 2 – Do any of our proposed output measures present potential difficulties in ensuring the submission of accurate and comparable data?

Currently the detailed development of output measures has not developed far enough for us to assess whether there are any difficulties in ensuring the submission of accurate and comparable data.

Question 3 – Are there any aspects of our proposed outputs framework where the reporting requirements are likely to lead to disproportionate regulatory costs?

We do have reservations that reporting regimes may become significantly more complex as the increase in the number of and sophistication of outputs of creating more of an overhead will be more of an overhead in reporting these outputs. It is therefore important to ensure that the outputs not only support the regulatory process but also have a clear business benefit.

Question 4 – Do you have any views on whether, in principle, it is appropriate to consider requiring the companies to do more to verify their regulatory reports?

We believe that the current process works well. Noting that the number of outputs will increase, we would like to avoid an overly burdensome regulatory overhead in reporting our outputs.

Question 5 – Should we introduce an independent examiner for the TOs to improve regulatory reporting?

We are happy for an independent reporter appointed by Ofgem verifying our returns. It is essential that any reporter has extensive experience in the particular area in question to ensure necessary considerations are taken into account. For example a reporter considering Asset Health changes would need to have extensive experience in the application of different asset management techniques to understand the trade-offs that a company may take to re-balance risks which result in changes in its delivery of outputs.

Question 6 – Do you have any views on our proposed approach to revising outputs?

We agree that areas where it might be appropriate to makes changes to outputs are administrative errors and unfit measurement. However, we also believe that it is important to provide for changes in other circumstances. In particular, if an incentive leads to exceptionally high and undeserved penalties, such as potentially through the NRIS incentive, then we believe arrangements that allow the transmission company to refer the matter are appropriate.

Chapter 2 – Safety Outputs & Incentives

Question 1 – Do you have any views on the primary output and secondary deliverables for electricity and gas transmission safety?

We agree that for electricity transmission the minimum safety requirements are detailed within relevant legislation. Our key objective is to undertake all activities without harm to staff or public. As safety performance information is already provided to the HSE duplication of reporting should be avoided. This effectively sets an internal target to exceed these requirements wherever practicable.

The proposed primary output is appropriate as it provides an overall output confirming whether companies are complying with the legislation.

The proposed secondary deliverables are appropriate as they will provide assurance that companies are providing stewardship of their network through management of asset condition and the risk this presents to stakeholders. Monitoring of the overall performance against the suite of secondary deliverables is as outlined in chapter 3.

Question 2 – Are these appropriate areas to focus on and are there any other areas that should be included?

We believe that the proposed outputs are appropriate and meet the objectives of outputs (i.e. measurable, controllable, comparable and auditable). Through discussion of options at the working group other potential measures were excluded as they didn't fit these criteria, therefore these are the most appropriate measures at this time.

Question 3 – Do you agree with the proposed approach to setting safety incentives?

Yes we agree that it would be inappropriate to include financial incentives on primary safety outputs as the HSE, as the primary regulator for safety, has power to apply penalties associated with poor performance through existing legislation.

Chapter 3 – Reliability & Delivery – Electricity Transmission

Question 1 – Do you have any views on the primary output and secondary deliverables for electricity reliability and availability, including: (1) are these appropriate areas to focus on? (2) are there any other areas that should be included? (3) do you agree with the proposed approach to setting reliability incentives?

Although our preference would be to continue with the current events based network reliability incentive which recognises that the Scottish transmission owners cannot control flows on the network in real-time, we are willing to accept an unsupplied energy incentive on the proviso that exclusion rules can be agreed and there is a cap on the maximum penalty.

We agree that Energy Not Supplied (ENS) is an appropriate primary measure of the performance of the transmission network. However it should be recognised that this measure is not directly within the control of Scottish TOs. In Scotland the SO has more control over this measure than the TOs.

The proposed secondary deliverables cover a wide range of variables:

- Asset health
- Criticality
- Replacement priority/ risk
- Circuit unreliability
- System unavailability
- System faults
- Asset Failures

We believe that the combination of asset health, criticality and replacement priority are the main secondary deliverables which should be considered. The other factors of circuit unreliability, system unavailability, system faults and asset failures are less important and where it may be helpful to monitor these areas, they are less important to delivery of the investment plan in Transmission.

Given the comprehensive suite of secondary deliverables SPTL do not believe that there are any other areas which should be included for reliability and availability.

We also agree that financial incentives should only be linked to the primary output of ENS. Development of the incentive mechanism must be directly related to the definition of the measure and the relevant exclusions. This will ensure that the financial incentive on the TOs relates to a measure which reflects their level of control on that measure.

The incentive mechanism should be fully symmetrical offering rewards as well as penalties. Following our discussions with Ofgem, we note that the NRIS incentive should be based around +1% with a slope based on a VOLL of around £16000/MWh. We do not agree that there should be no collar applied to the ENS incentive. A natural cap exists in the form of achieving zero ENS. To provide a fully symmetrical incentive a collar equal to double the target is required to ensure that TOs are exposed to the same level of penalty as reward. Hence, in our view a penalty limit of 1% of allowed revenue would be appropriate.

Analysis of our performance shows that over the last 10-years this level has only been exceeded once, in 2000/01. This was due to events related to the severe weather experienced in that year, which it would be unfair to penalise a TO for the full extent of a severe weather occurrence.

Question 2 – Do you have any views on our proposed treatment of different loss of supply events when calculating energy not supplied (ENS) including: (1) events lasting three minutes or less? (2) events that cause electricity not to be supplied to three or fewer directly connected parties? (3) events resulting from actions to ensure public safety, third-party damage, severe weather and other exceptional events? (4) planned outages? (5) events on an adjacent system?

We agree that events lasting three minutes or less should be excluded. This would allow exclusion of events caused by the weather which are quickly resolved through the correct operation of the transmission network. This exclusion is already utilised in electricity distribution and would provide consistency across the electricity network.

Excluding events affecting 3 or fewer directly connected parties was included in the NRIS as proxy measure of parties having a lower standard connection. This was included in the NRIS due to the short timescales available for development of the NRIS incentive. Given the low number of directly connected demand customers with a lower standard connection it is appropriate that this exclusion is amended to only exclude those events affecting customers with a lower standard connection.

One of the requirements of outputs is that they are controllable by the TO. Therefore it is appropriate that events beyond the control of the TO are excluded from the incentive mechanism.

There are a number of events each year where TOs are required to disconnect supplies to ensure public safety. For instance a member of the public may have climbed an overhead line tower and we are required to switch out the line to avoid electrocution.

The actions of the public in cases like this are beyond the control of TOs and exclusion of these events is appropriate.

The proposed approach for exclusion of third party damage and other exceptional events, where TOs would be required to demonstrate that they meet exceptionality requirements, is appropriate. Development of a process and agreement of the terms for exclusion will be important. The process for DNO IIS exclusions will provide a sound basis for this work.

We believe that the current exclusion for severe weather, seven faults in 24 hours, remains appropriate and should be used for the ENS incentive scheme. During the life of the current scheme SPTL have only applied for one severe weather event and consider the current criteria to be effective.

We believe that planned outages affecting demand customers should continue to be excluded. In principle interruptions to demand customers should be incentivised to reflect the inconvenience. However planned outages affecting demand customers on the transmission system are only taken with the agreement of customers. The process of the SO agreeing the planned outage with customers provides them with advance notice of outages and minimises their inconvenience.

During TPCR4 to date we have undertaken over 3000 sections of network out of service. None of this work has resulted in a customer interruption to a demand customer. Our customer connections arrangements minimize the need to interrupt supplies to demand customers and although these types of outages may be required on rare occasions to carry out essential works, these events would be unusual and negotiated individually with the customer.

Through stakeholder engagement we have not been become aware of any customer satisfaction issues with the planned outage process. To help understand whether this is an issue of concern to customers it would be useful to add some questions on the process to the customer survey discussed in chapter 6.

We disagree with the proposed approach for treatment of events triggered on an adjacent system. The DNO IIS incentive scheme has been used as a benchmark throughout the working group development of the ENS proposal. Within the IIS scheme DNOs are penalised for 0% of customer interruptions and 10% of customer minutes lost for an event triggered on an adjacent system. This is an appropriate approach as it is recognised that the DNO can only influence the duration of the event. In the same way a TO can only influence the duration of the event triggered on an adjacent system so a similar penalty should be applied.

Question 3 – Do you have any views on our proposed options for applying financial consequences in the case of material under or over-delivery of secondary deliverables?

We note that Ofgem propose an incentive framework for secondary deliverables that will require the TOs to demonstrate how their expenditure is linked to managing network risk both at the beginning and end of the price control period.

We agree with the principle that financial consequences may apply in cases where there is clear and material under or over-delivery and that these options are based on either revenue adjustment at the end of RIIO-T1 or to begin RIIO-T2 on the assumption that the TOs have achieved agreed levels for the deliverables. If this approach is to be taken then the following points must be taken on board by Ofgem:-

- Firstly, it will be important to ensure that Ofgem makes full use the network output measures detailed by the transmission licensees as part of the annual regulatory reporting process, and understands the reasons for changes for one year to the next.

- Secondly, that it would be inappropriate to benchmark performance between the transmission licensees given the different networks.

- Finally, it will be essential that we are given full access to the network by the SO in order to undertake our asset replacement and refurbishment programme. It is important that Ofgem acknowledges this point and works with us and the SO, who is incentivised to minimize their constraint costs, to ensure that we are given the level of network access we require.

Question 4 – Do you agree with our proposed approach to incentivizing the TOs for the impact of planned outages on constraints, including: (1) is it appropriate to incentivise TOs? (2) if so, should the incentive be broadened to other areas – for example, unplanned interruptions? (3) are the confidentiality issues around constraint costs material and if so, how might they be resolved? (4) is there a need to review the procedure for incorporating the full cost of cancellation to the TOs?

Avoiding constraints both within and from Scotland are best resolved by reinforcing the wider transmission system through undertaking reinforcements to the wider system as quickly as possible.

We note that Ofgem would like to have a linkage to actual constraint costs rather than a more general measure. Although a constraint incentive has the potential to compromise the essential asset replacement and refurbishment required to maintain quality of supply, we are willing to discuss with the SO an incentive based on minimizing constraints. Our concern is that we require system access to undertake essential asset replacement and refurbishment which we believe should take precedence over constraint minimization.

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We note the total value quoted for "within Scotland" constraints but we have no information on their location, duration or cost. In 2008 we first raised with Ofgem the possibility of SP Transmission being provided with more information on constraints in Scotland, as we believed that we could help to avoid or minimize constraints. Hence, if a constraint incentive scheme is to be based on actual constraints, then it will be essential that we are provided with full information from the SO such that we can verify that the actual savings or actual increases. Without this transparency we will not be willing to consider this incentive.

For example, if some constraints are caused by planned circuit outages necessary to undertake essential asset replacement and refurbishment, then it is important that this work takes precedence and the Scottish TO is not penalized. Where there is the opportunity to shorten the duration of outages safely, and with all work undertaken, then there should be a fair sharing of any constraint saving between the SO and TO

Chapter 4 - Reliability & Delivery – Gas Transmission

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Chapter 5 – Environmental Outputs

Question 1 – Do you have any views on the environmental outputs outlined?

We recognize and support that the electricity network companies have a key role in supporting the move to a low carbon economy, with increased reliance on electricity for transport and heat in the longer term. Secondary elements for a TO, such as losses, could be revisited in future price controls

Question 2 – Are these the appropriate areas to focus on and are there any other areas in which primary outputs and secondary deliverables should be set?

We believe that the areas identified cover the necessary primary outputs & secondary deliverables

Question 3 – Do you agree with the proposed approach to setting environmental incentives?

We support the proposed approach to setting environmental incentives.

Question 4 – Do you have any views on what the TOs 'full role' in a low carbon economy may involve by the year 2020?

In the short term, over the next 5 to 10 years we believe the focus should be on encouraging TOs to connect, and provide capacity for large scale renewable generation (principally onshore and offshore wind generation). As the low carbon economy develops, with suppliers of equipment for electric transport and heating developing their products from concept, through small scale trials into country wide deployment, our focus may need to change towards RIIO-T2 as clarity develops over their requirements for Transmission network capacity

Question 5 – What role is there for a primary output in RIIO-T1 on TO's contribution to the UK's environmental and energy objectives and what type of incentive would be most effective to drive TOs delivery in this area?

We believe a primary output to connect renewable generation, and increase boundary capacities in RIIO-T1 would be helpful.

Question 6 – Do you have any additional views on Renewable UK's proposal for a specific low carbon economy output including the form and size of such reward mechanism?

We agree with Renewable UK that network companies have a vital role to play in the delivery of the low carbon economy. However, more clarity is required on exactly how this output would work in practice. What would help is to work through a practical example.

Question 7 – Do you have views on the relative roles of the TO and SO in relation to gas shrinkage and venting, and how we might align the incentives between the two parties?

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Question 8 – What incentives should companies face to manage their carbon footprint?

We support the proposal that a reputational incentive is the most appropriate approach for carbon footprint management by the TOs.

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Question 9 – What incentive should be put on TOs in relation to losses?

We do not agree that the transmission companies should be incentivised on transmission losses.

National Grid as the System Operator could in theory take actions to reduce losses but the reality is that transmission losses are a function of the disposition of generation and demand on the transmission system. Indeed, the introduction of large scale renewables in remote parts of Scotland will increase losses.

It is notable that as part of the onshore reinforcements, we will undertake various measures such as voltage upgrades which will help reduce losses. In addition, where the opportunity arises, we will remove redundant ageing 132kV assets from our network and this will also help.

Our current approach to transformer procurement considers the transformer capital and operating costs, including losses, over the complete life cycle of the transformer. In theory, it may be possible to reduce losses is through the procurement of even lower loss transformers and we have considered this as part of our outputs work. Making use of information prepared by Renewables UK we concluded that the replacement of 30% of our transformers over the period of RIIO T1 at a cost of £240M will help reduce losses by 0.04%. Indeed Renewable UK's own analysis shows how little saving installing 30% of our transformer population over RIIO-T1, at a cost of well over £200M.

Question 10 – What are the options to avoid any perverse impacts on network development to connect renewable generation?

Perverse impacts could result, for example, if we are required to undertake sub-optimal investment to connect a renewable generator to agreed timescales, rather than waiting for the completion of a more economic, coordinated solution. There are many examples on our network of economic solutions based around our development of "collectors" i.e. optimal shared infrastructure, rather than large numbers of long radial connections for individual generators.

The development of collectors can mean that more time is required to obtain necessary consents; involving the development of detailed environmental impact assessments, engagement with local and national stakeholders, approval from local authorities and often also approval from the Scottish Government. In addition, obtaining agreement with landowners can take more time particularly when we must deliver the infrastructure cost-efficiently.

We actually have a good track record in delivering timely grid connections and our experience is that any changes from the originally contracted dates are due to factors out with our control; usually due to planning consent delays, changes to developer requirements and a lack of understanding or guidance within the industry of mitigating programme slippage.

Hence in terms of options to avoid perverse impacts, we suggest that any incentives around the timely connection of renewables should consider overall delivery over a period, taking into account exceptional circumstances, rather than incentivizing individual connections.[21]

Question 11 – Do you agree with the principle of full internalization of environmental costs? To what extent should the output for SF6 mover towards this objective?

The installation of assets which make use of SF6 have various benefits. For example SF6 based switchgear help minimize substation footprint, and the gas insulated transformers being installed at Dewar Place are essential from a safety standpoint. We manage our SF6 inventory in accordance with industry good practice, and have not identified projects above this level. Out of our current 40500kg of gas, 50% is located at Torness. In order to reduce our inventory and actual loss of gas, one solution would be to replace this site with a modern equivalent with a lower designed leakage rate. However we don't believe that this £30m replacement would be value for money for customers, as this site is generally in good condition.

Currently almost all transmission assets have been purchased and installed to IEC specifications which vary up to 3% leakage as design rating. Our current leakage rate at around 1.5% of total installed SF6 gas is on, if not below design standards. In effect, our operating regime is already performing much better than the equipment specification and we have determined that it is not possible to improve the performance further. Therefore our plans for a flat profile are appropriate and we believe there is limited scope for further savings.

As stated above the underlying asset age and the purchase specification contribute to ongoing levels of maintenance. We follow industry good practice for the management of SF6, above this; the only effective method of reasonably operating at a significantly lower target would be a substantial Capital programme of asset replacement. We believe our plans of 1.5% is significantly challenging due to the age condition of our fleet of switchgear and current transformers

Chapter 6 – Customer Satisfaction Outputs

Question 1 – Do you have any views on the primary outputs outlined for customer satisfaction?

We support Ofgem's approach for enhanced stakeholder engagement. Although we strictly only have one customer - National Grid Electricity Transmission as the NETSO – we recognize that we actually have many customers and stakeholders and even since the advent of BETTA in 2005 we have actively looked to maintain links with all

[21] It should be noted that the current connection charging arrangements incentivise us to complete connection as quickly as possible.

stakeholders; from developers and existing directly connected customers, to industry bodies and government.

We agree that a primary output based around a customer satisfaction is appropriate. We believe there should be two components; survey evidence and stakeholder engagement. Our experience as a transmission owner is that we have very few complaints and so we agree that a complaints handling metric may not be appropriate.

With so few customers, care must be taken around the development of a customer survey metric to ensure that no bias is introduced i.e. one negative response from a customer, which may not necessarily be justified, could skew the survey metric and potentially create a substantial penalty on the transmission company.

Question 2 – Are these the appropriate areas to focus on and are there any other areas that should be included?

Improving customer satisfaction is an area that our overall networks business is very focused on improving and we are keen to develop this area. We support two of the three components; covering survey evidence and , stakeholder engagement.

If anything, the best measure of customer satisfaction is quality of supply and annual information is provided in the GB Transmission System Performance report. Ofgem already intended to incentivise the transmission companies through the NRIS.

Question 3 – Do you have any comments on the proposed approach to setting incentives related to the customer satisfaction outputs?

We support the proposed approach being taken. We are pleased that Ofgem has taken due account of the fact that the relationship with customers and stakeholders in transmission is different from distribution, that there are differences between the Scottish TOs and NGET as a combined TO/SO, and has recognised the difficulties that the Scottish TOs can have in obtaining customer views.

We are very keen to work with Ofgem on the principles and design of a customer survey. There would be some issues to address. For example, as noted above we have a concern over the potential for bias across what would be a limited survey group i.e. the potential for one biased survey could impact on our overall score.

In terms of stakeholder engagement, we support Ofgem that any discretionary reward for effective stakeholder engagement should be about demonstrating that strong customer engagement directly leads to better outcomes.

Question 4 – Should the incentives apply to National Grid both for good performance as SO as well as its TO role?

We believe that NGETs role as a system operator and as a Transmission Owner should be clearly ring fended, and the TO business incentivized, as per the Scottish TOs, as if it were a separate company

Chapter 7 – Conditions for Connection

Question 1 – Do you have any comments on the key principles we have identified for the delivery for connections?

We agree that it is important that a transmission company delivers new connections to the network in a timely way. We have an excellent track record in delivering timely grid connections, and our experience is that any changes from originally contracted dates are due to factors out with our control.

We believe that there is a requirement for a extensive and holistic approach in reviewing wider industry and government processes surrounding planning consents. Obtaining all necessary consents is dependent on outside agencies, such as local authorities, providing consent approval to competent planning applications in realistic timescales. Fundamentally, the main reason for any connection delays is planning consents, and these delays are not within the control of the transmission licensees. In addition, the advent of considerable onshore wind in Scotland has led to Scottish landowners becoming much more aware of the value of land necessary to connect wind. Consequently, our experience obtaining landowner consents can take some time, particularly if we are to ensure that sole-use infrastructure is delivered cost-efficiently.

We should point out that we work very closely with both National Grid and developers during the connection application process to agree connection dates that take a realistic view of the consent, construction and commissioning processes. At this stage of the process, we will advise the developer of connection options that will improve their chances of obtaining timely consent such as, for example, consideration of wood pole single circuit overhead lines or undergrounding.

Pre-Application Incentive

In terms of preparing offers at the pre-application stage, under procedure 18-1 of the SO-TO Code, which covers the application process for new connections and for modifications, on receipt of a competent application we have ten weeks to then process the application and submit a TO Construction Offer to National Grid. The detailed engineering design for connection applications can vary considerably depending on the location of the connection, and user requirements e.g. required connection date, and willingness to consider undergrounding. In addition, we try to ensure that any offer is subject to full system and financial approval. Consequently, producing a fully engineered connection offer that has been through our approvals process can take time, and our experience to date is that we generally need the full ten weeks to make a competent offer.

However, we are willing to consider a pre-application incentive but we will need to ensure that this does not compromise the quality of an offer. At Ofgem's workshops, one party, in particular, believed that there should be an incentive on transmission companies to produce connection offers as quickly as possible. Ofgem should consider if this is the overall industry view. If anything, our experience is that developers would prefer a well engineered offer that takes the full offer period rather than a potentially lower quality offer.

Questions 2 – Do you have any comment on the interactions with the other workstreams, in particular Project TransmiT, for electricity transmission connections?

Connect and Manage provides for generation projects to connect to the transmission system in advance of the completion of the wider transmission reinforcement works. There is no longer a "GB Queue" for connections, and transmission companies no longer issue "Post-2018" offers. In addition, there is no longer a requirement to complete wider system works before allowing a generator to connect with firm access rights. Its introduction, along with the earlier Interim Connect and Manage (in which we advanced 441 MW in 2009 and 2010), has certainly helped to facilitate government energy policy.

The recent open letter for Project TransmiT sets out high level options for delivering timely connections. There is a question as to whether such incentives are necessary given that the transmission company is already incentivised through connection charges and its revenue driver to connect renewables as quickly as possible. Where there have been delays in our licensed area, these have all been due to delays in obtaining planning consents.

Please also note our response on "perverse impacts" on Environmental outputs where we would want to avoid a situation where we are incentivised to undertake sub-optimal investment to connect a renewable generator to agreed timescales, rather than waiting for the completion of a more economic, coordinated solution. In term of options to avoid perverse impacts, we suggest that any incentives around the timely connection of renewables should consider overall delivery of connections over a period, taking into account exceptional circumstances, rather than incentivizing individual connections. That said, overall delivery should not mean comparing against an average period to connect, as the period to connect, as set out in our response to the recent Open Letter on Project TransmiT can vary significantly.

We recently discussed with Renewables UK a potential connections incentive to support the UK's 2020 Renewable Targets by incentivising companies to connect renewable wind generation as early as possible to their respective transmission systems. We suggested that the incentive would be based on performance against an agreed programme of connections and the reward / penalty would be based on the overall carbon benefit / penalty for a MWh saved / incurred.

Question 3 – Do you have any views on the existing arrangements for gas transmission?

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Question 4 – Do you consider any specific obligations and/or incentives are required for gas transmission?

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Chapter 8 – Secondary Deliverables – Electricity Transmission Wider Works

Question 1 – Do you agree that there is a need for secondary deliverables that relate to wider reinforcement work on electricity transmission networks?

We agree with the principles set out in Section 8, in which wider system reinforcements will increase network boundary capacity and help minimize constraints, and that business plans should set out these secondary deliverables.

Over the period of RIIO-T1, the reinforcements specified by the Electricity Networks Steering Group that involve SPT[22] are all required in order to meet the Gone Green mid scenario.[23] These reinforcements will all increase network boundary capacity and minimize constraints.

Question 2 – Do you agree with our proposed approach to the specification of these secondary deliverables?

We agree that the specification of secondary deliverables can be defined with reference to boundary capability, or alternatively defined in project terms.

We note Ofgem's preference for boundary capability given that Ofgem believes that it is considered less restrictive in terms of a longer term regulatory framework. Since Ofgem first raised the matter of funding wider system reinforcements back in 2008, our continued position is that the best arrangements for funding wider system works should be based on a TIRG option (a) or Transmission Investment Incentive type approach option (b) i.e. a project based approach.

As part of TII and TIRG we are currently undertaking reinforcements whose capital investment will cover the roll-over period through to RIIO T1. It will be important to ensure that these projects have continuity of funding that avoids the piecemeal

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[22] These reinforcements are assessed by Ofgem as part of the Transmission Investment Incentives process.

[23] The Gone Green scenario was defined by the ENSG working group in their 2009 report and reflected in their updated cost benefit submitted in July 2010.

approach to date, and which due to regulatory uncertainty is very difficult to justify to our company Board.

Question 3 – How should we encourage timely delivery and deal with non-delivery?

In terms of encouraging early delivery of wider system reinforcements, transmission companies are already incentivised to complete projects funded by TIRG or Transmission Investment Incentives as early as possible. Not only is there a business driver in increasing the business RAV as quickly as possible, but there is also a reputational driver given that the reinforcements from our licensed area are key to supporting Government energy policy. Our business takes delivery of all investment, and particularly those associated with wider reinforcements, very seriously.

In common with our comments on connections delivery, we have concerns over incentives that cover the full delivery period of a project, which includes the period to obtain planning consents. The Beauly-Denny and South-West Scotland reinforcement projects are classic examples of major projects which have been delayed due to the time required in obtaining consents for new or up-rated overhead line infrastructure. These delays are due to outside agencies and are not within the control of SPT. We note in paragraph 8.37 that it may be appropriate to define some exclusion provisions. Local authority or Governmental consent delays, and even landowner delays to ensure cost-efficient delivery, should be excluded.

These major delays usually relate to major system works. In terms of providing connections, it is still necessary to obtain consents. For example, it is necessary to reach agreements with landowners. This process is becoming more problematic as landowners become more commercially aware. That said, even though there are significant risks we are willing to discuss incentives relating to timely connection delivery.

Question 4 – Have we identified appropriate options for bringing flexibility, over the price control period, to the secondary deliverables that TOs should deliver and to the revenues that they receive for this delivery? Which options work best for consumer interest? How would this depend on specific circumstances?

We have consistently stated that we see no compelling reason for a radical departure from the current transmission price control arrangements, which provides investors with as much certainty as can be expected that timely, cost-efficient investment will be fully funded. We are therefore pleased at the options set out in this paper.

Any of options (a) to (c) may all be appropriate to the transmission licensees. SPT's preference would be options (a) based on the deep revenue driver under TPCR4, and option (b) based on TII. However, it is important that any arrangement addresses funding across the full project duration, such as TIRG, rather than or for one or two years at a time, such as TII to date.

Since Ofgem first raised the matter of funding wider system reinforcements back in 2008, our continued position is that the best arrangements for funding wider system works should be based on a TIRG (option (a)) or Transmission Investment Incentive type approach (options b)) i.e. a project based approach. As shown by the recent Transmission Investment Incentives consultation, the costs of wider system works projects are significant. For example, the West Coast HVDC link will cost over £800M while even the onshore incremental reinforcements will cost over £300m.[24] Given the scale of investment associated with wider system reinforcement projects, we believe that it is right for each project to be given detailed regulatory scrutiny, in terms of need case, cost and timing. Once a project is accepted, and appropriate regulatory funding arrangements are agreed, then the respective transmission licences are updated to detail discrete funding for each project.[25] This may seem to be burdensome from a regulators point of view, but it does ensure that before a project proceeds it has been assessed carefully, and therefore protects consumers.

We note Ofgem's preference for option (c) based on a network planning policy and a volume driver. Although we prefer options (a) or (b), we are willing to consider this volume driver approach. However, the cost of Incremental Reinforcements and the West Coast HVDC link[26] highlight the "lumpy" nature of transmission investment. If this option is to work, it will be necessary to carefully consider the unit cost allowances particularly if projects provide benefits across multiple boundaries.

Question 5 – Do you agree with our plan not to develop proposals for an asset utilisation incentive scheme (option (d)), and to focus, instead, on the other options?

We agree that an asset utilization scheme is inappropriate. At Ofgem's request in 2008 we set out a similar scheme based on the extent to which boundary capability is contracted. However, in our licence area the next set of reinforcements are required to reduce constraints and move closer towards compliance with the NETS SQSS. In summary, the next reinforcements will be fully utilized.

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[24] These costs for the incremental reinforcements project reflect both SPT and NGET works

[25] In addition, appropriate arrangements are included in the licences to address changes in the scope and cost of the project.

[26] The Incremental Reinforcements and the West Coast HVDC Link projects are primarily but not exclusively about resolving the Boundary B6 constraint from Scotland to England

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Appendix 3 RIIO-T1 Overview Paper

Chapter 1 - Introduction

Question 1 – Do you have any comments on the proposed process and timetable for the review?

Ofgem's timetable to develop outputs has been far too rushed. In addition, the requirement placed on the companies to submit a detailed and "rich" business plan by July is extremely challenging. Effectively this compressed timetable is governed by Ofgem's desire to support their planned fasttrack process.

Chapter 2 - Context

Question 1 – Do respondents consider there are any interactions with other policy areas that have not been highlighted in this chapter?

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Question 2 – Do respondents consider that the transmission and gas distribution price control periods should remain aligned for future review periods?

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Chapter 3 – Making Sure Stakeholders' Views Are Heard

Question 1 – Do you have any comments of the overall approach to stakeholder engagement?

We fully support Ofgem's approach under RIIO for stakeholders to have greater opportunity to influence both Ofgem's and our own decisions. We have therefore embraced the requirement for demonstrating that we engage with our stakeholders; we have completed our stakeholder pre-consultation for RIIO-T1, and our full stakeholder consultation is now underway. One of the key challenges we have in the stakeholder engagement field is to ensure that we communicate our plans and engage with as wide a range of stakeholders as possible. To this end we have tried to target our communication process by publishing our consultation documents on our website and providing facilities to give feedback on our website and also by having a face-to-face stakeholder engagement event.

We have directly contacted a large number of stakeholders to participate in our consultation and stakeholder event however take up has been poor for both methods of engagement. We received only five responses to our pre-consultation meeting which was electronic based, and a similar number for our stakeholder event.

We believe that this may be due to a number of reasons including numerous other regulatory projects within the electricity industry and which stakeholders may believe are currently more important to them to engage with. Examples of such projects are Project TransmiT, Electricity Market Reform and the new Connect and Manage regime. There may also be an element that parties will only actively engage if they believe there is a major issue to be addressed and we therefore could acknowledge that generally our performance is to a high or at least acceptable standard.

We also need to acknowledge the structure of the UK electricity supply industry and in particular the different roles and responsibilities between a TO and the SO which were introduced under BETTA. For many customers, the distinction between the two different roles is unclear and can be become blurred, through the comparison with the set-up in England and Wales.

TOs generally have only one customer, which is the System Operator, and generally communications to customers must progress through them. However, we realise that the services we provide have a direct impact on the end consumers and will continue to engage with the widest possible range of stakeholders through individual bilateral meetings or other industry events.

Question 2 – Do you have any views on how our engagement process and that of the network companies could be made more effective?

Finally it is important that Ofgem understands that we already undertake ongoing “stakeholder engagement”. We regularly meet with stakeholders such as National Grid, wind farm developers and industry parties (such as DECC, Ofgem, Scottish Renewables Forum, Renewables UK,). We also frequently present at industry conferences e.g. IEA July 2010, Scottish Construction Congress February 2011, Scottish Renewables Conference February 2011, and are represented at industry forums such as the Grid Code review Panel. Our experience in undertaking our stakeholder consultations for RIIO T1 has made us realize that the best approach for engaging stakeholders is to build on our current engagement

Chapter 4 – Determining & Incentivising Output Delivery

Question 1 – Do you consider the proposed outputs and associated incentives, along with the other elements of the proposals, will ensure companies deliver value-for-money for consumers and play their role in delivering a sustainable energy sector?

No. Given Ofgem’s challenging timetable, it is important that Ofgem allow time for including or excluding outputs and incentives, or modifying the principles and policy around these, beyond their March strategy paper.

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Question 2 – Do you consider that the proposed outputs and incentive arrangements are proportionate?

No. We are particularly concerned over Ofgem's proposal to remove the maximum penalty on unsupplied energy events. Our view is that there is significant downside risk and in our recent presentation to GEMA we cited the potential for annual penalties of £12M or more. This is currently more that 5% of our allowed revenue. This is not proportionate.

In addition, Ofgem has not provided clarity on the impact of potential incentives around SO-TO constraints, transmission losses, or incentivising the delivery of connections.

Question 3 – Do you have any views on the proposed outputs or incentive mechanisms?

As set out in our answer to question 1 and 2 above, we are very concerned over Ofgem's proposal to remove the maximum penalty on unsupplied energy events. In addition, there is a lack of clarity on the impact of potential incentives around SO-TO constraints, transmission losses, or incentivising the delivery of connections.

Given Ofgem's timetable, it is important that Ofgem leaves room for including or excluding outputs and incentives, or modifying the principles and policy around these, beyond their March strategy paper.

Chapter 5 – Assessing Efficient Costs

Question 1 – Is our proposed approach to cost assessment appropriate?

There is little doubt that benchmarking Electricity Transmission operators is considerably more challenging than benchmarking Distribution operators, primarily due to the small number of GB comparators and the complexities of including overseas operators on a comparable basis.

Whilst in principle we support Ofgem giving greater weight to a total cost approach (something we lobbied for during DPCR5 negotiations), an over reliance on top-down benchmarking of Transmission operators, when the comparator data is not yet mature, would concern us greatly. Ofgem's ability to benchmark robustly and transparently at a totex level will be difficult; benchmarking subsets of costs e.g. Direct Opex will, in practice, prove unachievable in our view.

Given these difficulties we agree that it is important Ofgem use as wide a range of analysis as possible, including scrutiny of our business plans, to form a balanced view. It is of some comfort to us then that Ofgem propose to continue placing reliance on trusted methods for comparing Transmission operators.

Question 2 – Do you have any views on our proposed process for proportionate treatment?

We support the application of the principles of better regulation and agree that regulatory effort should be focused here it is most necessary to improve the outcome for customers.

It is important that the regulatory burden is demonstrably lightened for those companies which produce appropriate business plans.

Question 3 – Do you have any views on the criteria for assessing business plans? Are any of the criteria highlighted inappropriate? Are there any additional criteria that should be added?

It is not clear whether Ofgem consider these criteria to be of equal weight. It would be helpful for Ofgem to clarify what weighting will be applied to each of the criteria.

For the initial sweep we would favour giving more weight to the quality of the business plan, for no other reason than that the benchmarking results, specifically international benchmarking, may well prove unreliable and an assessment of past performance may be constrained by limited evidence.

Question 4 – Do you have any views on the proposed role for competition in third party delivery?

We believe that there are significant risks associated with third party delivery in terms of safety, quality of supply and value from money. Ofgem recently cited a major reinforcement in central Edinburgh as an example of such an approach. This raises a major concern for us as this is a major and very complex strategic asset replacement project, involving new technology, significant complex telecommunications changes, the creation of a cable tunnels for the 275kV circuits, and significant civil engineering challenges associated with railway tunnels below the substation and meeting stringent planning requirements (such as maintaining the facia of the original substation). This is not a project suitable for third party delivery.

The transmission companies are the only parties that have the overall skills, experience and capability to deliver major reinforcement and refurbishment projects. Our position on third party delivery is that may be a place for this model where it involves simple, new radial connections, and the current arrangements allow this to happen e.g. Hadyard Hill wind farm connection. But it must not cover projects which are more complex, and/or potentially have significant safety impacts, and/or could compromise security of supply.

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Chapter 6 – Managing Uncertainty

Question 1 – Do you have any views on the uncertainty mechanisms identified?

We agree that there is a requirement for 'uncertainty mechanisms' to allow a change to a network company's allowed revenues to be made during the price control period. The current uncertainty mechanisms, which include local and deep infrastructure revenue drivers, TIRG and Transmission Investment Incentives, are good examples of arrangements that adjust revenues during a price control. We believe that it is important that such arrangements continue in order to address uncertainty around load related investment. For example, our current construction contract arrangements with National Grid cover connections that complete by 2017/18 hence there is a three year period at the end of RIIO-T1 where we need to forecast load investment without any clear market signals. Uncertainty mechanisms can help address this gap.

Question 2 – Are there any additional uncertainty mechanisms required that we have not identified?

Ofgem must ensure that there are arrangements in place to address uncertainty in load investment.

Question 3 – Are there any mechanisms that we have included that are not necessary and, if so, why?

We note that Ofgem does not support uncertainty mechanisms to address real price effect changes or changes in legislation. The introduction of more outputs and incentives could limit our flexibility around the timing of investment. For example, there is a real risk that we could be forced to invest when supplier costs are significantly above RPI – this is not cost efficient and could lead to significant financeability issues. We therefore believe that it is important to include mechanisms covering RPE.

Changes in legislation and government policy must also be seriously considered. For example, a move in energy policy from wind to nuclear would have significant impact on capital investment.

Chapter 7 – Innovation

Question 1 – Do you have any views on the role of innovation in RIIO-T1?

Given the unprecedented challenges facing Transmission owners/operators over the next few decades, we welcome the recognition of innovation as being a key activity. Network operators will require considering alternative arrangements for the transmission of electricity and will involve both technical and commercial innovation. We do not believe that previous price controls have provided sufficient scope for innovation and welcome this natural progression to IFI and LCNF mechanisms.

Question 2 – Do you have any views on the time limited innovation stimulus?

The innovation stimulus appears to be an appropriate mechanism to promote innovation in networks activities. We are keen to understand Ofgem's views on how long the innovation stimulus will be provided as innovation activity is not a step change but will be an ongoing process. As technology is developed we anticipate that the process will be cyclic in nature and will involve periods of intense roll out followed by periods of monitoring. We are fearful that Ofgem perceive networks not to be utilising the innovation stimulus in a number of years down the line as they are in the process of delivering new projects and therefore withdraw the support.

Chapter 8 – Financial Efficient Delivery

Question 1 – Do you consider that the package of financial measures identified will enable required network expenditure to be effectively financed?

Please refer to our executive, and our detailed response to Appendix 1 covering RIIO-T1 and GD1 Financial Issues

Question 2 – Do you have any views on our proposed approach to depreciation?

Ofgem's assessment of economic lives for electricity transmission has been unduly influenced by the perceived long technical lives. This fails to take into account the uncertainty surrounding future use, especially of individual assets in a particular location. For example, generation projections are typically assessed over an expected life of 15 to 20 years. Subsequent developments depend on technological developments, relative primary fuel price movements and future energy, environmental, climate change and planning policies.

The technical lives for electricity transmission themselves appear to have been skewed by the weighting given to National Grid's 275kv and 400kV assets which are not representative of the Scottish TO networks, which also include 132kV assets that are part of distribution systems in England and Wales. Furthermore, the MEAV weights give undue weight to tower foundations, which are assumed to have the longest technical lives. This distorts the calculation of the average technical life.

In view of the extreme uncertainty surrounding energy market developments and future government policies, it is not reasonable to assume to economic lives of 45-55 years.

Individual circuits and plant items may be reinforced, modified, re-routed or removed well before they reach the end of their technical lives. Clearly, a significant proportion of assets are replaced or modified before the end of their technical life.

Ofgem's proposals are likely to result in future customers bearing the cost of both existing assets and their replacements. Furthermore, lowering the depreciation charge would result in a larger RAV and higher charges for future customers. This clearly would not be equitable, especially as real energy costs are expected to rise in future.

Moreover, Ofgem have also failed to take into the effect of incorporating a proportion of operating costs into the value of the RAV, so as to equalise incentives. The value of the RAV no longer simply represents the undepreciated part of physical assets. It is clearly not appropriate to apply technical lives to a financial construct that has resulted from a series of regulatory decisions from privatisation onwards.

We therefore consider it prudent to assume an average economic life for purposes of depreciating the electricity transmission RAV of no more than 40 years.

Question 3 – Do you have any views on our preferred approach to implement any transition arrangements over one price control period where possible?

Our initial financial modelling indicates that constraining the transition to the forthcoming price control period would result in an unacceptable deterioration in credit metrics. We will further develop our modelling in order to inform our FBPQ submission but initial indications are that the move to the longer lives (for post 1st April 2013 additions only) should be phased in over at least the next two price control periods and quite possibly longer (the stepped approach).

Question 4 – Do you have any views on our preferred approach to remunerating the cost of debt?

In our view, the proposed mechanism for indexing the cost of debt would not be consistent with Ofgem's financing duty.

The proposed ten year trailing average, by construction, only adjusts to an increase in interest rates (e.g. when quantitative easing is reversed) over a subsequent ten year period. This leaves the company facing a shortfall in revenues to cover the increase in interest payments and would adversely impact interest coverage ratios.

Moreover, Ofgem's approach to calculating the real cost of debt fails to allow for the inflation risk premium which is incorporated into the nominal cost of debt.

Ofgem propose to rely on data from Bloomberg, whereas many practitioners are more familiar with iTraxx indices. More generally, the benchmark is sensitive to the particular index used and the maturities of the constituents. In particular, the proposed 10 year maturity is not representative of network operators' financing.

The proposed mechanism would therefore be unacceptable to us without an appropriate form of amelioration. We propose the use of a weighted average index which reflects

SPT's own debt issuance. A "one size fits all approach" is inappropriate, especially where capex programmes and debt issuance profiles vary across companies.

Furthermore, we require the index to respond more quickly to changes in interest rates, through the use of a shorter trailing average of not more than 5 years.

Question 5 – Do you have any views on our proposed approach to assessing the cost of equity and the associated range of 4.0 – 7.2 per cent?

The absence of clarity surrounding the assumed gearing makes it impossible effectively to assess the cost of equity. In any case, the lower end of the range is implausible and inconsistent with estimates for the cost of debt and observed dividend yields for network operators.

European and US regulators are setting the cost of equity at 7.5% to 8.5%, which is 30 to 130bps above the upper end of Ofgem's range.

The upper end of the range for the cost of equity is below that derived from the Dividend Discount Model. Ofgem have not cross-checked their range with alternative approaches to estimating the cost of equity.

Furthermore, the CAPM estimates, which appear to underlie Ofgem's range do not allow for a higher forward looking risk premium which is higher than the historic average. Ofgem's assertion than "normal" market conditions will prevail has no basis. Indeed, equity market volatility remains higher than when the price controls for TPCR4 and the GDPCR were set (in December 2006 and December 2007, respectively). The last ten years have seen three major crises (i.e. the burst of the dot-com bubble, the credit crisis and collapse of Lehman Brothers, and the sovereign debt crisis. The 10 year average which Ofgem use as a reference level cannot therefore be considered as a period of normality. Moreover, the allowed return must be robust in the event of major unforeseen financial turmoil.

In addition, data from option prices show that investors perceive greater downside risk in equity prices. However, the CAPM assumes a symmetric distribution of risk and return. Extensions of CAPM which account for skewness in returns, indicate a higher cost of equity for negative skew. To take account of this higher expected downside risk, the allowed return has to be set above the CAPM estimate, to offset downside skewness.

UBS' estimate of the UK equity risk premium increased again during 2010 and is at level which was only exceeded following the collapse of Lehman Brothers.

Moreover, Ofgem do not allow for an equity beta of unity or above, which would result from an asset beta of 0.4 or above with gearing of 60% or more.

In addition, as the Scottish TOs are much smaller than NGET, they require a small company premium, as determined for small water companies.

Overall Ofgem's December range for the cost of equity appears arbitrary and fails to provide a sound basis on which to attract sufficient finance to fund the essential investment in the transmission system.

Taking into account the above, our investor tells us that the required return on equity for SPT is significantly above Ofgem's range and could be as high as 9.5%, at 50% gearing.

Question 6 – Do you have any views on other elements of our financial proposals?

Please refer to our executive summary, our response to the questions above, and our detailed response to Appendix 1 covering RIIO-T1 and GD1 Financial Issues.

Appendix 4 RIIO-T1 Tools for cost assessment

Chapter 2 – Cost Assessment Overview

Question 1 – Have we proposed the optimum range of techniques (a) Are there better techniques that we have not included? (b) Are we applying the appropriate techniques in the appropriate areas?

There is little doubt that benchmarking Electricity Transmission operators is considerably more challenging than benchmarking Distribution operators, primarily due to the small number of GB comparators and the complexities of including overseas operators on a comparable basis.

Whilst in principle we support Ofgem giving greater weight to a total cost approach (something we lobbied for during DPCR5 negotiations), an over reliance on top-down benchmarking of Transmission operators, when the comparator data is not yet mature, would concern us greatly. Ofgem's ability to benchmark robustly and transparently at a totex level will be difficult; benchmarking subsets of costs e.g. Direct Opex will, in practice, prove unachievable in our view.

Given these difficulties we agree that it is important Ofgem use as wide a range of analysis as possible, including scrutiny of our business plans, to form a balanced view. It is of some comfort to us then that Ofgem propose to continue placing reliance on trusted methods for comparing Transmission operators.

Chapter 3 – Real Price Effects & Ongoing Efficiency

Question 1 – Are there any additional analytical techniques that we should consider beyond those we have used at past price control reviews to assess the factors?

Question 2 – Are there any additional data sources that we should be aware of to assist with our analysis in these areas? In particular, are there specialist labour indices that would be relevant for the gas transmission sector?

Question 3 – Of the data sources presented in this chapter, are there are some that you think we should rely more on than others?

The lengthening of the Price control period to eight years will increase regulatory risk for Transmission operators if an ex-ante allowance for RPE's continues to be Ofgem's preferred choice.

Predictions of the expected real input price inflation over an eight year period are likely to vary enormously, when there is still huge uncertainty about when the UK and the global economy will emerge from recession and return to normal growth levels.

It follows then that different macroeconomic scenarios might have to be considered in developing a range of outcomes.

We would say that the techniques and data sources identified generally look fine but we are probably less concerned about them than we are in how they are implemented. For example a key consideration in the assessment process will be the mix of inputs, and in particular understanding the contractor input mix. Another is ensuring that the process effectively captures the flow through of oil and energy price movements into manufacturing and transportation costs.

Chapter 4 – Total Expenditure Analysis

Question 1 – Are our proposed cost drivers appropriate, should additional drivers be tested?

In the context of quantitative benchmarking, the sole value of any cost driver is its merit as a predictor of efficient cost. Given this, all candidate cost drivers should be tested ex ante to validate the hypothesised functional relationship between driver and cost, and the quality of the regression. This validation should include testing for collinearity between drivers, and for the impact of outliers (a substantial risk given the variation in scale of the GB TO's and the potential unreliability of international comparison).

Where multiple drivers are used, these should not be rolled up into a single composite driver. To do so is to make an ex-ante judgement about the relationship between regression coefficients. An appropriate functional form should be tested, and individual driver variables should be excluded from the model if they do not prove to be significant. The significant regression coefficients are the driver weights.

We believe that the drivers should not be normalised. While this is normally helpful in indicating the relative strengths of multiple drivers we believe that in DPCR5 it gave rise to situations where normalised coefficients were applied to raw costs. In the interests of accuracy and transparency we believe that the possibility of this occurring again is best avoided.

It should be noted that while for tractability and transparency there may be a preference for OLS, the OLS approach makes strong statistical assumptions and is likely to understate the uncertainty attached to any derived efficiency benchmark.

Question 2 – Are there additional sources of data we could be looking to in order to increase the robustness of our analysis?

We don't believe that total expenditure benchmarking will in itself provide reliable results. As mentioned already, comparability between operators and the size of the benchmarking population will create challenges in Transmission which are difficult to overcome.

We also note Ofgem's preference for a totex measure which includes the actual flow of capex, rather than a calculated measure of "capital consumption". The fluctuations in capital expenditure, most noticeable in costs to connect new generation, will obviously need careful consideration in an efficiency assessment.

We believe that benchmarking robustness depends on the quality of data and analysis rather than the quantity. This robustness extends to acknowledging the quality of the data available (and any derived quantitative models) and, given this, the limits of meaningful inference.

Chapter 5 – Direct Operating Expenditure

Question 1 – Do you agree with our proposal to assess closely associated indirect operating expenditure alongside direct operating expenditure?

Insofar as closely associated indirect costs do vary in relation to changes in levels of both direct opex and direct capital activity, then we would agree that it is sensible to assess these costs together.

Question 2 – Have we chosen the most appropriate mix of techniques from our cost assessment toolkit?

As mentioned earlier we have reservations over the reliability of results which are derived from benchmarking the GB Transmission Operators, even more so when looking at subsets of total costs.

Whilst the results may provide a point of reference, we would encourage Ofgem to use as wide a range of measures as possible for testing efficiency and long term value for money.

Chapter 6 – Indirect Operating Expenditure

Question 1 – Are there any additional business support costs that should be assessed?

As IT & telecommunication costs account for the largest proportion of business support costs it is understandable that Ofgem wish to engage specialist consultants for this area.

In that sense therefore, it is not immediately clear why Property costs have been chosen as they account for only a small proportion of our overall business costs.

Question 2 – Have we chosen the most appropriate mix of techniques from our cost assessment toolkit?

Determining an exogenous cost driver, or multiple drivers, which provide a good correlation to business support costs is the primary concern for us. We would also point out, as mentioned in Para 2 of Chapter4 (Q1), the importance of not rolling up multiple drivers but testing an appropriate functional form.

Chapter 7 – Capital Expenditure

Question 1 – Do you agree with our proposal to assess closely associated indirect operating expenditure alongside capital expenditure?

Insofar as closely associated indirect costs do vary in relation to changes in levels of both direct opex and direct capital activity then we would agree that it is sensible to assess these costs together.

Question 2 – Have we chosen the most appropriate mix of techniques from our cost assessment toolkit?

As Ofgem itself concedes, endeavouring to benchmark capital costs against overseas comparators is unlikely to provide definitive results given the obvious difficulty in collecting comparable data.

Although it might be possible to benchmark the three TO's, again the results are unlikely to be conclusive given the shortage of panel data.

Therefore, in relation to NLRE, we would support an approach primarily undertaken from an assessment of forecast volumes and unit costs. We also agree that deriving a consistent set of definitions of unit costs is essential, as we suspect the boundary of direct and indirect costs may well be different amongst operators.

Appendix 5 RIIO-T1 & GD1 Business Plans, Innovation & Efficiency Incentives

Chapter 2 – Form & Structure of the Price Control

Question 1 – Do you have comments on the description of the form and structure of the price control?

Question 2 – Is the scope of the price control including the range of services excluded appropriate?

Question 3 – What are the appropriate criteria for assessing whether a proposed change to the revenue profiling is appropriate?

Chapter 3 – Business Plans & Proportionate Treatment (including fast-tracking)

Question 1 – Are you content with the degree of guidance we are providing on a well-justified business plan? Is there additional guidance you would value?

We would like early sight of the proposed data templates and adequate opportunity to comment on them.

Question 2 – Do you have comments on the use of ten years as the basis for forecast data? What level of detail should additional five years data to place this forecast into context be? Where might a longer period be appropriate? Are there cases where ten years would be problematic? If so what alternative approach might we follow?

Plans extending for ten years would be consistent with the requirements of the EU Third Package for Transmission. We can understand Ofgem's wish to place these forecasts in context by requesting an additional 5/10 years of data. It is likely then that these forecasts would be provided in the context of long term scenarios, which should be developed on an industry wide basis.

Clearly the longer term plans would need to be in a summarised form, more readily accessible to third parties.

Assessment of financeability will need to take into account the effect of longer depreciation for electricity transmission, which will take a long time to reach the new equilibrium level.

Question 3 – Do you support the basis of our initial sweep assessment?

Ofgem's preference is for an initial sweep based on evidence from three sources:-

- An assessment of the business plan against a range of criteria
- Comparative evidence e.g. benchmarking
- An assessment of past performance based on pre-established principles

For the initial sweep we would favour giving more weight to the quality of the business plan, for no other reason than that the benchmarking results, specifically international benchmarking, may well prove unreliable and an assessment of past performance may be constrained by limited evidence.

Question 4 – What should be included in our assessment of past performance at these first reviews?

Clearly the absence of defined output measures for previous price controls restricts the assessment of past performance that Ofgem would like to have undertaken.

In terms of objective evidence, Ofgem can refer to information from the Annual Regulatory Reporting Pack for comparisons to capex and opex allowances, system performance, substation utilisation, unit costs, asset additions/disposals. Information on performance against existing incentive mechanisms is available from the annual Transmission Revenue Return.

Question 5 – Do you have comments on the proportionate treatment process?

We support the application of the principles of better regulation and agree that regulatory effort should be focused where it is most necessary to improve the outcome for customers.

It is important that the regulatory burden is demonstrably lightened for those companies which produce appropriate business plans.

Question 6 – Do you have comments on our assessment criteria?

It is not clear whether Ofgem consider these criteria to be of equal weight. It would be helpful for Ofgem to clarify what weighting will be applied to each of the criteria.

Question 7 – Do you support the way we propose to apply fast-tracking?

We support the introduction of the fast-track option. However, it must be shown to be a realistic process for companies to attain. We are concerned that there may be a perception that electricity transmission may be viewed as too difficult and complex to be fast-tracked.

Question 8 – For RIIO-GD1, do you have views on the additional reward reflecting their relative superiority over comparators. Which of the options for implementing the reward do you prefer and why?

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Chapter 4 – Greater Role for Third Parties In Delivery

Question 1 – Do you agree with our view that the case to develop the framework to enable third parties to compete to develop and own elements of the electricity transmission network is significant, and that we should work to develop this option as a priority? Do you foresee any areas of significant benefit or concern?

Ofgem is considering introducing competition such that third parties could construct and own assets on the onshore transmission system. Ofgem recently cited a major reinforcement in central Edinburgh as an example of such an approach. This example was completely inappropriate and raises a major concern for us as to Ofgem's thinking on this matter. This project is a major, complex strategic asset replacement project, involving new technology, major telecommunication infrastructure changes, and some of the most complex civil engineering challenges ever faced. This is absolutely not a project suitable for third party delivery.

The onshore transmission companies are the only parties that have the overall skills, experience and capability to deliver major reinforcement and refurbishment projects. Our position on third party delivery is that may be a place for this model where it involves simple, new radial connections, and the current arrangements allow this to happen e.g. Hadyard Hill wind farm connection. But it must not cover projects which are more complex, and/or potentially have significant safety impacts, and/or could compromise security of supply.

Chapter 5 – Innovation

Question 1 – Should the scope of the innovation stimulus be confined to projects which help deliver a low carbon future, or should the scope be wider to include long-term network sustainability? Should there be a different scope to the innovation stimulus that applies to electricity and to gas?

We believe that the scope for the innovation stimulus should be broader in order to consider proposals which will also assist with sustainability of networks, security of supply and affordability. Focusing solely on low carbon agenda may deter organisations, either gas or electricity, from looking at innovative solutions for improving customer service or reducing costs e.g. reduces interruptions to supply, yet may have a negative carbon impact.

In some cases the direct benefits for customers may make the innovation worthwhile considering. In addition, the outcome from the electricity market reform may require commercial innovation to assist with the operation of the market in the future, but again may not be solely for a low carbon agenda. The innovation stimulus should also allow network companies to look at other types of innovation such as undertaking studies for alternative technologies such as offshore routes opposed to onshore, undertaking a study of this nature may not require deploying a solution but would create future tools for analysis which requires investment to develop.

Question 2 – Do you agree that the level of funding available under the innovation stimulus for each of electricity transmission and gas distribution and transmission should be within ranges identified? Are there further arguments for different funding levels which we have not considered?

We believe that the upper value for the electricity transmission innovation stimulus (£35m) is broadly correct. By allowing a higher value, the selection panel for funding will have the discretion to award what they feel as the appropriate amount of funding to projects that merit funding. We believe that there is a risk if the funding level is set too low such that the selection panel cannot grant all the projects which they think deserve funding. At present we have identified a number of projects which we think would be relevant to the Innovation Stimulus and we would anticipate these to each have a value of many millions of pounds.

One concern we do have is that the innovation funding stimulus does not consider any inflation factor, therefore over the course of the eight year price control will diminish markedly. Additionally, the level of expenditure by transmission network operators is forecast to increase substantially over the price control period and a fixed fund of £35m does not reflect this increase.

We continue to question the value of viewing the innovation funding stimulus as a competition for electricity transmission owners due to the nature of the SO/TO relationship. Given the dominance of National Grid and their SO role, we believe that innovation projects should have an emphasis on collaboration. This will also create benefits across the UK and assist with disseminating the results. We would suggest that it is likely that only one or two substantial projects may be submitted in which case the competition will be unnecessary.

For the purposes of the innovation stimulus, the funding should be allocated to onshore projects only, in the event that innovation stimulus funding is to be identified for offshore transmission projects then a larger value would be necessary.

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Question 3 – How should network companies be required to meet the costs of the innovation stimulus? Should this be through fast cash, slow cash or the standard expenditure capitalisation ratio?

We believe that the innovation stimulus should be funded through fast money.

There is an argument that applying the standard capitalisation ratio is fairer from an intergenerational viewpoint. This is certainly the case where the results of a successful innovation are rolled out but less of an issue for the more limited costs and benefits of a trial project.

One of the main attractions for participation in the LCNF and IFI has been the availability of fast cash to fund projects. Given the large capital investments that TOs are already undertaking, which is forecast to increase in the future; to raise further capital may remove some of the attraction to participate. We also believe that the nature of innovation makes the financial modelling of such investments difficult on a slow cash or standard expenditure basis. Innovation may have a substantially shorter lifespan than traditional investments, and in some instances the trial may be unsuccessful. Should the contribution by the asset owner increase 20%, this is also placing a further burden on the organisation to fund such a project.

Given the success of LCNF in 2010, we think this justifies the innovation stimulus to be set at 90% opposed to the proposed 80%. Our suggestion is that the competitive element of the stimulus could be set at 90% which would incentivise organizations to develop eligible projects which can receive a higher proportion of funding compared to the direct funding allowance.

We are extremely disappointed that the discretionary reward has also been removed; even to cover the 10% or 20% investment being made by the networks company. For any other organisation to innovate they would be prepared to undertake this activity in anticipation of the reward that it will produce. For network organisations who are innovating to reduce the carbon impact of the system, they may not receive direct benefit such as a reduction in costs, yet they are still expected to participate in such initiatives with no reward.

Question 4 – Do you agree that we should provide a limited innovation allowance directly to each company? If so, do you have views on the form and scope and of this allowance, and on which mechanism would best incentivise efficient investment in innovation?

We welcome the provision of a limited amount of innovation funding directly for each company and believe that this should be in the form of a percentage of revenue rather than output based as by the very nature of innovation the expected outputs are highly uncertain. Even an unsuccessful project (in terms of outputs) is likely to provide information informing further innovation, to the benefit of all customers and TOs.

We believe that a limited innovation allowance is required and should be set at c1% of revenue which would represent a combination of LCNF Tier 1 and IFI funding which

DNOs currently receive. We do not believe that this should be linked to outputs as innovation outputs cannot be easily quantified, and in some instances the innovation may be looking at a concept which is unsuccessful; in which case there would be no tangible output yet may still provide a learning benefit. We think that the IFI and Tier 1 mechanisms have allowed for efficient delivery through the reporting mechanisms and given the fixed allowance, DNOs look to maximise what they can get from this limited funding. By setting an allowance it will be up to the individual companies to use as much as they desire depending on the opportunities they identify and the appetite for innovation by that organisation.

As discussed above, the innovation stimulus should be available for all forms of innovation other than solely low carbon solutions. The limited allowance should also apply to innovation at all stages of readiness; research, development as well as trialing in order to cover the opportunities that have arisen through IFI.

Question 5 – Do you agree that there should be a revenue adjustment mechanism to encourage innovation roll-out within the price control period? If so, do you agree with our views on the criteria for such an adjustment and how frequently should we allow companies to apply for this adjustment?

We are in favour of a revenue adjustment mechanism to encourage roll-out of innovations within the price control subject to the proposed conditions, although we do have some concern about the delivery of enhanced outputs. We are not convinced that a sufficiently robust view of performance under enhanced outputs could be formed where roll-out is late in the price control. For this reason we believe that there should be a single opportunity for funding at the midpoint.

We believe that a mechanism to allow a revenue adjustment within the price control review would be advantageous. As a result of innovation activity or other technology/commercial developments, it would be valuable to roll these out at the earliest opportunity should they produce material carbon savings. Our preference would be for a revenue adjustment at the mid-point of the price control review period. We do not envisage technology developments which would have such a profound impact that they could not have been forecast at the FBPQ stage or the mid-point review, and fear that an annual process may become onerous to deal with as different organisations adopt the technology at different stages. The criteria set out for a revenue adjustment of facilitating a low-carbon energy sector and outputs focused appear to be appropriate. If the technology were to have commercial justification then we would expect that this should be rolled out as part of the revenue allowance.

Chapter 6 – Efficiency Incentives & IQI

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Question 1 – Do you agree with our proposed approach to the implementation of the efficiency incentive rate? Do you have views on the intergenerational impact?

We agree that the incentive rate should be symmetric, and that retrospective revenue adjustments should be confined to circumstances where there is manifest waste or unjustifiable failure to deliver outputs.

Particularly for Transmission companies, expenditure is lumpy. We are concerned that adjusting for over/underspend within the price control may introduce revenue volatility as compared to the current approach of assessing expenditure relative to the price control allowance ex post (assuming the adjustment is spread over the subsequent price control).

We therefore believe that revenue adjustments should continue to be carried out in the subsequent price control.

If the adjustment is to be brought within this price control, a mechanism is required to smooth the revenue adjustments which will arise simply through change of profile in expenditure, and which given time may be largely self-cancelling.

In principle the split between fast and slow money (the intergenerational impact) should follow the business capitalisation policy. In a period of significantly increasing Capex there are two potential issues:

1. The capitalisation fraction may not be constant – opex is likely to lag capex.

2. We do not believe that in a business like Transmission, with expenditure dominated by capex, the fast/slow split will be adequate to smooth revenue fluctuations due to large over/underspends (for instance unavoidable delays in capex). We believe that this reinforces the argument that revenue adjustments should be made in the subsequent price control (or at least only at the midpoint?).

Question 2 – Do you agree with our proposed range for the efficiency incentive rate?

The range of the efficiency incentive rate is greater than both DPCR5 (30-50%) and TPCR4 (25%). Careful calibration not only of the efficiency incentive, but the full package of RIIO-T1 incentives will be required to ensure that TOs do not face an excessive increase in risk relative to the allowed cost of capital.

Question 3 – Do you agree with our proposed approach to the calibration of the IQI?

The IQI should be calibrated to ensure that TOs have a fair opportunity to earn a return equal to their cost of capital.

Historically it has been the case that companies' expenditure forecasts have overwhelmingly exceeded Ofgem's view. This is unsurprising, given that at least some of the cost allowance setting incorporates efficiency challenges based on quartiles or similar benchmarks. It does mean that under the proposed calibration, the majority of TOs who forecast higher costs than Ofgem, then spend at or close to forecast, will achieve a return less than the estimated cost of capital (ceteris paribus). The company matching Ofgem's view, which then spends what it forecast and so earns its cost of capital is a special case.

This downward bias is intrinsic to the IQI mechanism as long as it simultaneously tries to set allowances and incentivise accurate forecasting of costs – if companies collectively become more efficient, the Ofgem view decreases and the majority of companies' forecasts still exceed the Ofgem view (and the allowance).

We believe that there are two possible modifications to the proposal to ensure a more neutral incentive:

- An arrangement similar to that in DPCR5: where a company at 100 per cent or slightly above would earn additional returns. This would require calibration of the matrix to ensure the incentive is roughly neutral across companies but would leave allowance setting unaffected. This would work as an overall adjustment, and it would ensure that network operators have a fair chance of earning their cost of capital under this incentive.

- Separation of the Information Quality Incentive and the allowance setting: IQI should be set using a more symmetrical, mean-based benchmark wherever applicable. Cost allowances would be set with an efficiency challenge (upper quartile or other). This addresses components of expenditure where an analytical approach has been used to form the Ofgem view. Separate adjustment would be required to deal with more subjective areas of IQI cost assessment, but again the objective of this adjustment would be to ensure that network operators have a fair opportunity to earn their cost of capital under the incentive.

Question 4 – Do you agree with our proposals for the application of the RIIO approach to efficiency incentives to the areas of gas transmission expenditure that are currently covered by the suite of separate incentive schemes set at TPCR4?

Not applicable.

Question 5 – Specifically, do you agree with our proposals to apply the same efficiency incentive rate, and to have not caps and collars? Do you have any views on the potential downsides and risks to consumers?

Please note our response to the NRIS incentive for electricity transmission.

Question 6 – Do you have views on the scope for alignment between the TO and SO incentive schemes, including greater alignment than we have proposed?

Please note our response on a potential electricity constraint minimisation incentive in the section in the Appendix on Outputs and Incentives.

Although a electricity constraint minimisation incentive has the potential to compromise the essential asset replacement and refurbishment required to maintain quality of supply, we are willing to discuss with the SO an incentive based on minimizing constraints. Our concern is that we require system access to undertake essential asset replacement and refurbishment which we believe should take precedence over constraint minimization.

Appendix 6 RIIO-T1 and GD1 Uncertainty Mechanisms

Chapter 2 – Proposed Approach to Managing Uncertainty

Question 1 – Are there any additional criteria that we should take into account to guide the appropriate use of uncertainty mechanisms?

A more formal cost benefit approach would enhance the basis of decision making.

Wherever feasible, potential benefits and dis-benefits should be quantified in an objective and transparent manner. At present, the quality of impact assessments are variable and only published in a piecemeal and selective manner.

Question 2 – Do you agree with the information requirements that we set out to support the justification of additional uncertainty mechanisms? If not, what changes should we make to these requirements?

Wherever feasible benefits and dis-benefits should be quantified.

Chapter 3 – Potential Uncertainty Mechanisms for All Sectors

Question 1 – Do you think there should be a change to a 12-month average approach to RPI indexation of allowed revenues? If there were a change to a 12-month average approach, would there need to be any transitional adjustments?

We support the change to a 12-month average approach to the RPI. We recommend the use of the average for the 12-months from January to December, so as to ensure that the data is available in time to set charges.

We do not see a need for any transitional arrangements.

Question 2 – Do you have any views on the design of the reopener for the introduction of Traffic Management Act permitting schemes? In particular, is the timing of the reopener window appropriate and what approach should we adopt to set the materiality threshold before it can be triggered? Do you agree with our proposal that the reopener would only apply in gas distribution?

We do not seek a reopener for traffic management permitting schemes for SPT.

Question 3 – Do you have any views on the design of the mechanism for changes in the requirements required by the Center for the Protection of National Infrastructure? As above, is the timing of the reopener window

appropriate and what approach should we adopt to set the materiality threshold before it can be triggered?

We seek a similar mechanism to that implemented for DPCR5 for specific security expenditure.

Subject to any further policy developments, we accept the proposed timing. However, we believe it would be more transparent to users of the system to express the materiality in terms of the percentage of base allowed revenue, as this is a widely recognised amount. Expenditure allowances are not widely known.

Question 4 – Are there any additional mechanisms that we should be considering? If so, how should these be designed?

Consideration should be given to whether there is a potential need for a mechanism were there to be a change in the requirements for flood resilience, should such expenditure allowances not be agreed as part of RIIO-T1. If this were needed we envisage a mechanism similar to that to be implemented for changes in the requirements for the protection of national infrastructure.

Question 5 – Do you agree with our proposal to leave the dis-application arrangements unchanged?

We agree with the proposals to leave the dis-application arrangements unchanged.

Question 6 – Do you have any views on the other mechanism discussed in this chapter?

Please see our response to the Financial Issues section for our views on financial issues.

Chapter 4 – Potential Gas Distribution Uncertainty Mechanisms

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Chapter 5 – Potential Gas Transmission Uncertainty Mechanisms

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Chapter 6 – Potential Electricity Transmission Uncertainty Mechanisms

Question 1 – Do you think that an uncertainty mechanism for electricity transmission connections expenditure is likely to be in consumers' interests?

An uncertainty mechanism for electricity transmission connections expenditure would operate in customers' interests, as otherwise TOs would be discouraged from providing connections beyond the expenditure allowed for in RIIO T1. This would potentially delay the benefits of low carbon generation.

Question 2 – Do you have any views on future connections projects (number of projects, costs, etc), and the uncertainty around these numbers?

Our submission to the Adapted Rollover review sets out our view of connections connecting through to 2017/18. The key uncertainty relates to obtaining consents and we continue to depend on factors that are outwith our control. Our response to the Open Letter on Project TransmiT provides detailed information on the types of challenges, particularly around consents, faced by a transmission company in connecting renewables in Scotland.

Question 3 – Do you agree that volume drivers are the preferred option, and do you have any views on how they should be designed?

Yes, we agree that volume drivers are generally preferable for connections expenditure. However our experience is that the cost per MW for local connections infrastructure can vary significantly, depending generally on the distance of the connection from existing transmission infrastructure, and the connection voltage . At TPCR4, Ofgem ensured that extremely costly infrastructure was omitted from the revenue driver and we recommend that this arrangements continues. We propose a limited number of categories which reflect distance and/or capacity.

Question 4 – Are any other uncertainty mechanisms needed for connections expenditure? If so, how should these be designed?

Ofgem should avoid change for change's sake. The current revenue driver arrangements need to be updated arrangements ensure that the TO can be funded above a baseline level if required. We believe these arrangements should continue.

Question 5 – Do you have any views on the option of setting upfront revenue allowances, during the price control period, for qualifying high-cost connections projects?

Where a project is required but the timing is uncertain we propose an ex ante allowance with a trigger mechanism to activate the adjustment.

We propose a limited number of cost bands which would cover the vast majority of projects. If costs for a particular project were expected to be above the highest band we propose review of the expenditure forecast as a basis for setting an ex ante project allowance.

Question 6 – Do you have any views on the uncertainty mechanisms that we have proposed for wider reinforcement works?

Our preference is for a trigger mechanism with pre-specified criteria to trigger the associated additional revenue allowance.

Question 7 – Do you have any views on the treatment of Inter-TSO costs?

We support the continued use of pass-through for Inter-TSO costs.

Chapter 7 – Mid-Period Review of Output Requirements

Question 1 – Do you agree with the scope of the mid-period review? If not, what changes to the scope are needed?

We agree that the scope of the mid-period review should be tightly defined to prevent the price control period collapsing to four years.

Question 2 – Do you agree with the indicative process and timetable? If not, how could the process and timetable be improved?

It would be prudent to commence drafting licence modifications earlier in the process.

Question 3 – Do you have views on when we should make licence changes as a result of any actions taken at the mid-period review? If a threshold to make a licence change is seen as appropriate, what should this be?

We support the option for a more proportionate process for relatively small changes. We envisage that a threshold would be set at a level which is equivalent to a small percentage of revenue. Beyond this, a licence modification would be required.

Appendix 7 RIIO-T1 and GD1 Impact Assessment

At this stage in the RIIO-T1 review process it is not possible to quantify in detail the likely impacts of the review. Many of the key risk areas, for example, surrounding financeability have deliberately been left open by Ofgem with each of the companies being required to construct a holistic view of the price control package and submit these as part of their well justified business plans.

That said, we are concerned that much of the tone and thinking underpinning the consultation is similar to that observed at previous reviews. For example, there remains a focus upon historical data within Ofgem's early thinking and that of their advisors on allowed returns for the Companies. There is acknowledgement that cross-checks to forward looking analysis via, for example, Dividend Growth models should form part of the debate but there has been little evidence of this is in practice.

At a time when the UK and indeed global economy remains fragile, when we are seeing increased demand for finite capital resources and when as an industry we are seeking to play a full role in the delivery of a sustainable energy sector there are risks to achieving UK Government policy if we are to remain wedded to an econometric model which fails to fully reflect future economic and market conditions. Recent decisions on allowed returns have seen the major industry players reconsider their desire to participate in Networks activities. Regulators must be confident that the right investors can continue to be attracted to the sector.

We welcome Ofgem's improved transparency in their thinking around financeability. This was lacking at DPCR5 and bringing this into focus early in the review process is helpful and will allow companies to manage investor expectations.

In summary we are very much of the view, as highlighted by Ofgem in Para 3.18 that the impacts and risks surrounding RIIO-T1 are very much dependent on how the stated principles are interpreted and applied in practice.

Chapter 2 – Impact of RIIO-T1 & GD1 Proposals

Question 1 – Have we correctly identified the impacts that RIIO-T1 and GD1 would have on consumers, competition, sustainable development and safety?

Yes. In all areas identified there are undoubtedly measures which in theory will manage risk and reduce the likelihood of negative impacts. It is too soon to be able to anticipate how effectively these measures will be deployed during the review.

We are somewhat concerned about the continued emphasis on reducing costs for today's consumers. This, whilst being a perfectly valid concern is not the whole story. In terms of achieving a long term sustainable energy sector for example it may be that rational economic agents behaving individually may undervalue public benefits. Our specific views on impacts are documented elsewhere in our consultation response.

Question 2 – Are there any additional impacts that RIIO-T1 and GD1 may have?

We believe that Ofgem have considered an adequate range of impacts.

Question 3 – Are there any specific areas in which we should seek to quantify the impacts of implementing RIIO-T1 and GD1 in a later IA?

Ofgem should seek to quantify the acceptability or otherwise of the package to investors. It is critical to the achievement of government energy policy that a flight of capital is not seen in the sector which would have severe consequences for consumers. We must be convinced that there is investor appetite for the type of package that RIIO-T1 seeks to provide.

Chapter 3 – Risks & Unintended Consequences

Question 1 – Have we correctly identified the risks associated with implementation of RIIO-T1 and GD1?

We agree that the issues considered including delivery of primary outputs, over/ underestimating allowances and increased regulatory risk and failure to adequately consider the needs of future customers comprise a reasonable coverage of risks. As Ofgem point out there are a range of tools available to manage their impact. At this stage it is too early for either Ofgem or the companies to perform a quantified impact assessment since it is the substance and detail of how these tools are deployed that are key.

With regard to Ofgem's approach to financeability we would highlight the goal of encouraging investment is not assured via a commitment to transparent principles alone but instead will be achieved by a commitment to transparent principles that are attractive to tomorrow's investors.

We are encouraged that Ofgem have expressed a commitment to developing appropriate transition arrangements to ensure that the cash flows of companies are not unduly impacted.

Question 2 – Are there other risks that implementation of RIIO-T1 and GD1 may have?

We believe that Ofgem have considered an adequate range of risks.