Consultation on strategy for the next transmission and gas distribution price controls – RIIO-T1 and GD1

Response from Scottish Hydro Electric Transmission Limited (SHETL)

Summary

We do not support the approach to key financial issues – asset lives, cost of equity and cost of debt – set out in this consultation. Specifically:

§ We are strongly opposed to an increase in regulatory asset lives in electricity transmission, and do not believe that there is evidence to justify this when taken against a background of ongoing sectoral and technological change. If a case can be made to change asset lives, then any change must explicitly consider the impact on cash flows and be cash neutral over the period compared to the current position.

§ We believe that the proposed range for the cost of equity is below investors' expectations. The theoretical analysis presented to support this range does not take account of the increased risk inherent in the RIIO proposals nor does it take account of market evidence. In our view, the cost of equity needs to be >7%.

§ We do not believe that the proposed change to setting the cost of debt is better than the current approach. In our view, the increased risk associated with this approach means it is significantly worse. Importantly, by proposing to ignore real world costs, the new approach would be 'cost minus'. If this approach is to be pursued then an uplift of at least 50 bps for these real world costs must be included.

§ We welcome acknowledgement of the importance of equity and credit metrics in assessing financeability. However, we do not agree that this assessment should be only over the medium to long term, particularly when that duration is longer than the price control settlement.

We are also concerned about the apparent lack of importance assigned to the funding of large capital projects – considered as a 'secondary deliverable'. Delivery of the large capital programme necessary to facilitate renewables is a key business driver for SHETL over the coming decade. In particular, we support the continuation of the current Transmission Investment Incentives (TII) funding mechanism that was developed as part of the Government's Transmission Access Review.

Overall, we believe that these proposals are anti-investment and, if implemented, have the potential to seriously damage the transition to a low carbon economy.

Financial issues

Summary

- We are strongly opposed to an increase in regulatory asset lives in electricity transmission, and do not believe that there is evidence to justify this when taken against a background of ongoing sectorial and technological change. If a case can be made to change asset lives, then any change must explicitly consider the impact on cash flows and be cash neutral over the period compared to the current position.
- We believe that the proposed range for the cost of equity is below investors' expectations. The theoretical analysis presented to support this range does not take account of the increased risk inherent in the RIIO proposals nor does it take account of market evidence. In our view, the cost of equity needs to be >7%.
- We do not believe that the proposed change to setting the cost of debt is better than the current approach. In our view, the increased risk associated with this approach means it is significantly worse. Importantly, by proposing to ignore real world costs, the new approach would be 'cost minus'. If this approach is to be pursued then an uplift of at least 50 bps for these real world costs must be included.
- We welcome acknowledgement of the importance of equity and credit metrics in assessing financeability. However, we do not agree that this assessment should be only over the medium to long term, particularly when that duration is longer than the price control settlement.
- We are broadly comfortable with the proposed treatment of tax and pensions.

Asset lives, depreciation and cash flow

Currently, the regulatory asset life in electricity transmission is 20 years. Ofgem proposes to increase this to 45-55 years. We are strongly opposed to this change.

Regulatory assets lives are not the same as statutory asset lives or economic asset lives. This is a long held principle of GB economic regulation. Regulatory asset lives are a complex financial instrument that seeks to find a 'fair' balance of the costs of network assets between current and future customers. In doing this, it is not the economic lives of the assets that are important, but the use of the assets and the usefulness of those assets through time. In addition, there are financing costs inherent with the duration of asset lives – simply, the longer the asset life, the greater the financing cost and associated risk premium – and this too must be balanced between current and future customers.

To simply assert that regulatory asset lives should reflect the average expected economic life of the related network assets is, in our view, insufficient. Such an approach implies that network assets are used equally by customers over their economic life. Furthermore, such an approach implies that there is no cost (or risk) differential associated with the asset life assumption.

Ofgem justifies the proposed changes to regulatory asset lives using work undertaken by CEPA on the average expected economic life of network assets. While CEPA are confident in their analysis of the technical life of network assets, they are less confident in their analysis of the useful life. CEPA clearly acknowledge the uncertainty surrounding future network usage and the resultant difficulties in modelling future usage. CEPA's key conclusion from their modelling work is very high level – that it is almost certain that electricity demand will rise over the next four decades. From this, they conclude that electricity transmission assets will remain useful. We agree that this is almost certainly true for the electricity transmission system in totality, but this does not reveal the usefulness of individual assets.

In making an assumption about regulatory asset lives there is a world of difference between the existing asset base still being useful in 50 years and a different asset base (of equivalent value) being useful in 50 years. Given the background of changing generation sources and changing demand patterns, we would argue that it is not possible to be confident that current transmission assets are of the right size and in the right place to still be useful in 50 years' time. Yes, we agree that we will probably still need a transmission system – but new network and generation technologies might mean that it looks very different from today's transmission system. This issue is not addressed in CEPA's work. At this time, given the wider sectoral uncertainties, we do not believe that there is strong enough evidence of future asset usefulness to justify a lengthening of regulatory asset lives.

Our view is reinforced when we consider the revenue implications of the proposed change. In their analysis, CEPA show that a change of regulatory asset lives in electricity transmission from 20 years to 45 years would:

- Reduce current revenue by around one third; and
- Reduce revenue by around £3.5 billion in the RIIO-T1 period.

CEPA conclude that shifting to a longer regulatory asset depreciation life can have a significant impact on asset cash-flows and consequently financial ratios; this is exacerbated when linked with an above steady-state level of capex; and the implications of these effects on cash-flows will need to be considered as part of a broader financeability assessment. CEPA's conclusions are of particular relevance to SHETL, where we forecast capital expenditure in excess of £3 billion in the next decade against a current asset base of £450 million.

What CEPA does not consider in its analysis is the additional financing costs associated with the lengthening of regulatory asset lives. Longer regulatory asset lives equates to lengthening of cash flows and, hence, lengthening of returns. There is a greater risk associated with a longer investment cycle – simply, an investor might be more confident about being remunerated over

20 years than over 50 years. One of these risks is a change to the regulatory framework; illustrated, perhaps, by the risk of another 'RPI-X@20' Review in another 20 years. Similarly there is sectoral uncertainty over future technology choice and Government policy objectives. The impact of this uncertainty will be to increase the cost of equity.

The importance of the cash flow impact cannot be understated and, in our view, it is shocking that this is not examined in the consultation document. In essence, it is proposed to reduce cash flow by one third at the same time as licensees are undertaking unprecedented investment in the network. In broad terms, Ofgem's proposed reforms have the potential to remove over £10 billion of cash from network businesses over the next years – or a third of the forecast £32 billion of extra investment required over that period. It is a gross understatement to say that this would present a huge financing challenge. The effect would be a significant transfer of costs (and increased costs) onto future generations which, as we describe above, has not been justified.

To summarise, the CEPA work does not present compelling evidence for the ongoing use of today's transmission assets and does not adequately assess the cost to licensees (and ultimately customers) of doubling regulatory asset lives. Thus we believe that the case is not made for a change to regulatory asset lives in electricity transmission.

As described above, we do not support a change to regulatory asset lives in electricity transmission; hence our view is that this should not proceed and, accordingly, there would be no need for transitional relief to smooth the cash flow impact. If, however, a change to regulatory asset lives is progressed, then this must make sufficient adjustment to cash flows to enable an efficient business to attract the necessary financing to plug the cash shortfall caused by the change. In this regard, we emphasise the importance of being able to meet investors' expectations for adequate remuneration over a reasonable time period. In our experience, this means being able to make dividend payments within the price control period.

Allowed return

Cost of equity

The consultation document sets out an initial range for the cost of equity of 4.0-7.2%. **This range is not consistent with investors' expectations and, taken in the context of the wider RIIO proposals, is too low. In our view, the cost of equity needs to be >7%.**

Strong evidence of investors' expectations comes from the response to National Grid's equity issuance in May 2010. Despite offering an equity return of 13% (3% above the top end of the range proposed in the consultation document), the issuance met strong opposition from shareholders and has subsequently depressed National Grid's share price relative to the sector. Analysts' notes following publication of the consultation document call in to question National

Grid's ability to meet its offering. It is difficult to conclude from this that investors expect the cost of equity to decrease from the current level of 7.0% for electricity transmission.

The work undertaken by Europe Economics for Ofgem is predominately backwards looking, theoretical and has an (acknowledged) small evidence base. Thus, in our view, the conclusions need to be tested against three additional factors:

- The RIIO changes to the regulatory framework which increase risk and, if the proposal to increase asset lives is progressed, significantly reduce allowed revenue and increase the duration of cash flows.
- The wider industry landscape, in particular ongoing energy policy uncertainty and the driver for large scale investment in the electricity transmission system. Again, this increases investors' risk.
- Competing options for investors' capital.

All of these factors place an upward pressure on the cost of equity from the prevailing rate.

We note the work in the Europe Economics report on whether the duration of cash flows has an influence on the cost of capital. The empirical evidence presented does not address the question of to what extent the changes discussed were expected by investors (and thus already 'priced in') or to what extent expectations of uncertainty and risk were affected by these changes. Again, we would argue that more relevant and compelling evidence comes from the recent analysts' notes on National Grid that downgrade the value of stock largely on the basis of longer duration cash flows. It seems a truism that individuals value cash today higher than cash tomorrow, particularly as cash tomorrow is subject to change.

In order to bridge the gap between the allowed cost of equity and investors' expectations of returns of regulatory equity, there is a reliance on outperforming the price control settlement. The RIIO proposals remove some of the historic scope for outperformance, for example the proposed changes to the cost of debt (considered below). In electricity transmission, there has always been limited opportunity to use incentive mechanisms to outperform the settlement. More generally, traditional incentive mechanisms have become more complex and constrained in scope – increasing both risk and constraining potential rewards. Taking the proposals as a whole, we do not believe that there is sufficient scope for outperformance to deliver the additional 3-6% return on equity expected by investors.

Finally, we note and support the proposal to make an allowance for equity issuance costs. As with the current arrangements, this allowance should be made ex-ante based on a notional percentage of the modelled equity issuance requirement. Consideration of this allowance should be made as part of the wider consideration of financeability.

Cost of debt

Currently, the notional cost of debt for network licensees is determined upfront by Ofgem as part of the price control process. It is then fixed for the price control period. Ofgem proposes that, going forward, the price of debt would be set each year based on the ten year trailing average of Bloomberg 10-year BBB and A corporate bonds. Ofgem would then reassess the price control settlement, and the Authority would issue an annual direction to adjust the base allowed revenue in line with the new cost of debt assumption. **We are strongly opposed to this change.**

The rationale for any change to the price control must be that the proposed change is for the better. The case for change presented in the consultation document appears to be that the 'hard facts' of an historic index is better than an educated assumption about future costs. We argue that this is only the case when the historic index can be demonstrated to be a good guide to the future costs likely to be incurred by the licensee. This is not the case when it comes to debt issuance, and as a consequence there is a strong mismatch between average historic costs and incurred current costs.

The mismatch is a particular issue for SHETL given the large capital programme. To fund this programme, we need to incur additional debt at the prevailing market rate – at a time when interest rates are expected to increase after a long period of reducing, low rates. The approach to funding debt proposed by Ofgem means that the allowed cost of debt will be a historic average. There is clearly a difference between the current cost of debt and the historic average cost of debt. Over the next price control period, this difference is likely to be negative and thus exacerbate SHETL's already challenging financial situation.

Ofgem argue that, over time, this difference will balance itself out. We disagree – this is only the case if companies retain a constant amount of debt. At this time, the low historic cost of debt is likely to result in a shortfall compared with the actual market cost of debt. It is in this period that we expect to have a significant requirement for debt. This means we might never recover our cost of debt.

The current approach to the upfront setting of the cost of debt allows for consideration of historic evidence at the same time as assessing likely future costs and likely future debt issuance requirements. Licensees then have a certain allowance which, in accordance with the principles of utility regulation in GB, they can seek to outperform. If scope for outperformance is removed from this part of the settlement, then it must be replaced elsewhere.

We are also concerned about the index being proposed. The consultation document provides analysis that demonstrated the average weighted tenor of licensee debt issuance is 19 years, and then goes on to conclude that 10-year bonds is more appropriate metric than 20-year bonds. Furthermore, if the index is to reflect companies' debt it should be a mix of A-/BBB bonds. The consultation document agrees that transparency is an important criterion for the indexation mechanism, and then goes on to conclude that the Bloomberg index is preferred which many specialists view as opaque and a 'bad mix' for comparison with utilities.

Taken together, these factors are likely to strongly influence licensees' treasury strategies; in particular, encouraging hedging against the index.

The consultation document dismisses concerns that the proposed index does not include real world costs by stating "network companies have consistently outperformed the index" and referring to an erroneous comparison of spot issuance yields and a ten-year average of yields. This comment infers that Ofgem are prepared to set an 'index minus' where licensees have to outperform the index just to recover their costs – this, in our view, is not compatible with Ofgem's duty to ensure an efficient company can finance its functions.

The real world costs missing from the index are of at least 50 bps value and include:

§ New debt issuance premium (10 bps);

§ Liquidity, cost of carry costs (20 bps);

§ Issuance and rating agencies costs (10 bps), and

§ Risk premium for index mismatch (>10 bps).

If this approach is to be pursued, then these costs must be allowed for.

Finally, we believe that the implementation issues are more challenging than is suggested in the consultation document. A change to the cost of debt assumption fundamentally changes the determination of the base revenue for the price control period, the construction of the revenue profile, the resultant "P0" and "-X" terms, and potentially the RoRE analysis. It is not, therefore, straightforward to simply 'rerun' the financial model each year with a different cost of debt assumption and then adjust the base revenue accordingly. In order to do this, there will need to be a fundamental change to the way that the allowed revenue is set such that each year is treated essentially in isolation. Importantly, this removes the potential for 'smoothing' of revenue changes over the period.

The consultation document also suggests that there will be a timelag, with the index as at March 2012 being used to set initial allowed revenues in 2013/14. This approach compounds our concerns about timing mismatch described above.

Overall, the proposal to change the approach to the cost of debt significantly increases regulatory risk. It is more interventionist, with an annual base price control adjustment by the Authority. The final settlement would be more uncertain, making acceptance of that settlement more uncertain. It is backwards looking, exposing licensees to the mismatch between historic and current costs of debt – with little choice over when debt is required. The proposed index does not match current funding strategies of companies and the market, and is likely to perversely influence behaviour. The proposed index would explicitly exclude real world costs, incorporating an unfunded cost into the price control settlement.

In summary, we strongly disagree with this change. We believe it would increase risk and, hence, is anti-investment.

Assessing financeability

The assessment of financeability is a key issue for SHETL given the scale of investment required. We expect our current asset base of around £450 million to experience a significant and sustained increase over the next decade as we invest around £3-5 billion to facilitate the connection of renewable generation. This presents a significant financing challenge to our business.

Appropriate measures of financeability are critical. We welcome the acknowledgement of the importance of credit rating metrics and equity metrics. However, for SHETL at least, some of the proposed metrics are void (for example, PMICR as defined by Ofgem) or unachievable (for example, net debt to RAV as a fixed input). There is also an inconsistency in the suggestion that credit rating metrics will be considered over the medium to long term, when the metrics have been developed by the agencies for use over the short to medium term.

Other financial issues

Tax

We are comfortable with the concept of the proposed tax trigger in RIIO T1, based on the approach defined at DPCR5.

In response to the specific questions raised in the consultation document we have the following comments:

- We disagree with Ofgem's preferred option of modelling taxation in RIIO-T1 based on the tax proposals contained in the June 2010 budget. We believe that there is a risk that the changes to rates in future years may not materialise. Our preferred option is 'option B' in the paper. This would reflect any differences between actual rates and the June 2010 budget proposed rates as pass through.
- We agree that tax modelling should be done under UK GAAP pending adoption of IFRS, and are comfortable that any changes are then dealt with via the proposed tax trigger.
- We believe that for RIIO-T1 the deadband should be in line with that set for DPCR5 (i.e. equivalent to a 1% change in Corporate Tax rate). The level of the deadband may differ between sectors depending on sector specific issues and circumstances.
- We believe that any update to allowed revenue for clawback of the tax benefit of excess gearing should be reflected in a revenue adjustment at the mid-period review. We do not agree that this adjustment should take place every three years as proposed in the consultation document. The mid-period review after four years would appear to be a more appropriate point in the regulatory cycle to make any such adjustment.

We are comfortable with the proposed treatment of business rates, and the treatment of future ratings valuations.

Pensions

Generally SHETL support the ongoing application of the pensions principles established during DPCR5 and the subsequent June 2010 Pensions paper.

In response to the specific questions raised in the consultation document we have the following comments:

§ We do not agree that the true up adjustments for the existing transmission price control (TPCR4) should be spread over the eight years of the RIIO-T1. We believe that Ofgem should set a deminimis limit and if any adjustment falls below that level then the true up should take place in year one of the following price control period. If the true up adjustment is above the deminimis level then we would agree that the true up should be spread over the period of the subsequent price control period. The impact of any TPCR4 true up for SHETL is likely to be immaterial and we believe that this should be reflected in year one of RIIO-T1.

§ We believe that the pensions valuation used for setting allowances should be based on the latest available information. We would suggest that allowances for non fast-tracked companies should reflect the pension position at September 2012. We agree that an eight year price control period is too long a period for the established deficit funding to be fixed. However, we believe that it would appear sensible to use the opportunity of the mid-period review to update funding as opposed to every three years as proposed in the consultation document. Companies within the various sectors have differing dates for triennial valuations and therefore it would not be possible to set a common date that suits every company.

§ We do not agree that PPF levies should be part of benchmarked costs. These costs are currently subject to a significant degree of uncertainty as noted in Ofgem's policy paper. We believe that a specific allowance should be set during the price control process and that this is subject to a true up mechanism, as long as companies can demonstrate they have taken all reasonable steps to minimise the PPF levy.

§ Whilst we broadly support the pension principles in the June 2010 document we have a concern over the methodology being proposed for the calculation of the established deficit. The Ernst & Young (E&Y) paper on the methodology to calculate the established deficit is, in our opinion, overly complicated and potentially costly. We have been involved, via the ENA, in the preparation of an alternative methodology. We support this as a viable alternative to the E&Y proposal. However, we still see practical difficulties in being able to split pension scheme members between regulated and unregulated. This is particularly difficult for SSE where a significant element of services provided to our networks is from SSE Services plc. Many of these staff provide services to all three of our regulated entities as well as to other unregulated businesses within the SSE plc Group. This matter will require further discussion between Ofgem and licensees who have this issue. We would hope that a practical, proportionate and simple agreement could be reached on how this issue should be addressed.

Uncertainty mechanisms

Summary

- Many of the uncertainty mechanisms already in place are effective and well understood by the industry; accordingly, only small changes (if any) are required.
- The existing TII mechanism should be retained for RIIO-T1.
- The existing IAE provision should be retained for RIIO-T1.
- Clear and upfront rules are needed for the operation and scope of the mid-period review; in particular both output measures and cost allowances must be clearly within scope.

Uncertainty mechanisms are a key part of any price control settlement and, as the consultation document notes, will be of greater importance under the eight year RIIO settlement than previous five year RPI-X settlements.

To be effective, uncertainty mechanisms require clear justification and a clear process for implementation during the period. Different licensees will require different mechanisms to address the specific business challenges they identify during the development of their business plans. Thus we recognise that the justifications for, and workings of, uncertainty mechanisms will be a critical aspect of licensees' bespoke business plans.

Our initial views on the uncertainty mechanisms likely to be required by SHETL are set out in table 1 below. In this regard, we note that many of the uncertainty mechanisms already in place are effective and well understood by the industry; accordingly, our view at this time is that only small changes are required. However, three uncertainties are of particular concern to SHETL in respect of the RIIO-T1 period – large capital projects, framework changes and the mid-period review – and we comment on these further below.

<u>Large capital projects</u>

Over the RIIO-T1 price control period SHETL's activities and expenditure will be dominated by the delivery of the large capital projects necessarily associated with the continuing growth in renewable generation in the north of Scotland. It is acknowledged, however, that the timing, scale and location of renewable generation growth are uncertain. Key influencing factors include the onshore planning system, technological development for marine and tidal generation, and the economics of offshore wind. These factors are clearly outwith SHETL's control. Hence, while reinforcements can be identified as part of the business plan and associated pre-construction activities can be planned, the detailed programme for delivery of these large capital projects is uncertain. Thus it is very difficult to set ex-ante capital allowances as part of the price control settlement.

The current regulatory frameworkseeks to manage this uncertainty through the Transmission Investment for Renewable Generation (TIRG) mechanism and, more recently, the Transmission Investment Incentives (TII) mechanism. In essence, these mechanisms allow licensees to trigger funding provisions within the price control period as and when the needs case for reinforcement can be demonstrated. Under the TII mechanism, following notification by the licensee, the Authority determines on the capital expenditure allowance for the large capital project and the licence is modified accordingly.

Although the TII mechanism may be viewed by some as ‘micro-regulation’, we fully support it. The scale of the capital expenditure associated with these large capital projects is such that, in our view, the setting of upfront capital allowances (either directly or mechanistically as, for example, a volume-driven unit cost) would place an inappropriate and unnecessary risk on licensees and consumers. In part, this risk is financial – the impact of underspend or overspend on projects that can cost upwards of £1 billion. However, in an environment of technological innovation, it is important to also recognise the risks associated with fixing allowances based on today’s technology – will that still be the right answer in five or ten years’ time? Over the past five years, taking into account planning restrictions and the developing principles of ‘smart grid’, we have already begun moving away from the conventional approach of building more wires as the only means to increase the capacity of the network. If we do not know now what we are going to develop, never mind how much it will cost, we cannot set allowances or even outputs now and, hence, an open flexible mechanism is essential.

We strongly believe that the existing TII mechanism should be retained for RIIO-T1. This mechanism is transparent to stakeholders, robust to changes in technology and consumers’ needs, and minimises licensees and customers’ exposure to the uncontrollable risks associated with uncertainty over the pace and scale of future network growth.

<u>Framework changes</u>

The energy industry in GB is governed by statute at European and national level, by licence and by code. Significant framework changes are underway that affect the operation and costs of network businesses. For example, the implementation of the Third Package and, looking forward, the associated Network Codes; a new GB Energy Bill and associated Energy Market Review; ongoing reform of transmission access and charging; and greater scope for changes to industry codes. Given the ongoing pressure to decarbonise our economy, it is likely that significant framework change will continue through the RIIO-T1 period.

The transmission licence currently includes provisions to trigger an Income Adjusting Event (IAE) where an event results in an increase or decrease of costs of more than £1 million in any particular year. An IAE might be triggered by force majeure, a code change or such other event approved by the Authority for example framework changes.

The existing IAE provision should be retained for RIIO-T1. It is, in our view, a necessary protection from exogenous change that is essential for an eight year price control settlement that is to be agreed at a time of significant and sustained framework changes.

Mid-period review

In order to address the risks inherently associated with an eight year price control period, a mid-period review is proposed. If this is to successfully address these risks, and importantly not create new and unnecessary uncertainty, **clear rules are needed for the operation and scope of the mid-period review.** Such rules must seek to ensure the mid-period review is neither a “mini review” (creating a four-plus-four settlement) nor a “cursory glance” (that does not address substantive issues because they are considered outwith scope). These rules should be defined as part of the RIIO-T1 price control settlement.

In formulating the rules for the mid-period review, it is our initial view that both the Authority and the licensee should have the right to trigger the review. This should be subject to high-level criteria that are underpinned by a materiality threshold. In particular, both output measures and cost allowances should be within the scope of the mid-period review. Whilst we recognise that currently changes to costs and drivers tend to be borne by the network companies, it is clear that over an eight year period there is significantly more potential for exogenous influences on input prices and/or drivers to change, and for the aggregate impact of several individually hitherto seemingly insubstantial increases to have a material impact.

We strongly believe that any mid-period settlement proposal should be able to be referred to the Competition Commission. This again relies on a clear set of rules for the mid-period review. In particular, a referral should be possible where a licensee requests a mid-period review and the Authority rejects that request.

Table 1: Initial views on uncertainty mechanisms

Uncertain cost	Proposed mechanism
Force majeure	Disapplication on notice to the Authority. No change from current arrangements. and Income adjusting event (see comments above). No change from current arrangements.
Price inflation	Indexation of the revenue restriction provisions to RPI. No change from current arrangements; if a change is made to the relevant period then the effect should be revenue neutral. Separate provision will be made for Real Price Effects (RPE) in the operating and capital cost allowances.
Tariff forecast	Revenue restriction correction factor (K_t) to adjust subsequent years allowed revenue. No change from current arrangements (subject to licensees' views on the parameters).
Licence fees	Pass through of costs. No change from current arrangements.
Business rates	Pass through of costs, subject to reasonable endeavours obligation to minimise costs at revaluation. No change from current arrangement.
Critical National Infrastructure security	Logging up of costs. No change from current arrangements.
Compensation to landowners	Logging up of costs. New provision (currently allowed for National Grid Gas).
Sole-use infrastructure for new generator connections	Revenue driver mechanism with pass-through component and volume-driven unit cost allowance. Similar to current 'local revenue driver' arrangements, although detailed workings of mechanism and unit cost allowance to be reviewed. Full pass-through of costs of high cost schemes to be retained.
Large capital projects	Retain current TII mechanism (see comments above); although there may be scope to streamline the process.

Business plans, innovation and efficiency incentives

Summary

- Support bespoke business plans; however it is important that their effectiveness is not undermined by overly prescriptive guidance.
- The case has not been made for third party delivery.
- Research and development activities are not encouraged and supported by narrow project selection criteria for funding; we favour a wide-ranging open competition with bids led by network licensees.
- Efficiency incentives should be proportionate to the risks that businesses are exposed to.

Business plans

SHETL welcomes the opportunity to develop a bespoke business plan; in our view, this is one of the key benefits of the RIIO framework.

For this benefit to be realised, licensees must not be constrained by overly prescriptive guidance on content or targets that must be met. Our preference is for little (or indeed no) guidance for business plans and, in this regard, we support Ofgem's decision not to publish a template for the business plan narrative. We trust that a similar 'light touch' will be applied to the development of the business plan tables and that flexibility will be enshrined within the nascent financial model. At this time, and given the condensed process, we remain concerned that stakeholder views may not align with rules prescribed by Ofgem, and that there will be little scope for the licensee to thus propose a balanced business plan.

We note the high level criteria for assessing licensees' business plans. Consistent with our view that business plans should be developed and hence reviewed on a case-by-case basis, we welcome the generally subjective nature of these criteria. Our comments on the criteria are set out in table 2 below.

Table 2: Views on business plan assessment criteria

Criteria	SHETL views
Criteria 2 – Acceptance of our policies	As described above, we remain concerned about overly prescriptive guidance and, in particular, potential misalignment between stakeholders' and Ofgem's views. We understand that it is Ofgem's view that individual companies need to justify approaches that are not consistent with Ofgem's policies. However, this approach does not sit comfortably with the phrase *"we expect companies to comply"* as used in criteria 2.
Criteria 11-15 – Reflection of strategy in plan	Reference to historic data. For new performance measures or cost categories, data may not have historically been collected. It is not reasonable to expect licensees to 'guess' what these data were, and thus licensees should not be marked down where they are not able to provide complete historic records.
Asset health	In many cases our overall asset volumes (and historic replacement volumes) are statistically insignificant and, thus, do not lend themselves to a model-based approach. Scheme justifications, and variance from these justifications, better suit the small volume base.
Direct innovation funding	Welcome the inclusion of a direct Innovation Allowance as part of the RIIO-T1 settlement. See further comments below.

Third party delivery

It remains our view that the case has not been made for seeking third party delivery of network assets. The costs and risks of this are well elucidated; for example, delays to delivery, ensuring maintenance of security of supply, fragmentation of the network and loss of co-ordinated development. It is also acknowledged that the supplier base and procurement rules are the same regardless of the party responsible for delivery – significantly restricting the scope for capital cost savings. Against this background, we have not seen a compelling case setting out the benefits of third party delivery for consumers. Thus, **before this workstream is progressed further, we believe that an evidence-based impact assessment should be undertaken.**

If the case is made for progressing this work, then clear rules for when a competitive approach would be considered are essential. In particular, these rules must clearly state that where assets are already under development or construction these would not be subject to a competitive process. Otherwise, we believe that the criteria previously set out in the RIIO Recommendations document are reasonable. Finally, we note that further consideration of the regulatory risk to the existing licensees is required; in particular their price control settlement and, accordingly, their financing arrangements. This might require a new uncertainty mechanism.

Innovation

Acknowledgement of the ongoing need to encourage research and development activities is a further key benefit of the RIIO framework. In our view, such funding to stimulate and support innovation should be mindful of:

- That innovation is, by its very nature, unpredictable and uncertain. Schemes are as likely to fail as succeed. It is very difficult to evolve in an environment constrained by rules and outputs. In this regard, retaining learning as an output is key. Flexibility in the regulatory framework and associated funding arrangements is critical.
- That the separated structure of the industry should not act as a barrier to new ideas. Transmission and distribution might need to work together, as might asset owner and system operator. Again, the regulatory arrangements should be flexible to this.
- That all ideas are welcome. Non-licensed businesses should be able to participate in research and development activities. However, licensees have wider obligations to maintain a safe and secure network and this should remain the primary consideration in any innovation project.

Thus we conclude that a regulatory framework that successfully supports innovation needs in itself to be open and innovative.

Going forward, **we believe that an annual competition for funding research and development projects across the energy sector should be entirely open.** That is, any type of innovation should be permitted (not just projects with a low carbon objective) at any stage of development (i.e. inception through to deployment), there should be no restrictions on scope or size, there would be no constraints on who might participate (including other energy licensees such as suppliers), and success should be measured on learning (not achieving outputs). As with the Low Carbon Network Fund, the costs would be socialised across all GB consumers.

At a high level, there should be two rules. Firstly, the lead party in each bid should be a network licensee. The network licensees own and have ultimate responsibility for their network assets and, as such, have a particular responsibility for safety and security of supply bestowed upon them by virtue of primary and secondary legislation and their particular licences. We do not believe it is possible, or indeed desirable, for third parties to be granted ‘rights’ (of whatever form) to these assets. Secondly, no customer should experience a significant or sustained reduction in their level of service (unless they have expressed positive consent) as a result of a research and development project.

We recognise that an entirely open approach such as this goes against the prevailing regulatory trend in GB of increasing obligations on licensees and harmonisation of business practices. It is important that the regulatory framework in itself does not act as a barrier to research and development. For example, common charging methodologies or standard connection provisions should not prohibit non-standard innovative approaches. Thus, in our view, a key work area in developing the open competition needs to be specific consideration of how projects might be encouraged, and when appropriate permitted, to go beyond the existing regulatory restrictions.

Efficiency incentives and IQI

SHETL's initial view is that there should be three different categories of efficiency incentive for RIIO-T1:

- A 'totex' mechanism for controllable operating costs and "business as usual" capital expenditure (including pre-construction for large capital projects and an ex-ante sole-use infrastructure connections allowance). This could be linked, in whole or in part, to an IQI-type efficiency incentive.
- The revenue driver mechanism for sole-use infrastructure for new connections (above a baseline allowance), incorporating a unit cost allowance element. The starting point for this should be the existing local revenue driver mechanism, but resetting the unit cost allowance and improving the mechanics.
- The TII mechanism for large capital projects should continue in its current form.

For each of these categories, the risk faced by the business is different and the strength of the incentive should be set accordingly. Risk is a function of both magnitude and probability. The risk of overspend on a £1 billion project is very different to the risk associated with ten £0.5 million projects. This is an issue that needs to be clearly presented in companies' business plans. However, at this stage, our view is that an incentive range of 40-60% is too large for the TII mechanism.

We note Ofgem's intention to consider how within-period adjustments associated with efficiency incentives might be made. While we recognise the merits of this approach, we believe it is likely to be very complicated to implement and, hence, urge caution and rigour.

Outputs and incentives

Summary

- Outputs should be measures of performance that are relevant to customers; for example, network reliability, impact on the environment and stakeholder engagement.
- Output-based incentives must be material; proportionate; controllable by the licensee, and measurable.
- For SHETL, future reinforcement of the network is too important to be assigned as a ‘secondary deliverable’ and subject to a complex, potentially perverse, incentive scheme.

Output measures

SHETL supports the establishment of output measures as a mechanism for stakeholders to monitor our delivery of the RIIO-T1 settlement. Accordingly, output measures should be of relevance to stakeholders, and be able to be transparently measured and presented. Thus, if network reliability is a key output for stakeholders, then the primary measure of reliability must be clearly and consistently reported such that customers can gain a clear appreciation of a licensee’s performance over the eight year period.

In addition, in developing relevant output measures, it is important to reflect the nature of the transmission business and, in particular, recognise the differences with the distribution businesses. For example, system reliability is a very different concept for each network type. In electricity distribution, reliability has a well established process and considerable historic information to draw upon when setting targets to be achieved, or potentially improved upon, through targeted investment. In transmission this is not the case and we await stakeholders’ views to whether the current high standard of performance should be improved upon. Another considerable difference is the volume of assets (and therefore projects) and cost of assets between the two network types. In distribution, Ofgem carry out condition based replacement analysis and unit cost analysis. This is, by definition, on an ‘average’ project basis and this is considered acceptable given the portfolio effect of the considerable number of projects in a price control period. However, volumes are much lower in transmission and can vary considerably in cost due to their location (urban or rural). Accordingly, an average cost approach is ill-suited and might result in an outputs based settlement which cannot be delivered.

To summarise, while it might be desirable for simplicity to replicate output measures across the electricity (and even gas) network businesses, the resultant measures would be so generic that they would be meaningless or, worse, drive inefficient outcomes. Thus to attempt to do so would, in our view, devalue the output-based RIIO framework.

Output-based incentives

We draw a distinction between output measures and output-based incentives. The key features of incentive mechanisms are that they must be material (i.e. few and meaningful); proportionate; controllable by the licensee, and measurable. So, for example, some aspects of network reliability are controllable by the licensee (e.g. through asset maintenance) and some aspects are not (e.g. weather related events). While overall network reliability might be the output measure, only a subset of that – the controllable elements – might be incentivised.

In this regard, it is worthy of note that, for SHETL, controllability and measurability are constrained by the provisions of the British Electricity Transmission and Trading Arrangements (BETTA), which means that SHETL has no control over network utilisation and has limited access to operational information. Cognisance of such limitations will, necessarily, be vital in determining meaningful output-based incentives for the next eight year price control period.

Where an output-based incentive is proposed, it will be important to consider the context in which targets are being set. For example, the new eight year settlement will mean that forecast performance targets will be inherently less certain when compared to a five year control; for SHETL the step change in investment over the period will mean that targets based on historic performance alone are not likely to be appropriate; and, where there is no historic data, a period of monitoring may be an appropriate precursor to the application of a financial incentive in order to set meaningful incentive parameters and targets.

Electricity transmission wider works

It is proposed by Ofgem that reinforcement of the network be categorised as a 'secondary deliverable' and potentially subject to a complex "boundary capability" incentive scheme. We are strongly opposed to this.

For SHETL, timely reinforcement of our network in order to facilitate growth in renewable generation is the overriding driver of our business now and going forward. We are fully committed to this, and are deploying huge resource to make sure it happens. The work done in large part through the Government's Transmission Access Review has put in place a regulatory framework to support this – recognising the importance of network reinforcement to meeting national carbon targets. To disrupt this framework now seems imprudent.

Work on electricity transmission wider works is, in our view, a primary output of interest to all of our stakeholders from the GB and Scottish Governments to the domestic consumer. We will continue to treat it as such.

Furthermore, and as described above, we strongly believe that the TII mechanism should continue during RIIO-T1. To propose moving to an alternative approach ignores the work done over a number of years that has resulted in the TII mechanism. In addition, the TII mechanism is demonstrably working well.

We note Ofgem's preference to move to a system where funding is based on "boundary capability". We are not clear what Ofgem means by "boundary capability" and how you might measure it. For SHETL, many of our proposed reinforcements are within conventional planning boundaries – for example, the island links and intra-Caithness reinforcements – or even jump multiple boundaries – for example, the stages of East Coast works. In operational timescales, the capability of any boundary can change with the season, with demand use and generation installed, or measuring technique. In summary, this all appears highly subjective and certainly not an improvement on TII.

Timely and cost-effective reinforcement of the transmission system is extremely important. It is not suited to fixed financial allowances – whether ex-ante or mechanistically fixed to pre-defined outputs. To progress with this has the potential to delay vital upgrades, create perverse incentives in timing or which reinforcement to deliver, and stifle innovation.

Safety

Safety is clearly a key concern for our stakeholders, and this output measure should provide reassurance that we continue to operate our network safely. The primary output measure should be compliance with the safety standards which are set out in legislation and monitored by the Health and Safety Executive (HSE). The HSE already requires reporting in this area, and we do not believe that further reporting to Ofgem is necessary.

Given the strong statutory framework, in our view it is not appropriate for the economic regulator to set financial incentives around safety.

SAFETY	**SHETL views**
Primary output	Compliance with safety standards set out in legislation. No reporting to Ofgem required; stakeholders can easily access existing HSE reporting.
Secondary output	Asset health (see comments below).
Output-based incentive	Not appropriate.

Network reliability

Most stakeholders' experience of the electricity transmission network is when it is unavailable, i.e. there is a power cut. Measuring the reliability and availability of the network is thus a relevant and meaningful output measure.

Currently the performance of the GB transmission system is monitored through the report prepared each year by National Grid for the Authority ("the C17 report"). This report sets out on a consistent basis the availability and reliability of the network, and operational information on the quality of service. We believe that this report is comprehensive and accessible, and should continue in its current form as the primary output measure.

Given the importance of a reliable network to customers, we support an output-based incentive for reliability. In principle, we support the proposal to incentivise performance based upon energy not supplied (ENS) using the calculation for National Grid's existing reliability incentive. However, our support is subject to three qualifications:

- That only controllable events are included in the calculation;
- Targets are set based not on historic performance but on forecast performance during the period taking into account increased system risk associated with the large capital investment programme, and
- The strength of the incentive reflects the materiality of ENS and SHETL's risk profile during the RIIO-T1 period.

In particular, the performance incentive must exclude all ENS events lasting for three minutes or less to appropriately reflect the allowed parameters of the protection equipment. As with the current incentive arrangements, it must also have adequate exemptions for (at least) ENS resulting from severe weather; third party damage; events triggered by adjacent networks (both transmission and distribution networks) where the resulting ENS was out of the relevant TO's control, and exceptional events.

The financial aspect of any incentive associated with ENS performance should, in our view, be a function of risk and value to customers. We recognise that it is incumbent on licensees to correlate risk, potential performance and cost to customers when presenting their views on ENS in their business plans.

During the current price control period, transmission licensees have developed a suite of Network Output Measures (NOM) as a means to present the 'health' and associated risk of the network. We support the use of NOM as a secondary output for reliability. As the NOM approach has only recently been approved and implemented, we do not believe that this is the time to suggest changes to the approach.

The NOM includes assessment of asset health, criticality and replacement priority across a number of types of transmission asset. These measures can be considered as a package that describes the ongoing management of the network. It is not possible to sum the individual measures together to form a single meaningful 'risk' measure. In particular, any deviation from a proposed single measure would need to be explained and justified by essentially "unpicking" the single measure.

NOM is, by its very nature, a highly variable assessment of asset condition, performance and risk. Changes to a small number of assets can dramatically affect the measure. The timing of asset changes is not always a pure function of condition and performance, but can include resource availability, network access and changing user needs. Thus we believe it is very difficult to identify and achieve an optimum NOM (indeed, given the range of influencing factors, to do so would almost certainly be inefficient); hence NOM is not suited to a financial incentive.

RELIABILITY	**SHETL views**
Primary output	Established parameters set out in the C17 report: planned and unplanned system availability, unsupplied energy and loss of supply incidents. No change to existing C17 reporting requirements.
Secondary output	Overall asset health and criticality. No change to existing Network Output Measures currently reported to Ofgem, but review of output data within scope of mid-period review.
Output-based incentive	Energy Not Supplied (ENS), MWh per annum. Controllable events only with targets based on a risk-based assessment of future performance. We do not support a financial incentive on asset health.

Network constraints

Network constraints are important to customers; not least because they restrict access to the transmission system and because the costs are socialised across all. Thus we strongly believe that there should be transparency around the location, duration and costs of constraints, the reason there was a constraint and the actions taken to minimise any adverse effect.

It is important to remember that constraints are a part of efficient network development. As the recent access reform debate has demonstrated, it may be more cost effective to constrain than to reinforce. Similarly, once it can be shown that reinforcement is necessary, there is a certain level of constraint associated with delivering that reinforcement – "no gain without pain". Any objective to, in isolation, reduce constraints has a strong likelihood of achieving inefficient outcomes.

Accordingly, we do not support placing a financial incentive on TOs to minimise investment related constraints and operational/outage related constraints. We have set out our views on this issue in papers submitted to the Safety and Reliability working group (and published on Ofgem's website).

Investment related constraints are restrictions on the availability of the network arising from the 'early' connection of generation in accordance with the connect and manage access arrangements. The delivery of large capital projects is SHETL's single most important issue for RIIO-T1 where the forecast level of investment over the eight year period is unprecedented. The delivery of these projects is a major engineering challenge that is tightly constrained by planning, environmental and societal considerations. A crude 'boundary capability' type of incentive mechanism is grossly inappropriate in this context and might threaten timely delivery. As we describe above, it is essential that the existing TII mechanism continues in its current form during RIIO-T1.

Operational/outage related constraints are restrictions on the availability of the network due to planned maintenance and investment activities. While we totally agree that together the SO and TO should seek to minimise the overall cost of outage constraints, our earlier paper on this issue (referred to above) explains how outage related SO constraint costs are not controllable or measurable by the Scottish TOs, not least because the BETTA framework specifically prevents these TOs from having access to the relevant market information they would need in order to manage performance under such scheme. We are therefore wholly opposed to any proposal by Ofgem to expose the TO to a proportion of the SO's outage related constraint costs for RIIO-T1. Instead we advocate further enhancement of the TO/SO interactions for outage planning. Furthermore, we would be willing to work with the SO to develop a mechanism that reports upon actual outages where they vary from the agreed outage programme and the reasons for such variation.

Environment

SHETL operates in the unique environment of the north of Scotland and we understand that environmental considerations are extremely important to our stakeholders.

As a business we are committed to playing a full part in the overall national objective of achieving a low carbon economy. Our role in this relates to both our activities (i.e. how we run our business and the decisions we take) and to supporting, in particular, the development of low carbon generation and demand-side technologies. We believe we should be judged against both of these measures – but in different ways.

In our supporting role, this is predominately about facilitating connections, delivering network reinforcements and engaging in research and development activities. These issues are discussed elsewhere in this response. While we recognise the underlying merit in the RenewableUK proposal for a 'broad measure', it is important that the scope of network companies' activities is recognised – we are not policy makers. In particular, we would not want to create a conflict of interest between our existing obligation to avoid undue discrimination in our actions and a new obligation to favour one type of activity.

Turning to our own business activities, we support the development of the business carbon footprint (BCF) of the TO companies as a relevant environmental output measure. However, at this time, more work is needed on the parameters to be included in this measure. Importantly, from the perspective of the TO, we do not believe that this measure should include operational factors such as network losses. The level of operational losses will very much be determined by the pattern of generation (be it self- or centrally- despatched) and demand on the system at any one time, which in turn will depend upon the size and location of both, and cannot be controlled by the TO. However, there might be merit in reporting on the impact on losses in investment appraisals and the installation of low loss equipment on the network (which is already an important asset investment criterion upon which the TOs provide an annual statement).

We are keen also to develop a wider measure that captures those environmental issues of particular concern to our customers. Visual amenity, in particular, might be improved through selected re-routing or undergrouding of overhead lines. If an output measure is to be developed in this area, it would require a specific funding allowance.

ENVIRONMENT	**SHETL views**
Primary output	Business carbon footprint. Further work needs to be done to establish how this might be measured in a consistent and transparent manner, and how this is reported to stakeholders.
Primary output	Wider environmental footprint (for example: non-carbon emissions, noise, visual amenity, water management). Further consideration required; outputs would be linked to a specific funding allowance.
Output-based incentive	Will need further consideration after development of output measures.

Connections and customer service

It is at the time of connection that our customers most directly experience our service. Hence we support output measures for connection and, in addition,believe connections performance is an important barometer of customer satisfaction.

The provision of a connection to the electricity transmission system is a large engineering project that typically takes many years to complete. In our view, success is when we can work closely with the developer concerned to do our works in parallel with theirs. However, there a large number of factors to be taken into account including planning, environmental considerations, the local landowners' requirements, the supply market and operational constraints. Thus there is no such thing as a 'typical' connection.

Potential output measures for connection include time taken to provide an offer, time taken to deliver a connection after offer acceptance, and cost of connection. These are high-level metrics that do not capture the many factors associated with delivering a connection – and, hence, do not provide a good measure of our performance. While we might report these metrics, we believe a better assessment of our performance is likely to be achieved through customer satisfaction.

As a TO, the biggest challenge we face in seeking to find out customers' views of the service we provide is being able to clearly explain what it is we do. From a customer perspective, the 'upfront' elements of transmission are access arrangements, charging and operation – all functions of the system operator. A domestic customer, in particular, is likely to be largely unaware of our activities.

In light of this, we favour a more targeted approach to measuring customer satisfaction that does two things: firstly considers our ongoing stakeholder engagement, and secondly considers our response to our customer-facing activities (such as connections). While we support the rationale behind broader customer satisfaction measures, we do not believe this approach would measure very bespoke TO functions. In particular, we would be strongly opposed to our TO performance being an adjunct to National Grid's GB-wide survey of its business performance. A further important consideration is the volume of customer-facing activities in any one year. For example, the number of connections completed is typically less than five and complaints are infrequent.

Recognising the importance of good customer service, we support the development of a financial reward for excellence – perhaps based on the discretionary reward approach. However, in recognition of the issues identified above and the fact that there is no historical information available upon which a meaningful benchmark could be set, we do not believe that it is appropriate in the first instance to introduce a customer satisfaction financial incentive. Further evidence is likely to be needed to be gathered to justify and calibrate any such proposal – for example, at the mid-period review.

CONNECTIONS AND CUSTOMER SERVICE	**SHETL views**
Primary output	Basket of timescale metrics. Further work needs to be done on what these might be and how they can be consistently measured. Our view is that they do not provide a good measure of performance.
Primary output	Basket of customer service measures. Further consideration required; based on ongoing stakeholder engagement and customer-facing activities (e.g. connections).
Output-based incentive	Discretionary reward for excellence in customer service.

Tools for cost assessment

Summary

§ We support the use of benchmarking as a tool for cost assessment where suitable comparators exist. We remain uncertain that sufficient comparable data exists to undertake meaningful analysis for electricity transmission, and hence continue to favour a 'bottom-up' approach.

SHETL supports the use of benchmarking as a useful technique for providing additional information on which to assess historic expenditure and forecast costs.

However, effective benchmarking relies on having access to statistically significant volumes of data and a sufficiently large pool of comparator companies. As is recognised in the consultation document, there is limited gain to be achieved from benchmarking between the three GB TOs as they have such different scales of operation. Therefore, it is proposed to gather data from international sources, in particular the US Federal Energy Regulatory Commission (FERC). While we believe there is merit in undertaking this work, we would like to see any dataset developed by Ofgem being freely available to stakeholders. This is essential if companies are to take account of the analysis in developing their business plans.

e3 Grid Project

Given that the scope of the substantial 2008/09 e3 Grid Project was to benchmark electricity transmission system operators on an international scale, we would have expected to see this project as a specific source for Ofgem's work. However, this does not appear as a suggested dataset and no reference to the project's findings has been included in the consultation document. We believe that it is important to consider the general conclusions of the e3 Grid Project when assessing the role of transmission benchmarking in setting the RIIO-T1 price control.

Although the e3 Grid Project had access to the largest number of comparator companies used in a transmission company benchmarking study to date (22 TSOs across Europe), the overall conclusion of the project was that electricity transmission companies are complicated to benchmark given the low number of comparators. Whilst the project examined a number of benchmarking models, it concluded that "only simple models make sense from a statistical point of view" and ultimately used only four or fewer drivers to explain costs. The project found that normalised totex is the most useful single cost driver to assess and the one most likely to provide meaningful comparisons between companies.

Whilst density and the level of connected renewables are also important cost drivers, the low number of comparators means that inclusion of these cost drivers can turn certain transmission companies into statistical outliers and, hence, skew the results. In simple terms, companies that serve densely populated urban areas and those that have a high level of connected renewables are likely to incur higher costs than other companies. Bearing this in mind, it might be more useful to concentrate on normalised totex or compare similar transmission companies (based on geography, population, renewables penetration) rather than to strive for the elusive 'normal' transmission company.

In any case, given that the e3 Grid Project concluded that 22 companies provided a relatively small dataset for the meaningful results that were sought, we would expect that, as new information is being collated by Ofgem for benchmarking, the dataset would need to comprise an even larger number of companies.

Transparency of data

If the results of the benchmarking studies are to be used to inform the RIIO-T1 process, it is important that stakeholders (in particular, affected licensees) are able to review the complete dataset and methodology used. In the interests of transparency and openness, it would be expected that no "black box" methodology would be used and that stakeholders, should they wish to, would be able to replicate the analysis. This is also important to maintain the credibility of the results.

Extent of study and proportionality

Given that Ofgem are proposing to establish a new, non-European dataset (US FERC) rather than draw on existing studies, providing initial results in March appears an ambitious target. However, we understand the necessity of such a target – yet given the requirement for such a sufficient volume of data from a large number of comparator companies in order to compile any useful results and bearing in mind that the e3 Grid Project took over a year from start to finish, we are concerned of the effect that any delay in producing results will have on the RIIO-T1 process. This is not only a concern in terms of the output from Ofgem but also the subsequent time required for licensees to review the data, methodology and results. As a consequence, we would question whether this approach to cost assessment is, in fact, proportionate.