National Grid Transmission

RIIO-T1: Initial Proposals consultation response

Table of contents

Introduction

1 This document contains the formal responses from National Grid Electricity Transmission and National Grid Gas Transmission to Ofgem's RIIO-T1 Initial Proposals consultation, and where possible:

(a) highlights errors to be corrected

(b) provides new information in response to Initial Proposals

(c) reiterates salient points in light of this new information

2 It also includes (at the end of the document) comments on other issues not covered by the Q&A.

3 This is one of three parts comprising our response to the Ofgem consultation, the others being:

(a) A covering letter summarising the key points in our response

(b) More detailed supplementary information on specific topics (submitted separately)

4 The Initial Proposals present a number of material issues which need to be resolved over the coming months to ensure that the efficient delivery of network outputs is not adversely affected.

5 These issues can broadly be categorised as those resulting from the quality of analysis and evidence used in the justification of a number of key changes to our business plans, and those resulting from errors contained within Ofgem's (or their consultants') calculations.

6 We look forward to working with Ofgem to resolve these issues in advance of Final Proposals in December 2012.

Overview document

Chapter: Two

Question 1: Do you have any comments on the overall package of proposals for NGET?

National Grid response:

Our comments on the overall package of proposals focus on the following areas:

- **Network risk**
  - We are concerned that the proposed treatment of under and over delivery does not achieve Ofgem's stated aim to expose National Grid to the risk of uncertain asset renewal volume, and that the proposed penalties and rewards have the potential to create a conflict between our interests and those of consumers.
- **RIIO-T2 Outputs**
  - Our preference would be for base funding for spend required in RIIO-T1 to deliver outputs in RIIO-T2, but, in any case, Ofgem's financeability assessment must be consistent with their proposals. A mechanism to deal with this category of expenditure is crucial given its potential scale, and we have proposed a number of competing options.
- **Capex uncertainty mechanisms**
  - Ofgem have proposed a number of changes to our proposed uncertainty mechanisms, particularly the generation connection uncertainty mechanism.
  - We are concerned that conclusions on the appropriate mechanism have been drawn based on the consideration of a limited number of scenarios.
  - We have carefully considered Ofgem's comments on our proposals and developed and assessed an alternative mechanism which is more accurate.
- **Real pay assumptions**
  - Adequate real pay assumptions are vital to ensuring the long term development of skills and retention of key resources
    - Lower pay growth forecasts than the Fast Track outcome will create pressure for our people with critical skills to leave and causes challenges for attracting new recruits
    - Not reflecting energy sector pay pressures will exacerbate the migration of graduates away from the Industry and reduce the already diminishing skills pool in the UK
- **TO opex**
  - Opex is critical to maintain safety, reliability and environmental outputs and will need to increase as asset numbers grow over the RIIO-T1 period
    - Opex assessment has been performed on its constituent parts with no

regard for top down deliverability

    - Assessment is founded on analysis errors and an abandonment of the RIIO principles of totex and consideration of the longer term
    - Basing catch up efficiencies on TPCR4 performance has no justification and ignores benchmarking evidence and consultants' recommendations
    - Double counted efficiencies, analysis errors and ignoring totex benefits of asset painting give rise to inappropriately low allowances
    - Logic errors and inconsistencies within the business support benchmarking methodology ignore future growth in cost drivers and benchmarking evidence

- **SO costs**
  - Efficient operation of the transmission network and UK electricity market is dependent on the timely provision of required capabilities within the System Operator (SO).
    - Initial Proposals reduce allowances due to uncertainty, however do not include any mechanism to manage that uncertainty - in direct contrast to Ofgem's consultant's recommendation - which will result in overall SO costs increasing
    - Errors in calculations for opex allowances incorrectly assume that these costs are linear to capex
    - Market facilitation has been reduced to 2010/11 expenditure levels based on analysis errors and despite the growing influence of European energy policy

- **Physical security costs**
  - A zero baseline for mandated physical security work undermines previous funding promises and perpetuates cashflow risk we have borne during the TPCR4 period

- **TPCR4 efficiency review**
  - We are concerned that Ofgem are not planning to complete the efficiency review of TPCR4, which impacts cashflow in the RIIO-T1 period, until 2013.

- **Finance package**
  - The movements in asset beta (risk) implied by the proposed cost of equity and notional gearing are not credible and not substantiated by the evidence presented.
  - Ofgem's risk assessment omits a number of key risk factors and fails to adequately reflect the underlying drivers of risk under RIIO.
  - The RORE analysis presented by Ofgem contains errors and omissions. Corrected analysis supports reducing gearing for NGET to 55% (or lower)
  - We are concerned that Ofgem's financeability assessment was misinformed as a consequence of both accounting / modelling errors and a failure to reflect the detail of the Initial Proposals in the assessment.
  - We remain concerned that the cost of debt allowance will not fund efficient

- debt costs. Ofgem's own consultants have expressed similar concerns.
- The totex capitalisation rate for the System Operator control needs to be updated to match the mix of opex and capex allowances.

Network risk

- **We are concerned that the proposed treatment of under and over delivery does not achieve Ofgem's stated aim to expose National Grid to the risk of uncertain asset renewal volume, and that the proposed penalties and rewards have the potential to create a conflict between our interests and those of consumers.**

We welcome Ofgem's confirmation that the tier 1 and tier 2 network risk assessments will be based on Network Output Measures rather than asset replacement volumes. This is more consistent with the RIIO emphasis on the delivery of outputs rather than inputs.

We remain concerned that the proposed treatment of under and over delivery does not achieve Ofgem's stated aim to expose National Grid to the risk of uncertain asset renewal volumes, and that the proposed penalties and rewards have the potential to create a conflict between our interests and those of consumers.

We also remain concerned that Ofgem's refusal to confirm the details of these proposals, for example to define the network output measures target, until the RIIO-T2 price control review will at best make these arrangements irrelevant to our RIIO-T1 asset management decisions and will at worst distort those decisions.

We have included detailed proposals in this area as part of our consultation response. There is no reason to delay development of this process to RIIO-T2 and therefore it is crucial that the arrangements are finalised as part of the RIIO-T1 control and captured in the relevant Licence Condition.

RIIO-T2 Outputs

- **Our preference would be for base funding to cover the spend required in RIIO-T1 to deliver outputs in RIIO-T2 but, in any case, Ofgem's financeability assessment must be consistent with their proposals. A mechanism to deal with this category of expenditure is crucial given its potential scale, and we have proposed a number of competing options.**

Our March 2012 business plan submission was based on the Gone Green scenario. Rather than limiting our forecast to the RIIO-T1 period, we also focussed on the longer term and considered delivery of the necessary primary outputs in RIIO-T2 such that the Gone Green scenario (which runs to 2030) could be achieved.

Ofgem have disallowed expenditure required in RIIO-T1 to deliver outputs in RIIO-T2 and, unlike the previous price control arrangements, there is no proposed mechanism to deal with this category of expenditure. Again, Ofgem has not explained these decisions, but has proposed that any expenditure in this category would be reviewed as part of Ofgem's assessment for the next price control on 'the principle that NGET is fully remunerated, on a cost neutral basis for the efficient costs of delivering the RIIO-T2 outputs'[1].

Capex uncertainty mechanisms

- **Ofgem have proposed a number of changes to our proposed uncertainty mechanisms, particularly the generation connection uncertainty mechanism.**
- **We are concerned that conclusions on the appropriate mechanism have been**

[1] 'Cost assessment and uncertainty Supporting Document', paragraph 4.35

drawn based on the consideration of a limited number of scenarios.**

- **We have carefully considered Ofgem's comments on our proposals and developed and assessed an alternative mechanism which is more accurate.**

Ofgem has proposed a revised local generation uncertainty mechanism on the basis that it is a simpler, more accurate version. Ofgem have since conceded that their approach is less accurate, but we continue to be concerned that the analysis on which the conclusion was based is systematic of an overly simple approach. For example, it was based on the consideration of only three scenarios and ignored the impact of a number of critical aspects (for example, changes in demand and embedded generation and spend in RIIO-T1 that delivers outputs in RIIO-T2).

We have carefully considered Ofgem's comments and developed further proposals in this area which aim to address the issue of complexity without compromising accuracy, thus mitigating the risk of windfall gains or losses for National Grid or consumers. Details of these proposals are included in our response and we look forward to working with Ofgem on these.

Real pay assumptions

Adequate real pay assumptions are vital to ensuring the long term development of skills and retention of key resources

- **Lower pay growth forecasts than the Fast Track outcome will create an artificial pressure for our critical skills to leave and causes challenges for attracting new recruits**
- **Not reflecting energy sector pay pressures will exacerbate the migration of graduates away from the Industry and reduce the already diminishing skills pool in the UK**

Initial Proposals' pay growth assumptions are 50% lower than the Fast Track outcome, placing pay growth in Transmission at the same level as Distribution rather than the inherently closer Scottish Transmission companies. This will create an incentive for our people with critical skills - already in short supply in the UK - to leave and cause recruitment challenges. These specialist roles, including power systems engineers and commissioning engineers which are on the government shortage lists, are vital for delivering the capital and maintenance workloads in RIIO-T1 and with them the outputs our stakeholders require. In addition, using whole economy forecasts for pay growth over the next few years, rather than growth within the energy sector, will produce uncompetitive pay levels across the sector. This will reduce the number of graduates coming into the Industry and create a further drain away from the UK skills pool.

TO opex

Opex is critical to maintain safety, reliability and environmental outputs and will need to increase as asset numbers grow over the RIIO-T1 period

- **The opex assessment has been performed on its constituent parts with no regard for top down deliverability**
- **Assessment is founded on analysis errors and an abandonment of the RIIO principles of totex and consideration of the longer term**
- **Basing catch up efficiencies on TPCR4 performance has no justification and ignores benchmarking evidence and consultants' recommendations**
- **Double counted of efficiencies, analysis errors and ignoring totex benefits of asset painting give rise to inappropriately low allowances**

- **Logic errors and inconsistencies within the business support benchmarking methodology ignore future growth in cost drivers and benchmarking evidence**

The NGET opex assessment separately reviews the constituent activities with little or no regard to interactions with capex, other opex activities or the deliverability of the resulting allowances overall. This assessment is based on errors and results in unachievable targets which focus on cost reduction rather than considering the outputs delivered or totex benefits of the expenditure.

The application of 1.25% per annum catch up efficiencies based on TPCR4 performance against allowances has no sound basis and does not take account of benchmarking evidence which shows we both improved our cost efficiency during the TPCR4 period and are in the upper quartile for cost efficiency. Poor analysis means efficiencies are double counted in the calculation for direct opex, and the clear totex benefits of asset painting are ignored. The business support benchmarking takes no account of future cost drivers, instead using 2010/11 costs and drivers to set a benchmark going forward. This is despite high projected growth in both FTEs and revenue over the RIIO-T1 period which will increase cost requirements. In addition, errors in calculation and no assessment of Transmission benchmarking and market testing evidence are understating the resulting allowances which will impact on IS innovation and our ability to recruit adequate numbers of people with critical skills.

Whilst individually the impact of each of these errors could be considered to be of a lower magnitude, cumulatively they are material and the result is a set of allowances which are divorced from reality and a departure from RIIO principles. RIIO guidance was to consider planned expenditure as a whole; these proposals appear to revert to RPI-X principles when the result of this assessment is an increased opex requirement.

SO costs

Efficient operation of the transmission network and UK electricity market is dependent on the timely provision of required capabilities within the System Operator (SO).

- **Initial Proposals reduce allowances due to uncertainty, however do not include any mechanism to manage that uncertainty, in direct contrast to Ofgem's consultant's recommendation which will result in overall SO costs increasing**
- **Errors in calculations for opex allowances incorrectly assume that these costs are linear to capex**
- **Market facilitation has been reduced to 2010/11 expenditure levels based on analysis errors and despite the growing influence of European energy policy**

Initial Proposals disallows the majority of SO capability enhancements which will be required in the latter half of the RIIO-T1 period to efficiently operate the transmission network. As the UK energy sector decarbonises and demand side intervention grows, power flows will necessarily change on the network. This, coupled with significant regulatory change as a result of the European Third Energy Package, drives the need for new and enhanced capabilities within the SO. Without these investments balancing and constraint costs will increase significantly, far outweighing the proposed investment costs.

Ofgem's consultants proposed that, rather than funding these enhancements on an ex ante basis, an uncertainty mechanism should be created to ensure the need case is valid prior to the provision of funding. Initial Proposals has removed the ex ante funding, however does not include such a mechanism. Without the corresponding uncertainty mechanism to ensure required funding can be made available in a timely manner, Initial Proposals incentivises us not to develop those capabilities and allow balancing costs to grow. This position needs to be rectified by including a specific uncertainty mechanism for SO costs, based around a mid-period assessment of the need case.

Opex allowances have been reduced based on the percentage reduction for capex. This assumes opex is linear to capex which it is not. This error should be rectified and any opex costs removed due to uncertainty added into the scope of the proposed uncertainty mechanism.

In addition, market facilitation work due to the growing influence of Europe has been disallowed despite the Initial Proposals stating that we will be incentivised to play our full part in European interactions. This inconsistency should be rectified by allowing the expenditure in relation to Europe that we have already started to incur.

Physical security costs

A zero baseline for mandated physical security work undermines previous funding promises and perpetuates cashflow risk we have borne during the TPCR4 period

No ex ante funding is included in Initial Proposals for physical security upgrades despite significant expenditure to date and TPCR4 promises to fund the logged up costs. This increases the cashflow risk we are bearing for expenditure mandated by DECC and undermines regulatory consistency. Baseline funding should be included which covers the cost of completed schemes and those which have passed through value for money audits with the all opex costs added to the ex ante funding.

TPCR4 review

We are concerned that Ofgem are not planning to complete the efficiency review of TPCR4, which impacts cashflow in the RIIO-T1 period, until 2013.

The proposed review of TPCR4 potentially has the ability to amend the opening Regulatory Asset Value (RAV) for the start of the RIIO-T1 period, should Ofgem consider than any spend incurred during the TPCR4 period was inefficient. The RAV is used to calculate the depreciation and return we can recover through revenue, and therefore uncertainty over the opening RAV leads to uncertainty over revenue and cashflow. This uncertainty prevents us from assessing the financeability of the proposals in relation to the RIIO-T1 period. It is our view that this review should be conducted ahead of Final Proposals, as has been the case in other price control reviews.

Financial Package

Risk assessment

Companies within the same sector have traditionally been given the same financial package. One of the principles of RIIO is that the allowed return can differ across sectors and within sectors if there are material differences in cash flow risk. This approach is appropriate provided there is robust evidence of material differences in business risk.

NGET provided detailed risk modelling to demonstrate an increase in risk relative to TPCR4. Ofgem has not engaged with us on the detail of this modelling so the Initial Proposals represent our first opportunity to gauge Ofgem's views on relative risk. Unfortunately we find Ofgem's risk assessment to be deficient in several respects:

- It is not backed by robust analysis or evidence
- The subjective risk assessment presented in the Initial Proposals omits a number of important risk factors and in other cases fails to adequately reflect the detail of Initial Proposals.

- It does not support the movement in asset beta implied by the proposed financial package

Ofgem has not performed any cash flow risk modelling of their own to support their analysis. Instead, their conclusions are based on a tabular summary of a number of risk factors.

The subjective risk assessment fails to consider a number of key risk drivers including:

- The risks associated with the System Operator (SO) activities (risks which Ofgem does not remunerate through the SO control)
- The duration of cash flows
- The difference between ex ante allowances and within period determinations, and
- Notional gearing

Also, where risk factors are considered we typically find that elements of the regulatory package are double counted or simply do not reflect the detail of the Initial Proposals. We provide more details on these errors in the supplementary information document: 'Relative_risk_assessment'. That paper presents an alternative risk assessment demonstrating an increase in risk relative to TPCR4 and higher risk than both SPTL and SHETL. The paper also includes explanations to support the assessment.

Not only do we find that Ofgem's risk assessment contains errors and omissions and is not backed by robust analysis but the financial package proposed is not credible from an implied risk perspective.

On behalf of the Energy Networks Association, Oxera has reviewed the changes in asset beta implied from the proposed cost of equity and gearing assumptions, both across time and between sectors. Their report is included as part of this response. They find that the movements in asset beta are not substantiated by the evidence presented.

By way of example, the scale of capex to RAV is considered the biggest driver of risk in Ofgem's proposals yet NGET's implied asset beta has fallen by 5% relative to TPCR4 despite an increase in the capex to RAV ratio, an increase in the totex sharing factor, an increase in the length of the price control and an increase in cash flow duration. By contrast, the asset beta has been increased by 7.5% for SHETL and SPTL who are in the same industry. NGET's implied asset beta is 11% lower than that of SPTL despite the capex to RAV ratio being only 2% lower.

We therefore conclude that the proposed financial package fails to recognise and adequately remunerate the risks faced by NGET during the RIIO-T1 period.

The Initial Proposals sought to validate the financial package through the use of RORE analysis. Unfortunately this RORE analysis omitted a number of material incentive schemes (for example the SO incentives were omitted despite including the SO RAV in the denominator), included inconsistencies in the calculations for NGET compared to both fast tracked networks, misrepresented a number of incentive schemes in the calculations, and even included entries for an incentive that does not actually exist. Our paper presents a corrected analysis demonstrating that the RORE range is wider for NGET than SPTL under both the 'base' and 'best' view scenarios, and wider than SHETL for the 'base view', even if NGET's gearing is reduced to 55%,.

<u>Financeability</u>

With regard to financeability, insufficient weight has been given to the needs of equity investors when determining the financial package. Under Ofgem's 'best view' scenario they are assumed to provide an additional £1.3 billion of equity over the RIIO period, much of it in the knowledge that the profits of the business are expected to decline sharply. If the delays implicit in the uncertainty mechanisms (and apparently ignored by Ofgem) are taken into account the requirement for notional equity rises to £2.1 billion. We do not understand the basis on which investors can be expected to provide additional finance on these terms, particularly given our concerns above that the return does not adequately remunerate the risks to their equity.

Ofgem could partially mitigate the decline in projected earnings by moving to the new asset life of 45 years over 16 rather than 8 years. Earnings would still be expected to decline during the latter half of the RIIO period and so extending the transitional measures may not be sufficient to attract the required equity. An increase in the WACC would help to improve the investment proposition.

Our separate paper on financeability addresses our concerns on financeability in more detail.

Cost of debt index

Our response to question 2 from the Finance Supporting document expresses our concerns with regard to the cost of debt allowance. These concerns include:

- The removal of headroom in the allowance leaves unfunded risks to equity
- Transaction costs may not be fully funded – our proposed uncertainty mechanism could resolve this
- Allowance needs to be made for the inflation risk premium
- Basel III and Solvency II could increase utility debt costs relative to the debt allowance
- The proposals on financeability and cost of debt index are inconsistent

Several of the concerns above appear to be shared by Ofgem's own consultants (FTI Consulting) yet Ofgem are still opposed to adjusting their proposals or providing for an uncertainty mechanism that could address some of the concerns.

Summary for the NGET Transmission Owner Control

The financial package as proposed for NGET is inadequate. The assessment of relative risk indicates that, as a minimum, notional gearing should be reduced to 55% and, even then, the higher risk relative to SHETL and SPTL is sufficient to justify an increase in the cost of equity above the currently proposed 7.0%.

The package as proposed is unlikely to attract the equity required to fund the investments in the network. Transitioning to the new asset life over 16 years may help in this respect. An increase in the allowed WACC may also help to make the investment proposition sufficiently attractive to ensure the required notional equity injections take place.

We also maintain that the cost of debt allowance should be adjusted to allow for the inflation risk premium. In addition, an uncertainty mechanism should be put in place to ensure that efficient transaction costs, such as new issue premia, are funded if the observed differential between utility and general corporate debt costs, on which Ofgem currently relies, falls below the level required to fund those transaction costs.

System Operator

Ofgem's proposals for the NGET System Operator financial package include a totex capitalisation rate of 31%, consistent with the 'natural' rate included in our business plan. However, the Initial Proposals allowances result in a natural rate of 26%. This means that the Initial Proposals consistently provide less fast money than the operating costs of the business. The capitalisation rate should be reset to match the final proposals allowances rather than being set independently of those allowances.

Our concerns with regard to Ofgem's decision not to award a risk premium to compensate for the risks associated with SO incentives are covered in our separate response to those proposals.

Chapter: Three

Question 2: Do you have any comments on the overall package of proposals for NGGT?
National Grid response:

Our comments on the overall package of proposals focus on the following areas:

- **Pipeline unit costs**
  - The unit costs proposed in Initial Proposals will create a significant shortfall in funding for pipeline projects to reinforce the NTS.
    - Errors contained in the analysis lead to an underestimation of cost
    - Comparison to external benchmarking information demonstrates this shortfall
    - Relevant cost drivers and complexity evident in future projects must be appropriately considered in the methodology for determining funding
- **Compressor unit costs**
  - The unit costs proposed in Initial Proposals for compressors will provide insufficient funding for projects to both comply with environmental legislation and to reinforce the NTS.
    - Errors in the source data used in the analysis leads to underestimation of cost
    - Comparison to external benchmarking information demonstrates this shortfall
    - Complexity evident in future projects must be appropriately considered in the methodology for determining funding
- **Scope of environmental legislation-driven investment**
  - It is essential for there to be complete alignment between the legal obligations that will be placed on NGGT then the IED is transposed into UK law and the funding allowed by Ofgem under RIIO-T1 to manage these legal obligations.
- **Real pay assumptions**
  - Adequate real pay assumptions are vital to ensuring the long term development of skills and retention of key resources
    - Lower pay growth forecasts than the Fast Track outcome will create pressure for our people with critical skills to leave and causes challenges for attracting new recruits
    - Not reflecting energy sector pay pressures will exacerbate the migration of graduates away from the Industry and reduce the already diminishing skills pool in the UK
- **Incremental capacity provision**
  - Ofgem's proposals regarding funding for incremental capacity in the Overview document are inconsistent with the detail contained within paragraph 3.11 of the Outputs, incentives and innovation Supporting Document
  - Further clarity has been provided through discussions with Ofgem regarding the detail and intent of our proposals
  - All elements of our proposals can be implemented for the RIIO-T1 period, with the exception of the change to obligated lead times to 24 months.
  - In the absence of the two stage revenue driver approach proposed in our

business plan, an appropriate ex ante allowance is required to ensure that we receive adequate funding for feasibility works.
  - The balance of risk between permits allowance, obligated lead times and constraint management caps and collars must be considered within the package of proposals.
  - It is imperative that some guidance and direction is provided by Ofgem to industry to allow appropriate commercial proposals to be developed.

- **Charging volatility**
  - The charging volatility proposals are essential in facilitating a proper assessment of the whole package, and we await Ofgem's consultation decision in this area.

- **System Operator costs**
  - Efficient operation of the NTS and UK gas market is dependent on the timely provision of required capabilities within the System Operator (SO).
  - Errors in calculations for opex allowances incorrectly assume that these costs are linear to capex
  - Market facilitation has been reduced to 2010/11 expenditure levels based on analysis errors and despite the growing influence of European energy policy

- **Capex Real Price Effects**
  - The risk of a longer price control period and higher price rises for the grade of steel NGGT use should be factored into forecasts
    - Not including long term forecasts for steel prices we are exposed to in the Initial Proposals is understating the risk of RPE exposure
- **Business Support benchmarking**
  - Benchmarking results do not accurately reflect the cost drivers we will face over the RIIO-T1 period, giving rise to allowances which will inhibit IS innovation and skills development
    - Logic errors and inconsistencies within the benchmarking methodology create inadequate allowances
    - Our benchmarking and market testing evidence must be fully incorporated into the assessment
- **Physical security costs**
  - A zero baseline for physical security undermines previous funding promises and perpetuates cashflow risk we have borne during the TPCR4 period
- **Finance package**
  - We are concerned that Ofgem's financeability assessment was misinformed as a consequence of both accounting / modelling errors and a failure to reflect the detail of the Initial Proposals in the assessment.
  - The movements in asset beta (risk) implied by the proposed cost of equity and notional gearing are not credible and not substantiated by the evidence presented.
  - Ofgem's risk assessment omits a number of key risk factors and fails to adequately reflect the underlying drivers of risk under RIIO.
  - The RORE analysis presented by Ofgem contains errors and omissions. Corrected analysis supports reducing gearing for NGGT to 55% (or lower)
  - We remain concerned that the cost of debt allowance will not fund efficient debt costs. Ofgem's own consultants have expressed similar concerns.

- **PCR process**
  - We should not be penalised for volume differences under the Information Quality Incentive where Ofgem has moved ex ante funding to new uncertainty mechanisms to allow agreement on the proposed scope of future legislation to be reached or expected timing of planning consent approval
  - We are concerned that Ofgem are not planning to complete the efficiency review of TPCR4, which impacts cashflow in the RIIO-T1 period, until 2013.
  - Any future discussions of policy points through licence drafting consultations need to be very clearly identified.
  - All errors must be corrected in Ofgem's analysis prior to Final Proposals.

We provide further explanation of these points below.

Pipeline unit costs

The unit costs proposed in Initial Proposals will create a significant shortfall in funding for pipeline projects to reinforce the NTS:

- **Errors contained in the analysis lead to an underestimation of cost**
- **Comparison to external benchmarking information demonstrates this shortfall**
- **Relevant cost drivers and complexity evident in future projects must be appropriately considered in the methodology for determining funding**

The analysis underpinning the proposed unit costs has been based on data provided by Ofgem's engineering consultant, which is based on estimated costs from an unknown overseas location using a feasibility study for which outturn costs are not available. Outturn cost information must be used to allow a reasonable comparison to future costs to ensure all costs are reflective of actual build costs. We understand from the consultant that the pipelines used as comparators have been designed to different technical standards and built in a different environment to that experienced in Great Britain. More complex pipelines within the feasibility study, which are typical of the level of complexity in Great Britain, have been ignored resulting in a lower unit cost being proposed. In addition, no account has been taken of historical (2006/07 – 2009/10) real price effects, which is inconsistent with the approach taken in the TPCR4 settlement. Correction of these two errors would result in a proposed unit cost which is 45% higher than that contained in Initial Proposals. For these reasons we conclude that the data used by Ofgem does not form a valid basis for our unit costs.

This stance is further supported by comparison to international benchmark data and TPCR4 allowances, both of which are materially above the unit costs included in Initial Proposals.

Further detail on our views is included in the response to question seven in the 'Cost assessment and uncertainty supporting document' and within the details provided in our supplementary information document, 'NGGT_unit_costs'.

Compressor unit costs

The unit costs proposed in Initial Proposals for compressors will provide insufficient funding for projects to both comply with environmental legislation and to reinforce the NTS:

- **Errors in the source data used in the analysis leads to underestimation of cost**
- **Comparison to external benchmarking information demonstrates this shortfall**
- **Complexity evident in future projects must be appropriately considered in the methodology for determining funding**

Ofgem has created their own unit cost model, which is based on a combination of incomplete cost estimates from a feasibility study for gas turbine compressor units in Alaska, and a subset of outturn data for electric drive compressors built in Great Britain. The model has been designed to estimate the cost of the simplest project scope on a greenfield site, which demonstrably underestimates the costs for our future projects, that unavoidably involve varying levels of complexity. The modelling needs to be evolved to take account of such complexity in the scope of future projects. The level of underestimation created by Ofgem's model is demonstrated by the comparison of Ofgem's unit costs to international benchmark data of outturn costs for 67 European gas transmission compressor units.

Further detail on our views is included in the response to question seven in the 'Cost assessment and uncertainty supporting document' and within the details provided in our supplementary information document, 'NGGT_unit_costs'.

Scope of environmental legislation-driven investment

It is essential for there to be complete alignment between the legal obligations that will be placed on NGGT then the IED is transposed into UK law and the funding allowed by Ofgem under RIIO-T1 to manage these legal obligations:

- **QC advice supports our business plan submission assumption that the IED will apply to NGGT plant, regardless of operating hours**
- **Timely provision of funding is essential to ensure deliverability of IED programme**

Establishing the impact of the Industrial Emissions Directive (IED), which will be transposed into UK law early in 2013, on our fleet of compressors and the extent of the works required has been of utmost importance to ensure we can deliver the required changes in a timely manner and maintain legislative compliance.

Ofgem has an obligation to ensure we are appropriately funded to meet legislative compliance. This principle has been echoed by our stakeholders through the 'Talking Networks' programme of engagement. If meeting the UK law will require us to cease operating a number of operationally critical compressor units, we have to invest to replace them.

The interpretation of the 'emergency use' clause as defined within the IED has recently become the subject of much debate with Ofgem and the environmental regulators. We have sought clear unambiguous direction on what the UK law will require and how it will be interpreted and enforced from an eminent QC in this field, with particular focus on the application of this 'emergency use' clause. A copy of this advice has been provided to the EA, SEPA and Ofgem. The QC has advised that this 'emergency use' clause will not apply to NGGT compressors, thus supporting the approach to impacted compressor units we took in our RIIO-T1 submission. We accept, however, that until absolute clarity is received through the publication of guidance by DEFRA and/or the Scottish Parliament after the transposition of this Directive into UK law there remains a possibility, albeit remote, that the 'emergency use' clause could apply to some of our plant.

For this reason, we agree with Ofgem that the introduction of an uncertainty mechanism to be triggered on clarification of the need case is an appropriate way to proceed, but it is essential that the trigger for the uncertainty mechanism is appropriately defined, that it provides appropriate funding in a timely manner, and no penalty is applied through the Information Quality Incentive (IQI) mechanism (see IQI section later in this response).

If such an uncertainty mechanism were to be introduced, necessary Front End Engineering Design (FEED) costs should be funded on an ex ante basis to ensure the replacement projects can progress in a timely manner such that, should the 'emergency use' clause not apply, we are not left to manage a programme of work which is undeliverable in the remaining timescales. Failure to deliver the required replacement compressor units by 2023 (the date by which all non-compliant compressor units must be decommissioned), would materially impair the safe operation of the NTS and our ability to meet our obligations under the Gas Act.

There is also a risk of misalignment between legislative requirements and availability of reasonable funding for existing environmental legislation. The Integrated Pollution Prevention and Control (IPPC) Directive requires us to invest in our compressor fleet to mitigate the gaseous emissions. Whilst we welcome the funding agreed in Initial Proposals for the imminent phase three of the IPPC programme, the proposal to review the need case for phase four after phase three has commissioned does not align with our requirement to commence phase four soon after the start of phase three. This requirement has been set out and agreed with our environmental regulators.

Real pay assumptions

Adequate real pay assumptions are vital to ensuring the long term development of skills and retention of key resources

- **Lower pay growth forecasts than the Fast Track outcome will create an artificial pressure for our critical skills to leave and causes challenges for attracting new recruits**
- **Not reflecting energy sector pay pressures will exacerbate the migration of graduates away from the Industry and reduce the already diminishing skills pool in the UK**

Initial Proposals' pay growth assumptions are 50% lower than the Fast Track outcome, placing pay growth in Transmission at the same level as Distribution rather than the inherently closer Scottish Transmission companies. This will create an incentive for our people with critical skills - already in short supply in the UK - to leave and cause recruitment challenges. These specialist roles, including control room engineers and network analysts, are vital for delivering the capital and operating workloads in RIIO-T1 and with them the outputs our stakeholders require. In addition, using whole economy forecasts for pay growth over the next few years, rather than growth within the energy sector, will produce uncompetitive pay levels across the sector. This will reduce the number of graduates coming into the Industry and create a further drain away from the UK skills pool.

Incremental capacity provision

Funding arrangements for incremental capacity are not clearly stated:

- **Ofgem's proposals regarding funding for incremental capacity in the Overview document are inconsistent with the detail contained within paragraph 3.11 of the Outputs, incentives and innovation Supporting Document**
- **Further clarity has been provided through discussions with Ofgem regarding the detail and intent of our proposals**

Due to the inconsistency within Ofgem's Initial Proposals, we have sought clarity from Ofgem regarding the intent of the proposals. During a meeting in mid August, Ofgem confirmed that its intent is for Revenue Drivers to only be calculated when required, hence its policy statement in paragraph 3.11 of the Outputs, incentives and innovation Supporting Document is correct.

All elements of our proposals can be implemented for the RIIO-T1 period, with the exception of the change to obligated lead times to 24 months.

Within the Initial Proposals Ofgem states that it does not want to pre-judge the changes to the commercial regime through providing an opinion on any elements of our plan. We believe the changes to funding arrangements that we have suggested (such as the removal of existing revenue drivers from the licence such that they are calculated on an 'as and when necessary' basis according to an agreed methodology and the inclusion of two-stage revenue drivers where the first stage covers the "feasibility" type of work with the second stage to cover construction costs only being triggered on a formal application signal) do not need changes to the commercial regime to be implemented, as they can work alongside the current commercial regime, whereby existing processes (such as the bilateral agreements introduced following the implementation of UNC modification proposal 373) could be used as the trigger point for initiation of the stage one process. Our proposals also provide an improvement over the existing arrangements such that they should avoid the customer having to commit to capacity prior to receiving planning consent and reduce the risk of that project not progressing following a formal capacity signal. We therefore contend that our full proposals could, and should be, implemented from April 2013 to avoid a material cash impact on NGGT resulting from the provision of incremental capacity. Given that Ofgem has not included any direction on our proposals, we feel it is essential that Final Proposals contains clarity regarding the timescales and process that will be followed to ensure that the regulatory contract is adequately amended to take account of any commercial developments that are implemented.

In the absence of the two stage revenue driver approach proposed in our business plan, an appropriate ex ante allowance is required to ensure that we receive adequate funding for feasibility works.
Further meetings with Ofgem following the publication of its Initial Proposals have clarified the Initial Proposals position that funding arrangements for the start of RIIO-T1 should be based on the principles underpinning the existing ones, except that the allowed revenue would be provided via a change to the totex allowance and would be provided earlier than at present. Current arrangements release allowed revenue at the year of obligated capacity delivery (via a funding allowance in the SO control) whilst the Ofgem proposals would release 20% of the allowed revenue entitlement two years before and 80% one year before obligated capacity delivery. Whilst this provides better alignment with the timing of costs compared to the arrangements from TPCR4, NGGT is still exposed to early feasibility work costs if a formal auction/application signal for incremental capacity does not materialise. In order to ensure that NGGT is appropriately funded, we believe that an appropriate allowance should be provided (as for the NGET control) to provide for such eventualities.

Further detail on our views is included in the response to question three in the 'Outputs, incentives and innovation supporting document'

The balance of risk between permits allowance, obligated lead times and constraint management caps and collars must be considered within the package of proposals.
Ofgem has not agreed to change the permit allowance for the rollover year and has refused our request to allow us to go overdrawn (whereby we would be able to use more permits than we hold, with associated financial consequences) within the first year of the RIIO-T1 period. This creates the risk whereby NGGT cannot appropriately manage delivery lead times, changing the risk profile to consumers of increasing constraint management action costs. With the current form of the scheme this would result in exposure to a greater level of costs to all parties. In relation to our proposal to combine entry and exit schemes into a single incentive scheme, Ofgem has indicated that it believes this has merit, but has proposed the abolition of caps and collars if a combined scheme is adopted. The removal of the collar on our potential losses from this scheme is inappropriate as these costs are not entirely within NGGT's control due to the lack of competition in some areas to respond to constraints. This approach incentivises us to conduct network modelling to a lower risk tolerance to factor the unbounded risk we would then face, leading to more conservative build programmes for the provision of incremental capacity.

Further detail on our views is included in the response to question four and question five in the 'Outputs, incentives and innovation supporting document'.

It is imperative that some guidance and direction is provided by Ofgem to industry to allow appropriate commercial proposals to be developed.
As noted above, Ofgem has refrained from offering any opinion on our proposals in order to avoid prejudging the commercial developments. It is crucial, however, that Ofgem provides guidance on any areas of the proposals that are not acceptable from a regulatory point of view

in order to ensure time is well spent on developing appropriate arrangements. We look forward to engaging further with Ofgem and the industry on this matter.

Charging volatility

The charging volatility proposals are essential in facilitating a proper assessment of the whole package, and we await Ofgem's consultation decision in this area.

It would have been useful to see the conclusions of Ofgem's charging volatility consultation (reference 52/12) at least at a high level in this consultation; this view was echoed by our stakeholders at a recent Talking Networks event. It is difficult to fully assess the whole price control package, especially in terms of financeability, without seeing any details of Ofgem's proposals for dealing with charging volatility. Of particular interest is an understanding of the proposed treatment for under or over recovery i.e. whether it will factor in the Weighted Average Cost of Capital (as being proposed for other truing up mechanisms) or would use the base interest rate as per existing arrangements.

In line with the views expressed by our stakeholders, our proposals considered how transparency and predictability could best be improved through the publication at the earliest opportunity of anticipated changes to allowed revenue to allow customers to factor this into their charges. As the detail of how the uncertainty mechanisms are expected to work is not included in the Initial Proposals or associated licence drafting, it is difficult for us to assess whether this focus on transparency and predictability has been maintained.

System Operator costs

Efficient operation of the NTS and UK gas market is dependent on the timely provision of required capabilities within the System Operator (SO).

- **Initial Proposals reduce allowances due to uncertainty, however do not include any mechanism to manage that uncertainty, in direct contrast to Ofgem's consultant's recommendation**
- **Errors in calculations for opex allowances incorrectly assume that these costs are linear to capex**
- **Market facilitation has been reduced to 2010/11 expenditure levels based on analysis errors and despite the growing influence of European energy policy**

Initial Proposals excludes the majority of SO capability enhancements which will be required to efficiently operate the NTS throughout the next decade. As gas supplies change and the UK energy sector decarbonises, gas flows will necessarily change on the NTS. This, coupled with significant regulator change as a result of the European Third Energy Package, drives the need for new and enhanced capabilities within the SO. Ofgem's consultants proposed that, rather than funding these enhancements on an ex ante basis, an Uncertainty Mechanism should be created to ensure the need case is valid prior to the provision of funding. Initial Proposals has removed the ex ante funding, however does not include such a mechanism.

Without the corresponding uncertainty mechanism to ensure required funding can be made available in a timely manner, Initial Proposals incentivises the SO to not develop those capabilities it requires to operate in the more dynamic environment of the future, and therefore not support decarbonisation and the efficient operation of the market.

It is our view that, if ex ante funding cannot be made available, a mechanism should be created which can address this material issue in a timely manner whilst allowing for the necessary development lead times for such capabilities.

Opex allowances have been reduced based on the percentage reduction for capex. This assumes opex is linear to capex which it is not. This error should be rectified and any opex costs removed due to uncertainty added into the scope of the proposed uncertainty mechanism.

In addition, market facilitation work due to the growing influence of Europe has been disallowed despite the Initial Proposals stating that we will be incentivised to play our full part in European interactions. This inconsistency should be rectified by allowing the expenditure in relation to Europe that we have already started to incur.

Capex Real Price Effects (RPEs)

The risk of a longer price control period and higher price rises for the grade of steel NGGT use should be factored into forecasts:

- **Not including long term forecasts for steel prices we are exposed to in the Initial Proposals is understating the risk of RPE exposure**

Our proposed steel tracker has not been included in Initial Proposals with Ofgem referencing that we are best placed to manage this risk. We accept this position but are concerned that the baseline RPEs do not accurately reflect the price rises expected over the next eight years in the grade of steel which we necessarily use for our pipelines. Initial Proposals use general civil engineering steel forecasts, rather than those which incorporate long term historical averages for steel price rises. These steel price forecasts should be factored into the forecasts for the RIIO-T1 period, increasing the future RPEs.

Business support benchmarking

Benchmarking results do not accurately reflect the cost drivers we will face over the RIIO-T1 period, giving rise to allowances which will inhibit IS innovation and skills development

- **Logic errors and inconsistencies within the benchmarking methodology create inadequate allowances**
- **Our benchmarking and market testing evidence must be fully incorporated into the assessment**

The business support benchmarking takes no account of future cost drivers, instead using 2010/11 costs and drivers to set a benchmark going forward. This is despite high projected growth in both FTEs and revenue over the RIIO-T1 period which will increase cost requirements. In addition, errors in calculation and no assessment of Transmission benchmarking and market testing evidence are understating the resulting allowances which will impact on IS innovation and our ability to recruit adequate numbers of people with critical skills.

See our supplementary information document, ‘Business_support’.

Physical security costs

A zero baseline for physical security undermines previous funding promises and perpetuates cashflow risk we have borne during the TPCR4 period

No ex ante funding is included in Initial Proposals for physical security upgrades despite significant expenditure to date and TPCR4 promises to fund the logged up costs. This increases the cashflow risk we are bearing for expenditure mandated by DECC and undermines regulatory consistency. Baseline funding should be included which covers the cost of completed schemes and those which have passed through value for money audits with the all opex costs added to the ex ante funding.

Process

Information Quality Incentive (IQI)

We should not be penalised for volume differences under the Information Quality Incentive where Ofgem has moved ex ante funding to new uncertainty mechanisms to allow agreement on the proposed scope of future legislation to be reached or expected timing of planning consent approval:

- **Ofgem's assessment of IQI within Initial Proposals is inconsistent with Ofgem's March 2011 RIIO Strategy document**

Ofgem's movement of ex ante funding (as requested in our RIIO-T1 submission) to an uncertainty mechanism creates a penalty under the Information Quality Incentive (IQI). Where it is clear that such a movement is as a result of a different legal interpretation (e.g. IED) or expectation of timing of planning consent approval (e.g. Feeder 9 replacement), rather than an alternative view of likely costs, it is inappropriate to assume that such a difference is 'inefficient' and that a penalty should apply. In these circumstances, an adjustment should be made to unwind the impact these alternative treatments have on the IQI assessment.

This approach being proposed by Ofgem is in direct contrast to that suggested in Ofgem's March 2011 strategy document[2] (paragraph 6.30): "*It is important that the comparisons between company forecasts and our own cost assessment that feed into the IQI are made on a like-for-like basis. In particular, there should be consistency in the set of outputs that the expenditure contributes towards. This may require adjustments as part of the IQI calculations.*". It is also inconsistent with the approach taken with NGET, where no such penalty applies for a movement of expenditure from 'best view' into an uncertainty mechanism.

TPCR4 review

We are concerned that Ofgem are not planning to complete the efficiency review of TPCR4, which impacts cashflow in the RIIO-T1 period, until 2013.

The proposed review of TPCR4 potentially has the ability to amend the opening Regulatory Asset Value (RAV) for the start of the RIIO-T1 period, should Ofgem consider than any spend incurred during the TPCR4 period was inefficient. The RAV is used to calculate the depreciation and return we can recover through revenue, and therefore uncertainty over the opening RAV leads to uncertainty over revenue and cashflow. This uncertainty prevents us from assessing the financeability of the proposals in relation to the RIIO-T1 period. It is our view that this review should be conducted ahead of Final Proposals, as has been the case in other price control reviews.

Licence drafting

Any future discussions of policy points through licence drafting consultations need to be very clearly identified.

With regard to the price control process, it is stated in the Initial Proposals and has become apparent through subsequent discussions that a number of clarifications on the overarching policy and detail of the proposals will be provided through licence drafting (for example, the allocation of proposed the Permits allowance between Entry and Exit capacity). If this is the case, those clarifications on policy need to be very clearly identified and discussed alongside the draft licence conditions to allow all stakeholders a full and proper consultation opportunity.

Errors within analysis

All errors must be corrected in Ofgem's analysis prior to Final Proposals.

To allow the generation of a reasonable set of proposals, all errors must be corrected in

[2] Decision on strategy for the next transmission and gas distribution price controls - RIIO-T1 and GD1 Business plans, innovation and efficiency incentives, 31st March 2011

Ofgem's analysis. Failure to do so represents a failure of due process within the price control.

Financial Package

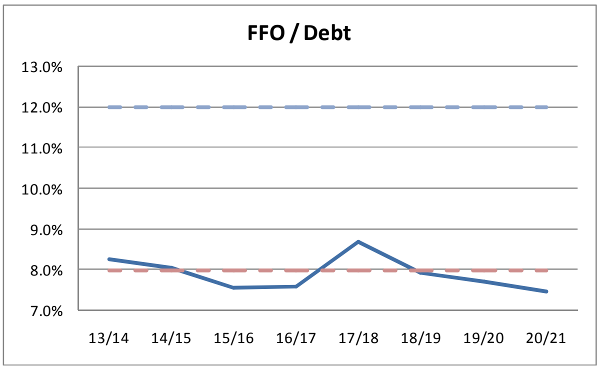
<u>Financeability</u>

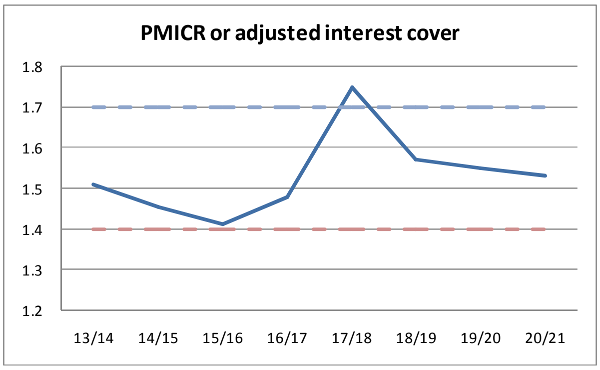
We are concerned with Ofgem's financeability assessment on several levels including:

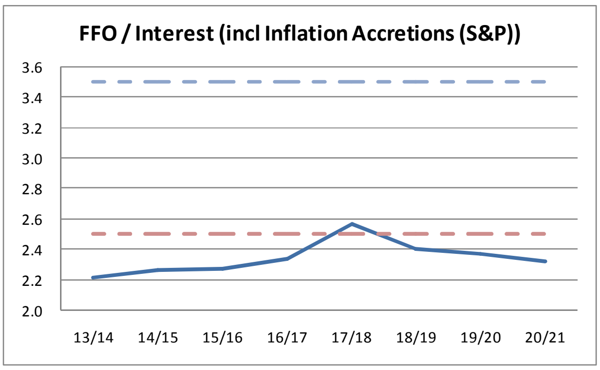
- A lack of transparency with regard to how Ofgem has calculated the credit metrics or determined that the proposals are financeable, despite the significant changes to the regulatory regime introduced by RIIO
- Accounting errors in the model such that the calculated financial statements are incorrect and misleading such that any credit metrics calculated from them would also be incorrect
- A failure to reflect the detail of the regulatory package actually proposed by Ofgem, particularly the delays implicit in the operation of the uncertainty mechanisms
- The credit metrics projected for NGG
- The unsustainable nature of the proposed financial package
- The inadequate scope of the stress testing performed

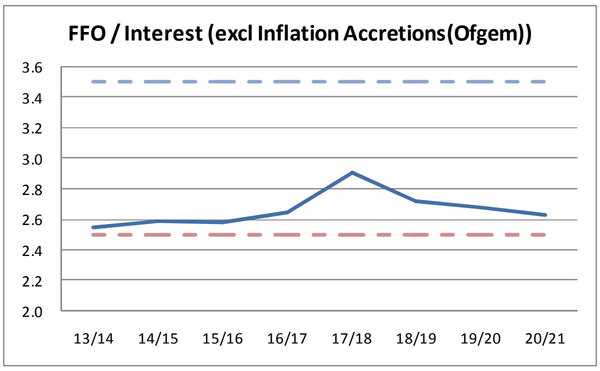
These concerns are documented in more detail in the supplementary information document: 'Financeability'.

When we correct the Ofgem model to calculate financial statements correctly, reflect tax payments on revenue driver income that have been omitted from the financial model, and reflect the impact of the inevitable delays in funding caused by the operation of the uncertainty mechanisms we calculate that the credit metrics for the 'best view' to be as shown below.









Different rating agencies focus on different metrics. The most optimistic position view would be to focus on the PMICR (or AICR) or the FFO / interest measure excluding the impact of inflation accretions in the denominator, but even then the metrics are low BBB. Both the FFO / debt and S&P method of calculating FFO / interest metrics are typically sub investment grade over the RIIO-T1 period.

We cannot see how the ratings shown above can be considered to represent the ‘comfortable investment grade’ referred to by Ofgem. Even if Ofgem does consider the above metrics to be acceptable, they are certainly inconsistent with a cost of debt allowance based on an average of A and BBB rated debt. Debt costs would therefore exceed the allowance putting further pressure on credit metrics and financial stability.

Since the accounting and modelling errors were discovered subsequent to the publication of Initial Proposals we consider it probable that Ofgem’s assessment was misinformed. It is equally possible that the extent of the timing delays in the uncertainty mechanisms were not fully understood when the modelling was performed. We will share further details of the modelling errors and approach taken by us to address them over the coming weeks.

If, on the other hand, Ofgem do consider the above metrics to be acceptable then this would represent a worrying development as it indicates that financeability is being given a very low priority by Ofgem.

Our financeability paper explains that, not only is the proposed package not financeable for the RIIO-T1 period but it is also unsustainable on a long term basis due to the combination of a real return on equity, 45 year asset life, and requirement to pay (or at least charge in the accounts) nominal interest costs.

Our business plan explained that gearing had to be 55% or less and the totex capitalisation rate had to be below the ‘natural’ rate on baseline allowances to achieve a financeable package. We remain of this view and consider a reduction in gearing to 55% to be a minimum requirement.

One of the drivers of the poor credit metrics during RIIO-T1 is the delays in funding from uncertainty mechanisms. In addition to a reduction in gearing we believe there are strong grounds to mitigate these funding delays by providing allowances (and revenues) on account which could then be trued up through the operation of some of the uncertainty mechanisms.

Risk assessment

Companies within the same sector have traditionally been given the same financial package. One of the principles of RIIO is that the allowed return can differ across sectors and within sectors if there are material differences in cash flow risk. This approach is appropriate provided there is robust evidence of material differences in business risk.

NGGT provided detailed risk modelling to demonstrate an increase in risk relative to TPCR4. Ofgem has not engaged with us on the detail of this modelling so the Initial Proposals represent our first opportunity to gauge Ofgem’s views on relative risk. Unfortunately we find Ofgem’s risk assessment to be deficient in several respects:

- It is not backed by robust analysis or evidence
- The subjective risk assessment presented in the Initial Proposals omits a number of important risk factors and in other cases fails to adequately reflect the detail of Initial Proposals.
- It does not support the movement in asset beta implied by the proposed financial package

Ofgem has not performed any cash flow risk modelling of their own to support their analysis. Instead, their conclusions are based on a tabular summary of a number of risk factors.

The subjective risk assessment fails to consider a number of key risk drivers including:

- The risks associated with the System Operator (SO) activities (risks which Ofgem does not remunerate through the SO control)
- The duration of cash flows

- The difference between ex ante allowances and within period determinations, and
- Notional gearing

Also, where risk factors are considered we typically find that elements of the regulatory package are double counted or simply do not reflect the detail of the Initial Proposals. We provide more details on these errors in the supplementary information document: 'Relative_risk_assessment'. That paper presents an alternative risk assessment demonstrating an increase in risk relative to TPCR4 and higher risk than both SPTL and SHETL. The paper also includes explanations to support the assessment.

Not only do we find that Ofgem's risk assessment contains errors and omissions and is not backed by robust analysis but the financial package proposed is not credible from an implied risk perspective.

On behalf of the Energy Networks Association, Oxera has reviewed the changes in asset beta implied from the proposed cost of equity and gearing assumptions, both across time and between sectors. Their report is included as part of this response. They find that the movements in asset beta are not substantiated by the evidence presented.

By way of example, NGGT's implied asset beta has fallen by 15% relative to TPCR4 despite an increase in the totex sharing factor and an increase in the length of the price control. Pension costs are also expected to increase relative to TPCR4. NGGT's implied asset beta is a massive 20% lower than that of SPTL.

We therefore conclude that the proposed financial package fails to recognise and adequately remunerate the risks faced by NGGT during the RIIO-T1 period.

The Initial Proposals sought to validate the financial package through the use of RORE analysis. Unfortunately this RORE analysis omitted a number of material incentive schemes (for example the SO incentives were omitted despite including the SO RAV in the denominator), included inconsistencies in the calculations for NGGT compared to both fast tracked networks, misrepresented a number of incentive schemes in the calculations, and even included entries for an incentive that does not actually exist. Our paper presents a corrected analysis demonstrating that the RORE range is wider for NGGT than SPTL under both the 'base' and 'best' view scenarios, and wider than SHETL for the 'base view', even if NGGT's gearing is reduced to 55%,.

Cost of debt index

Our response to question 2 from the Finance Supporting document expresses our concerns with regard to the cost of debt allowance. These concerns include:

- The removal of headroom in the allowance leaves unfunded risks to equity
- Transaction costs may not be fully funded – our proposed uncertainty mechanism could resolve this
- Allowance needs to be made for the inflation risk premium
- Basel III and Solvency II could increase utility debt costs relative to the debt allowance
- The proposals on financeability and cost of debt index are inconsistent

Several of the concerns above appear to be shared by Ofgem's own consultants (FTI Consulting) yet Ofgem are still opposed to adjusting their proposals or providing for an uncertainty mechanism that could address some of the concerns.

Pension deficit allocation methodology

The Initial Proposals do not provide any further update on the details of the Pensions Deficit Allocation Methodology which will determine the proportion of pension deficits funded by consumers in future years. We believe it is vitally important that any such methodology should allocate the deficit between regulated and non regulated elements rather than to separately allocate scheme assets and liabilities. Separately allocating assets and liabilities risks exposing both consumers and networks alike to unwarranted risk and volatility, particularly in the case of NGGT due to the size of the pension scheme.

Summary for the NGGT Transmission Owner Control

The financial package as proposed for NGGT is inadequate. It represents a non sustainable finance structure that is not even financeable during the RIIO-T1 period. On financeability grounds there is a need to reduce gearing to 55% or below and to take other steps to secure the financeability of the notional network including the provision on account of allowances subject to true up in uncertainty mechanisms and a reduction in the totex capitalisation rate to be applied to baseline allowances.

The assessment of relative risk also indicates that notional gearing should be reduced to 55%. Even if gearing is reduced to 55%, the higher risk of NGGT relative to SHETL and SPTL is sufficient to justify an increase in the cost of equity.

We also maintain that the cost of debt allowance should be adjusted to allow for the inflation risk premium. In addition, an uncertainty mechanism should be put in place to ensure that efficient transaction costs, such as new issue premia, are funded if the observed differential between utility and general corporate debt costs, on which Ofgem currently relies, falls below the level required to fund those transaction costs.

Customer bill impact

In the Initial Proposals Ofgem states that their proposals result in an increase in allowed revenue for NGGT of 31% over the RIIO-T1 period relative to 2012/13 adding £2 to the average annual household gas bill. These figures are misleading as they exclude the System Operator (SO) allowed revenues. In NGGT the distinction between SO and Transmission Owner (TO) revenues can be unclear at times, for example revenue driver income is recovered through the SO but relates to expenditure incurred by the TO. When the TO and SO revenues are combined, Ofgem's Initial Proposals result in an increase in allowed revenues of only 4%. While the impact on the annual average annual household bill is to increase it by 56p by 2020/21, the average impact across the RIIO-T1 period is actually a decrease of 51p.

Outputs, incentives and innovation Supporting Document

Chapter: Two

Question 1: Do you have any comments on our Initial Proposals on NGET's output and incentives?

National Grid response:

There are many important areas, such as safety, where we agree with Ofgem's Initial Proposals. On the other hand, we have the following specific issues:

- **Lack of clarity around the incentivisation of network renewal**
- **The setting of a financial penalty for connections when this is already a licence obligation**
- **Lack of consistency between the three TOs of target parameters for the new SF_6 environmental incentive scheme**
- **Errors in the outputs associated with wider works**

Reliability

The description of the treatment of Network Output Measures as set out in the RIIO-T1 Initial Proposals 'Cost assessment and uncertainty Supporting Document' is incomplete and confused.

We agree that the NOMs targets should be set out in a Licence Condition, along with the associated dead-band. We welcome Ofgem's confirmation that the tier 1 and tier 2 network risk assessments will be based on Network Output Measures rather than asset replacement volumes. This is more consistent with the RIIO emphasis on the delivery of outputs rather than inputs.

We remain concerned that Ofgem's proposed treatment of under and over delivery does not achieve their stated aim to expose National Grid to the risk of uncertain asset renewal volumes. Furthermore, we are concerned that the marginal reward/penalty could skew the cost benefit analysis of asset management decision-making. Having an incentive that we have to ignore to make the 'right' decision is not logical and has the potential to create a conflict between our interests and those of consumers.

We also remain concerned that Ofgem's refusal to confirm the details of these proposals until the RIIO-T2 price control review will at best make these arrangements irrelevant to our RIIO-T1 asset management decisions and will at worst distort those decisions. This level of regulatory uncertainty on approaching £4bn of lead asset replacement expenditure significantly adds to the risk associated with the RIIO-T1 price control package. Without understanding the process, the definitions (e.g. justified/unjustified) or the parameters of any reward/penalty, we will not be able to make fully-informed investment decisions.

As part of this Supplementary Information document, we have therefore made a proposal which starts to address Ofgem's declared concerns around network renewal performance. There is no reason to delay further development of this process and we would wish to see the arrangements finalised as part of the RIIO-T1 price control review process. We note that non-load related expenditure appears to be receiving a significantly different treatment to load-related, where algebra is being developed for draft Licence conditions; we would prefer to see the full process for network renewal incentivisation set out in a Licence condition.

Finally, Ofgem have rejected the need for an uncertainty mechanism to cover the financing costs associated with advancing non-load related expenditure if load-related expenditure were triggered more slowly than forecast against the Best View Gone green scenario. In not recognising these costs, Ofgem are penalising us for developing a business plan which took appropriate consideration of adaptability and robustness to change. The potential financing cost of £76m is approximately two and a half times the effective materiality threshold proposed by Ofgem for other uncertain costs.

Connections

We disagree with the financial penalty associated with the timely meeting of existing licence obligations in relation to delivering connections.

This approach is not consistent with the RIIO Handbook which states [Page 76; para 9.12] 'We will use financial incentives when: [….] there are not already incentives in place on the network company through other schemes or obligations'.

Some licence obligations require interpretation and can usefully be supported by incentive schemes. For example, the obligation to operate the transmission system in an economic and efficient manner is supported by the Balancing Services Incentive Scheme.

However, in the case of the obligation to make connection offers within three months, this obligation is clear and no interpretation is required. In these circumstances, the proposal to apply a financial penalty simply puts a financial value on failure to meet a licence condition.

This proposal is therefore unnecessary and sets an inappropriate precedent.

The 'Outputs, incentives and innovation supporting document' suggests [para 2.24] that NGET has sought revenue to reflect the imposition of this financial penalty. For the avoidance of doubt, we have sought revenue to reflect our existing licence obligations but, since the penalty exactly mirrors the licence obligation, we have not sought further revenue to cover this.

Environmental outputs – Sulphur hexafluoride (SF_6) emissions

There is an error in paragraph 2.27 which states that the calculated change in SF_6 emissions should be added to the "actual emissions for the previous year"; this should read "calculated emissions for the previous year" otherwise the incentive will not have the desired effect.

The exception is year 1 of the scheme, where Ofgem has proposed a start point of our inventory multiplied by 1.75% which is our Rollover target under the TPCR4+R SF_6 incentive scheme. This is inconsistent with the March 2011 strategy decision for RIIO-T1 which stated that "companies should use existing emissions as a starting point" ['Outputs and Incentives Supplementary Annex'; para 4.34].

In order to be consistent with the March 2011 strategy decision, we should use our existing emissions. This gives two options:

- Our actual emissions performance from 2012/13 (we forecast 1.86%); or
- Our actual emissions performance from the last full year of the TPCR4+R scheme (2011/12), which was 1.83%.

We note from the Scottish TOs Final Proposals that the starting figure for the SHETL scheme is 2%, while that for SPTL is not specified.

In our March 2012 submission, we tried to more accurately reflect the impact of changes to asset inventory by including a marginal increase in leakage from ageing, existing assets in addition to halving our proposed leakage rate for new assets. This marginal increase for existing assets (0.05%) was half the forecast increase based on historical data, thereby setting a challenging baseline for future under-/over-performance. In accepting our stretch target of 0.5% leakage for new assets but not allowing our reasonable baseline for existing assets, Ofgem has set us a more demanding target than that faced by the Scottish TOs. SPTL, for example, have secured a 1% leakage rate for new assets at outdoor substations while SHETL also have an initial leakage rate for baseline investment of 1%. This is in spite of the fact that all three TOs buy equipment to the same international specification. We cannot see any justification for these differences in treatment.

Finally, Ofgem has added a new requirement, namely that the emissions from new assets should be added proportionately based on the amount of time they were commissioned during the year. The detail of this calculation needs clarification as part of the Licence drafting process.

Environmental outputs – Visual amenity of new transmission infrastructure

Paragraph 248 discusses undergrounding of new overhead lines required to connect customers and says “We will also monitor developments under this mechanism and we propose to retain the option to review the mechanism it if becomes clear to us it is not delivering efficient outcomes.” We seek clarification as to what the process would be for reviewing this mechanism within the RIIO-T1 period, i.e. on what basis and when could this review be triggered and how would any changes be made?. Furthermore, if there is to be a re-opener on this uncertainty mechanism, we propose that we should also be able to trigger a review.

Wider system reinforcement works

Table 2.2 in this supporting document and table 4.12 in the ‘Cost assessment and uncertainty supporting document’ do not entirely reflect the boundary capabilities of the baseline wider works. Boundary B14 has been stated incorrectly and does not include an increase that should occur in 2015/16. Additionally, Ofgem has made the assumption that the Western HVDC link will provide 2.4GW of additional capacity from 2015/16. This is not correct for two reasons. Firstly, it is only the short-term rating of the HVDC link that will be 2.4GW and this does not relate to the long-term capability that the link will provide across the relevant boundaries. The boundary increase that is achievable with the proposed link is 2.2GW. Secondly, the proposed link is not expected to be completed until March 2016 and therefore will not be able to provide boundary capacity for the winter peak 2015/16. It is therefore more appropriate to show the link providing an increase in boundary capacity in 2016/17 as included within our submissions.

Both of these corrections are shown in the revised boundary capacity table below. The table does not show our proposed adjustment to B13 which is discussed later.

	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
B6	3300	4300	4300	6500	6500	6500	6500	6500
B7	2000	3400	3400	5600	5600	5600	5600	5600
B7a	4900	5300	5300	7500	7400	7400	7400	7400
B8	11300	11300	11300	11500	11500	10600	10600	10600
B9	12600	12600	12600	11500	11500	11500	11500	11500
B10	5800	5800	5700	5700	5700	5700	5700	5700
B11	9900	9900	10000	10000	10000	10000	10000	10500
B12	5800	5800	5100	5100	5100	5100	5100	5200
B13	1800	1800	1800	1800	1800	1800	1800	1800
B14	9600	9600	10400	10400	10400	10400	10400	10400
B14e	8700	8700	9400	10150	10150	10150	9950	9950
B15	6400	6400	6400	6400	6400	6400	6400	6500
B16	15200	15500	15500	15500	15500	15500	15500	15500
B17	5200	5200	5200	5200	5200	5200	5200	5200

NW1	1800	1800	1800	1800	4400	4400	4400	4400
NW2	1500	1500	1500	4600	4600	4600	4600	4600
NW3	2900	2900	2900	2900	4400	4400	4400	4400
NW4	6000	6000	6000	6000	6000	6000	6500	6500
EC1	4100	4100	4100	4100	4100	7000	7000	7000
EC3	3200	3200	4300	4300	4300	4300	4300	4300
EC5	2600	2600	3600	3600	6800	6800	6800	6800
SC1	5600	5600	5600	5600	6100	6100	6600	6600

Question 2: Do you have any views on our Initial Proposals on setting an expenditure cap for the start of RIIO-T1 in relation to addressing the visual amenity impacts of existing infrastructure in designated areas?

National Grid response:

In summary:

- **Our independent, best practice research shows a willingness amongst consumers to pay for this mitigation**
- **Based on the research results, we have made a conservative recommendation for a capped national allowance of £1.1billion over the RIIO-T1 period**
- **Ofgem's initial cap of £100million is insufficient to carry out any meaningful mitigation**

The results of our stakeholder engagement and the findings from the independent Willingness to Pay (WTP) research carried out earlier this year show support amongst the general public and other stakeholders for an allowance to mitigate the visual impact of existing transmission infrastructure in designated areas. We therefore welcome the existence of an allowance and have made our recommendations to Ofgem regarding its possible size.

Our recommendation, based on the research findings and accounting for consumers' feedback on their ability to pay more in the current financial climate, was for Ofgem to set a national transmission allowance capped at £1.1billion for the eight year RIIO-T1 period.

Our proposal was the result of best practice research carried out in early 2012 by an independent research agency who are widely recognised as one of the industry leaders in Willingness to Pay studies. Ofgem was involved in the scoping of this study.

We understand that Ofgem wishes us to carry out further research and/or analysis before setting a final amount for the allowance, and has therefore set its initial allowance at £100million pending further review. Our view is that we have provided Ofgem with the information they need to set a final allowance. This view has been supported by many of our stakeholders, including at our stakeholder workshop on this topic on 8th August 2012.

A particular issue raised by Ofgem concerns the use of the mean value that consumers are willing to pay (rather than the median) as the basis of our recommended allowance. The use of a mean is in line with best practice and follows precedent for the setting of previous similar allowances. Of note, our earlier research, carried out by another research agency in 2011, generated a median around 50% of the mean. In that research, however, over 40% of respondents expressed no willingness to pay. In our latest research, only c.20% of respondents expressed no willingness to pay, suggesting that the median value for this latest research would be well above 50% of the mean. Our proposed allowance of £1.1billion is well below 50% of the mean in relation to undergrounding in designated areas. It therefore seems highly implausible that the median would be lower than £1.1billion, so while we don't believe that the median is required to set an allowance, even if it was, our previous research has provided sufficient information in this regard.

When deciding on a final figure, Ofgem should set the allowance at a level at which meaningful mitigation activities can be carried out. Whilst recognising that other, less expensive mitigation activities such as tree planting may be prioritised, an allowance of £100million would only allow us to underground approximately 4 miles of double circuit overhead line during the eight year RIIO-T1 period (undergrounding of lines was consumers' preferred method of mitigation).

Over the coming months, we will work with Ofgem and the wider stakeholder community to develop a process for selecting which projects should be funded by this allowance. National Grid will naturally play a key role in this decision-making process, but we recognise that the selection of projects should not simply be a decision for Ofgem and us. As such, we are proposing that a committee is established to advise on which projects are prioritised. Members would represent a broad range of stakeholders, as well as National Grid and Ofgem.

Regarding the allowance itself, we understand that Ofgem's latest view is that this should be national, and not split into England/Wales and Scotland. If this is the case, the two Scottish transmission owners will need to play an active role in how it is used.

Further areas where clarity is required from Ofgem include the type of work covered by the allowance, the definition of boundaries to designated areas, and how funding will be phased.

More details on the research, its findings and our proposals can be found in our report on the Talking Networks site[3].

Chapter: Three

Question 3: Do you have any comments on our Initial Proposals on NGGT's output and incentives?

National Grid response:

Our comments on NGGT's outputs and incentives focus on the following areas:

- Reliability
  - Ofgem's thoughts on our proposals for NOMS targets and treatment of over or under performance against it are unclear.
- Environmental impact
  - Timely funding of the Industrial Emissions Directive (IED) requirements is essential to facilitate compliance with environmental legislation.
- Timely connections
  - We continue to believe that the proposals relating to funding the provision of incremental capacity can be implemented from April 2013 and utilise existing processes (such as the UNC Modification 373 process) as trigger points.

We provide further explanation of these points below.

Reliability

Ofgem's thoughts on our proposals for NOMS targets and treatment of over or under performance against it are unclear.

[3] http://www.nationalgrid.com/NR/rdonlyres/88431596-2009-4CDE-BE51-EC5E536FF2BC/55358/NationalGridWTPreport.pdf

Following Initial Proposals, there remains a degree of uncertainty over the Network Output Measures (NOMs) target to be used to assess network risk. We are keen to understand whether Ofgem agree with the target we proposed in our RIIO-T1 submission, and of equal importance, the treatment of any under or over performance against that target. Discussions with Ofgem since the publication of Initial Proposals have indicated that additional penalties and rewards are being considered in this area; however Ofgem does not believe it can confirm the magnitude of such penalties or rewards until the RIIO-T2 price control review.

We are concerned this lack of clarity over treatment risks skewing what would otherwise be effective economic trade-off decisions on the acceleration or deferment of asset health expenditure. Such decisions are taken during the normal course of business, for example to avoid a short-term spike in prices for particular assets we may defer investment, or to take advantage of synergies with existing system outages we may accelerate or defer planned asset health investment. In both examples, the decision taken would seek to minimise overall cost to both NGGT and (through the application of the efficiency rate) the end consumer.

In reality, the only way such decisions can be optimised for efficiency is to ignore the additional incentive created by an unquantified cost or benefit. It is our view that such an incentive is therefore inappropriate.

We do understand, however, that Ofgem is keen to disincentivise behaviour which would otherwise result in an unjustified reduction in asset health investment on the network resulting in an increase in network risk. We believe this could be achieved through a single, quantified penalty to be applied where we are unable to justify to Ofgem the decision to defer particular asset health investments. This penalty should be agreed in advance of the start of the RIIO-T1 period and scaled to negate the short-term financing benefit we would receive from that deferral (i.e. make the outcome of NPV neutral and remove any preserve incentive that would otherwise arise from that deferral). Any greater penalty would have the effect, described above, of skewing the otherwise economic trade-off.

We look forward to clarity over whether Ofgem agree with our proposals for NOMs targets, the criteria Ofgem will apply in its consideration of what is ‘justified’ or not, and the treatment of under / over performance.

Environmental impact

Timely funding of the Industrial Emissions Directive (IED) requirements is essential to facilitate compliance with environmental legislation.

The requirement to comply with environmental legislation is an appropriate output for NGGT. Our RIIO-T1 plan has been designed to achieve this, given our understanding of the requirements of the new European IED as supported by QC advice. Ofgem has proposed an uncertainty mechanism to be triggered on clarification of the need case as driven by transposition of the IED into UK law early next year (to be potentially supplemented by guidance from DEFRA and/or the Scottish Parliament).

We agree in principle with this approach, provided the following issues can be managed:

- To mitigate the risk that administration of an uncertainty mechanism may delay receipt of funding and therefore risk the replacement of key compressor units on the NTS before they have to be decommissioned under the legislation, the Front End Engineering Design (FEED) work needs to be funded on an ex ante basis.
- Clarity is required over the timing of funding, once triggered, to ensure alignment with the timing of costs.
- Recognition that the scope of each replacement project will be driven by the Best Available Technique as agreed with our environmental regulators (which cannot be dictated ahead of time) and site specific factors.

- The impact on the Information Quality Incentive (IQI) calculation of Ofgem's movement of this funding from ex ante to a new uncertainty mechanism is unwound.

If replacement of any impacted compressor units is not achieved by the date on which they become legally non-compliant and must cease operation, the capability of the network will be materially reduced, which will result in NTS constraints.

Timely Connections

Process

Our business plan detailed a number of developments to the regulatory framework, both to ensure that the gas transmission business is financeable in light of the scale of investment envisaged during the RIIO-T1 period, and to change our obligated lead times to deal with the implications of the Planning Act (2008) on delivering large scale infrastructure. Shortening the obligated lead time associated with delivering capacity to cover just the construction period can only be implemented if changes are also made to the commercial (UNC) framework. The rest of our proposals can be implemented without any changes being needed to the commercial framework, utilising existing processes (such as the UNC Modification 373 process) as trigger points for allowed revenue adjustments.

We have been discussing the issues surrounding the Planning Act and the connections and capacity processes since summer 2010 through our 'Talking Networks' stakeholder engagement. Following feedback from stakeholders that we should let the closely linked UNC modification proposal 373 (Governance of NTS Connection Processes) conclude prior to engaging in discussion of the details regarding changes to the capacity processes, we first discussed potential developments to the UNC at the UNC Transmission Workgroup in January 2012. It has become apparent that, due to the level of complexity in this area, significant further discussion is required and any changes to the UNC will not be in place by the start of the RIIO-T1 period. Ofgem has consequently refrained from providing a view on any of the regulatory proposals contained within our business plan as it feels it would not be appropriate to make any changes to the regulatory arrangements in this area where these could prejudge commercial changes. It is essential that Ofgem provides early guidance on any areas of potential changes that are not acceptable from a regulatory point of view in order to ensure that industry time is efficiently spent on developing appropriate arrangements; failure to do so is likely to delay development of options due to the likely need to develop multiple options in parallel. We look forward to engaging further with Ofgem and the industry on this matter.

Funding

Our business plan proposed that a revenue driver approach would continue to fund the provision of incremental capacity but with a slight modification so that funding is released in two stages with one revenue driver funding activity prior to a formal capacity signal being received and the other funding activity after this point and being calculated according to a pre-agreed generic methodology.

Paragraph 3.11 of Ofgem's Outputs and Incentives supporting document states that revenue recovery will be via a totex approach with consequential implications on funding release, but it provides no details on how or when that funding will be triggered. Subsequent discussions with Ofgem has revealed that Ofgem proposes to release 20% of a calculated revenue allowance adjustment in year T-2 (where T is the year of capacity delivery) and 80% in year T-1. Although we recognise this is an improvement on the current funding arrangements (where funding is not released until capacity delivery), it still leaves NGGT in the position of having to finance the capital requirements in the early years of work prior to revenue being released, with consequential impacts on cash flow. Of particular concern is the impact of Ofgem's proposals if the customer pulls out of the project before making a formal capacity signal. In this situation, with the totex mechanism applied, NGGT will have been exposed to 45% of the expenditure in each year but will never receive any adjustment to the allowed revenue to make NGGT 'whole'. The introduction of the Planning Act has changed the level of costs associated with this pre-capacity signal activity and the length of time required to complete such activities due to the greater level of engagement required. Therefore the scale of costs to which NGGT is exposed should a formal auction/application signal not materialise is greater than before the introduction of the Planning Act. It is therefore clear that continuation of the TPCR4 arrangements whereby no explicit funding is provided to cover this type of activity is not appropriate going forwards. We suggest that funding arrangements associated with this pre-capacity signal activity is explicitly included within the regulatory settlement, such as provided for in the NGET control.

Over the TPCR4 period, the revenue drivers which were set at the time of that settlement have become out of date, as they were calculated using analysis conducted in 2005 based on a forecast of the network configuration and flow patterns expected to be seen in 2008. Due to the meshed nature of the network, the calculation of one revenue driver is highly dependent on the assumptions being made regarding the timing of any neighbouring incremental signals; hence calculation of all revenue drivers at one point in time can be problematic. For these reasons we proposed within our business plan that all existing revenue drivers should be removed from our licence and then calculated as and when required according to pre-agreed methodologies. The main reason for this proposal was to ensure that revenue drivers would be set to be more closely aligned with the actual costs of providing incremental capacity (as they would be based on up-to-date information regarding forecast supply and demand information, take into account the prevailing capacity obligations on the system and the resultant network topology). Subsequent discussions with Ofgem has indicated that this approach may be appropriate but that an obligation should be included within the relevant licence condition to ensure that revenue drivers are calculated in a timely manner in order to enable parties to apply for incremental capacity when required. We agree that such an obligation is appropriate as we are keen to ensure that users continue to be able to provide signals for capacity in a timely manner. To that end, we will work with Ofgem over the coming months to ensure that the Licence is appropriately drafted to ensure this is achieved.

However, for completeness, we include an outline of the proposed approach which has been discussed with Ofgem:

The Licence would be drafted to not include specific details of any revenue driver allowances relating to entry capacity at the time the RIIO-T1 price control is set (i.e. at 1 April 2013) as the first time that such revenue drivers would be required would be for the March 2014 QSEC auction[4]. There is therefore sufficient time to calculate the appropriate revenue driver values once their requirement has been established following discussions with Industry parties. With regard to exit capacity, revenue drivers would be needed to support any signals for incremental exit capacity received as part of the July 2012 annual exit application window. To address this, taking account of the contact we have had with customers regarding potential exit signals, we propose that the recent revenue drivers which have been set relating to potential incremental exit capacity signals in the South East of the system should be retained, but are amended to fit in with Ofgem's proposals to employ the totex framework (i.e. be calculated as a £m/GWh). These revenue drivers are based on comparably up-to-date information and calculated in a manner which took into account the interactive nature of projects in that area, hence retaining these values is consistent with the principles behind our proposals for future revenue drivers. However, the appropriateness of these revenue driver values should be regularly reviewed throughout the RIIO-T1 period as more information becomes available.

[4] We would expect any signals for incremental capacity received during the March 2013 QSEC auction to utilise the existing revenue drivers and associated funding within the Licence.

Any further revenue drivers (for both entry and exit) would be set in a timely manner following indications from users that they were interested in signalling incremental capacity at that particular point.

In order to facilitate this, an associated document[5] to the Licence would be created which would detail the order of preference for the calculation of revenue drivers:

1. Via an approved Generic Revenue Driver Methodology, which has been consulted upon (as long as this is fully discussed and consulted on such that it is approved by 1 April 2013)
2. If 1 above is not achieved, with reference to a table within the associated document which will include revenue drivers for any entry or exit points that are expected to be required during the early years of the RIIO-T1 period following discussion with Industry
3. If neither 1 nor 2 above is achieved, with reference to a table within the associated document which will include the current (TPCR4) revenue drivers, amended to fit with the totex approach (i.e. £m/GWh) using up to date unit cost information

Our current understanding is that Ofgem will consult on this approach in conjunction with the second informal licence drafting consultation and this would then be followed by a letter published by NGGT clearly indicating the approach being proposed and asking anyone who believes they may want to trigger incremental capacity that we are not already in discussions with to contact us so that calculation of the appropriate revenue drivers can be considered.

We would welcome confirmation from Ofgem that this course of action is appropriate and look forward to clarity regarding the proposed approach for funding of incremental capacity from 1st April 2013 being provided within Final Proposals.

<u>Fleetwood</u>

Within our RIIO-T1 submission, we set out a methodology to manage the evolving situation at Fleetwood. We welcome Ofgem's approach in Initial Proposals that it will take steps to protect the interests of consumers, and seek clarity as to whether our proposed methodology is an acceptable way forward.

Question 4: We welcome your views on the appropriate permits arrangements from 1 April 2014 if no other changes to the incremental capacity arrangements have been made?

National Grid response:

Following ongoing discussions between ourselves and Ofgem, we provided within Annex B to our SO External Incentives Plan in May 2012 the evidence that we have available to us to support our proposal that the permits allowance for the rollover year should be increased. We believe this increase is needed to take account of our inability to deliver incremental capacity, where reinforcement is required, to prevailing obligated lead times. Ofgem's Initial Proposals did not allow the increase to the permits allowance on the basis that the TPCR4 rollover deal has been accepted, despite a letter received from Ofgem on 8th February 2012 stating that this could be revisited if further evidence was provided. Imposing TPCR4 obligated lead times onto capacity delivery in conjunction with an insufficient allowance of permits to adjust these accordingly, changes the risk profile to end consumers of constraint management costs

[5] Such as those being developed alongside other conditions within the licence, such as relating to the NIA/NIC or the Financial Model

and sets false expectations, as we are highly unlikely to be able to deliver to those timescales where a Development Consent Order is required.

Ofgem has consulted on two options for managing constraint costs going forwards; one being a continuation of the existing schemes and the other being a move to our proposal of a combined scheme, but without caps and collars or any risk premium. Under the current constraint management schemes, NGGT is fully exposed to constraint management costs relating to the delivery of incremental Entry capacity up to a monthly cap of £4.6m (09/10 prices) or an annual cap of £41.3m (09/10 prices) with any costs incurred over this cap being fully borne by users and, ultimately, end consumers with a similar scheme applying relating to the delivery of incremental Exit capacity. Within our March 2012 submission[6] (and also included within Annex A to our May 2012 SO External Incentives submission), we included a table of the potential level of constraint costs for 2020/21 with current network capability, plus another table which showed the effect on constraint costs for the same year of one large supply project (again assuming current network capability). The difference in the values in these tables show that the increase in the potential level of constraint costs for that year associated with one large supply project could be between £18m to £291m (90% confidence interval) with the mean increase being £116m. Under the proposed combined scheme (without caps and collars) NGGT would bear 45% of the constraint management costs, with the remainder being borne by users and, ultimately, end consumers.

An insufficient allowance of permits, in conjunction with an uncollared constraint management scheme, potentially exposes NGGT to open-ended risk as a result of capacity signals and the planning regime, over which we have no direct, and very little indirect, control. We would therefore require explicit recognition in the cost of capital to reflect this increased risk. If signals do materialise in the March 2013 QSEC that are likely to result in constraint management costs being incurred, we would need this to be addressed through discussions with Ofgem to consider available options to manage the subsequent risk which would materialise at the obligated capacity release date (2015/16).

When we proposed interim arrangements based on the current permits scheme to manage the risk associated with the delivery of reinforcement associated with incremental capacity (whilst changes to the commercial regime are being developed), we considered a number of factors in order to be able to make an assessment over the efficient level of permits that should apply for 2013/14. For the projects we are currently aware of that may apply for incremental capacity before April 2014, we calculated a proposed permit allowance based on their indicated first gas date (rather than obligated lead time) and also factored in our view of the likelihood of that project going ahead – this led to us proposing a permit allowance of £19.2m (09/10 prices). This is an efficient level of permits which covers our assessment of the risk that we are exposed to, according to the information that is currently available to us. This level of permits is only applicable, however, provided we can go overdrawn (i.e. indicate in an invitation letter that we could require more permits to cover the potential risk than we currently have and expose ourselves to the associated cost of going overdrawn as proposed in our business plan). This provides customers with the flexibility to apply for differing levels of capacity or start dates than we have factored into our analysis, which would ultimately result in a higher level of risk than we have proposed is covered by the permits allowance ex ante.

It is imperative there is an ability to go overdrawn in order to protect against the risk of incurring unlimited constraint management costs. Implementing an agreed mechanism for going overdrawn with negative financial consequences, as included in our proposals, would incentivise National Grid to ensure it proactively manages its customer base to ensure it has the most up to date information and therefore can play the permits allowance available in the most efficient manner, but also protects National Grid and end consumers from sizeable constraint costs where an unexpected customer signal is received that cannot be delivered to

[6] See paragraphs 162 and 167 of our March 2012 'Managing Risk and Uncertainty' annex

obligated lead times whilst avoiding the need for a more sizeable permits allowance to manage the risk. Recent discussions with Ofgem concerning licence drafting have revealed that Ofgem proposes to retain the current form of drafting around permits whereby there is an explicit allowance relating to entry and a separate one relating to exit. We do not agree with this approach as our proposals were based on an optimised permit allowance across entry and exit together[7]. A scheme based on a split permit allowance would require in aggregate a higher allowance of permits to achieve the same level of risk mitigation, as this removes the ability to make the most efficient decision across entry and exit. Therefore we do not accept this approach to the licence drafting.

The ex ante permits allowance and the ability to go overdrawn, should be implemented along with caps and collars on the constraint management scheme to provide an appropriate incentive package around incremental capacity delivery. Should Ofgem not wish to adopt this approach, a suitable premium reflected in the cost of capital should be provided to manage this risk on behalf of consumers, in order that the risk of not being able to deliver reinforcement for incremental capacity within obligated lead times can be appropriately managed. If the permit arrangements and constraint management options remain as proposed in Initial Proposals we would be compelled to support the retention of the existing complicated constraint management schemes with their associated parameters and caps and collars, rather than supporting the proposed combined scheme which encourages trade offs between the most efficient actions, but without caps and collars.

In relation to the potential for a permits scheme to apply further into the future, it is important that an appropriate allowance is set for the level of permits based on a likelihood of projects applying for incremental capacity taking account of information such as customer intelligence, TEC dates and Transporting Britain's Energy data. This would enable us to manage the delivery timescales associated with incremental capacity whereby a generic lead time covering all projects (as contained in the TPCR4 arrangements) is not appropriate going forwards in light of differing supply and demand patterns which result in different customer requirements. An appropriate permits allowance allows individual lead times to be created to best meet individual customer's requirements. With regard to future permits schemes it would be useful to have clarity over when the interim arrangements (i.e. those to apply in 2013/14) and any future arrangements are to be 'cashed out'. If commercial developments are implemented so that permits are only utilised for the first year of the RIIO-T1 period, it would seem unreasonable to wait for the end of the RIIO-T1 period for our allowed revenue to be adjusted, where applicable.

Question 5: We welcome your views on the two options on constraint management tools retained in our Initial Proposals. Are you aware of any evidence that might help us in judging between these two options?

National Grid response:

Ofgem is consulting on two options in relation to constraint management. The first is the introduction of a combined scheme covering entry and exit operational and incremental constraint management actions, as proposed in our business plan, albeit with no caps and collars or associated risk premium. The alternative is to roll over the existing arrangements which would mean there would be separate entry and exit incremental schemes and an entry operational scheme. We note that no view has been provided within the Initial Proposals consultation on our proposal that the target of any combined scheme could move upwards or downwards with the triggering of any of the other uncertainty mechanisms[8]. Subsequent

[7] An example of the complexity in this area can be seen in the revenue drivers for the South East, whereby the same projects can be triggered by either entry of exit signals.

[8] We note that within the licence drafting consultation, the suggested text for GTC120 (Entry and exit capacity constraint management) includes the provision for a dynamic target

discussions with Ofgem on this matter have indicated that Ofgem support the introduction of a dynamic target. In addition no detail was provided in Initial Proposals on the form the existing individual schemes would take if they were rolled over; although within recent meetings, Ofgem has stated that it intends to retain the existing targets, sharing factors and caps and collars whilst potentially reviewing the overall collar that sits across all of the schemes. We have provided our assessment of the two options being consulted on below, taking account of the absence of these aforementioned details, which we look forward to seeing clarified in writing later in this process.

We consider that a combined entry and exit constraint management scheme, with appropriate caps and collars, is the most appropriate incentive to apply in this area. We note that stakeholders have previously expressed the view that a combined scheme may reduce our risk exposure; however, it could be argued that the current constraint management incentive scheme structure creates a perverse incentive for constraint management actions to be focussed on entry rather than exit, due to the asymmetrical incentive structure. The equalisation of the treatment of all constraint costs, irrespective of whether they relate to entry or exit, will ensure that the incentive treatment does not create any perversions or distortions in the actions that are taken by the System Operator. As we move into the future a constraint caused by an entry flow could be resolved by an entry or exit action and vice versa. We also believe that identifying whether a constraint is caused by an entry or exit flow may prove difficult given that the within day and inter-day supply and demand volatility could cause constraints, rather than constraints being specifically attributable to the quantities being input or off-taken from any one point. It therefore seems inappropriate to target actions and costs to any one particular type of user.

Feedback from stakeholders has revealed that in principle there was agreement regarding simplification of the constraint management incentive arrangements, however there were concerns raised about transparency if entry and exit actions were combined under a single incentive and further details were sought explaining how the combination of the schemes would affect the various actions which NGGT could take to resolve constraints. Recent discussions regarding the examples provided to show the use of different constraint management actions under separate and combined schemes have indicated that stakeholders are more comfortable with the concept of a combined scheme.

In order to aid transparency, we envisage that, if a combined scheme were adopted, arrangements similar to those in place currently could continue whereby information is made available to stakeholders with regard to the constraint management actions that have been taken in accordance with the System Management Principles Statement.

Treating all constraint management costs in an equitable manner is consistent with the underlying RIIO-T1 principles ensuring that efficient trade offs occur. Additionally, a single scheme which covers entry and exit capacity constraint management will allow the licence to be simplified such that there is more clarity and transparency over the resultant incentive arrangements.

We therefore, in principle, support the move to a combined scheme, although we do not understand the rationale for removing the concept of caps and collars. Indeed this policy decision is inconsistent with the approach being proposed by Ofgem in regard to other SO incentive schemes, whereby caps and collars are being retained. In relation to caps and collars, Ofgem has taken the analysis that NGGT provided and has calculated the average exposure each year and factored it into their assessment of our risk exposure, arguing that this leads to a “likely maximum downside of £23m”. We do not agree with this approach as it does not take account of the low probability high impact events that could occur outside the boundaries of the average and considerably change the absolute level of risk exposure. If, however, Ofgem feels that this figure is an appropriate likely downside amount, then we do not understand why it would not therefore be appropriate to set a collar at this level, reflecting that NGGT has little control over the outlying risks. Caps and collars exist to protect against high impact low probability events over which NGGT has little or no control. The utilisation of caps and collars protects from these outlying risks and in addition incentivises appropriate, rather than extreme, buyback pricing given that the exposure of industry to these costs is likely to create an environment where there is peer pressure for these costs to be kept at an appropriate level.

The caps and collars assessment is particularly pertinent when considered alongside the permits proposals (our views on which are expressed in the answer to question four of the Outputs and Incentives document above). The ex ante permits allowance and the ability to go overdrawn, should be implemented along with caps and collars on the constraint management scheme to provide an appropriate incentive package around incremental capacity delivery. If this is not adopted, a suitable premium reflected in the cost of capital should be provided to manage this risk on behalf of consumers, in order that the risk of not being able to deliver reinforcement for incremental capacity within obligated lead times can be appropriately managed. If the permit arrangements and constraint management options remain as proposed in Initial Proposals we would be compelled to support the retention of the existing complicated constraint management schemes with their associated parameters and caps and collars, rather than supporting the proposed combined scheme which encourages trade offs between the most efficient actions, but without caps and collars.

Chapter: Four

Question 6: We welcome your views on the proposed level of funding for the licensees' NIA, based on the quality and content of their innovation strategies.

National Grid response:

The 0.6% NIA allowed for both NGET and NGGT within Initial Proposals does not provide sufficient stimulus to generate the rate of innovation required over the RIIO-T1 period:

- **Confirmation of an increased scope to cover TO and SO, commercial, operational and IT related schemes reinforces the value to be derived from our business plan proposal for a 1% NIA allowance**
- **An external review of our innovation strategies concludes that for both businesses the NIA should be at the top end of the 0.5% to 1.0% allowance**
- **Limited justification has been provided to support the reduction in allowance from 1% to 0.6% NIA**

We have reviewed Ofgem's justification for the 0.6% allowance within the Initial Proposals, namely that Ofgem believes our innovation strategy to be lacking in three specific areas. Our response to each of these is detailed below

- Evidence of additional value 1% NIA funding would provide
    - Wider scope of NIA unlocks the potential for innovation to be a core enabler in delivering outputs at the least cost for consumers now and into the future across the whole of Transmission

- Lack of detailed stakeholder engagement conducted
    - Multiple stakeholder events have been held with innovation explicitly discussed, with many other sessions touching on it indirectly

- Lack of delineation between business as usual innovation and scheme funded

innovation
- This detail was covered in Appendix B of our innovation strategies and innovation was denoted throughout our narratives by use of an innovation 'light bulb'

We look at each of these in turn and provide further evidence in support of our position.

Additional value of enhanced NIA funding

Since 2008/9 we have utilised the full IFI allowance for both NGET and NGGT. Our portfolio of IFI projects has a positive Net Present Value (NPV) for both NGET and NGGT of £17m and £11m9 respectively. We continually have to delay or stop schemes due to lack of funding and have traditionally been oversubscribed by 10% at any one time. For example we have six projects on hold at the moment due to lack of funding and the current scope of the IFI scheme.

In viewing the NPV figures, it is important to note that innovation can deliver benefits that are difficult to quantify in financial terms, such as safety, environmental and security of supply benefits. We will continue to pursue innovation that deliver these benefits as these areas are valued by our stakeholders. The move towards creating a monetary value on these aspects will allow Ofgem to more readily appreciate the full value that we will deliver through 1% NIA funding.

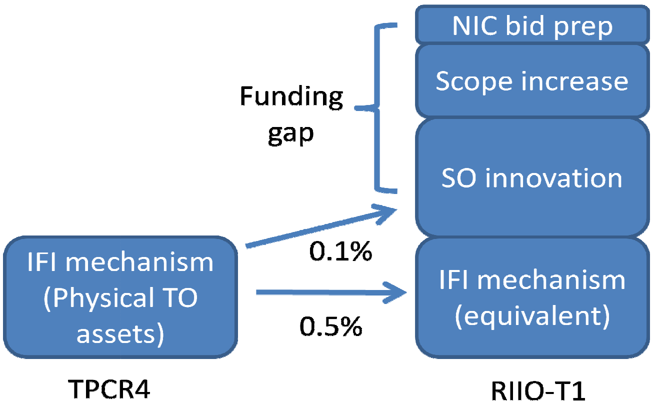
The value we will deliver from our innovation portfolio is best characterised by the ambitious efficiency levels we embedded into our March RIIO-T1 business plans. The ability to innovate is integral to delivery of the continuous improvement efficiency that we proposed over the RIIO-T1 period. Indeed, innovation will provide the catalyst to push the productivity frontier further to the benefit of existing and future consumers.

The case for 1% allowance

Over the next decade, substantial investment is expected in our networks and innovation will be key to establishing efficient, effective and economic solutions to the upcoming challenges to deliver desired stakeholder outputs at least cost. With the growth in workload over the RIIO-T1 period it is paramount that we find new and innovative ways to deliver. This was highlighted through an external review of our innovation strategies by Henley Business School (HBS). They concluded that for us to continue to drive efficiency gains, achieve an innovation performance at least in line with peers and to start to build strategic leadership in the sector, we require an innovation allowance at the top end of the NIA range. We will forward this document on separately.

Against this increase in scope, a 0.1% increase in funding seems disproportionate, especially when recognising that the scheme now needs to cover our SO functions and has been expanded to cover commercial, operational and IT based innovation. To deliver value from this, it needs to be supported by a proportionate increase in allowances. This point can be best illustrated by the diagram and discussion of each driver below.

[9] Greater details are contained within our most recent IFI reports: http://www.nationalgrid.com/uk/Gas/OperationalInfo/IFI/ http://www.nationalgrid.com/uk/Electricity/Info/IFI/



IFI mechanism equivalent

IFI currently relates only to TO asset based innovation. Evidence from the last three years shows that we continue to fully utilise the 0.5% funding available. With the existence of a work stream of schemes this underlying level of spend will continue into the RIIO-T1 period. Currently we have agreements to commit to 110% of the IFI allowances. To live within the allowances we have to delay or stop certain projects, nullifying the potential value of these schemes to consumers.

SO innovation

As highlighted within our March business plan submissions, our SO functions face considerable challenges over the price control period. We are therefore encouraged that this part of the business can access NIA funding but request that the increased scope of potential NIA projects reflects the size of our organisation when the SO functions are included. This is especially relevant when comparing NGET with the allowances provided to SHETL.

Our SO roles span the whole of GB and interact with the wider energy distribution chains, Ofgem needs to consider that our involvement is required with innovative projects that will not necessarily directly benefit the SO, such as those associated with the Low Carbon Network Fund (LCNF) and the proposed NIC. These projects will require coordination with, and resources from, the SO in order to deliver the expected benefit and to ensure that impacts on other aspects of system operation are appropriately managed. In sizing the potential cost of such involvement we can review recent evidence from a LCNF project with Electricity North West (ENW), where we have contributed ~£0.4m over three years.

We therefore propose that the importance of the SO function for enabling innovation across the energy value chain is reflected within an increased allowance. On a stand alone basis 1% of SO revenues equates to roughly £1m a year for ESO and GSO. This does not fully reflect the value proposition that SO involvement can deliver. Instead, Ofgem should view the value that can be driven by our dual SO-TO role and reflect this in funding the full 1% NIA.

As the GSO we need to focus on research into network modelling techniques to understand unpredictable demand and supply scenarios and what the implications of unusual supply sources are on both the physical and commercial regimes. In addition, we will need to innovate around system shrinkage, metering and advanced data and alarm techniques.

As the ESO we will need to face the challenges of operating and optimising series compensation embedding HVDC technologies and further SMART tools. Variable generation and demand will require research into stability and voltage related network problems. We need to investigate innovative ways of undertaking network analysis to cover the range of outcomes that could occur. Combined with these, finding commercial solutions to incorporating energy storage and innovative ancillary service provision will be priorities.

All these SO innovation areas should generate customer benefit through lower operational costs and enable outputs to be delivered at least cost. We gave further details of SO innovation within our detailed business plans and our innovation strategies[10].

<u>*Scope increase*</u>
We are pleased that the scope of the definition of innovation has increased to cover commercial, operational and IT related schemes as this opens doors to a greater selection of ideas. As HBS suggest, *"Beyond technological innovation, NG will need to re-engineer its business processes to meet the growing complexity of its relationships with its customers, suppliers and other stakeholders"*. Our strategies further expanded on how we are going to manage this and capture all forms of innovative ideas.

<u>*NIC bid preparation*</u>
Whilst relatively small, within the RIIO-T1 period we will need to allocate £175k per annum of the available NIA funding to be used to develop feasible NIC projects, adding further weight to the funding requirements.

<u>Lack of specific stakeholder engagement</u>

We disagree with the concern expressed about the lack of stakeholder engagement that we have undertaken to support our innovation strategies. As outlined within our 'Stakeholder engagement process' annex, under the Talking Networks banner we have been consulting with our stakeholders to understand what they need from our networks over the price control period. This process has included hosting multiple workshops on a variety of topics, with two of these workshops (in October 2010 and April 2011) focused entirely on innovation. As innovation is a key lever in overcoming network challenges, innovation was also discussed at the various other workshops we held, for example when we discussed the role of a smarter transmission network. All of the findings of these events are available on our Talking Networks website[11].

As expressed within our strategy annexes, for certain parts of our business plan, we received specific stakeholder feedback on areas where we need to focus on innovating such as energy storage. In other cases, our stakeholders helped articulate specific challenges that they face and how we could innovate to help them, such as developing solutions to addressing visual amenity concerns. Finally, we have listened to our stakeholders and what outputs they require us to deliver. This has helped shape the direction of our innovation priorities.

We continue to engage with stakeholders through a wide variety of forums across many different aspects of our business operations. A few examples to illustrate the breadth and depth of such engagement include:

- Benchmarking conferences such as ITOMS where we facilitated a workshop on the subject of innovation, identifying innovation projects undertaken by international TSO peers. Subsequently 15 companies have expressed an interest in working together to sharing experience in projects and we are proposing to chair an ongoing forum on innovation.

- Stakeholder interaction through infrastructure projects and the associated consultations including local events such as village hall presentations, Focus Groups and Community Forums. Innovation is part of the engagement with typical feedback on how we this can provide solutions.

[10] http://www.talkingnetworkstx.com/electricityplan/innovation.aspx
[11] http://www.talkingnetworkstx.com/consultation-and-engagement.aspx

- Involvement in driving a variety of collaboration networks such as the Energy Research Partnership (ERP) and Hub Net where we engage with stakeholders form different disciplines (Technology, Construction, Energy, Councils etc) on projects across our innovation portfolio. For example through the HV Cable Systems workshop, we engage with 13 different stakeholders, from varied sources including Marine Biological Association (MBA), Eirgrid and Suppliers, influencing our innovation with respect to subsea assets.

Our continuing engagement with multiple stakeholders means that we can make amendments to our strategic direction and reprioritise our innovation portfolio. This forms part of the terms of reference for our Innovation Team. We will therefore continue to review our innovation portfolio so that it addresses the needs of our stakeholders as we progress through the RIIO-T1 period.

Delineation between business as usual innovation and scheme funded innovation

Ofgem suggests that our innovation strategies do not clearly delineate between what innovation would be funded through our baseline submission and what would be funded through the innovation stimulus package. Contrary to this view, we provided this information as part of our Innovation strategies document. Appendix B of the annexes lists out the major areas of innovation where we have included costs within our central business plan. These have been included within our normal business plan because the concepts have been sufficiently developed and proven to the extent that they can be classified as business as usual. An example of this has been our Linescout collaboration[12]. This was initially funded through IFI, however, now that the concept has been proven the cost of procuring these robots to perform live inspections and repairs has been included within our baseline plan.

To clarify, within our business plan submission, the use of the 'light bulb' symbol was adopted to show all aspects of innovation across our plan. This included a mixture of areas where we had included costs within our business submissions (as illustrated by the table in the appendix) and those areas where we have previously used innovation funding or are likely to be utilising the available innovation stimulus going forward. As was illustrated by the use of this symbol, we are looking to embrace innovation and the benefits that it can construe across all aspects of our business operations.

In conclusion

As recognised by our stakeholders, innovation will be crucial in overcoming the challenges of the future and it is be vital that sufficient funding is made available. To make the most of the innovative opportunities available, we developed a business case to support the full 1% Network Innovation Allowance (NIA) as set out in our Innovation strategy documents. We are therefore extremely disappointed with Ofgem's Initial Proposals of 0.6% NIA for both our gas and electricity transmission businesses which we feel will be inadequate to provide a suitable incentive for the level of innovation needed to meet the challenges over the RIIO-T1 period.

[12] Linescout demonstration http://www.youtube.com/watch?v=hAR_j0V_Y3Q&feature=g-all-u for further information

Question 7:	In relation to funding the Gas NIC for 2013/14, do you support either Option 1 (run the NIC and raise the required funds from the winning licensees' customers) or Option 2 (no Gas NIC, but roll-over funds to 2014/15). If NIC is delayed beyond 2014/15, what option would you support?

National Grid response:

On the basis that the Gas Act does not currently allow implementation of NIC in the Gas Sector, and therefore cannot be implemented until a change in Primary legislation is progressed, we would support option 2 as the only viable option. This would ensure the appropriate socialisation of costs across all consumers whilst maintaining the level of aggregate funding across the RIIO-T1 period.

Cost assessment and uncertainty Supporting Document

Chapter: Two

Question 1: Do you agree with our assumptions for real price effects and ongoing efficiency?

National Grid response:

NGET capex

Our forecast capital expenditure (capex) costs are not just efficient but will also be challenging for us to deliver. Due to the commercial confidentiality of capital unit cost data, we have provided a confidential Supplementary Information document to set out our response in full. In summary:

- **Ofgem has chosen a scenario for efficiency savings that double-counts our built-in construction efficiencies**

- **There are material errors in the analysis, and the consultants' capex benchmarking process has not met Ofgem's own standards**

In making their Initial Proposals, Ofgem has included efficiency savings of £281.4m on our load-related baseline allowances and £483.8m on our non-load related baseline allowances. This has been done based on Ofgem's assessment of their engineering consultants' benchmarking.

These proposed cost efficiencies are in addition to the £258.6m of load-related and £266.1m of non-load related construction efficiencies that we built in to our March 2012 submission at a scheme level.

We have reservations regarding the quality of the consultants' analysis. These concerns can be summarised under two main headings:

1. Errors – the analysis contains a number of mistakes and inconsistencies. For example:

- The consultants do not differentiate between GIS and AIS high voltage switchgear costs. This is counter to previous discussions with Ofgem, external benchmarks and benchmarks provided by Ofgem as part of the TPCR4 Rollover process.

- The consultants' comparisons with historic unit costs do not appear to take account of changes of definition since TPCR4+R, and in the case of switchgear units they have applied incorrect volume weightings to AIS and GIS switchgear to produce misrepresentative comparisons.

- There are inconsistencies between the bottom-up assessment of scheme costs and the 'Ofgem level' unit cost comparisons for the same schemes.

2. Poor process – the benchmarking approach adopted does not meet Ofgem's own stated requirements for transparency and robustness. This issue is explained by the Professor of Industrial Economics from the School of Business and Economics,

Loughborough University, in the attachment titled “Benchmarking Procedures in RIIO for National Grid”. Relevant examples are listed below.

- By far the largest reduction is associated with switchgear ‘lead asset’ spend. In Pöyry’s bottom-up analysis of non-load related schemes, they did not review a single circuit breaker replacement scheme; circuit breaker replacement makes up over £700m (or 60%) of our non-load related forecast expenditure.

- In order to benchmark, it is absolutely essential that costs are compared for the same scope (equipment and activities). We know from a preliminary meeting in March 2011 that there was significant variation in interpretation between ourselves, the Scottish TOs and the consultants. Given the wide range in reported costs and discussions during cost visits, we still have scope issues.

- The bottom-up assessment of scheme costs is far from transparent. Consultant costs are only provided for a subset of units, and there is then a balancing figure to get to their total scheme estimate which is not explained at all.

- Due to the different nature and size of the three TOs’ networks, there are many units for which the Scottish TOs have not provided a cost and, even where they have, the different scale of business plans mean that these might be based on statistically-insignificant sample sizes (or, in one case, no projects at all).

- For cable replacement in tunnels, the consultants have based their reductions on a small sample of projects which happened to be atypical. We have provided further information to demonstrate that our March 2012 submission was reasonable.

Ofgem has taken the consultants’ benchmarks and applied them as cost efficiency adjustments against the NGET submission. Ofgem has used a scenario for load-related transformer projects and the majority of non-load related projects which ignores (effectively double-counts) the construction efficiency which we built into our business plan.

Based on the issues raised above, we challenge the starting values of the consultants’ benchmarks. In order to accept that the benchmarks are comparable, we need the consultants to provide the related scope of works for each of their Upper and Lower Boundary values and the inferred median value. As this data was not made available as part of the Initial Proposals, we have not been able to respond fully and would welcome ongoing discussions between now and Final Proposals.

Regardless of the appropriateness of these benchmarks, we strongly challenge the lack of recognition of our built-in construction efficiencies.

NGET opex

Although the Initial Proposal allowances for Real Price Effects (RPEs) and efficiencies have clearly been set following some detailed review of historical data and an averaging of the latest UK economic forecasts, some key assumptions and their application to transmission give rise to concern.

Our comments focus on:

- **Pay comparison to Fast Track outcome**: Pay growth assumptions for NGET and NGGT which are half that of the RIIO Fast Track outcome introduces worrying incentives for our staff, which would have a knock-on impact for costs and productivity within the RIIO-T1 period if applied

- **Lack of energy sector pay comparison**: Basing real pay growth in the short term on private and whole economy forecasts rather than energy sector levels is inappropriate

- **No account of civils RPE**: the impact of civil cost RPE on the overall plant and equipment RPE has been ignored
- **No justification for NGET catch up efficiency**: Basing catch up efficiencies on TPCR4 performance for NGET has no justification, ignores consultants' recommendations and reverses decisions on the efficiency of overspending NGET TPCR4 allowances made in Rollover
- **ITOMS evidence:** Providing new evidence for why NGET TO is operating at upper quartile level of efficiency in ITOMS which proves limited, if any, catch up efficiency is required
- **No justification for NGGT catch up efficiency**: NGGT catch up efficiency has no sound basis and ignores benchmarking evidence.

The sections below outline our concerns in these areas and others with evidence for why the proposals give rise to issues and ways that these should be rectified. Included within these sections are references to work we commissioned with Oxera to perform independent assessments of the efficiency assumptions within the Initial Proposals documents and related consultant reports. The reports that are referred to have been sent to Ofgem as separate documents: 'A review of Ofgem's RPE and ongoing efficiency appendix' and 'Productivity, efficiency and growth'.

Pay RPE (specialist):

Within the National Grid RIIO-TI and GD1 submissions we differentiated pay growth between our Gas Distribution and Transmission networks by giving evidence for a premium reflecting the more specialist nature of staff within critical Transmission roles. There are three main reasons why a higher pay growth assumption should be applied to specialist skills:

- There is a fundamental disequilibrium between supply and demand for these skills, as evidenced by our current vacancy levels and by pay levels and movements in resources with these skills outside National Grid
- This is reflected in historical growth rates in the relative pay of the relevant staff (see the relevant BEAMA index below)
- Ofgem is assuming higher rates of pay growth for the Fast Track outcome despite the fact that we are disproportionately affected by this pay growth premium because of the relative concentrations of these staff in our business (both in the TO, which applies equally the Fast Track outcome, and in our SO function)

The Initial Proposals dispel this evidence stating that: "*we have assumed the same labour RPE across the GDNs, NGET and NGGT as we do not consider that the growth in wages for these industries will be materially different*".

This, however, is inconsistent with the approach taken by Ofgem for both the Fast Track outcome for RIIO-T1 and DPCR5 where a specialist premium was allowed giving rise to higher pay growth in both of these outcomes than assumed in the Initial Proposals. By inference the Initial Proposals therefore place pay growth in NGET and NGGT in line with that in the GDNs, rather than that in the inherently closer industries of Scottish Transmission and Electricity Distribution.

[Text deleted]

Pay RPE (general):

As mentioned above we are broadly happy with the Initial Proposals forecast of 1.4% per annum for long term average pay growth for general staff as it is broadly in line with our assumptions, however, the Initial Proposals forecast a longer, deeper recessionary impact on pay early on in the RIIO-T1 period than we forecast, setting inappropriately low values between 2011/12 and 2013/14.

The lower level of real wage growth than the trend of the last 30 years is based on the uncertain economic outlook, which is understandable. Nevertheless this affects different sectors in different ways and there remain pockets – such as the motor industry – experiencing high growth. Jaguar Landrover's most recent pay review was at 5.5% and they are likely to continue with increases of this magnitude for the next couple of years as competition for skilled auto people continues to increase. Jaguar Landrover's situation is analogous to ours with a large proportion of specialist skills required which are in short supply in the market.

In view of the differences between sectors, it is not credible to take either a Private sector or whole economy view to assess wage increases which are going to affect National Grid. A more comparable data set should be used for this assessment such as the energy and process market used in our Trade Union pay negotiations and referenced in our benchmarking in this started.

Our concerns regarding these forecasts are for the following reasons:

- ***Energy sector peer group***: The Initial Proposals figures for 2011/12 are based on ONS data from the AWE for the private sector economy, whilst the forecasts for 2012/13 and 2013/14 are based on HM Treasury forecasts from May 2012 for the whole economy. This is opposed to having any reference to pay growth within the energy sector which is a more appropriate peer group to link networks' pay growth to because the sector is subject to different economic pressures compared to the whole economy.

  In the benchmarking report Hay Group provided for us (included as part of our RIIO submission) they state that "…*it is certainly an option to use a very general 'all organisations' market as the comparator group. This, however, would include many organisations which have nothing in common with National Grid*" When you are reviewing a short period of time (rather than a long term average) as the Initial Proposals are doing for 2011/12 to 2013/14 these differences in economic pressures become magnified and will have a skewing impact on the pay outcomes.

  Ofgem has selected an appropriate comparator group for their efficiency assumptions, rather than using whole economy assumptions which would be lower than those assumed for our industry. They have, however, not done similar in the area of pay where the impact would be to increase the assumptions. This is an inconsistent approach which should be rectified by using the energy and process comparator group for assessing pay in the first three years.

- ***Whole economy versus private sector***: For 2012/13 and 2013/14 the basis for the Initial Proposal forecasts revert from private sector to whole economy. This is justified by the statement that "*Historically there has been no systematic difference between private and whole economy wage growth".* Data seems to back up this statement over the longer term but the crucial difference for these two years is that it is a short period of time and on this basis - like between different industry sectors - differences do occur.

  Over the next two years we agree there is going to be lower pay growth than long term average but this is likely to be weighted towards the public, rather than private sector, as it has been over the last few years. According to ONS figures public sector pay makes up 20% of whole economy pay, with private pay making up the other 80%. Assuming public pay growth is expected to zero across the next two years - and hence drives the below RPI growth forecasts within the Initial Proposals - private sector pay growth is actually 1.18%[13] higher than the Initial Proposals presume.

This assumption is backed up by the forecasts of the Office of Budget Responsibility (OBR) which we pointed out before Initial Proposals were published as shown by the table below. This forecast also shows higher figures for 2011/12 than the Initial Proposals:

% RPE[14]	2011/12	2012/13	2013/14
HMT (May 2012)	N/a	(0.9%)	(0.2%)
OBR (March 2012)	(2.6%)	(0.6%)	1.2%

The Initial Proposals do consider and state that "..*the difference in the impact on totex by applying the two forecasts is not material"* however by our calculations using the OBR forecasts would add over £100m of totex in Transmission alone over the RIIO-T1 period which is a substantial figure and should be adjusted. At present this is another area in the Initial Proposals where data has been 'cherry-picked' to give the least possible allowances without reference to the most likely outcome.

Plant and equipment RPE

Within the submissions for NGET and NGGT this category includes costs for both machinery and civils work (for example scaffolding and concrete used on cable tunnel builds). We agree with the data sets used to assess the machinery RPE element of the category but are concerned that the civils element included in this category is not considered at all. Whilst this cost is linked to machinery (hence included in the same category) it is subject to different price drivers, so an assessment of price movements in this expenditure needs to be factored into the forecasts. Without this the forecast is skewed towards the machinery element of the expenditure.

There are two potential methods that could be used to factor in price movements in the civils element of expenditure:

- The work within this category is very similar to the work covered by the FOCOS resource cost index which has been used to forecast civils related opex RPE in the Initial Proposals which average 1.6% per annum, as opposed to the -0.8% per annum currently assumed for plant and equipment. The main difference in cost nature between the civils work for opex and capex is just that one is capital in nature and the other is opex in nature. The forecast from the FOCOS index could be included into the historical unweighted average of the PAFI indices currently used for equipment and plant to give a less skewed forecast.
- Long term average price rises from the BCIS indices which capture the resource cost of infrastructure materials and construction (non-housing) materials could be factored into the unweighted average currently used. These indices were referenced by First Economics in their RPE report in the civils area and (we assume) have fed into the Fast Track outcome for the Scottish TOs therefore their inclusion would not be a departure from any precedent already set. Again these forecasts show RPE increases over the period, as opposed to the reductions currently assumed in Initial Proposals. In this case the long term RPE increases over the last ten years of approximately 2% per annum.

One of these two routes should be taken to adjust the forecasts in plant and equipment

[13] Based on pro rating calculations
[14] Using forecast RPI of 3.1% for 2012/13 and 2.7% for 2013/14 in line with Initial Proposals

otherwise the RPEs are not indicative of all the costs within the category.
In summary, FOCOS or BCIS resource cost forecasts for civils should be factored into the plant and equipment assumptions to reflect this element of plant and equipment prices we will be exposed to over the next eight years

NGGT capex materials

The Initial Proposal forecasts for NGGT capex materials are based on the BCIS data for steelwork used in civil engineering. This same index is used to represent the exposure that the Gas Distribution Networks (GDNs) have to steel prices. Using this index may reflect the exposure for the GDNs but it cannot be translated across to NGGT due to the different nature of the steel structures used for general civil engineering compared to Transmission pipelines and the necessary difference in grade of steel.

There are limited worldwide suppliers for steel pipes with the diameter required for Transmission purposes which has an impact on the related prices. The BCIS data will also pick up a range of grades of steel across different civil engineer works, whereas the steel grade used for Transmission pipes is at the highest end of steel manufacture and therefore attracts higher price rises. This premium should be reflected in the RPE assumptions.

One way of incorporating this premium into the forecasts is to consider other indices which better represent the Transmission grade of steel. There is unlikely to be an available index which fully reflects the niche nature of this work but rather than solely using the BCIS data set which skews the projections away from Transmission grade of steel ONS data showing the cost of iron and steel could be used in tandem. Indices[15] of this nature were reviewed by First Economics in producing their RPE report for the Transmission companies which showed a long term RPE forecast of at least 2% per annum. Certainly reviewing historical values for these indices show long term price rises (including RPI impacts) of 6% and 9% per annum respectively. Removing RPI at ~3% this represents RPE price rises of 3% and 6% which are both higher than the Initial Proposal forecasts.

Whilst this incorporates direct commodity costs into the forecasts rather than just construction indices it will introduce a more balanced outcome, which is better aligned to the price pressures that we face. Such an adjustment should therefore be made as the current alignment of RPE between the Gas Distribution networks and Gas Transmission in this area is not an accurate reflection of the price pressures involved given the historical impacts for Gas Transmission and levels of cost increase seen in steel price.

In summary, Initial Proposals use general civil engineering steel forecasts, rather than those which incorporate long term historical averages for steel price rises we are exposed to. These steel price forecasts should be factored into the forecasts for the RIIO-T1 period, increasing the future RPEs.

Efficiency

We have a number of concerns in relation to the efficiency assumptions applied within the Initial Proposals. These split into two main categories regarding the:

- Evidence for assumed ongoing efficiency levels (i.e. the ‘frontier shifts’ of 1% per annum for opex and 0.7% for capex)
- Application of these assumptions and evidence for ‘catch-up’ efficiency to our NGET TO and NGGT TO forecasts

Whilst this question specifically relates to the ongoing efficiency the two areas are so intrinsically linked that we discuss both areas in this section. In summary, the main concerns

[15] K3X4 EU imports and K3X5 non-EU imports

we have are that:

- The Initial Proposals incorporate opex efficiency assumptions of 2.25% per annum for NGET TO and 1.5% per annum for NGG TO which are not justified by the evidence provided. These figures are significantly above Ofgem's assumption for ongoing efficiency of 1% per annum, suggesting targets for catch up efficiency of 1.25% per annum for NGET and 0.5% for NGG.
- In the case of NGET the 2.25% per annum was proposed by Pöyry as the highest range of efficiency, but this was based on the assertion that 1.5% per annum, not 1% per annum (as assumed by Ofgem), is the level of ongoing efficiency of a frontier company. At the very least the efficiency assumption should therefore be reduced to 1.75%, but in reality the reduction should be higher because the reason given for the higher efficiency levels is that we overspent opex allowances in the TPCR4 period. This reverses a decision at the TPCR4 Rollover when Ofgem agreed that we had to undertake this expenditure to both maintain network outputs and to renew and grow our workforce in advance of the RIIO-T1 period.
- For NGG the application of a 0.5% per annum assumption for catch up efficiency is based on no evidence at all. We are the frontier company in the Gas Transmission Benchmarking Initiative (GTBI) showing that we are already exhibiting the costs of an efficient company. This evidence has been ignored in the assessment of efficiency and instead what limited justification provided for the catch up refers to extra efficiencies from IS investments. This logic is unsound because the Initial Proposals disallow a large proportion of the IS investments, reducing any benefits that would apply.
- Using our proposed efficiency levels as a comparator to justify efficiency levels is not valid because the efficiency definitions in each are not like-for-like and become even less so as soon as upward cost pressures are disallowed from the expenditure
- Some of the analysis used by Ofgem to demonstrate 1% as the ongoing efficiency target is questionable, including the timeframes used in assessing the ongoing efficiency assumptions and double counting of efficiencies.

These are expanded on in the sections below which consider the efficiency assumptions for NGET and NGG TO separately and then discuss the assessment of ongoing efficiency.

NGET TO

The Initial Proposals incorporate opex efficiency assumptions of 2.25% per annum for NGET TO direct and Closely Associated Indirect (CAI) opex. Assuming the 1% ongoing efficiency figure as proposed by Ofgem is valid then this suggests we should exhibit 1.25% per annum catch up efficiency throughout the RIIO-T1 period. This 2.25% per annum assumption was proposed by Pöyry within their low case assumption for allowances informed by two main items:

- Our statements that we have delivered over 2.5% year-on-year efficiency during the TPCR4 period and have embedded between 2.2% and 2.5% per annum efficiency into our forecasts
- Pöyry's view that ongoing efficiency levels should be 1.5% per annum for a frontier company

Ofgem then add to this assessment in their Initial Proposals document by stating that: '*NGET have consistently overspent (or forecast to overspend) in the TPCR4+R period and therefore we believe an element of catch up efficiency is required.*'

This section discusses each of these assumptions in turn to give evidence that the 2.25% per annum figure assumed is too high, with this detail informed by work undertaken with Oxera.

Our efficiency statements:

There are two reasons why the efficiency figures we quoted in our submission are not directly comparable to the figures proposed by Pöyry and Ofgem, and why they cannot be used as justification for the higher efficiency percentages, these are:

- Differences in the calculation used
- Impact of disallowed workload

This section takes each in turn and gives the equivalent figure to that proposed in the Initial Proposals.

The efficiency figures we quoted for both the TPCR4 and RIIO-T1 periods were calculated based on a different method than Pöyry use in their figures. We included efficiencies which were or would be delivered by economies of scale within our figures. For example, as our asset base is growing we recognised that the cost per unit would reduce overall because, whilst there would be an increase in opex required, it would not be linear to the cost driver (in this case asset numbers) as the growth would enable more savings to be delivered.

Having worked with Oxera on links between productivity and efficiency (see linked paper on 'Productivity, efficiency and growth') we now recognise that we should have expected an element of scale economy to apply and by including this element within the efficiencies figures we overstated them. Oxera point out that it is assumed that regulated entities have an element of fixed costs which would not vary with the size of the relevant driver (in this instance asset numbers) so that the fixed cost can effectively be absorbed over the higher figures for the relevant cost driver.

Oxera use a partial productivity measure called Real Unit Operating Expenditure (RUOE) to calculate what costs should be assumed based on growth of a cost driver which factors in an economy of scale assumption. This economy of scale assumption would vary by company / sector (as the proportion of fixed costs would vary) but based on specific studies on Transmission would be in the range of 0.6 to 0.9 (i.e. that for a 10% increase in the relevant cost driver rather than unit costs expected to increase by 10% as well, they should be assumed to increase by 0.6 to 0.9 multiplied by this being 6 to 9%). For direct and CAI opex which are closely linked to growth drivers Oxera note that the assumption would be closer to 1. For these purposes we have used 0.9. This is explained further in the Oxera document.

Reflecting this expected economies of scale assumption into our forecasts and using the same basis of efficiency as Pöyry use adjusts the headline efficiency figures between 2010/11 and 2020/21 for direct and CAI opex down to between 1.2% and 1.6% from the 2.2 to 2.5% per annum figures originally quoted. This represents a like-for-like comparison against the 2.25% per annum figure used within the Initial Proposals. It is quoted as a range here due to variances between direct and CAI opex figures.

The second point in this area is that the impact of disallowed expenditure in the Initial Proposals impacts on the efficiencies we quote. For example tower painting costs have been reduced significantly and several of our efficiencies were focused on minimising the costs in this area. Once costs have been disallowed the efficiencies included within that activity are superseded so cannot be included in the comparable figures.

As Pöyry note in their report in relation to why the outcome of their case 1 assumptions are lower than our plan despite the headline efficiency numbers being similar: '*It is not wholly clear why this has occurred, but it may relate to adjustments made to specific items where (sic) much higher levels of spend have been proposed by NGET, or potentially to the method by which the rates have been applied to activities and cost."* The explanation above shows that it is both of these points that give rise to the difference. Given Pöyry have noted this difference their (and Ofgem's) use of our quoted efficiency factors as justification for the Initial Proposal levels is misleading.

The difference between Initial Proposals and our assumptions to which Pöyry refer is also impacted by double counting of over £30m of efficiencies within Pöyry's calculations for planned maintenance. This is explained further within the planned maintenance section of direct opex in response to question 3 below.

In addition to these points, one of the reasons why we incorporated the higher efficiency levels was due to the specialist real pay growth assumption used in our RPE forecasts. As noted above this has not been allowed within the Initial Proposals so again, using the efficiency figures we quoted for a comparison to those used in the Initial Proposals is misleading.

Pöyry's view of ongoing efficiency:

Whilst the previous section explains why using our quoted figures for efficiency to justify the efficiency assumptions in Initial Proposals is misleading, the rate applied may still be right. The next sections show why a catch up efficiency assumption of 1.25% per annum is not appropriate for NGET TO. This section considers Pöyry's assumptions in this area.

As stated above Pöyry's worst case assumption for the appropriate level of efficiency for NGET TO is 2.25% per annum which has been used in the Initial Proposals. In relation to the 1.5% per annum efficiency assumption used for their case 2 Pöyry state that this: '*represents a more long term aspiration for a company clearly operating at an efficient level.'* This is equivalent to Ofgem's definition of ongoing (or long term) efficiency which is used in the RPE and efficiency appendix to the Initial Proposals and has been used to mean 'frontier shift' in previous price control reviews. This ongoing efficiency represents the productivity improvements a company at the frontier (i.e. proven to be efficient) should demonstrate due to continuous improvement.

Using this 1.5% per annum figure as the ongoing efficiency means that Pöyry are proposing that a maximum of 0.75% per annum of catch up efficiency should be applied to our costs. This is 0.5% lower than the 1.25% per annum which is applied within Initial Proposals using Ofgem's assumptions for ongoing efficiency.

Rebasing the ongoing efficiency assumptions back to the 1% per annum figure quoted by Ofgem and using Pöyry's highest case for catch up efficiency of 0.75% per annum shows that the efficiency assumptions used for NGET TO should at least be adjusted down to 1.75% per annum. Without this adjustment Ofgem are ignoring the views of their consultants in this area despite quoting in the Initial Proposals regarding efficiency that they: '*agreed with the consultants' proposals'*. This reduction in efficiency value that should be applied is before any discussion on the justification for the 0.75% per annum catch up efficiency assumption Pöyry have proposed.

TPCR4 overspend

Within Initial Proposals the reason Ofgem give for incorporating the 2.25% per annum efficiencies despite it being higher than the 1% per annum figure quoted in their RPE and efficiency appendix is that: '*NGET have consistently overspent (or forecast to overspend) in the TPCR4+R period and therefore we believe an element of catch up efficiency is required.'*

Whilst we acknowledge that part of the cost assessment methodology under RIIO principles is to review past performance, the fact that we have overspent allowances is not a barometer of our past performance. Performance should be assessed based on the outputs delivered for the expenditure, rather than purely a view on costs spent. Currently this 'cost only' assessment is divorced from any view of outputs delivered or totex efficiencies delivered.

We explained the reasons for overspending allowances within the 'TPCR4 review' annex of our submission. Each of these reasons either maintained outputs delivered (which otherwise would have deteriorated) or produced totex efficiencies factored into our plan going forwards. With no opex sharing factors in the TPCR4 period all of this overspend has been at our shareholders' expense. These reasons for overspending were mainly due to:

- Changes in asset management strategies during the period which increased opex but reduced totex costs considerably
- Workforce renewal and growth costs to recruit and train resources in advance of RIIO-T1 workloads
- One-off costs for reorganising our business support functions
- The impact of risks identified to Ofgem at the time of the TPCR4 outcome which materialised during the period such as higher costs for RPE in fuel, painting and electricity

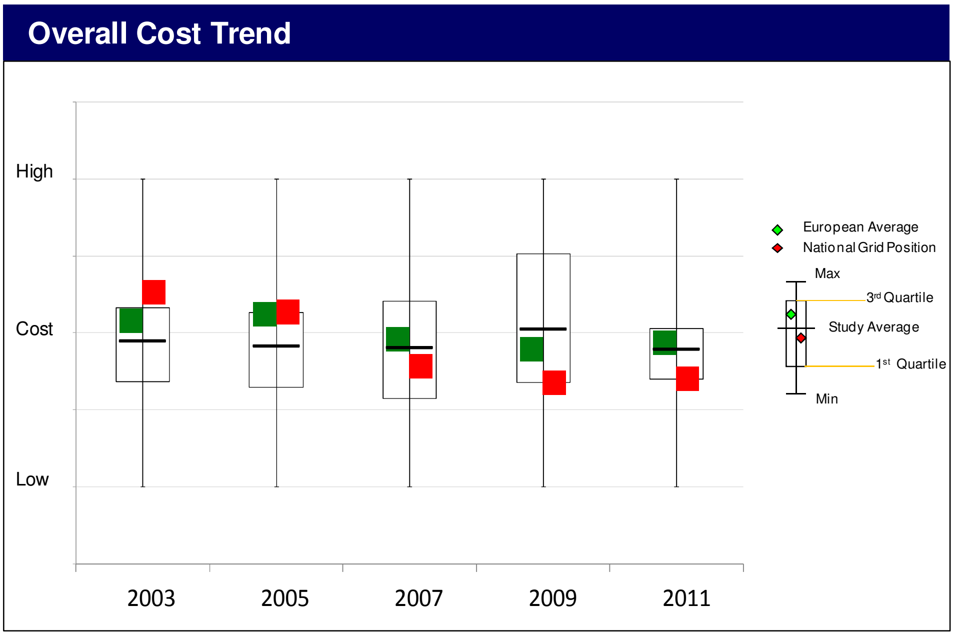
In addition, we explained these reasons in detail to Ofgem after the Initial Proposals for the TPCR4 Rollover. Within the TPCR4 Rollover Initial Proposals there was an additional efficiency assumption included in allowances but, based on our reasoned explanation for the overspend in the TPCR4 period, this additional efficiency was reversed for the final proposals. Including a catch up efficiency in the Initial Proposals for RIIO due to this overspend is therefore reversing this Rollover decision.

Including such an assumption means that Ofgem are using the TPCR4 allowances as a proxy for the efficient level in the period. Whilst this may have been the case at the time the allowances were set (although we did not believe this at the time as we only accepted the proposals 'in the round') changes during the period – such as the emergence of sustainability on the political agenda – alter this position. If past performance is to be assessed as part of the RIIO review then the outputs and efficiencies delivered from the extra expenditure need to be taken into account.

It is pertinent to reflect on the consistency of this point raised by Ofgem. During the TPCR4 period we have under spent our capex allowances for ETO, so based on this statement used for opex we should be praised for efficient delivery. On the contrary Ofgem are using data to question our performance during the period. At least in this case Ofgem are assessing the outputs as well - or inputs as a proxy for outputs – although as proven elsewhere in this response the logic used is unsound.

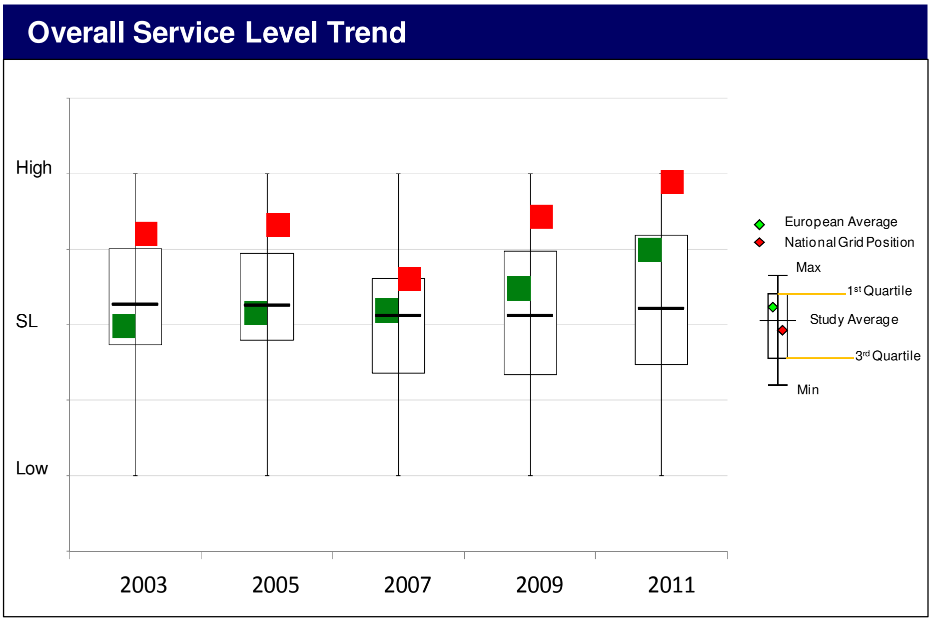
As a final point in this area it is worth discussing our benchmarking results in the International Transmission Operations and Maintenance Study (ITOMS) during the TPCR4 period and before. The graph and summary from UMS (ITOMS independent facilitator) below shows that our performance in the opex benchmarking has been improving over the TPCR4 period, which runs counter to Ofgem's assumption that the overspend has been inefficient (which would suggest deteriorating efficiency). This graph plots our cost position within the study once results from all cost areas are consolidated (red square) versus the average (middle line) and European average (green square) positions:

Composite ITOMS cost results trend



This shows that our efficiency has improved from below average level to first quartile, well above the European average. This improvement has come with an average increase in performance (reliability) as shown by the next composite graph:

Composite ITOMS performance results trend



The independent report these graphs are taken from is included below:

High Level Composite Trends.pdf

ITOMS evaluates transmission company maintenance performance in terms of customer service level or reliability and cost. Both areas are obviously important to the customer and it is important to understand the relationship between these two areas. The best performing companies get the balance right between cost and performance, achieving high reliability whist providing value for money in a sustainable way. Therefore it is the balance between these two metrics which should be taken as being the result, rather than the specific cost position.

The journey of one of the longer term participants is a good case example of what can go wrong when cost is seen as the only metric for performance measurement. This particular company made the decision to strategically under invest in Transmission maintenance and asset replacement, convinced that 'transmission' would not be a critical part in the future of energy delivery. For a period of time this company's ITOMS results looked very good, being at the best performing frontier, however this position was not sustainable and asset reliability deteriorated, to the point that its reliability caused major customer dissatisfaction with power cuts and increase cost of energy due to transmission constraints. This company has subsequently been on a long and costly journey to improve its standing.

Overall our ITOMS results are at or near to the best performance and cost frontier, with a sustainable balance between cost and performance. 9 out 12 of the plant areas are on or close to this frontier as shown by the blind copy report included as part of our submission. The composite graphs (above) show our cost performance is first quartile. Given the inherent comparability issues with benchmarking studies (see for example the supplementary information document: 'NGET_asset_painting' submitted as part of our response) we take this first quartile position as showing limited, if any, catch up efficiency is required. This is in line with conclusions from other benchmarking that Ofgem has performed in the areas of business support and for Distribution companies where upper quartile performance is used to set the benchmark.

Evidence for catch-up efficiency

Although the reasons given by Ofgem for incorporating catch up efficiency are unsound there is still a question to answer as to whether there is evidence for catch up efficiency in NGET TO, and if so, how much.

Within our submission we acknowledged that there was some catch up efficiency we needed to incorporate in our plan, mainly in the business support area but also in the direct and CAI activities. This direct and CAI catch up was required due to organisational improvements identified by HayGroup when they reviewed our structure, for which we incorporated spans and layers organisational efficiencies into our plan based on the HayGroup review as explained in our submission.

Whilst we recognise the need for some catch-up efficiency, the level embedded into the Initial Proposals is overstated. If this assumption is to be believed then we are currently inefficient by over 13%.[16] This is a significant gap which has not been justified by any evidence. ITOMS shows we are close to the frontier in performance and are within the upper quartile for costs. This is even before any non-normalised costs such as environmental factors (as explained more in the supplementary information document: 'NGET_asset_painting') have been adjusted for.

In conclusion, the evidence provided for the NGET TO efficiency assumptions is very limited and founded on both unjustified comparison to our own quoted figures and assessment of performance in the TPCR4 period. Whilst we acknowledge that based on 2010/11 costs there is some requirement for catch-up, the level proposed is overstated and based on no evidence. At the very least the assumptions should be reduced to 1.75% per annum by using Pöyry's assessment, but in reality this should be reduced further to at most 1.4% per annum which

[16] Once the 1.25% per annum figure is compounded over ten years

would represent catch up and growth efficiency of 0.4% per annum. This is both half way between the two cases Pöyry proposed (of 0% and 0.75% per annum catch up) and the 1.2 – 1.6% per annum embedded into our plan.

NGG TO

The Initial Proposals incorporate opex efficiency assumptions of 1.5% per annum for NGGT TO direct and closely associated indirect opex. Assuming the 1% ongoing efficiency is valid then this suggests we should exhibit 0.5% per annum catch up efficiency throughout the RIIO-T1 period. There is no evidence provided for any level of catch up efficiency in the Initial Proposals or Pöyry's related report, let alone 0.5% per annum, indeed on the contrary there is strong evidence we are already at the frontier. The evidence that has been included for why this high level of efficiency has been applied is based on:

- Our statement that 1.3% per annum efficiency has been embedded into our plan
- Ofgem's statement that we are: *'investing in new IT systems in RIIO-T1 and therefore should be able to drive out increased efficiencies above those already identified.*'

Ofgem do note that the 1.5% per annum is lower than a 2% per annum suggestion from their consultants.

This section discusses each of these assumptions in turn to give evidence that the 1.5% per annum figure assumed is too high.

Our efficiency assumptions

Within our submission, as noted by Ofgem, we embedded 1.3% per annum efficiencies into our plan; however this figure has been impacted by the economies of scale assumptions which affected the stated NGET efficiencies too. This impact is not as large on NGGT TO as it is on NGET TO but once the economies of scale factor is removed from the efficiencies figure it drops to 1.1% per annum.[17] This is then the equivalent figure to that proposed by Ofgem.

Impact of IS systems

Ofgem's justification for increasing the efficiency targets for NGGT TO is that we are investing in new IT systems which would generate efficiencies above those already in the plan. This is not a pertinent argument because firstly, as discussed further in response to question 3 below, IS capex has been significantly reduced and secondly, the impact of technology improvements is already included in the ongoing efficiency assumption and our efficiency forecasts.

By disallowing 35% of the IS capex for TO in the Initial Proposals Ofgem are reducing any benefits from these programmes, therefore even the benefits we embedded into our plan - let alone any extra benefits Ofgem think exists - are at risk. Using these investments to justify a higher efficiency level is therefore inconsistent.

The other point to note in this area is that the majority of our proposed IS investments in the RIIO-T1 period are for asset refresh purposes. Such investments maintain the current business capability we have by ensuring that the IS systems are reliable, rather than improve our business capability which would produce benefits, only some of which would be in terms of financial savings as opposed to output (reliability, safety) benefits.

The financial savings from our planned IS system investments are already included within our

[17] On this basis there could be said to be a 0.1% per annum level which could be badged as catch up efficiency but this is more a function of our comparators for ongoing efficiency level than by design

efficiency forecasts (as explained within the 'IS investment descriptions' annex) so adding extra efficiencies due to these adjustments is double counting. In addition, savings from technology improvements (which includes these IS investments) have already been factored into the ongoing efficiency assumption of 1% per annum. This is because the comparator industries used for calculating this ongoing efficiency assumption will have invested in technology to improve their performance in the same way we are planning to.

Evidence for catch up efficiencies

In their report Pöyry propose a 2% per annum efficiency level which equates to 1% per annum catch up, whilst Ofgem reduce this catch up efficiency target to 0.5% per annum. Both of these proposals are based on no factual evidence of a requirement for catch up at all.

Pöyry's report mentions our quoted efficiency levels delivered within the TPCR4 period, but as discussed above we now recognise that these were overstated and not on a like-for-like basis. The report also mentions that water companies have been targeted with 1.5% per annum and the GDNs achieved 5% per annum efficiencies post Network Sales. Both of these comparators are not valid either. The water companies target includes an element of catch up efficiency proven through benchmarking whereas there is no proof of catch up requirement in NGGT TO. Similarly the GDN's efficiencies were, as stated within our submission, delivered in a period just post a step change in industry structure in a stable operating environment. This is similar to catch up efficiency.

From an NGGT TO perspective there is no evidence for catch up requirements. We are the top performers in the Gas Transmission Benchmarking Initiative being top quartile performers in all opex elements of the review. This is as evidenced by the Juran report included within our submission. Therefore we question why any catch-up efficiency has been included within the Initial Proposals and suggest that this position is reviewed.

In conclusion, there is no evidence of catch up efficiency requirement within NGGT TO and use of our forecast efficiency levels to justify 1.5% per annum efficiency targets is misleading. The efficiency assumptions should be reduced to at most 1.1% per annum, removing the catch up efficiency level included within the Initial Proposals.

Ongoing efficiency

We have several concerns with the efficiency assumptions which apply equally to both NGET and NGG. These concerns relate to the validity of the 1% per annum ongoing efficiency assumption. While the appropriate level of ongoing efficiency is clearly a 'grey' area, there are two pieces of evidence which suggests that the ongoing efficiency assumptions are high. Our evidence is as follows:

- There has been a reduction in productivity growth in the UK over time which has been ignored by the Initial Proposals
- Efficiencies are double counted by using historical UK comparator data, a notion accepted in other regulatory outcomes by Ofwat, ORR and the Competition Commission

These are expanded on below:

- **UK economy slowdown**: There has been a general slowdown in the UK economy over the last forty years which is not reflected in the 1% per annum assumption. Ofgem use data from 1970 to 2007 to set the efficiency level but the applicability of 1970s and 1980s data to productivity today is questionable. A decade-by-decade breakdown of the productivity figures from EU KLEMS shows that this figure would reduce if a shorter timescale is used. A ten year period, more reflective of current productivity levels, should be applied instead.

- **Efficiency double count**: the historical UK comparator data used to set the ongoing efficiency rate represents industry average productivity, which contains an element of catch-up efficiency as well as ongoing efficiency. The catch-up element needs to be removed, just leaving the frontier shift element of productivity, before this is applied as ongoing efficiency. This principle was agreed by the Competition Commission in the Bristol Water inquiry.

  The IP argues that the double count adjustment does not need to be made because "…*we have excluded industries (namely utilities) from our comparator set where we would expect there to be systematic catch-up*".

  It then continues: "…*for our comparator industries, we consider that the historical change in productivity is a good proxy for the movement in the efficient frontier. Consider if this were not the case. For example, if our historical productivity measures (i.e. based on Klems) were materially greater than the actual movement in the efficiency frontier over the same period, this would imply systematic convergence of all companies in all industries to the efficiency frontier. However, it is not clear to us that the distribution of companies' relative efficiency across all industries at the end of our data period should be materially different from the distribution of technical efficiency at the beginning.*"

  The first argument in the Initial Proposals is that there is no systematic catch-up in the comparator set. This view is not held by the Organisational for Economic Co-operation and Development (OECD), as demonstrated by the following two quotations from The Measuring Productivity Manual. Note that "efficiency change" represents catch-up in UK regulatory terminology.

  - The table on page 18 states that "*Conceptually, the KLEMS productivity measure captures disembodied technical change. In practice, it reflects also efficiency change, economies of scale, variations in capacity, utilisation and measurement errors.*"
  - "…*pure changes in efficiency (as opposed to shifts in the technological frontier) are common empirical phenomena.*"

  We note that not only the Competition Commission, but also Ofwat and ORR have accepted this point.

  Having demonstrated that catch-up is a widespread phenomenon, there remains the question of how large a proportion it represents of UK comparators' productivity growth. An academic study that examined the overall productivity performance of the UK economy found that, on average, 75% of the economy wide TFP growth is due to frontier shift (Fare, Grosskopf, Norris and Zhang 1994).

  An assumption that 25% of comparator productivity improvements are due to catch-up is also consistent with UK regulatory precedent. Based on a 2005 Oxera / LEK study, ORR in 2008 made a 25% assumption, and, although not entirely transparent, the Competition Commission appears to have made an adjustment of at least 20% in its Bristol Water inquiry.

  In addition to the empirical argument above, the second, higher level Initial Proposals argument was that if historical productivity were materially greater than the actual movement in the efficiency frontier, this would imply systematic convergence to the efficiency frontier – which was not credible. We agree that we would not expect systematic convergence to the frontier. However, neither would we expect relative efficiency for different organisations to be set in stone forever – which is the present assumption in the Initial Proposals. Instead, we would expect there to be changes in relative efficiency over time, with a continuous process of different companies innovating, advancing the frontier, and then being caught up, overtaken by another company innovating etc. This is a world of constant flux and differences in relative efficiency, rather than efficiency gaps being either set in stone or entirely removed.

On both a conceptual and empirical level we do not believe the Initial Proposals' position on this double count is right or reasonable. There is a 25% double-counting of efficiency gains within the 1% per annum figure based on a split between frontier shift and efficiency gain. This precedent was set by the Competition Commission review of Bristol Water where the EU KLEMS data was reduced down by 25% to reflect this.

In conclusion, the 1% per annum assumption should be reviewed in light of this information with a shorter timescale applied for the assessment and the 25% double counting of efficiency removed from the resulting figures.

Question 2: Do you agree with our proposed materiality thresholds of 1 per cent (subject to the efficiency incentive rate) for the majority of costs to be treated under the re-opener mechanism?

National Grid response:

We cannot see the justification for such high materiality thresholds, but in any case, Ofgem's financial modelling must take proper account of their materiality threshold and re-opener window proposals.

In our business plan, we had proposed the following materiality thresholds:

- NGET Critical National Infrastructure - 5% of the RIIO-T1 cost forecast ([text deleted])
- NGG Critical National Infrastructure - 10% of the RIIO-T1 cost forecast ([text deleted])

It should be noted that these thresholds were used in our risk and cashflow Monte Carlo analysis. Ofgem has indicated that they have made extensive use of this analysis.

Ofgem has proposed a much higher materiality threshold (taking the application of the efficiency incentive rate into account, this is approximately £30m for NGET and £12m for NGGT), but their financial modelling appears to ignore both the materiality threshold and the re-opener windows, and assumes that allowances change exactly as required.

We cannot see the benefit of such high materiality thresholds but, if Ofgem are unwilling to reduce this, it is crucial that the financial modelling takes proper account of the proposed uncertainty mechanism for CNI expenditure, including the re-opener windows and the materiality threshold.

We also note that Initial Proposals do not provide clarity on whether the threshold level will apply on an annual basis or whether incurred and forecast costs can be carried over from year to year with the total being compared with the materiality threshold. From the associated licence drafting, we are assuming that incurred and forecast costs can be carried over from year to year, but we would welcome confirmation of this.

Question 3: Do you agree with our proposal to restrict the re-openers for the roll-out of innovation to the two standard re-opener windows, ie 2015/16 and 2018/19?

National Grid response:

We agree it is appropriate that the two standard RIIO-T1 re-opener windows are used for the application of the Innovation Roll-out Mechanism. This is based on the assumption that the re-opener will allow the remuneration of both retrospective and future cost forecasts. However, it is not clear from the proposals as to whether the SO also has access to the Innovation Roll-out Mechanism (IRM). This element is particularly important for the SO as it has the capacity to create solutions with demonstrable and cost effective low-carbon or environmental benefits and thus meeting the criteria set out for the mechanism. We seek positive confirmation that the SO can access this funding.

Question 4: Do you have any other comments in relation to our approach to uncertainty mechanisms?

National Grid response:

General

- **As with the materiality thresholds discussed above, it is essential that Ofgem's financial modelling takes proper account of their uncertainty mechanism proposals.**
- **GB & EU market facilitation outputs will always be difficult to quantify and therefore a re-opener is the most appropriate and consistent uncertainty mechanism.**
- **We are concerned about the replacement of the Income Adjustment Provision with the specified Uncertain Cost term.**

NGGT specific

- **The initial, minimum-regret Front End Engineering Design (FEED) phase of IED work should be included in base funding with a re-opener for the main construction phase, similar to that proposed for Critical National Infrastructure expenditure.**
- **Ofgem has incorrectly applied the Information Quality Incentive to the movement of NGGT forecast expenditure (e.g. IED and Feeder 9) from base funding to uncertainty mechanisms.**

NGET specific

- **Flood & erosion protection will always be difficult to quantify and therefore a re-opener is the most appropriate and consistent uncertainty mechanism.**
- **If the cost of tower flood protection is to be disallowed, then the scope of the flood & erosion protection uncertainty mechanism needs to include both tower flood protection costs and contributions towards the Environment Agency's flood defence costs.**

General

As with the proposals for materiality thresholds described above, it is critical that the financial modelling correctly reflects the final decision on these uncertainty mechanisms.

GB and EU market facilitation

In our March 2012 business plan submission, we proposed a re-opener for GB and EU market facilitation (with a materiality threshold of £1m for NGET, and 10% (~£4m) of our forecast cost for NGG). This mechanism was used in our risk and cashflow Monte Carlo analysis. Ofgem has indicated that they have made extensive use of this analysis.

We understand that using the mid-period review is Ofgem's preferred option for GB & EU market facilitation uncertainty because of the lack of evidence around the type and quantity of outputs that we may be required to deliver in the first four years of the RIIO-T1 period.

We agree that there is a lack of evidence around the quantity of these outputs we will need to deliver. This is the reason for our uncertainty mechanism proposals.

In terms of evidence around the type of outputs that may be required, we share Ofgem's desire to define network requirements in terms of outputs rather than inputs but note that this has proved difficult in certain areas.

The primary output for GB and EU market facilitation could be argued to be customer and stakeholder satisfaction. As with other outputs (e.g. reliability), other leading measures or secondary deliverables are also required. Given that it is always going to be difficult to measure the output provided by a facilitation activity, because the impact of an individual change cannot be isolated given the lack of a counter-factual, the associated inputs will need to be agreed.

As with CNI, these inputs (rather than outputs) are likely to be specified by a third party and we will have an obligation to complete them. To illustrate this point, we have previously undertaken investment in our IS systems triggered by required improvements to cross-border balancing data (across Europe). This change was triggered by a legislated EU requirement and required alterations to several of our IS systems.

For this reason, it would be more appropriate for the GB and EU market facilitation uncertainty mechanism to be the same as for CNI (i.e. re-opener with specific windows and materiality threshold).

Income Adjusting Events

We are concerned about the removal of the general Income Adjusting Event provision from the licence and its replacement with a specified 'uncertain cost' term. Recent feedback from stakeholders has revealed concerns that they were not aware of the potential for this provision to be removed and do not support this approach, although one stakeholder did question whether the current materiality threshold was still appropriate. As communicated in previous meetings with Ofgem, with the extension of the price control period to eight years, there is an increased likelihood of events occurring within that period that could affect costs or benefits that we are unable to predict now. The general Income Adjusting Event term provides a method to address this.

Of more concern is the fact that the current Income Adjusting Event terms allow for third parties to question whether there should be an adjustment to our allowed revenue; this is a facility that has been utilised within the TPCR4 period. We note that the uncertain cost licence conditions which are intended to replace the Income Adjusting Event terms do not contain similar provisions and so the ability for a third party to question whether there should be an adjustment to our allowed revenue has been removed. This has not been consulted on in Ofgem's previous strategy documents and the effect on third parties is not specifically drawn out in Ofgem's Initial Proposals. We note that Ofgem do express concern that a general Income Adjusting Event is too broad and could be used in too many situations but we contend that this can be controlled by retaining the existing form of licence drafting that specifies a strict process for assessing requests. We note that Income Adjusting Events have only been raised twice in the TPCR4 period, with one occurrence being rejected. The general Income Adjusting Event provision should therefore be maintained.

NGGT

IED

The approach taken to IED-driven investment takes no account of the deliverability of such a significant programme of works ahead of the legislated deadline of 2023. Delaying this work until 2017 will render it undeliverable and consequently constrain the NTS from 2023 onwards. The minimum regret Front End Engineering Design (FEED) work should be included in base funding to allow the early stages of the projects to progress in a timely manner. If the full IED investment turns out not to be required, then the maximum regret associated with this step is considerably lower than the regret associated with delaying if the IED investment turns out to be required. Under this scenario, we would incur two years of significant constraints on the NTS.

The re-opener mechanism should be used for the construction phase of the works. The use of the first re-opener window would allow the main construction phase of the works to be completed in a timely manner.

Application of IQI

Ofgem's movement of funding that was requested as baseline (ex ante) in NGGT's RIIO-T1 submission into an uncertainty mechanism creates a penalty under the Information Quality Incentive (IQI).

Where it is clear that such a movement is as a result of a different legal interpretation (e.g. IED) or expectation of timing of planning consent approval (e.g. Feeder 9 replacement), rather than an alternative view of likely costs, a penalty should not apply and an adjustment should be made to unwind the impact these alternative treatments have on the IQI assessment.

The approach being proposed by Ofgem is not consistent with the March 2011 strategy decision document[18] which states (paragraph 6.30) that "It is important that the comparisons between company forecasts and our own cost assessment that feed into the IQI are made on a like-for-like basis. In particular, there should be consistency in the set of outputs that the expenditure contributes towards. This may require adjustments as part of the IQI calculations." This approach is not consistent with the approach taken with NGET, where no such penalty applies for a movement of expenditure from base funding into an uncertainty mechanism.

NGET

Flood & erosion protection

The arguments supporting the use of a re-opener mechanism for GB & EU market facilitation above also apply to the requirement to complete flood and erosion protection works or contribute to the cost of Environment Agency schemes.

Again, these works are very similar to the requirement to complete Critical National Infrastructure work in that inputs (rather than outputs) are being specified by a third party and we have an obligation to complete them. For this reason, it would be more appropriate to use the same uncertainty mechanism as for CNI (i.e. a re-opener with specific windows and a materiality threshold).

We note that there is an apparent contradiction with respect to the scope of the flood and erosion protection mid-period review of outputs. The 'Cost assessment and uncertainty supporting document' describes this as "contributions towards the Environment Agency's flood defence costs" [para 2.28] but then states that "There is a high degree of uncertainty over the work scope and cost for the tower flood protection forecast by NGET. Therefore we propose to disallow it from the ex ante baseline cost. We note that there is an uncertainty mechanism that can deal with this." [para 5.60]. We assume that Ofgem's intention is that the scope of the mid-period review of outputs would cover both Environment Agency contributions and tower flood protection costs.

[18] Decision on strategy for the next transmission and gas distribution price controls - RIIO-T1 and GD1 Business plans, innovation and efficiency incentives, 31st March 2011

Chapter: Three

Question 5: Do you consider that our proposed funding baseline for NGET (TO) has been set at an appropriate level?

National Grid response:

We consider that the proposed baseline for NGET (TO) is set at an inappropriate level in the following areas:

Opex

- **Overall opex levels** – The opex assessment has been performed on its constituent parts with no regard for top down deliverability, being founded on analysis errors and an abandonment of the RIIO principles of totex and consideration of the longer term
- **Real pay –** Pay growth figures which are half that of the Fast Track outcome will create pressure for our people with critical skills to leave and causes challenges for attracting new recruits
- **Efficiency -** Basing catch up efficiencies on TPCR4 performance has no justification and ignores benchmarking evidence and consultants' recommendations
- **Business support benchmarking:** Logic errors and inconsistencies within the business support benchmarking methodology ignore future growth in cost drivers and benchmarking evidence
- **Non-operational capex –** Arbitrarily reducing IS projects by 50% will hit key outputs and mean we have to keep ageing systems on line for eight to twelve years
- **Physical security -** A zero baseline for mandated physical security work undermines previous funding promises and perpetuates cashflow risk we have borne during the TPCR4 period

Capex

- **Load-related baseline funding -** The £0.55bn reduction to the load-related baseline funding is not consistent with Ofgem's Best View, does not meet the intention to make the volume-driver work in a more symmetric manner and has the potential to cause charging volatility and stability issues. The forecast for this expenditure based on the Gone Green scenario should be included in baseline funding.
- **Hinkley – Seabank -** We do not agree that it is appropriate to treat the Hinkley - Seabank reinforcements as Strategic Wider Works and propose an alternative approach.
- **DNO mitigation measures -** We do not agree with the change made to the DNO mitigation measures uncertainty mechanism. The £18.1m reduction to the baseline funding for DNO mitigation works does not reflect the costs of non-unit items (such as substation civil costs) that were not included in the calculated unit cost allowances in order to achieve a balance between transparency and accuracy.
- **RIIO-T2 outputs -** The £462m reduction to the baseline funding for outputs delivered in RIIO-T2 is not consistent with Ofgem's Best View and has the potential to cause charging volatility and stability issues. We do not understand how Ofgem has reached the conclusion that an uncertainty mechanism is not required. The forecast for this expenditure based on the Gone Green scenario should be included in baseline

funding with arrangements to deal with material changes (upwards or downwards) and a true-up at the RIIO-T2 price control review.

- **Pre-construction works -** Ofgem's proposed allowances for pre-construction works do not fully reflect the extent of development engineering that we will be required to undertake.

The RPE and efficiency assumptions are discussed further under the response to question 1 above, with physical security costs discussed in response to question 6 below.

In addition, Ofgem's overall approach for the proposals has been to base opex and capex allowances on the low case recommendation from consultants. This is despite the consultants not offering a 'best view' and using a range approach due to uncertainty over their confidence with their assessment. The sections below outline that the consultants uncertainty over their assessment was justified because in a number of instances their assessments are not sound and do not take into account all available evidence. In addition, several proposed expenditure reductions by both Ofgem and their consultants are made on an arbitrary, rather than well justified, basis and there are numerous occasions where the principles of RIIO such as transparency and consideration of the longer term are ignored

In order to outline our concerns in each of the baseline areas we split the rest of the response to this question into sections covering the various cost categories. The information given below is complimented by additional supplementary information papers which accompany our response and are referred to in the detail below. Specifically these are:

- Asset painting
- Business support benchmarking

Direct opex:

Opex is critical to maintain safety, reliability and environmental outputs and will need to increase as asset numbers grow over the RIIO-T1 period, however

- **The opex assessment has been performed on its constituent parts with no regard for top down deliverability**
- **The assessment is founded on analysis errors and an abandonment of the RIIO principles of totex and consideration of the longer term**
- **Basing catch up efficiencies on TPCR4 performance has no justification and ignores benchmarking evidence and consultants' recommendations**
- **Double counted efficiencies, analysis errors and ignoring totex benefits of asset painting give rise to inappropriately low allowances**
- **Logic errors and inconsistencies within the business support benchmarking methodology ignore future growth in cost drivers and benchmarking evidence**

The NGET opex assessment separately reviews the constituent activities with little or no regard to interactions with capex, other opex activities or the deliverability of the resulting allowances overall. This assessment is both based on errors and results in unachievable targets which focus on cost reduction rather than considering the outputs delivered or totex benefits of the expenditure. The next sections discuss the elements within the assessment in turn and outline the poor analysis which gives rise to inappropriate allowances.

Direct opex has received a £159m (20%) reduction within the Initial Proposals which gives rise to inappropriately low allowances which have the potential to fundamentally impact safety and reliability outputs. The level proposed is based on several calculation errors and insufficient focus on the long term and totex principles. The proposals include inadequate allowances for workload driven by asset growth (mainly due to double counting of efficiencies in the calculation), reductions to asset painting (which will increase long term totex) and allowances for asset condition drivers being based on asset age not asset health data. Reductions from these areas are in addition to the application of inflated efficiency factors as discussed above and in combination reflect unrealistic targets.

Our comments in this area focus on errors which need to be corrected, new information provided in response to the Initial Proposals and reiteration of salient points in light of this new information in the following areas:

- **Asset painting**: Based on Initial Proposals feedback we include a more detailed explanation of the drivers and totex benefits related to asset painting increases we proposed and how the Initial Proposal levels of allowance - at ~£2m per annum less than expenditure we undertook in 2011/12 - are £45m below what would represent appropriate funding
- **Efficiencies double counted**: We give evidence that ~£40m of efficiencies have been double counted in the calculation of planned maintenance requirements
- **One-off 2010/11 benefits**: We highlight that a one-off impact in 2010/11 from insurance proceeds are artificially deflating allowances by ~£2.6m per annum due to the calculation method used
- **Asset condition:** We explain why Pöyry are confusing the impacts of asset age on opex with the very real impacts of asset condition deterioration giving rise to inadequate allowances
- **Asset growth**: We show that pressures from asset growth have erroneously not been fully incorporated into Initial Proposals with inconsistencies applied between asset types
- **Outputs:** Outlining the potential impacts on outputs from the disallowances within Initial Proposals and giving evidence for why another specific area of spend - liveline electricity charges for unmetered sites - should be assessed separately from other planned maintenance work due to the outputs delivered

The sections below outline our concerns in these areas with evidence for why the proposals give rise to issues and ways that these should be rectified. Included within these sections are references to the work we commissioned with Oxera.

In highlighting these points we are making the assumption that Ofgem has used the Pöyry report on NGET opex on which to base its proposals. This is a logical assumption given that Ofgem's comments in their Initial Proposals document align with those made by Pöyry. As such the sections below refer both to points raised by Ofgem and by Pöyry in their report.

Direct opex outputs

Direct opex is directly linked with reliability, safety and environment outputs. Any uncontrolled reduction in this expenditure or not performing maintenance for additional assets would give rise to deterioration in these outputs. Adequate allowances in this activity are therefore critical to maintain current levels of these outputs which are important to our stakeholders.

The Initial Proposals fall short of being adequate with reductions to required asset painting and forecasts for opex growth due to asset growth. As they stand the allowances would ultimately increase totex costs because more asset replacement would be required due to the resulting lower volumes of painting and increase the risk of deteriorating outputs. This is in contrast to RIIO principles which focus on totex, not opex and capex separately.

In their document Pöyry refer to a number of factors that should act to minimise direct costs including, mainly, our application of risk and criticality maintenance and the IT system enablers to this change. The Initial Proposals suggest there are more savings possible than embedded within our plan which ultimately translates into delivering the step change in maintenance policy quicker than we have assumed. However this view does not consider the risk impact from any reduction.

There are critical risk assessments and enablers (chiefly the implementation of the Strategic Asset Management (SAM) systems) that need to be in place before a risk and criticality approach can be adopted for any asset type, else we risk deterioration in outputs. To cover all the asset base these risk assessments would need to be performed for over three thousand equipment group identifiers which will take several years. The Initial Proposals suggesting that more maintenance volume should be removed from our forecasts is therefore moving the cost frontier even further to an unattainable level, with no consideration of the risk impact.

Planned maintenance and inspections – main plant types

Submission	£263m	**Initial Proposals**	£223m
Reasons given for disallowance	• Reassessment of costs from a base of 2010/11 which factors in lower increases due to asset growth and 2.25% per annum efficiencies • Assessment of asset condition impacts based on asset age		
Action required	• Efficiency double count removed • Asset condition impacts to be based on asset health indices, not age • Asset growth and condition impacts applied to all relevant categories		

The main categories of maintenance within planned maintenance and inspections relate to the primary asset types of:

- Overhead lines
- Cables (excluding HVDC)
- Transformers
- Switchgear (mainly circuit breakers)
- Reactive compensation (mainly SVCs and MSCs)
- Protection and control equipment
- Substation site care and other maintenance

There is significant growth in the number of all of these assets on our network over the RIIO-T1 period which is not adequately accounted for in the Initial Proposals. Having reviewed the method Pöyry have used to calculate their case 1 proposal (the basis for Initial Proposals) we understand this to be due to three errors within the calculations:

- **Efficiency double count**: The allowances include a credit balance each year for ‘capitalisation’. This figure has been calculated from a line called ‘continuous improvement and capitalisation’ in our financial tables. The rate of ‘capitalisation’ implied by dividing this line by total costs in the submission is applied to the allowances on a pro-rata basis. We have no issue with this calculation for the capitalisation element of this credit line however - as suggested by the title - the credit within this line also includes some continuous improvement task which has not been allocated to the relevant asset types. Using this element of the line within the calculation is double counting efficiencies because of the way the 2.25% per annum efficiencies have been embedded into the calculation of allowances.

The continuous improvement task was kept separate from specific asset lines because it is unidentified in nature, in that we do not know which asset type we are expecting to get the improvement from, but in order to show a justified level of efficiencies we had to include the cost reductions. The value of the continuous improvement task within the line is shown on a phased basis in the table below, totalling £37m over the RIIO-T1 period:

	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Task	3.1	3.6	4.0	4.4	4.8	5.3	5.7	6.1

These figures should be removed from the capitalisation line of the calculation and in doing so effectively added back to the allowances because of the double count. This double count arises because efficiencies have been embedded into the allowances in each of the asset type areas at the 2.25% per annum rate so keeping this reduction in the calculation would add more efficiency savings to this level. This would be over and above the level intended by the Initial Proposals and Pöyry as it is stated that 2.25% per annum of efficiencies would be applied, not 2.25% per annum plus this extra £37m.

- **Asset age being used as a proxy for asset condition:** Within their document Pöyry state that: '*the scale of the forecast of additional costs that NGET is proposing appears questionable'* in relation to our cost increases due to asset condition deterioration. This seems to be because they have become confused between the age of our assets and the condition of our assets, which are two different concepts. Whilst age is linked to condition (because the older an asset becomes the more likely its condition is to deteriorate) it is not the same, especially not when viewed across different asset types. For example, an asset which is subject to more environmental factors such as wind and rain is more likely to deteriorate earlier than one which is not subject to these factors. This is shown by the deterioration of the switchgear assets at the Sizewell site, as shown in the Asset Painting issue which forms part of our response. In this example outdoor Gas Insulated Switchgear (GIS) assets built in the mid 1990s have deteriorated to a level where they require repair whereas indoor GIS at the same site and of the same age are in a much better condition. This difference between age and condition is the fundamental reason why performing asset interventions based on condition, rather than time periods, is more efficient in nature (as under our risk and criticality asset replacement strategies).

  Pöyry refer to movement in average age of the assets on our network to determine whether or not there is deterioration in the assets. This is not even a good indicator of the overall age of assets on our network, let alone of asset condition. The history of our network means that we have a large number of assets built in the 1950s and 1960s and then due to our recent increase in asset replacement and load related activity we have a large number of assets from post 2000 on the network. There are only a few assets which were added to the network in the intervening years. This gives our age distribution a horseshoe shape putting the average asset age somewhere between the two periods of peaks in expenditure and producing an effectively meaningless comparison.

  Rather than use age to determine asset condition impacts Pöyry should use the data we referred to within our submission on this area, which is the projected asset condition data of the assets on the network. This data is included within detailed data table 4.28.1 which shows the output from Monte Carlo modelling of asset condition at

2013, 2017 and 2021 factoring in the impact of our forecast asset replacement activity. This forecast data has been used to set the Network Output Measures (NOMs) target for reliability so in order to ensure consistency should be used to assess the condition of assets in the future.

This data shows a general decline in the condition of our assets as higher levels of poor condition assets are left on the network under risk and criticality asset replacement. For example between 2012/13 and 2020/21 there is projected to be a 17% increase in the number of circuit breakers in the Asset Health (AH) category 5 which represents the worst condition and a 6% increase in all assets within this category. Assets under deteriorating asset health indices attract more planned and unplanned maintenance as described within our submission so this deterioration will have an increasing impact on our costs.

Whilst there is a condition impact through to 2020/21 it is the data shown for 2016/17 on table 4.28.1 which better illustrates the condition issues we will face during the RIIO-T1 period. As described in our submission we have deferred some asset replacement work from the early RIIO-T1 period into the second half due to deliverability concerns. This causes more assets to be left on the network in a state near to their required replacement. Comparing asset health data from 2012/13 to 2016/17 shows that there is expected to be an 11% increase in the population of assets in the AH5 category over the period. This will again increase planned and unplanned maintenance requirements.

In addition to this data, we have used historical trends of defect work to project impacts of condition on our unplanned maintenance workload. We have seen 5% per annum increases in defects over the TPCR4 period within the switchgear asset category but we are assuming we can minimise this to 1% per annum through the RIIO-T1 period.

The calculations for setting the allowances use an uplift of 5% on unit costs for all years in relation to asset condition. This is underestimating the impact. Asset condition data suggests a figure in the region of 6 to 11% is more appropriate.

- **Asset growth and condition assumptions not being applied to certain categories**: Asset growth and condition assumptions have been applied to most asset types within the Initial Proposals but crucially not all. This either seems to be an oversight or a specific decision but no justification has been provided for it. The asset types not included in the calculation are shown in the table below:

Cost driver	Category with no projected increase
Asset growth	Protection and control
Asset condition	Site care

The number of protection assets on the network is growing significantly over the RIIO-T1 period as shown by table 4.15.1 of our plan. Between 2009/10 and 2020/21 there is expected to be a 14% increase in assets in this category which will have an upward driver on maintenance like asset growth will in other categories. Not applying the asset growth driver in this category is inconsistent with the application in others.

Site care activities (including safety, environment and planning work) consist of maintenance at substation sites on items such as civils installations, auxiliary assets and LVAC assets. These assets will be subject to the same asset condition deterioration over the period as other main asset types so the asset condition assumption should equally apply to this category of expenditure.

In summary, the double counted efficiencies and erroneously excluded asset growth and condition drivers should be adjusted for the calculation of the allowances in planned maintenance, increasing allowances back up to the level of our submission. In addition, asset condition upward pressures should be updated to reflect asset condition, rather than age, drivers.

Planned maintenance and inspections – specific areas

Submission	£124m	**Initial Proposals**	£77m
Reasons given for disallowance	• Tower painting increases reduced to 50% of that proposed and plant painting increases reduced by 60% based on a limited case given		
Action required	• Asset painting allowances increased to proposals based on further evidence given and totex benefits		

In addition to the main maintenance categories, planned maintenance contains categories of expenditure that should be assessed separately due to the nature of the outputs delivered or the impact on totex efficiencies. These categories are:

- Asset painting (including tower and plant painting)
- HVDC cable maintenance

We forecast an increase in levels of asset (tower and plant) painting over the RIIO-T1 period but Initial Proposals allows only 50% of this increase with no justification provided for the reduction and then subjects the costs to further efficiencies. This assessment has been made on a cost-only basis and does not consider that painting is a key enabler to achieving the technical life of an asset. Reduced funding in this area will increase totex costs in the long term because asset replacement would have to be undertaken earlier than would otherwise be the case. This cost-only assessment is a departure from the RIIO totex principles.

Pöyry state that we have provided limited cases for our projected levels of asset painting. We do not agree with this opinion but include a specific supplementary information document: 'NGET_asset_painting' within our response which explains all elements of our painting requirement including the drivers for painting, why our costs are efficient under ITOMS and the requirement for 18 year painting windows to state our case in more detail.

The key points in this area are:

- Initial Proposal reductions have no basis giving rise to undeliverable targets and representing an abandonment of the RIIO principles of totex and consideration of the longer term
- In line with recommendations from whole life cost modelling we need to paint our metal work in towers and plant assets on an average 18 year cycle (within a 15 to 20 year window). This strikes a balance between the costs of ongoing maintenance to prolong the asset life and capital expenditure to replace them. Without painting, the technical lives of the assets will not be achieved giving rise to higher whole life costs.
- To meet this policy for our 22,000 towers and over 2,700 switchgear assets under present procurement arrangements and applied paint systems would entail us spending nearly £19m per annum. Our work with research institutes, painting manufacturers and suppliers has led to several innovations and improvements, such as a single coat system, which are projected to reduce this cost in the RIIO-T1 period to ~£14m per annum, with further continuous improvement expected over the period to offset asset growth drivers.
- Our unit costs benchmark well versus worldwide comparators and are in line with other European TOs with similar age assets subject to similar environmental factors. We are introducing longer term views of workload to our suppliers to supplement nationally

negotiated contracts which allow contractor benchmarking and drive savings.

- The Initial Proposals reduce our painting expenditure by £45m over the RIIO-T1 period, with annual tower painting allowances £2m less than we spent in 2011/12. Our unit costs are proven to be efficient and this reduction is too high to relate solely to the costs of delivery so this must suggest Ofgem wants us to deliver lower volumes.
- These allowances therefore only consider the opex costs, rather than the far larger capex costs which would result from not undertaking painting. The allowances in this area should be increased to enable the totex savings to be delivered. Without this, costs for our customers and consumers alike will be higher in the long term.

In summary, given the clear totex benefits from asset painting the proposals should be increased to the level submitted in our plan of ~£14m per annum, which represents a £45m increase on Initial Proposals. Without such an adjustment future capex costs would increase by a much larger figure in order to rectify the condition of assets that would have been left to deteriorate to maintain reliability and safety outputs.

Unplanned maintenance (fault repairs)

<table>
<tr><th>Submission</th><th>£265m</th><th>Initial Proposals</th><th>£214m</th></tr>
<tr><td>Reasons given for disallowance</td><td colspan="3">• Reassessment of costs from a base of 2010/11 which factors in lower increases due to asset growth and 2.25% per annum efficiencies
• Assessment of asset condition impacts based on asset age</td></tr>
<tr><td>Action required</td><td colspan="3">• Asset condition impacts to be based on asset health indices, not age
• Asset growth and condition impacts applied to all relevant categories
• Impact of one-off insurance proceeds which artificially deflate 2010/11 base should be removed from calculations</td></tr>
</table>

We have three concerns with the low allowances in the unplanned maintenance category. These are that:

- Asset condition upward pressures are underestimated in Pöyry's assessment with average age used in error as a proxy for the very real asset opex pressures due to deterioration of asset condition
- Asset condition and asset growth drivers are not applied to all asset types within the calculation for allowances
- Insurance proceeds received in 2010/11 are artificially reducing the allowances in all years by £2.6m due to the methodology Pöyry have employed

Unplanned maintenance allowances for the Initial Proposals have been calculated in a similar way to the planned maintenance figures by using the 2010/11 figures as a base, then projecting efficiency levels and increases for asset growth and condition. As with planned maintenance we have no issues with the methodology employed, but the magnitude of the opex increases due to growth and condition are underestimating the impact of the upward pressures.

In relation to our concerns regarding asset growth and asset condition drivers, we will not repeat the same analysis here which proves that the forecasts are underestimating the impact. Both the use of asset age rather than condition metrics and inconsistent application of asset condition and growth drivers to all categories are the same issues as noted within the planned maintenance section. The errors here should be rectified in the same way as for planned maintenance. The issue we do discuss is in relation to the misleading use of unadjusted 2010/11 costs as base expenditure for the allowance calculation.

Generally, 2010/11 is a good base for allowance calculations because it is the last year of actuals (or was at the time of submission) and was mostly not impacted by large one-off costs or credits. The one exception to this is that during 2010/11 we received £2.6m of insurance proceeds in relation to flood repair work in the Croydon cable tunnel. These related to exceptional costs incurred in 2008/9 and were put into the other HV maintenance category of fault repairs in table 2.1 of our submission.

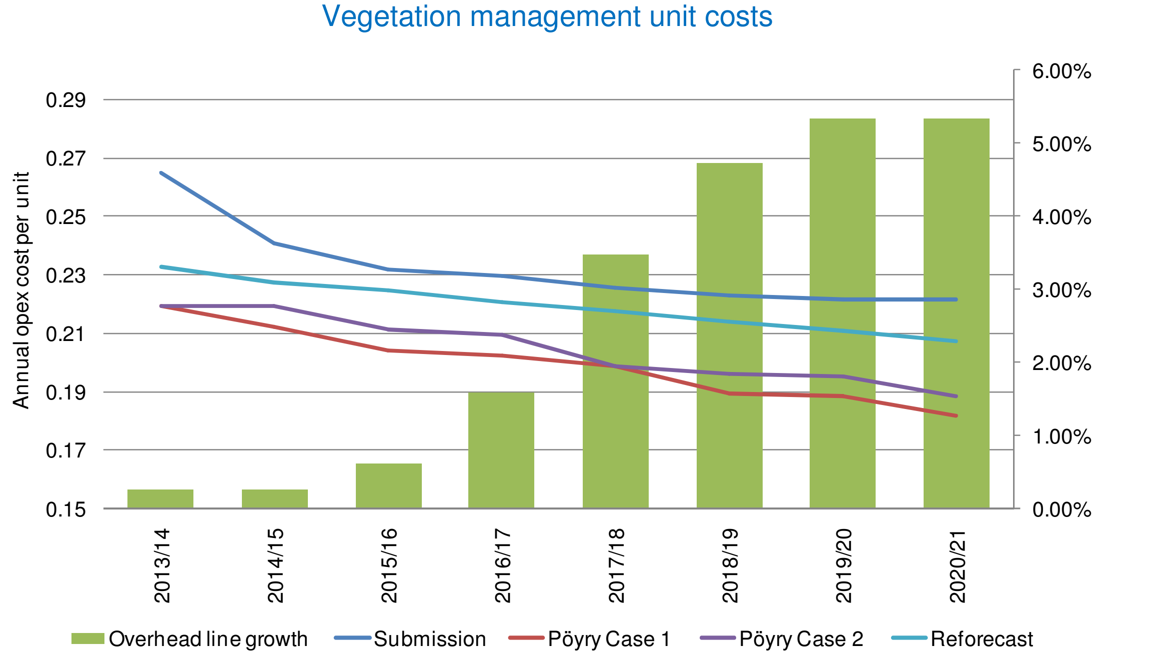
These insurance proceeds are one-off in nature and should be adjusted out of the 2010/11 balance before future projections of cost are calculated from this base position. Without this adjustment the allowances are artificially deflated and do not represent the costs that we would incur in a normal year of operation. This adjustment is the opposite of an adjustment made by Pöyry within the operational IT and telecoms category of Closely Associated Indirect (CAI) opex where Optel costs incurred in 2010/11 but not included in future years are adjusted out of the base year.

In summary, asset condition and growth factors should be accurately reflected into fault repairs projections and 2010/11 costs in the calculation should be adjusted for one off insurance proceeds of £2.6m which will increase allowances for all years.

Vegetation management

Submission	£27m	**Initial Proposals**	£23m
Reasons given for disallowance	• Reassessment of costs from a base of 2010/11 which does not factor in increases due to asset growth and 2.25% per annum efficiencies		
Action required	• Impact of growth of overhead lines should be factored in		

As with the main categories of maintenance within the planned maintenance activity Pöyry do not take full account of asset growth within their assessment of vegetation management. In this case there is no account taken. The key cost driver in this activity is overhead line length as it is along these route lengths that we need to gain access to cut trees and reduce vegetation interference with our lines to ensure that they do not cause flashovers or reliability concerns. By projecting costs on the same basis as have been used by Pöyry for other planned maintenance categories the following unit cost comparisons are produced (with the reforecast line representing the projection of costs on Pöyry's basis for other lines factoring in the growth in overhead lines):



This gives rise to a £2m shortfall in Initial Proposals funding within this category despite the reforecast reducing our costs in this activity from our submission. As with other categories of maintenance this highlights that opex due to asset growth has not been sufficiently funded within the Initial Proposals and should be rectified.

Operational property management

Submission	£124m	**Initial Proposals**	£107m
Reasons given for disallowance	• Reassessment of costs from a base of 2010/11 which factors in lower increases due to asset growth and 2.25% per annum efficiencies		
Action required	• Separately assess electricity costs from unmetered sites		

We broadly accept the proposals within this category, although we do propose that the incremental cost for electricity at unmetered sites is separately assessed.

During 2012/13 we have started the process to install electricity meters at previously unmetered sites which will lead to us having to pay for the load consumed. Previously this cost would have flowed onto downstream companies rather than ourselves due to legacy arrangements with the metering process. Rather than keep the status quo in this area, and give no visibility of this applicable cost, we have taken the approach to bring this cost into our remit. Taking this approach adds £1.3m to 2012/13 and £2.3m of cost per annum from 2014/15 to our operational property management activity. The cost movement is net neutral over the electricity supply industry but will increase our costs in the period. The costs are estimated based on comparing the size of substation involved to others on the network and using the electricity costs they incur.

In summary, the £17m cost of electricity usage at currently unmetered sites should be assessed separately and funded based on realigning the costs to the user of the electricity

Closely Associated Indirect (CAI) opex

Like direct opex CAI opex has been subject to a significant disallowance from the levels of our plan with £62m (12%) removed. This level of disallowance is excessive and unjustified – especially in the operational training activity - and gives rise to an inappropriate baseline level.

The main reasons for this are explained below but in summary are:

- **Operational training costs** - have been arbitrarily cut, with 20% of the proposed increase removed, with no reference to what impact this will have on delivery of outputs or availability of skills during the RIIO-T1 period
- **Cost driver links** - The Initial Proposals do not assess the link between CAI opex and its cost drivers of direct opex and capex workloads which gives rise to over-inflated cost reduction targets
- **Mandatory costs -** The assessment for costs does not fully take into account the mandatory costs for the Carbon Reduction Commitment (CRC) scheme and European energy policy interaction, whilst at the same time incentivising us to minimise land contamination remediation

In highlighting these points we are making the assumption that Ofgem has used the Pöyry report on NGET opex on which to base its proposals. This is a logical assumption given that Ofgem's comments in their Initial Proposals document align with those made by Pöyry. As such the sections below refer both to points raised by Ofgem and by Pöyry in their report.

Operational training

Submission	£134m	Initial Proposals	£124m
Reasons given for disallowance	• 20% of the proposed increase disallowed based on potential for efficiencies other than those in the plan		
Action required	• Arbitrary reduction reversed due to impact on long term approach for increasing skills base		

The Initial Proposals arbitrarily cut our proposed increases in operational training by 20% based on Pöyry's assessment that '*there should be some potential for efficiency improvements other than those included in the NGET plan'.* This statement is based on no evidence giving rise to a reduction which is both a departure from RIIO principles and from the headline efficiency target of 2.25% per annum.

The departure from RIIO occurs because the RIIO strategy document states that the tools used for cost assessment would be evidence based. This adjustment clearly is not. It also results in an additional efficiency target for 2013/14 on top of the 2.25% per annum already being applied.

Adequate funding for operational training will be critical to delivering required outputs over the RIIO-T1 period, and vital for our long term approach for filling up the diminishing pool of specialist skills that we source our people from. Without such funding both of these are at risk. As stated by key advocates for the skills agenda such as EU Skills the longer term approach to solving the skills gap is the most economic approach. Our submission showed this to be true through a case study on grow-your-own resources compared to those sourced externally. Such an approach should therefore be encouraged - especially under the RIIO principles of considering the longer term - not subject to arbitrary unjustified cuts.

There are only two factors that the reduction could be applied to: the volume of trainees or the cost of training. There is no evidence that either of these have scope for reduction and on the contrary our submission gave ample evidence that both were at the efficient level.

We outlined the evidence showing the growing need for workforce renewal and growth that we will have to undertake over the next decade in our 'Workforce renewal and growth' annex. Our forecast figures were backed up by independent modelling performed by EU Skills and incorporated several innovative resourcing strategies which minimised the trainee requirement. The same annex provided evidence from a recent Ofsted report and EU Skills modelling that the costs of the training were efficient, with Ofsted classing all elements of our training (including cost efficiency) as 'outstanding'.

The reduction in cost for operational training should be reversed as it has been in Pöyry's case 2 due to impacts on availability of critical skills and independent assessment of cost efficiency. Without this reversal future outputs are at risk and the diminishing number of skilled electrical engineering resources will reduce even further, creating an ever growing skills gap.

Environmental costs

Submission	£45m	Initial Proposals	£38m
Reasons given for disallowance	• Not clear that CRC and land contamination remediation will have as significant impact as we forecast		
Action required	• Cost reduction reversed based on mandatory nature of CRC and environmental impacts of not remediating land		

The health, safety and environment activity includes two main upward drivers for costs over the RIIO-T1 period. These are costs for:

- The mandatory Carbon Reduction Commitment (CRC) scheme
- Monitoring and remediating land contamination caused by previous use of the land some of our substations are situated on

Whilst the Initial Proposals allow some of the cost increases in this area, the costs of the activity are reduced because Pöyry state that '*It is not clear that these factors should have as significant effect as suggested by NGET'.* This is a curious comment to make when in the initial draft of their report the reduction in costs for this activity were exactly the same as those currently used for the Initial Proposals but they stated that '*it is not clear what is driving this profile'.* This suggests that the evidence for the requirements in these areas have not been assessed as the outcome has remained the same once the drivers – which were clearly shown in our submission - were pointed out to them.

In response to Pöyry's point, these two drivers will have the effect on us that we outlined in our plan and are already doing so.

The CRC scheme was introduced by the government in 2011 and we made our first payment in August 2012 for the financial year 2011/12. This totalled £0.5m for ETO. CRC charges are impacted by higher electricity usage so with the growth in substations and cable tunnels, which each use significant levels of own use electricity, this figure is subject to grow over the RIIO-T1 period. The other item to note in this area is that CRC is not a viable candidate to apply an efficiency factor to as its value it outside of our control. It is essentially an environmental tax so if anything costs are likely to increase as government policy in this area toughens.

From a land contamination perspective whilst we have some control over the timing of expenditure any deferral would only increase the potential impact on the environment from the land on which our substations are built. This is not a consequence we would like to occur and could give rise to higher costs in fines and other clean up measures. Cutting expenditure in this area would have a detrimental impact on environmental outputs from our operations, an incentive that does not seem to align with the RIIO principles, with environmental impact a key output.

We are planning to spend an average £3m per annum on remediation and monitoring work throughout the RIIO-T1 period. This expenditure does, however, have a growing profile over the RIIO-T1 period to a peak of £3.5m in 2015/16 from £2m at the start of the period, and then a £0.5m drop off towards the latter half of the RIIO-T1 period. This profile is due to remediating the more critical sites earlier whilst maintaining a deliverable workload before returning to the enduring level of £3m.

This expenditure will minimise the impacts of our sites and implement improvements to the surrounding environment. The necessity of this work was recognised in the TPCR4 Rollover outcome with full allowance for the expenditure, so it is a reversal of this position which gives rise to the cuts included in Initial Proposals. The Initial Proposals should therefore be reassessed to ensure that this work can be undertaken in full.

Taking the average TPCR4 expenditure for this activity before these two drivers began (i.e. 2007/8 to 2010/11) gives an underlying cost of £2.8m. Adding the £3m per annum for land contamination and £0.5m for CRC costs produces an average annual expenditure level of £6.3m. Once efficiencies are factored in forecasts are in line with our submission. It is this level that should therefore be funded for the RIIO-T1 period rather than the costs currently in the Initial Proposals which represents only a £7m increase on current funding.

Market facilitation

Submission	£9m	**Initial Proposals**	£7m
Reasons given for disallowance	• Some increase in workload can be foreseen but this needs to be tempered by likely future efficiency improvements		
Action required	• Costs reductions reversed due to mandatory nature of EU impacts and double counting of efficiencies		

Whilst at ~£2m the reductions in market facilitation costs for NGET TO are small in comparison to others, their inclusion is symptomatic of the nature of the Initial Proposals. In their report Pöyry state in relation to this activity that: '*there is a significant increase in costs with a limited justification.'* Whilst we acknowledge there was limited evidence specifically on the NGET TO costs in this area they are of the same nature as those explained within the SO section of the plan and were explained as such in our submission. Indeed the cost increases in this area are all due to European interaction requirements, the same drivers as increases in the SO part of the plan, and we included an annex (the 'European context' annex) on this subject in our submission.

Costs of Europe impact the TO as well as the SO due to the cross TSO nature of the work. European code developments will affect both parts of our business so therefore the work required to develop the codes and be involved with ENTSO-E is allocated across both forms of control.

Within their assessment Pöyry and Ofgem has missed this link, resulting in an arbitrary, non-evidence based cut in the costs of the activity. Including this cut does not allow us to play our full part in European interactions, something that the Initial Proposals state we will be incentivised to do. Given the vital work in this area and similar, but deeper, cuts within the SO funding of this activity we have included a specific supplementary information document: 'Market_facilitation' within our response to the Initial Proposals. This paper should be referred to when considering the costs in this activity.

Capital and maintenance support

Submission	£156m	**Initial Proposals**	£137m
Reasons given for disallowance	• Costs projected forward from 2010/11 based on 2.25% per annum efficiencies but no impact of cost drivers		
Action required	• Asset growth and capex workload drivers should be added into the assessment		

As Pöyry state in their report costs in the CAI opex area '*represents activities linked (but not directly related) to capex and direct opex delivery including elements of planning and* *designing the network'.* However, in their assessment Pöyry have ignored this link to capex and opex delivery and assessed many of the activities on an input only basis and thus reduced costs from our submission. This impacts the activities which fall under our definition of 'capital and maintenance support'.

The oversight in relation to not assessing the workload driver may have arisen because of the wording used above (which is sourced from our submission) which stated that costs in this area were not directly linked to capex and direct opex delivery. This does not mean the costs are not driven by this delivery – indeed the level of activity here is precisely the main driver for the costs – it just means that the activities are one step removed from the direct activity. For example, the planning of the network (covered by the network planning activity) is inherently more complex when there is more activity on the network and the same can be said for each of the activities in this area. It is, however, not directly linked to direct opex and capex because it does not link to one - or a handful of - specific schemes or maintenance visits, rather the portfolio of work overall. In this way such workload must be taken into consideration in the assessment.

We acknowledge that we did not specifically note this workload link when discussing the capital and maintenance support costs within our submission. We assumed that this would be clear due to references throughout our documents. With the overall category broadly flat in nature across the period we did not discuss this in detail in order to be proportionate in our submission. Ofgem on the other hand is proposing allowances in line with our submission when costs for individual activities in this area are reducing or flat, and reduced costs if there are any increases in forecast. This is not a balanced view of the related costs and is the function of the cut of activities within the financial tables rather than understanding and assessing the underlying cost drivers.

We recognise that higher workload in direct opex or capex alone would not justify higher costs in the future. We have to prove that not undertaking this workload would reduce current levels of output or increase costs of delivering outputs in other areas. This is absolutely the case for the costs in the capital and maintenance support activities. This is explained within the attached document below which cover the activities within this area that have had proposed cuts within the Initial Proposals.

In addition to this explanation, we articulate the projected impact of this workload on our costs using the calculation of a partial productivity metric for each activity, like Pöyry have done for direct opex. We use a summation of asset growth and capex values[19] as the measure for this productivity as it is a good proxy for direct opex and capex workloads. Efficiency levels of 2.25% per annum have been used in this assessment, in line with that in the Initial Proposals and (unless stated) an economy of scale assumption of 0.9 has been assumed to reflect that there is an element fixed costs. This projection of costs takes on board the work we have undertaken with Oxera This projected case for costs, which represents our adjusted best view of costs, is called the EOS (Economies of Scale) case in the graphs in the document.

Capital and maintenance support

The analysis for these 'capital and maintenance support' costs shows that the Initial Proposals do not factor in any of the cost driver impacts for costs in this area and instead just focus on cost reductions. Analysis on the same basis Pöyry used but factoring in cost driver movement shows allowances should be £11m above that of the Initial Proposals. This is even without adjusting for the lower efficiency factors that should be applied based on the evidence provided in response to question 1.

In summary, asset growth and capex drivers should be factored into allowances in these

[19] using Initial Proposal forecasts, rather than our submission

activities as currently the allowances represent an unrealistic funding position, rather than one that fully represents the costs drivers we will face over the RIIO-T1 period. Without reflecting these cost drivers there would be a diminution in outputs which would not be acceptable to us or our stakeholders.

Operational IT and telecoms

Submission	£153m	Initial Proposals	£132m
Reasons given for disallowance	• Costs projected forward from 2010/11 based on 2.25% per annum efficiencies and consideration of upward pressures		
Action required	• Efficiencies updated to 1.4% per annum		

Given the overall approach used by Pöyry in CAI opex and discussion on this activity we accept the proposals for Operational IT and Telecoms noting that the efficiency factor applied should be updated to the 1.4% per annum as discussed in response to question 1 and that 2011/12 would be a more appropriate base year as described below.

Under the new managed services Operational Telecoms contract signed in 2009 there is a £1.0m pa charge in relation to gaining access to operational sites for maintenance. However, until the end of 2010, and as a transitional arrangement these costs were not passed through to National Grid by Cable and Wireless, giving a one year benefit of lower costs, therefore the costs in 2011/12 year are more representative of our ongoing CAI opex for IT and Telecoms and should be used as the baseline from which allowances are calculated.

In addition, we note that, although the £4.3m Optel allocation change has been (correctly) adjusted out of the calculation for allowances in this activity, it has not been factored into allowances for ESO opex from 2013/14. This is explained further below within the response to question 11 on SO but it seems like an oversight due to the differing method used to calculate the allowances in each form of control.

Business support opex

Submission	NGET: £406m NGG: £144m	Initial Proposals	NGET: £318m NGG: £113m
Reasons given for disallowance	• Benchmarking of 2010/11 costs versus other networks and independent data set		
Action required	• Use future FTE and revenue metrics rather than 2010/11 figures • Include Transmission submitted benchmarking and market testing evidence in assessment • Non-normalised costs for regulation and more automated IT approach should be adjusted		

The Initial Proposals used cross network benchmarking for business support costs with reference to data from Hackett to produce a reference point outside of the utility sector. As stated in our submission if costs are adequately normalised and the methods used are applied consistently the use of such benchmarking for business support costs is a valid assessment method. The issue with the use of such benchmarking in Initial Proposals is that neither of these conditions have always been adhered to, giving rise to logic flaws in the methodology used and a deflated resulting allowance.

Benchmarking of business support costs purely on 2010/11 costs and metrics such as FTEs and revenue represents a material departure from Ofgem's published RIIO principles which favoured benchmarking future, not historical costs. The analysis underestimates the impact of Transmission workload growth over the next decade giving rise to wholly inappropriately low allowances. Errors in the calculations and unsound logic in the assessment compound this position.

Reversing the analysis and logic errors in the benchmarking would increase combined allowances for Transmission and Distribution by approximately £94m, this is even before adjusting the benchmarking to only refer to Networks' levels of performance due to lack of comparability with the Hackett data.

As they stand we have concerns around the suitability of the Initial Proposals in the these key areas:

- **Future benchmarking:** The lack of benchmarking based on future metrics contradicts Ofgem's published RIIO principles, with Ofgem stating: "*We will place much more emphasis on the benchmarking of forecasts (as opposed to historic costs) as these are likely to be more relevant in the context of our sustainable development duties and the introduction of new output measures*." We have been unable to ascertain whether any such benchmarking has taken place but are aware that our costs have been benchmarked based solely on 2010/11 metrics such as FTEs or revenue, rather than considering the impact of forecast increases in these over the RIIO-T1 period reflecting growth. This is inconsistent and demonstrates a departure away from the RIIO core principles.
- **Ignoring our benchmarking and market testing evidence**: We agree that including efficiency additions based on the strength of independent benchmarking in the business plans is a positive step. However several of the benchmarking results and market testing evidence submitted by us has been ignored by Ofgem's own admission, creating artificially low allowances.
- **Non-normalisation of costs**: Regulation costs have been benchmarked against a comparator set of data which contains no regulated entities. Hackett data has been used to set a target in several activities despite specific guidance from Hackett not to do this. In addition, there has been no account taken of the benefit of us having more automated (and hence more IT led) processes than those we have been benchmarked against, despite Hackett themselves stating this needs to be performed.

The resulting impact of these errors and inadequate analysis is a set of allowances which do not reflect an accurate assessment of the costs in this area and would introduce unachievable targets that would inhibit investment in key areas such as IS innovation and skills development through the period.

We provide supplementary detail and evidence in **Supplementary information document – business support benchmarking**.

Non-operational capex:

Non-operational capex investments are key to maintain and improve safety and reliability outputs over the RIIO-T1 period, however:

- **Arbitrarily reducing IS projects by 50% will hit key outputs and mean we have to keep ageing systems on line for eight to twelve years**
- **Disallowing 15% of unsanctioned SAM and TFO investments will erode benefits delivered and is based on no justification**

For completeness, we have duplicated the following information on non-operational capex in our responses to both this question and the equivalent question for NGGT (SO).

Within non-operational capex the assessment of our Strategic Asset Management (SAM) and Transmission Front Office (TFO) systems has been performed separately from the other investments within our forecasts. The SAM and TFO assessment have been performed by

Pöyry with the other investments assessed by Ofgem. There is a marked difference in approach between the two with the Pöyry assessment being more considered as it was based on more interaction with ourselves. By contrast, the assessment for the other investments does not consider the impacts of the proposal made on other areas of the plan and proposes an arbitrary, unjustified reduction. We will discuss both of these assessments in turn below giving more evidence why the expenditure levels proposed in our plan are justified.

In summary the main concerns we have with the Initial Proposals are:

- **Arbitrary 50% reduction in other schemes**: The 50% reduction in other investments is wholly inappropriate and premised upon ill founded and unsupported assumptions. A reduction of this scale will mean that thirteen projects delivering safety related outputs will be put at risk, and a further eighteen initiatives delivering capital and reliability related outputs will be compromised, including refresh of essential network analysis capabilities, field user device refresh and remote site communication infrastructure upgrades, essential to realise SAM benefits. Implementing this reduction will force us to leave IS systems in service for at least eight years and in some cases up to twelve years which will not only compromise safety and system reliability, but will increase totex costs due to incremental support costs and embedded efficiencies we would no longer be able to deliver
- **Lower outputs**: The 15% reduction on unsanctioned TFO and SAM work is arbitrary and incentivises us not to integrate and extend the capability across all of our network giving a diminution in output benefits (i.e. we will not get all the safety, reliability environmental and customer outputs envisaged). Forecast costs for TFO and SAM have been refined as the programme has matured, and have been tested against available external comparators. We believe that our implementation costs are challenging, offering value for money when compared to other implementations of a similar scope, scale and complexity.
- **Erosion of SAM and TFO benefits:** One of the justifications used by Pöyry and supported by Ofgem for proposing lower direct opex allowances is higher expected benefits from SAM / TFO than those included in our plan. The proposed reduction in non-operational capex will reduce opportunities for investments that deliver direct opex efficiencies, and is inconsistent with this position. TFO and SAM investments must be maintained at our plan levels if the associated direct opex benefits are to be achieved.
- **Ignoring flexible IS delivery model**: Our flexible IS delivery model which enables demand to be met across National Grid using external resource where required has been ignored in assuming that our IS department will be too busy with TFO and SAM investments to work on other projects. In addition, the competitively tendered arrangements put in place with our delivery partners include provision for annual external benchmarking, to ensure value for money for National Grid and our customers.

Other investments:

The Initial Proposals recognise that IT expenditure (outside of SAM and TFO) is spread over a number of systems which are proposed to be enhanced or refreshed at differing times over the RIIO-T1 period. Investments in this category are necessary to replace/refresh existing systems at end of life essential for asset maintenance and capital commissioning supporting network planning and efficient capital investment.

A number of proposed investments are to replace systems which are at end of life within the early years of the RIIO-T1 period, (e.g. HEAT Alarm Response, Safe Control of Operations and Transmission Test Laptops). Failure to replace these systems as planned will mean that we will have to maintain some systems in service for at least eight years, and in some cases up to twelve years, which will not only compromise safety and system reliability, but increase totex costs due to incremental support costs and embedded efficiencies we will no longer be able to deliver.

Enterprise Content Management is an essential enterprise wide application that will require replacement in the middle of the RIIO-T1 period. This application manages operational drawings and documentation, essential to the safe and reliable operation of the electricity and gas transmission systems, and to the delivery of our capital plan. Failure to maintain this system will expose us and our customers to an unacceptable level of risk.

Other investments, e.g. Operational Site Communications Infrastructure and Field Device Replacement are essential to the delivery and maintenance of SAM and TFO respectively. The breakdown of Other investments by RIIO output is set out below:

RIIO Output	NGET (No of Projects)
Safety	9
Reliability	11
Environment	3
Customer	5
Customer Connections	3

A 50% reduction in Other investments will clearly have a significant impact on our ability to deliver RIIO outcomes, and in some cases will expose us and our customers to an unacceptable level of risk. We maintain that these planned investments are an essential and well-justified component of our overall non-operational capex investment strategy, which has been structured to optimise IT asset lifecycle and deliverability.

Asset refresh and deliverability:

Within either Pöyry's report or the Initial Proposals there are several statements regarding delaying asset refresh work:

> *"…application refreshes planned for the end of RIIO-T1 could be delayed until RIIO-T2"* [in relation to TFO]
>
> *"…we consider that some of the proposed system refreshes in the NGET business plan will not take place within the RIIO-T1 period"* [in relation to other investments]
>
> *"With respect to system refreshes, our Initial Proposals assume are based on the view that whilst IT system will be reviewed regularly (maybe every 5 years) to ensure they are up to date, system refreshes will not happen every time such a review is taken."* [in relation to other investments]

We are compelled to provide further background to the plans set out in our original submission regarding asset refresh and replacement, which are integral to our ability to operate in a safe and efficient manner in the coming RIIO-T1 period.

In parallel with the capability-related activities, a review of the current system landscape, which considered system constraints and dependencies, was completed. The key observation taken from the assessment was that an asset refresh/replacement programme to address ageing systems and infrastructure as well as known support constraints is required.

Whilst we looked across the Transmission applications landscape on an application by application basis (as set out in our submitted Business Plan) to assess when a refresh or replacement would be required, we also verified this against our asset refresh policy, as described in some detail in the 'IS Strategy' annex of our March submission. A final step that we took was to re-test our intended approach against IT Industry benchmarks. This found that we are seeking to execute our refresh and replacement activities in line with common IT Industry practice in the UK:

- **UK High Street and Global Bank** – For leading edge applications (e.g. city, treasury systems etc) they had a 3 year asset refresh cycle, for the branch network it was 5, but for some corporate applications it went up to 7 years because of the cost/complexity of replacement

- **Insurance organisation** – Typically between 3-5 years refresh across infrastructure
- **Telecoms & Networks** – Have a number of different refresh policies across their asset base; most fall within a 5 year refresh cycle
- **Government** – 5-7 years on large government procurements, including interim refreshes – sometimes based on Moore's law[20] for infrastructure/hardware to show "innovation" against e.g. green targets

The key driver for delivering a regular refresh of systems (without changing functionality) is ensuring that systems are supported by vendors so that spare parts are available and software patches can be applied to fix faults and resolve security risks. It must be stressed that we have assessed our requirements on an application by application basis, as opposed to applying a broad principle-led approach to application refresh or replacement.

Although extended support may be available, it is expensive (first year increase is approximately 60%, with 20% increases applied for each subsequent year) and would be time limited. As the rate of technology change is accelerating, the availability of skills to support older software and hardware declines. This is a challenge that we face with our Transmission application landscape, with applications such as Office in the Hand (OiTH).

We are moving towards purchasing more off-the-shelf applications as this is a more economic option, but these economies can only be maintained if we remain close to the manufacturer's upgrade path. Falling behind will lead to increased costs for future refreshes.

Ofgem's suggestion that the refresh approach could be extended to 12 years, based on their reduction in other investment expenditure of 50% is substantially out of alignment with the normal IT market, would increase opex and force us to operate inefficiently and at increased risk, relying on manual workarounds and spreadsheets to replace what would be unreliable and inoperable systems.

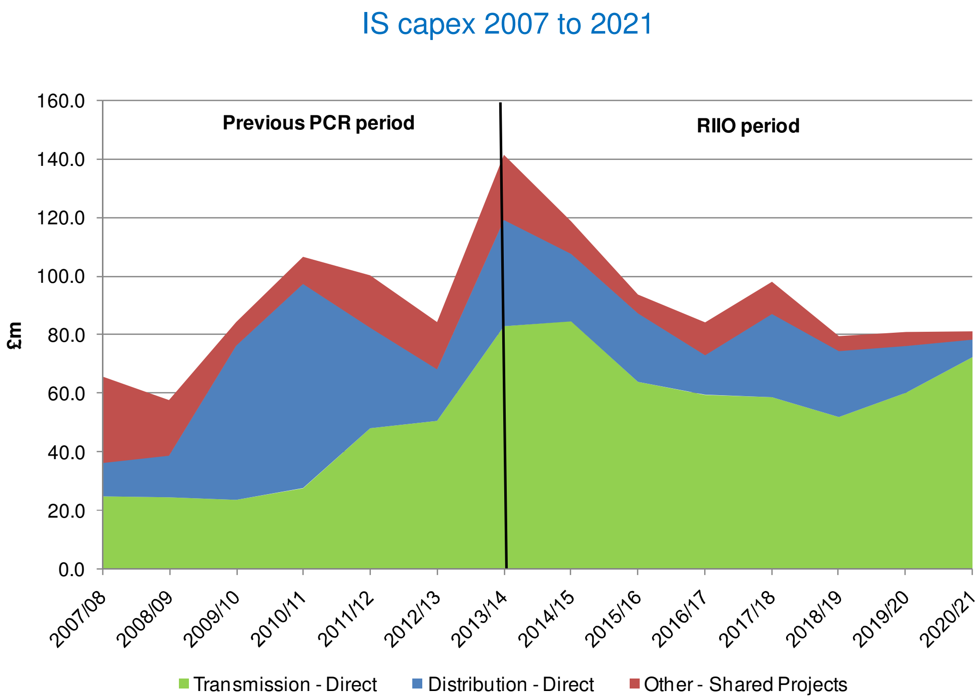
Ofgem's consultants state a further assumption, relating to deliverability, in support of a proposed reduction of 50% to 'other' IT systems expenditure: *"…a lot of IS resources within National Grid's IT department will be consumed in ensuring TFO and SAM are delivered."* This statement does not take into account our flexible IS delivery model which covers all of National Grid's forms of control, not just ETO, and means we have access to significant levels of external resource so that we can deliver all required business IS requirements rather than be limited by internal resource levels.

Over the TPCR4 period National Grid IS have delivered an average of ~£80m of capex projects per annum across our UK Electricity and Gas Transmission, Gas Distribution and Business Support businesses. During this period expenditure has been highest in our Gas Distribution business reflecting the changes in that sector of the industry. Correspondingly, expenditure in our Transmission businesses has been comparatively lower.

In the RIIO-T1 and GD1 period however these relative expenditures are reversed. This is to be expected as our Gas Distribution business leverages the IS investments of the previous period. Our Transmission businesses correspondingly enter a period of significant change and the systems which have supported them in the earlier period require refresh or replacement.

Our combined UK IS capex expenditure during this previous period compares favourably with our proposed expenditure in RIIO-T1/GD1 period. This is illustrated in the following figure:

[20] States that processor speeds, or overall processing power for computers will double every two years



The peak in 2013/14 results from the deferral of Transmission expenditure from the Rollover year, necessitated by the reduced allowances provided through the TPCR4 Rollover review.

Our IS department is a Global function and supports all of our businesses in both the UK and US. As such we are able to concentrate our resources towards those areas with greatest demand at any given point in time. A key benefit of this approach is that these resources are able to bring the learning and experience from one area of our business and apply it on other areas. Also, given our strategy to adopt Commercial Off The Shelf (COTS) applications across our organisation wherever appropriate, these resources are able to bring specific application expertise from previous projects to our current initiatives, promoting efficiency and exploiting learning. A prime example of this is the transfer of many IS resources from the Gas Distribution Front Office program onto our Transmission TFO program.

We acknowledge that there is an increase in our total UK IS project planned expenditure for the RIIO-T1 period as compared with the previous period. The average UK annual expenditure for 2007/08 to 2012/13 was £83m per annum compared with a forecast of £97m per annum for the RIIO-T1 period. We were aware of this forecast increase a number of years ago through our business planning activities, and was one of the key factors in development of our IS Strategy and IS Transformation programme.

Two key features of our strategy and Transformation programme are specifically targeted at this overall increase and securing our ability to deliver our plans;

- Our strategy of adopting common applications across our organisation and moving towards COTS solutions supports deliverability of our plans through;
    - Enabling us to build knowledge, expertise and learning in a reduced number of applications which can be applied across our entire organisation as each area reaches its period of need
    - Deploying COTS applications which are leading solutions in their respective capability areas for which there is an established and sizeable pool of

qualified and knowledgeable resources in the open market

- Providing the potential for re-use of solution components or designs, developed in one area of our business and exploited in other areas thereby reducing design and build (configuration) effort on subsequent deployments.

- Our IS Transformation programme includes a number of elements designed to bring efficiency and scalability to our programme/project delivery capability. These include;
    - Centralising all programme/project delivery into a single IS departmental function. This promotes consistency and familiarity of process and more granular and effective planning and allocation of resources
    - Consolidation of projects into programmes of related work. This promotes re-use, increases efficiency of governance and allows for more fluid management of priorities within programmes. This approach is evidenced in our 'IS Strategy' annex and supporting 'IS Investment Descriptions'.
    - Appointment of two external Solution Delivery Partners, IBM and Wipro through competitive tendering. Key factors in our evaluation of these partners (prior to appointment) included clear capability within;
        - Relevant experience; evidence that the partners had a track record of direct experience in successfully delivering solutions similar to those that are required in National Grid
        - Scale; evidence that they have the volume of suitably qualified and experienced staff to support delivery of our Investment Plans

Furthermore, the McKinsey Benchmarking study shows that we have achieved 'A' Utility status in the capability area of 'Set up centralised skills and establish a vendor partnership model'. This is evidence that we are demonstrating best practice in this area and is further illustrated through the ramp up in delivered capex over the period since 2009/10.

In summary therefore, whilst the planned increase in Transmission IS investment during the RIIO-T1 period (compared with TPCR4) is significant, this represents a much smaller increase in our overall IS programme demand when viewed for the UK as a whole. Acknowledging this increase we have taken measures to ensure that we have both the capability and capacity to deliver our plans and to leverage the knowledge, experience and learning from previous related investments elsewhere in our business.

SAM / TFO

Following the review of the Initial Proposals we note that Ofgem's consultants agree with the need for TFO and SAM, stating that '*these developments will enable NGET (and NGGT) to deliver further efficiencies within direct opex and non-load related capex*'. However, in light of the reduced cost expenditure forecasts proposed of 15% for unsanctioned elements which incentivises us to reduce work and hence outputs in this area, we feel compelled to provide greater insight to the challenges that we are facing and the resulting transformational journey that is required to meet these challenges. This will demonstrate the origins of our requirements, the background to our funding requests, and how Ofgem's suggestions will limit our ability to deliver the required benefits and hence our proposed plan.

With the introduction of RIIO and the move to a low carbon economy, set against a background of significant change involving workforce renewal, infrastructure renewal and increased levels of supply and demand volatility, the UK TFO systems landscape faces a number of key challenges:

- **Increase in capital investment:** Significant volume increases in capital delivery are required over the RIIO period in order to maintain network reliability and meet changing customer needs and energy sources. New capabilities will be required to support this increase in the capital plan, as well as the enhancement of existing tools and processes.
- **Changing network environment**: The expected evolution in the network, including changing supply and demand patterns, and the increasing influence of the carbon agenda will introduce changes to our business environment requiring new capabilities to maintain business continuity and delivery to our customers
- **New technologies**: The challenge of adapting to the introduction of new technologies will represent opportunities for new capability development focused on enhancing the safety, reliability and deliverability of our business outputs through the RIIO-T1 period
- **IS asset health:** Ageing TFO system infrastructure and operating systems must be optimised with the release of new capabilities in order to maintain effective support arrangements and ensure ongoing system asset reliability

In addition to these challenges above, we need to address further capability-related challenges posed by the existing IT system and process landscape. Over the past decade we have introduced a series of efficiency saving programmes, including 'Staying Ahead' and 'Ways of Working', delivering industry-leading capabilities in work delivery and asset management. Whilst these capabilities have been enhanced over time through subsequent refresh and change initiatives, they were delivered to a very different business and technology landscape to that facing us today.

Against this background, a capability maturity assessment using an industry-specific model (Accenture's High Performance Utility Model, HPUM), was undertaken to explicitly position as-is capability, and identify the required future business capabilities that would address the key challenges to be faced (to-be capability), and also to provide insight into the level of change required to be delivered during the next regulatory period.

The outputs from this assessment highlighted a significant journey that we will need to undertake to deliver the required capabilities to meet our challenges in the coming period. In particular, a series of new capabilities have been identified as being essential to business requirements with regards to: delivering the augmented capital plan; implementing enhanced work delivery capabilities; and supporting workforce flexibility and customer service. Underpinning these areas will need to be a focused effort on data quality and data management frameworks. The gap in maturity between the as-is and required to-be states is depicted in the diagrams below (full-scale versions of each of the below have been included in an attachment):

To-be and as-is capabilities

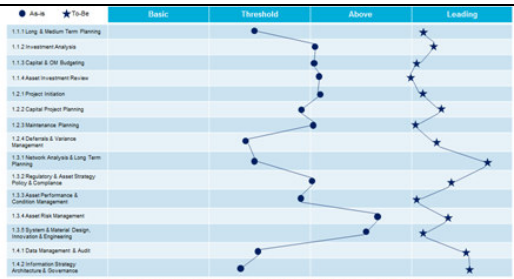


Figure 1: Manage the Asset Infrastructure (Electricity)

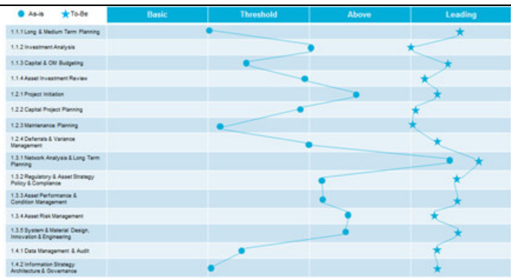


Figure 2: Manage the Asset Infrastructure (Gas)

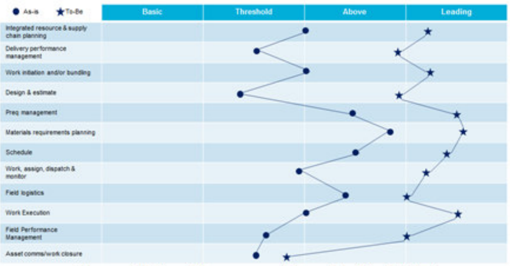


Figure 3: Plan, Manage and Execute (Electricity)

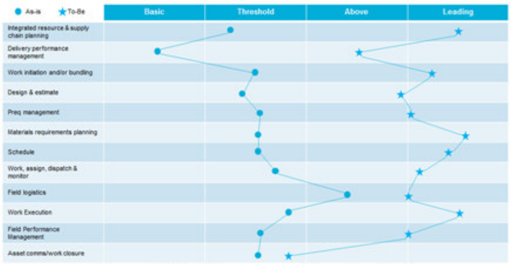


Figure 4: Plan, Manage and Execute (Gas)

TFO as-is and to-be.docx

These diagrams highlight not only the gap between the current state and the required future state, but also the pressure that the business challenges are placing on us to be at or near to the 'leading' end of the capability scale across areas relating to capital delivery, asset management, work delivery and execution. It is clear that minor and incremental enhancements to existing systems and processes would be insufficient to deliver the level of change required.

Our commitment to the TFO and SAM (including RAMM) programmes has been demonstrated during the TPCR4 Rollover period, where required expenditure in excess of £10m has been committed against a Rollover 'allowance' of £4.2m. During this period, the TFO programme has further developed understanding of the scale and complexity of the transformation that it is seeking to undertake. It is from this more mature position that we now understand that the original cost case - which already included an embedded cost challenge of 10% - represents a genuine stretch target.

TFO and SAM forecast costs have been tested against available comparator information from other front-office transformation programmes. As a result of this comparative analysis, we have concluded that whilst there is evidence to support that some non-complex, small scale asset refreshes have out-turned in the range £20-40m, other larger scale complex implementations, similar to our requirements, are more typically in the range £70-100m.

Pöyry recognise the scale and complexity challenge and state in the case of SAM: *"In view of the innovative and "leading edge" nature of this activity there is some risk the necessary expenditure to complete the work may out-turn at a higher figure than expected.'* The same could be said of TFO. Pöyry further note that the "*integration of some 260 sites seems good value"* and raise the question "*whether NGET intend to extend the approach to all assets and, if so, when*". Any reduction in expenditure in this area is therefore questionable given that they recognise the challenge and support the outputs.

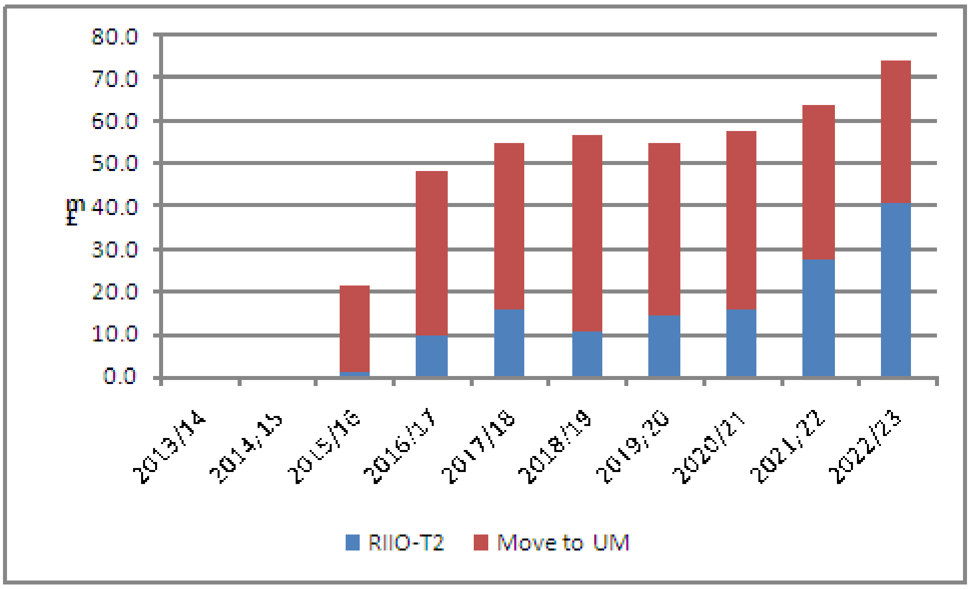
We therefore believe that Ofgem's proposed cost expenditure reductions will mean that we will be unable to fully deliver planned systems enhancements through TFO and SAM, thereby compromising our ability to meet the challenges of delivering RIIO outputs and efficiencies across the period. The reductions in these areas for unsanctioned projects should therefore be reversed.

Capex

Load-related baseline funding

Ofgem states in the 'Cost assessment and uncertainty supporting document', [para 3.14] that 'our "Best View" of expenditure is based on the Gone Green scenario'. If this is the case, then it is difficult to understand why the funding baseline has been reduced below the Gone Green scenario. This reduction would be augmented by the application of uncertainty mechanisms, but this is not without charging stability and volatility consequences that our stakeholders noted that they were particularly concerned about during our extensive engagement activities.

The graph below shows an estimate of the within-period changes to revenue caused by the change to the base funding if the Gone Green scenario outturns. The revenue change has been split by driver, with the red block representing the changes from base funding to uncertainty mechanism (revenue provided by the operation of the relevant uncertainty mechanisms) and the blue block representing the disallowance of RIIO-T2 outputs (revenue provided by the application of the efficiency incentive rate to the apparent overspend). The revenue change would have a direct impact on customer charges, and whilst customers would receive notice of these changes, charging stability would be impacted.



Ofgem then states in the same paragraph that 'We have reduced NGET's proposed baseline by £0.55bn to reflect the greater downside risk that new generation capacity will be less than that on which the Gone Green scenario is based'. We do not understand this statement.

If Gone Green represents Ofgem's Best View of expenditure, then it is unclear why funding needs to be adjusted to reflect a greater downside risk, i.e. even if the probabilistic distribution of new generation capacity is not symmetrical, if Ofgem agrees that the Gone Green scenario is the most likely outcome, then it still represents the most appropriate funding baseline.

Even if Ofgem thinks that the most likely outcome is a lower level of new generation than the Gone Green scenario and are reducing baseline funding such that the volume-drivers work in a more symmetrical manner (a concern expressed following the submission of our first business plan in July 2011[21]), these reductions do not achieve this. The £0.55bn reduction

[21] Ofgem Initial assessment of RIIO-T1 business plans – Supplementary Annex; Page 25; Para 4.60

(post efficiency) is made up of £246.1m (pre-efficiency) for new overhead lines to connect new generators and new demand connections and £318m (pre-efficiency) for wider works schemes in East Anglia. We do not understand the rationale for removing the overhead line costs from the baseline funding whilst not making any adjustments to the associated substation costs. Rather than making the volume-drivers work in a more symmetrical manner, reducing the baseline funding to zero for new overhead lines guarantees that this volume-driver is upwards only.

Ofgem states [Cost assessment and uncertainty supporting document; para 4.64] that 'We do not consider it is consistent with the RIIO emphasis on outputs to undertake a separate reconciliation of OHL actually delivered relative to an assumed baseline of OHL used in the connections. We consider it would be more consistent with the RIIO principles to only include LRE in the baseline that is directly linked to the output measure. Therefore we propose to exclude the OHL component of new connections from the baseline LRE and to remunerate NGET for the OHL component of connections when these are delivered.'

If Ofgem wanted arrangements that were more consistent with the RIIO emphasis on outputs, then the costs of OHL connections could be included in the calculation of the unit cost allowance(s) for generation and demand connections. However, Ofgem states [Cost assessment and uncertainty supporting document; para 4.62] that they 'propose that it would be more efficient to separate the costs of OHL from the other costs of connecting a megawatt of new generation capacity such as substation works'. Given that Ofgem supports this approach of measuring the input (OHL km) rather than the output (MW) in this instance, we do not understand how the use of a baseline is inconsistent with any of the RIIO principles that we have been made aware of. A number of the other uncertainty mechanisms include this feature. It may be that Ofgem is concerned about the associated administrative burden, but the effort required to reconcile against a positive baseline is exactly the same as the effort required to reconcile against a zero baseline.

Strategic Wider Works: Hinkley – Seabank

Ofgem proposes to move the Hinkley – Seabank new overhead line project from the wider works uncertainty mechanism to Strategic Wider Works (SWW). This is as a consequence of the total cost of the project exceeding £500m due to the reallocation of other works to the project following Ofgem's request for us to identify outputs for some non-boundary works (RT1-Ph3-261 refers). In moving the expenditure to the SWW process, funding within the RIIO-T1 period would be subject to Ofgem's review and it is unlikely that any submission or determination could be made prior to April 2014 (we anticipate applying for development consent for the overhead line in January 2014).

The works that are associated with the Hinkley – Seabank overhead line contain many individual elements which may be subdivided into discreet reinforcements with alternative triggers and providing differing outputs, as shown in the table below.

Element	Driver	Boundary output	Cost
New overhead line	First unit of the new nuclear power station (stability)	1,635MW on boundary B13	[text deleted]
Reconductoring works	N-3 conditions and further generation connections	1,365MW on boundary B13	[text deleted]
Aust substation and Nursling QBs	NPS and off-peak	0MW on boundary B13	[text deleted]

The first element of the works is the overhead line construction and associated works to provide the connection at each end of the circuit. This piece of work is essential to allow the connection of the new nuclear power station unit at Hinkley Point and provides an increase in the capacity across the B13 boundary of 1,635MW.

The second element is the wider reconductoring works that are necessary to ensure the efficient management of constraint costs, along with the expectation of future generation connections in both the South West and South Wales area. This element provides additional capability across the B13 boundary of approximately 1,365W. The full potential of this reinforcement is not achieved as the limiting factor moves from being a thermal limit to a voltage limit and the benefit of the reconductoring work is predominantly during N-3 conditions, providing only a modest increase to the winter peak boundary capability.

The third element is the additional non-boundary works (Aust and Nursling QBs - £76m) that were allocated to the reinforcement following Ofgem's request. These works that were driven separately by Negative Phase Sequence considerations and off-peak transfers respectively and do not provide any specific boundary capacity output on the B13 boundary, as specified in our March 2012 submission.

Based on these requirements, retaining the Aust and Nursling works (the third element) as discreet non-boundary elements would prevent the boundary output being polluted by these works and also ensure that the works can be completed for the differing requirements, beyond the trigger of MW across a boundary within the NDP. We therefore propose that these works are included in the general wider works category, similar to the treatment of the replacement of Walpole substation.

As this would reduce the value of the works to below the SWW threshold, it would then be covered by the proposed NDP process. We also propose that the works are split into the two elements identified above. This also resolves the issue we identify below on the use of an average UCA on boundary B13.

We propose that the first element – the construction of the new overhead line – is retained within the baseline at [text deleted], with an output of 1,635MW on boundary B13 in 2019/20 and a UCA of £100.0/kW (pre-efficiency). We propose that the second element – the reconductoring works – is moved to the wider works uncertainty mechanism 'above the baseline' with an output of 1,365MW on boundary B13 and a UCA above the baseline of £182.0/kW (pre-efficiency) and will be assessed through the agreed NDP process to confirm the need case. The tables below show the baseline capabilities, proposed UCAs and capability threshold:

	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
B13	1800	1800	1800	1800	1800	1800	3435	3435

Boundary	Below the Baseline		Above the Baseline
	UCA (£/kW)	Capability Threshold (MW)	UCA (£/kW)
B13	100.0	3,435	182.0

DNO Mitigation measures

We proposed a baseline funding level for DNO mitigation measures which was consistent with the Gone Green scenario, with unit cost allowances for the main drivers of expenditure only. This proposal represented a trade-off between transparency and accuracy, with cost changes due to many 'non-unit' costs ignored (e.g. substation civil costs, etc.). Under this proposal, we would have been exposed to these non-unit costs being higher or lower than the Gone Green forecast.

We do not agree with Ofgem's proposal to cherry-pick the volume-driver for the main drivers of expenditure and simply disallow all costs for non-unit items.

This represents another area where establishing a direct linkage between the output (improved visual amenity) and the cost is difficult. We would be happy to provide further justification for the non-unit element of our DNO mitigation measure cost forecast. The baseline funding allowance to cover non-unit items with volume-drivers for the main drivers remains a pragmatic approach.

If this approach is unacceptable to Ofgem, then an alternative approach would be to extend the number of volume-drivers to cover non-unit items. The nature of these items would make this difficult, and it is likely that the suite of volume-drivers for DNO mitigation measures would become significantly more complex.

RIIO-T2 outputs

Our March 2012 business plan submission was based on the Gone Green scenario. Rather than limiting our forecast to the RIIO-T1 period, we also focussed on the longer term and considered delivery of the necessary primary outputs in RIIO-T2 such that the Gone Green scenario (which runs to 2030) could be achieved.

This is consistent with the RIIO handbook which states that: 'we expect the network companies to focus on the longer term and consider whether it is appropriate to include costs in their business plans that are related to delivery of primary outputs in future price control periods and to long-term value for money'[22].

The handbook goes on to state that: 'Assuming the network company presents a well-justified case for including such costs in the price control for the forthcoming period, providing coherent and comprehensive evidence to support the case, we expect to include costs of this type in the price control'.[23]

In the Proposals, Ofgem has disallowed our entire forecast of £462m of expenditure associated with the delivery of outputs in RIIO-T2 but has not explained why. Subsequent discussions have also failed to adequately explain why this should be completely disallowed.

Unlike the previous price control arrangements, there is no proposed mechanism to fund expenditure that is required in RIIO-T1 to deliver outputs in RIIO-T2. Again, Ofgem has not explained why, but has proposed that any expenditure in this category would be reviewed as part of Ofgem's assessment for the next price control on 'the principle that NGET is fully remunerated, on a cost neutral basis for the efficient costs of delivering the RIIO-T2 outputs'[24].

Ofgem then states that they 'have looked at the potential level of works for RIIO-T2 outputs that NGET might be required to start in the latter years of RIIO-T1' and that they 'consider that the potential level of such works would be fairly modest relative to NGET's overall asset base'. Our forecast for the Gone Green scenario is that the expenditure required in RIIO-T1 to deliver outputs in RIIO-T2 is £462m. This is over 14 times greater than the effective materiality threshold that Ofgem has proposed for other uncertain costs (1% of average forecast base revenue following the application of the efficiency rate of 48% is approximately £30m). There is no explanation for these inconsistencies of approach to materiality of spend.

Consequently, Ofgem 'do not anticipate this would have any significant implications for NGET in terms of its cash flow or credit ratings to warrant any measures in addition to the totex sharing factor ahead of the efficiency assessment at the next price control'[25]. Ofgem has not

[22] RIIO handbook, paragraph 6.27
[23] RIIO handbook, paragraph 6.28
[24] 'Cost assessment and uncertainty Supporting Document', paragraph 4.35
[25] Cost assessment and uncertainty Supporting Document, paragraph 4.37

provided any further details of this assessment and has not mentioned the potential impact on charging volatility.

Our preference would be for a base funding allowance for RIIO-T2 outputs, but in any case Ofgem's financeability assessment must be consistent with the proposals for this category of expenditure. Given its potential scale, it is also crucial that a mechanism to deal with this category is agreed. We have proposed a number of competing options in our detailed consultation response.

We set out our proposal in this area in a separate Supporting Information document entitled 'RIIO-T2 outputs'.

Pre-construction works

Ofgem has proposed to allow pre-construction funding for projects included within the baseline (£54.2m) and for Strategic Wider Works projects (£46.0m). Ofgem has not allowed a sum of £24.4m for projects that are in neither of these two categories. Since we provided the spreadsheet that Ofgem has used to define this value and the parallel work on defining outputs and UCAs for the new boundary, three potential additional projects have been identified which increase the pre-construction funding in this category to £28.5m.

Ofgem incorrectly considers this sum to cover activities for outputs delivered in RIIO-T2, when it is actually for outputs that are above the baseline values set by Ofgem and, if customers drive a need for the works, would be progressed within the RIIO-T1 period. If the Ofgem Best View were to occur, we would be under-funded during RIIO-T1 as the unit cost allowances (UCAs) proposed by Ofgem exclude the pre-construction costs identified here.

Ofgem suggests that no supporting information for this amount has been received. The calculation of the pre-construction funding, the projects against which it is derived and the ultimate output of the projects were included within the spreadsheets that have been provided to Ofgem supporting the baseline definition and the UCA calculations, except the slight increase due to the definition of a new boundary. Ofgem has accepted the related UCA calculation where the pre-construction funding has been excluded, so not including these costs is inconsistent with the other Ofgem decisions.

In the Final Proposals supporting document for SP Transmission and Scottish Hydro Electric Transmission (SHETL), Ofgem includes pre-construction funding for SHETL against 'Future Design Costs' at a total of £15.7m (23% of total pre-construction funding of £67.6m). The value proposed for NGET's pre-construction 'Future Design Costs' is £28.5m, which represents 22% of the total pre-construction costs (£54.2m + £46.0m + £28.5m = £128.7m) which benchmarks particularly closely to the Ofgem allowance proposed for SHETL.

Question 6: Do you consider that our proposed uncertainty mechanisms for NGET (TO) are appropriate?

National Grid response:

Our response to Initial Proposals for the Critical National Infrastructure, flood and erosion protection and GB & EU market facilitation uncertainty mechanism are described above. In addition, we make the following points:

- **Whilst accepting that our generation uncertainty mechanism was complicated, Ofgem's counter-proposal is too simple to reflect the wide range of uncertainty faced over an eight-year control period. We therefore propose an alternative of intermediate complexity.**

- **We support the adoption of our demand-related infrastructure uncertainty mechanism.**
- **We challenge two of the changes made to the wider works uncertainty mechanism, and in particular suggest an alternative treatment for the Hinkley-Seabank reinforcements.**

Generation connection uncertainty mechanism

As part of Initial Proposals, Ofgem has significantly simplified our generation connection uncertainty mechanism proposals. The substation cost volume-driver (£/MW of new generation) and the within-zone cost volume-driver (£/surplus zonal MW) have been replaced with a single substation cost volume-driver (£/MW of new generation). We set out our analysis of the Ofgem proposal and include a simplified alternative to our original proposal in a separate Supporting Information document entitled 'Generation Connection Uncertainty Mechanism'.

Demand-related infrastructure uncertainty mechanism

We support the inclusion of our proposed uncertainty mechanism for demand-related infrastructure.

Network Development Policy

The Ofgem proposed inclusive conditionality for the Network Development Policy (NDP) to support the progression of Wider Works outputs is overly restrictive. In many cases, customers seeking new connections put in place significant financial securities to allow the progression of the necessary reinforcement works whilst the customer's project may not be within the generation and demand scenarios consulted on with industry. In these instances, waiting for Ofgem approval prior to the progression of works could result in a delay to the customer's connection date. Additionally, the majority of investments for boundary reinforcement have lead times greater than three years and so many projects would be excluded from being automatically included within the NDP process. Our intention is that the criteria specified are mutually exclusive, such that if any one of these criteria is met, the development of the project is determined by the requirements of the NDP.

We note that Ofgem does not make any proposal to include a de-minimis value below which projects would automatically be included within the NDP mechanism. If this were to remain, it is possible that a small project such as an MSC with a value of less than £10m would qualify, using the criteria defined above, into the Strategic Wider Works process. On the balance of projects identified within our submission, we proposed a value of £150m below which investments would be automatically determined through the NDP. We would welcome discussion with Ofgem on a suitable value for this threshold.

Wider works uncertainty mechanism

Beyond the cost reductions, Ofgem proposes to make two changes to our proposed wider works uncertainty mechanism;

1. Apply an average UCA to boundary B13
2. Introduce bandings for 'above the baseline' on boundaries B14e and EC5

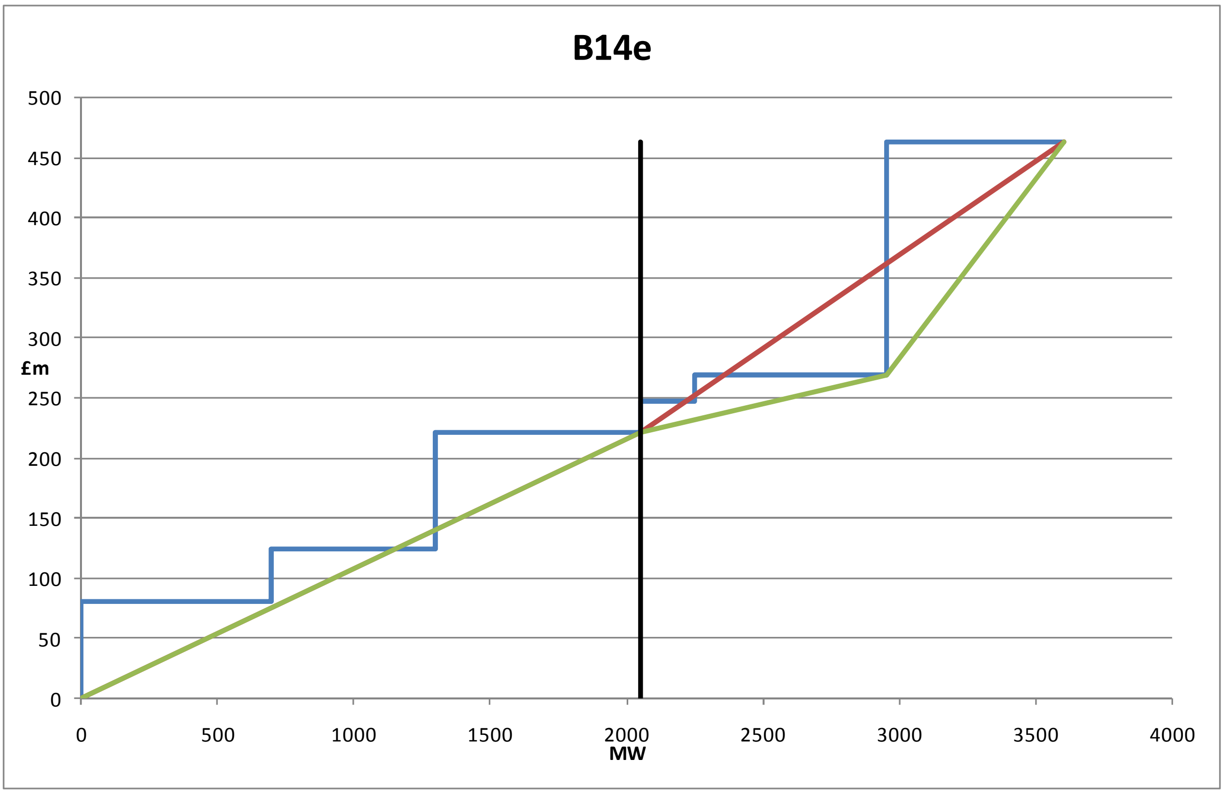
As a consequence of moving the Hinkley Point – Seabank reinforcements to Strategic Wider Works (SWW) (as discussed above), there are no longer any reinforcements that are associated with this boundary. Ofgem proposes to use an average of all other UCAs (which equates to £65.7/kW) for this boundary should any future reinforcements be identified. We do not understand the logic of using this method of calculating a UCA as there is no relationship between the reinforcement costs and the different boundaries as is evidenced by the variation in boundary UCAs from £9.6/kW to £548.8/kW. Indeed, our original UCA for boundary B13 was £155/kW, recognising the significant investment that is required to increase its capability above the current level. Our proposal to subdivide the Hinkley Point – Seabank reinforcements into separate elements resolves this and would result in UCAs of £100.0/kW ‘below the baseline’ and £182.0/kW for ‘above the baseline’.

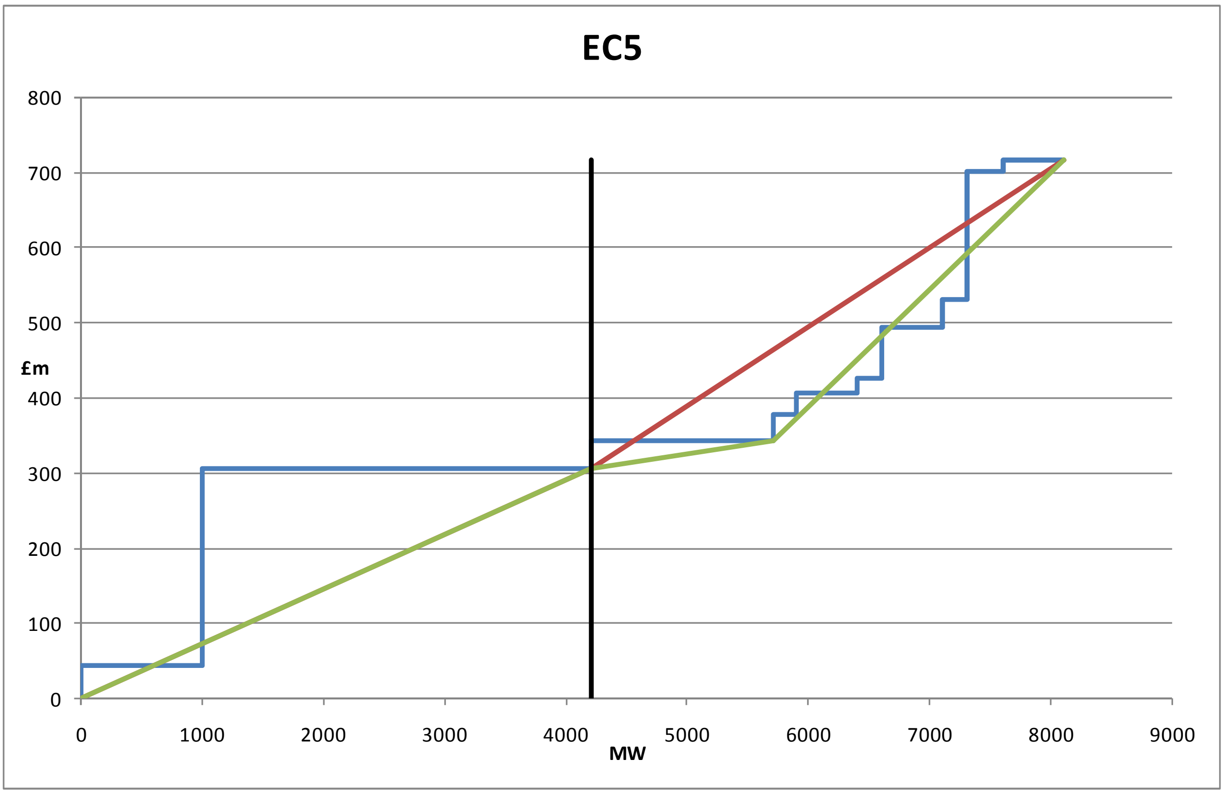
Ofgem also proposes the introduction of bandings for ‘above the baseline’ reinforcements on boundaries B14e and EC5 and we understand that the ‘threshold’ level is defined by the £/kW of the reinforcement that is being proposed. Considering that the principles of RIIO are founded on defining outputs as the principal measure, it is inconsistent to use the input-based reinforcement cost/kW to define which UCA is selected. Ofgem has stated that the ‘threshold’ levels are based on judgement. We are concerned with this approach and that there has been no analysis of the ‘threshold’ levels. The proposed banding of UCAs on an input basis is further complicated by the allocation of costs between boundaries in the calculation of the reinforcement cost/kW.

Instead of using this approach, we propose using a stepped approach to ‘above the baseline’ reinforcements for both boundaries B14e and EC5 with thresholds that are output based and reflect the intended development of the boundary. This will enhance the accuracy of the uncertainty mechanism and incentivise the correct behaviour in capacity development. Our proposed ‘threshold’ levels and associated UCAs (prior to Ofgem efficiency) for both of these boundaries are shown below.

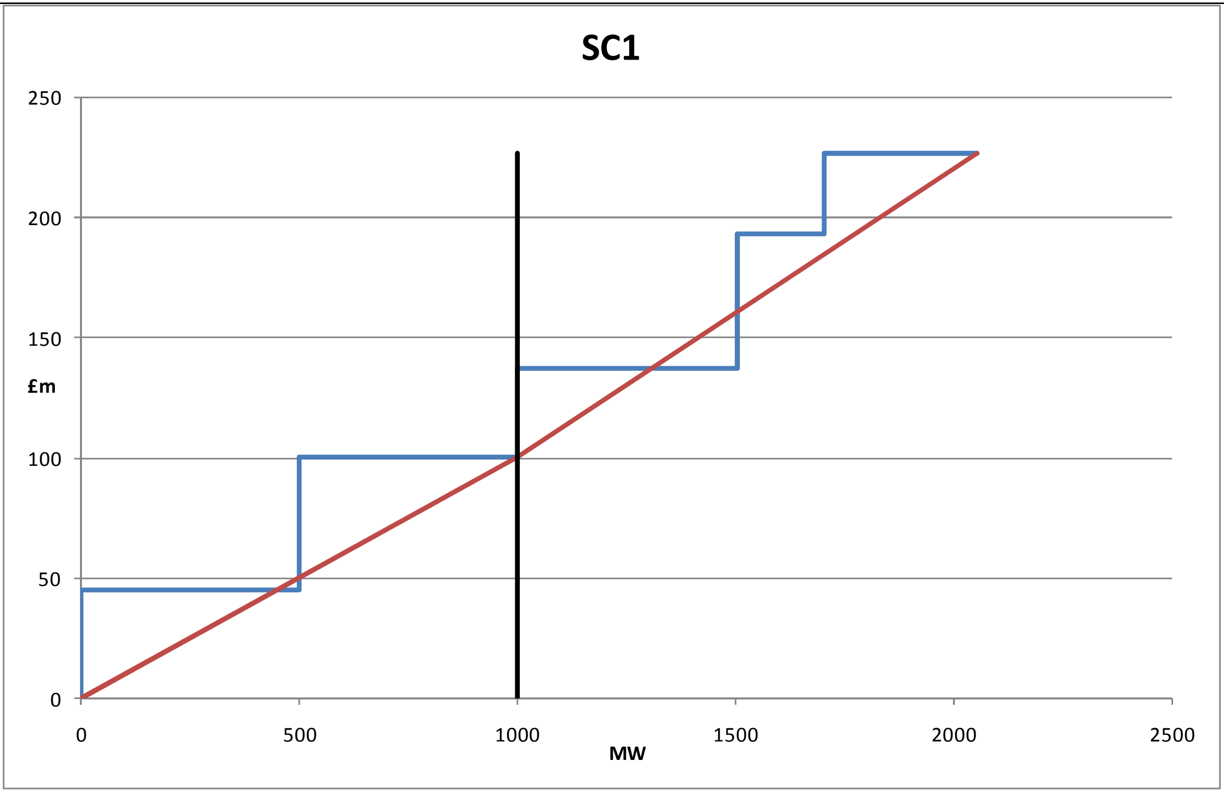
Boundary	Below the Baseline		Above the Baseline	
	UCA (£/kW)	Capability Threshold (MW)	Threshold (MW)	UCA (£/kW)
B14e	107.9	9,950	< 10,850	53.2
			> 10,850	298.5
EC5	72.7	6,800	< 8,300	25.4
			> 8,300	155.1

The accuracy of the proposed UCAs can be seen on the following graphs, where the blue line shows the stepped nature of reinforcements, black line shows the baseline capability threshold, red line shows our original proposed UCAs and the green line the revised proposal using the threshold limits defined above.





Since we provided our supporting spreadsheet for the boundary UCAs, we have identified three additional reinforcements associated with the 'above the baseline' capacity development across the new boundary SC1. This identifies the relevant UCA for 'above the baseline' as £120.3/kW (or £115.4/kW post-efficiency). These are shown in the graph below.



Detailed data table 4.12 baseline does not reflect the correct boundary capabilities. This is discussed in our response to chapter 2, question 1 of the Outputs, incentives and innovation supporting document above. Similarly, table 4.15 would need to have the capability threshold for boundary B14 to be adjusted to 10,600MW.

Meeting planning requirements (undergrounding) uncertainty mechanism

We support the inclusion of our proposed uncertainty mechanism for meeting planning requirements.

Financing costs for the advancement of asset replacement uncertainty mechanism

As part of our well-justified business plan, we showed how (if Gone Green or a similar generation and demand scenario occurred which required an ambitious spend profile in the early years of the RIIO-T1 period) we would delay some of our asset replacement work to make the plan as a whole more deliverable. As was made clear in our submission, this was just one view of many possible future scenarios. If the works related with new generation (in particular) were to be triggered more slowly and over a longer period, we would wish to move our asset replacement spend back to the beginning of the period. This would avoid the temporary increase in network risk (i.e. we would again be replacing our assets in line with their Replacement Priorities), and would also make more efficient use of our resources (internal manpower, external manpower and system access opportunities).

The financing costs associated with moving from post- to pre-profile adjustment plan has a financing cost of £76m over the RIIO-T1 period based on our financial package proposals and our March 2012 non-load related submission. In our July 2011 submission, we had proposed that the load-related uncertainty mechanisms be developed to include a dead-band such that we were held whole against the time value of money costs associated with efficient non-load related work advancement.

Initial feedback from Ofgem indicated that they would prefer to see a more positive option which allowed more on the basis of delivery of advanced non-load related works. Having said this, table 3.5 of the Initial Proposals ‘Cost assessment and uncertainty Supporting Document’ stated about a NLRE advancement mechanism “Do not intend to include. The efficiency incentive will provide some protection to financing costs."

In not recognising these costs, Ofgem is penalising us for developing a business plan which took appropriate consideration of adaptability and robustness to change. We note that the forecast potential financing cost of £76m is approximately two and a half times the effective materiality threshold proposed by Ofgem for other uncertain costs.

To address this, the simplest option would be a comparison of year-on-year NOMs targets which would be undertaken at the end of RIIO-T1. This comparison can be used to identify any advancement and our unit costs can then be used to quantify any additional financing costs associated with advancement. Adjustments can then be made to correct this on an NPV neutral basis using the financial model.

Enhanced security re-opener

The Initial Proposals do not include any baseline funding for NGET TO physical security costs (either capex or opex) and instead propose that funding will only be triggered in 2016 and 2019 by separate submissions under the re-opener uncertainty mechanism. Whilst we agree with the proposal for re-openers in this area due to the uncertainty involved, Initial Proposals do not fund the significant levels of expenditure we have already incurred to date for completed projects and those which are backed up by value for money audits. The Initial Proposals baseline should be updated to reflect these costs and include all opex costs on an ex ante basis, with the re-openers used to adjust from this baseline position if required. This would represent a more balanced view of the uncertainty and our cashflow risk in this activity, as well as ensuring adherence to the logging up principles from TPCR4.

We therefore propose the following, more reasonable position for capex schemes on an ex ante basis:

- Schemes which have had a Value For Money 2 audit (VFM2) to be funded at the level within the VFM2
- Completed projects which have not yet had a VFM2 but are just awaiting commercial completion with the contractors to be funded at the forecast level for 31st March 2013
- Schemes which have a VFM1 audit to be funded at the VFM1 audit level

All these costs should be entered into the Final Proposals base revenue allowances from 1st April 2013.

In addition, opex costs should be funded on an ex ante basis in their entirety. These costs are a function of the PDSA contract unit cost multiplied by the number and type of sites, and costs of the Alarm Receiving Centre (ARC). Information required to assess the efficiency of the PDSA unit costs have already been sent to Ofgem and the ARC is already in place, again with details already sent to Ofgem. The only variable that is subject to any uncertainty is the timing of when sites will be commissioned but there are defined dates which set this point so funding the relevant costs on an ex ante basis seems the most appropriate approach.

Ex ante funding on this basis would create baseline expenditure as outlined in the table below:

	£m
Capex	[text deleted]
Opex[26]	[text deleted]
Total	[text deleted]

This compares to a current forecast of expenditure by the end of 2012/13 of [text deleted], and a total expected cost for the projects currently required of [text deleted]. At approximately one third of this total expected spend, it represents a more balanced level at which to set the

[26] Includes £7.5m opex to the end of 2012/13 and £41.9m forecast for the RIIO-T1 period.

as a baseline.

From a process perspective, the use of re-openers would work more efficiently if there was sign-off from Ofgem on each of the VFM2 audits as they were completed during the RIIO-T1 period, with any further work required completed at this point. This would ensure both that the review occurs in a timely manner thus allowing for any key issues to be resolved in readiness for future projects, and that regulatory burden is minimised. If this sign off was not finalised until the re-opener windows, necessary information to support the analysis is unlikely to be readily available for those projects which had closed years earlier, and teams would need to be remobilised to answer questions, diverting resources from other projects and increasing costs overall.

Ofgem recognised we need to discuss the funding in this area, and we are currently in dialogue with them.

Chapter: Seven

Question 7: Do you consider that our proposed baseline for NGGT (TO) has been set at an appropriate level?

National Grid response:

We consider that the proposed baseline for NGGT (TO) is set at an inappropriate level in the following areas:

- **Pipeline unit costs** – the unit costs proposed in Initial Proposals are ill-founded and will create a significant shortfall in funding for pipeline projects to reinforce the NTS.
- **Compressor unit costs** – similarly, the unit costs proposed in Initial Proposals for compressors are ill-considered will provide insufficient funding for projects to comply with environmental legislation and to reinforce the NTS.
- **Asset Health** – whilst of a lower level of materiality than the above unit costs, the proposed reduction to Asset Health volumes expenditure will result in a greater level of network risk by the end of the RIIO-T1 period than has been targeted.
- **Network Flexibility** – the proposed treatment of the Lockerley compressor and Bacton rationalisation projects will potentially expose end consumers to greater risks through increased system management costs.
- **Appropriate funding for Planning activities** – an appropriate funding mechanism is required to ensure that there is not a considerable cash impact on NGGT resulting from pre-capacity signal activities being carried out.

We set out below our views and supporting evidence to support our position in these areas, and provide supplementary detail and evidence in our supplementary information document, 'NGGT_unit_costs'.

We consider that the proposed baseline for NGGT (TO) is set at an inappropriate level in the following areas:

- **Capex RPE -** Not including long term forecasts for steel prices we are exposed to in the Initial Proposals is understating the risk of RPE exposure
- **Real pay –** Pay growth figures which are half that of the Fast Track outcome will create pressure for our people with critical skills to leave and causes challenges for attracting new recruits

- **Efficiency –** catch-up efficiency has no sound basis and ignores benchmarking evidence
- **Business support benchmarking:** Logic errors and inconsistencies within the business support benchmarking methodology ignore future growth in cost drivers and benchmarking evidence
- **Direct opex** – errors in the calculations used to disallow expenditure on rectifying Coal Tar Enamel (CTE) deterioration create a false level of allowances
- **CAI** – no funding of increasing IS support costs and arbitrary reductions will erode benefits from IS innovations
- **Non-operational capex –** Arbitrarily reducing IS projects by 50% will hit key outputs and mean we have to keep ageing systems on line for eight to twelve years
- **Physical security -** A zero baseline for mandated physical security work undermines previous funding promises and perpetuates cashflow risk we have borne during the TPCR4 period

The RPE and efficiency assumptions are discussed further under response to question 1 above, with physical security costs discussed in response to question 8 below.

Pipeline unit costs

Initial Proposals include the costs for the pipelines required to remove the need for services from the ageing Avonmouth LNGS facility, and provide unit costs for these 915mm diameter pipelines. No unit cost is provided for any other diameter pipelines.

Whilst we welcome Ofgem's decision to fund the pipelines on an ex ante basis, we do not agree with the unit costs which have been applied to calculate the proposed allowance for this work.

<u>Proposed pipeline unit costs</u>

The unit cost used for these projects has been taken from a dataset provided by GL Noble Denton (engineering consultant engaged by Ofgem) (GL). Due to commercial confidentiality, GL are unable to provide any further information about the dataset beyond that stated in their report to Ofgem. We understand from this that the dataset is based upon:

- A feasibility study – GL are unable to provide outturn costs for these projects, therefore the unit cost assessment included in Initial Proposals is limited to estimated costs from a feasibility study which have been used to derive in-country costs with the use of 'calibration factors'. Such estimates introduce uncertainty and inaccuracy to any assessment, and will typically underestimate the final cost as they do not include emergent issues and compensation events which are common to most significant construction projects, such as adverse ground conditions and weather.

- Pipelines to be constructed overseas – GL are unable to confirm where these projects were, however have stated that they were designed to the ASME B31.8 standard where possible, and to the IGEM/TD1 standard (used in the UK) where ASME was not applicable. Without further detail, this difference in design standard prevents a comparison of factors which have a material bearing on construction costs, such as:

    - length of construction season: where the climate allows for a longer construction season, there are fewer instances of mobilisation and demobilisation activities

- environmental standards: different countries apply different standards for factors such as control of water run-off into local watercourses, ground reinstatement (for example scrubland requires far less reinstatement activity than arable farmland), noise control, restriction of permitted working hours and the limitations placed on the transportation and movement of plant
- safety standards: for both construction and commissioning activities, for example the proportion of welds which require testing (UK standard required field testing of 100% of welds, whereas the ASME B31.8 standard requires between 10% and 75%, depending on location of the pipeline)
- design standards: identification of the impact of specific differences between the ASME B31.8 and IGEM/TD1 standards, which include:
  - permitted pipeline locations – TD1 does not permit pipelines in town areas, whereas B31.8 does
  - pipe wall thickness
  - depth of burial
  - field weld inspection
  - pressure testing
  - intermediate block valve spacing
  - minimum building distance proximities
- Other factors: for example whether the pipeline was built above or below ground.

The above factors have an impact on the length of a pipeline project, the materials used and the cost of construction.

Other concerns include some errors and omissions in the data used in Ofgem's assessment of unit costs:

- A simple RPI uplift of the GL data from 2006/07 prices to 2009/10 prices has been used. This approach ignores the real price effects on materials and labour incurred during this three-year period, leading to understatement of the unit cost. This simple error should be corrected within Ofgem's modelling.

- Since the publication of its Initial Proposals, Ofgem has confirmed that GL's classification of 'normal' and 'difficult' fall within NGGT's own classification of 'normal'. It is therefore not appropriate to use GL's 'normal' pipeline unit costs as this represents only the lower cost sub-set of all projects. If Ofgem continues to use this data it should consider the use of the GL classified 'overall' unit cost. We set out in our supplementary information document, 'NGGT_unit_costs', the corrected calculation of this unit cost, however it should be noted that we still believe this to be an invalid source upon which to set a unit cost. This simple error should be corrected within Ofgem's modelling.

- It is unclear from the report whether these cost estimates include only the Main Works Contractor costs, or whether they allow for total costs (for example, including materials, essential project services costs, easements and compensation costs). These costs typically make up around 35% of total construction costs (circa 20% for materials and 15% for other non-Main Works Contractor costs).

We have included further detail on this in our supplementary information document, 'NGGT_unit_costs'.

The lack of transparency in relation to Ofgem's (i.e. GL Noble Denton's) numbers, and the lack of outturn costs for these projects (assuming they were built), mean it is not possible for any party to verify the applicability of these costs to future GB pipelines. Without more information on how Ofgem's unit costs have been derived, this failure of due process risks material mistakes in Initial Proposals.

For the reasons set out above, we conclude that the data used by Ofgem does not form a valid basis for our unit costs.

Comparison to TPCR4 allowances

We note the pipeline unit costs for the Avonmouth pipelines included in Initial Proposals are 16% below those agreed for TPCR4 on an equivalent price base. However, average construction prices have increased significantly in excess of RPI over the TPCR4 period providing further evidence that the proposed pipeline unit costs for the Avonmouth pipelines are far lower than an efficient market price.

Comparable international pipeline cost data

Recent research into available international pipeline cost data has demonstrated that data is publicly available from FERC (Federal Energy Regulatory Commission in the USA) and the EIA (US Energy Information Administration). Additionally, we have procured additional data from Ziff Energy Group[27].

This data, which we have since shared with Ofgem as supporting evidence for our pipeline unit costs, demonstrates that in common to GB there is a wide range of unit costs for pipelines in the US and that in general the average unit cost for both 915mm and 1,000mm+ diameter pipelines are broadly in line with those we have presented in our RIIO-T1 business plan. There are valid regional differences to take into consideration when normalising the data to make it directly comparable to GB, such as planning and design standards (some of which are described above), however this data provides a reasonable indication of the magnitude of efficient pipeline unit costs.

For 915mm diameter pipelines, a simple weighted average, once outliers are discounted due to either extreme length (beyond anything we plan to have to build in Great Britain) or extreme high costs (which would suggest exceptional circumstances or cost items), is £2.47m/km. When compared to Ofgem's unit costs of £1.23m/km, this external data demonstrates the disparity which exists between Ofgem's unit cost and what is, in reality, the expected cost.

We have included the detail on these datasets in our supplementary information document, 'NGGT_unit_costs'.

Costing of Avonmouth pipelines

Within our RIIO-T1 submission, all pipelines were included as incremental, to be funded by appropriately triggered revenue drivers. We included indicative costings of potential pipeline projects which could be triggered during the RIIO-T1 period to aid in the financeability assessment of the package, and stated that this was calculated using generic business planning assumptions. Revenue drivers should be calculated on a more detailed level, using intelligence such as route parameters (for example, terrain and number of crossings). As such, we do not consider the application of a very simplistic unit cost approach to be appropriate as more detailed information is available on the likely pipeline parameters of this live project.

Subsequent to our RIIO-T1 submission, we proposed to Ofgem a methodology for calculating

[27] Ziff Energy is an expert consulting company to the international energy industry.

revenue drivers which takes account of these specific complexity factors. As the funding for these pipelines is included in Initial Proposals as ex ante, it would be appropriate to calculate the cost of these works using the best information available. Since the publication of Initial Proposals we have been working with Ofgem to review this very granular information, with a view to agreeing an appropriate costing methodology, and will continue working closely with Ofgem to create a meaningful library of pipeline unit costs over the coming weeks to allow the formation of an appropriate set of Final Proposals.

Way forward

The database we use to challenge and assess tender responses for pipeline construction projects contains a large amount of data on efficient unit costs for pipelines in Great Britain. We propose this database is validated against outturn costs of recent pipeline construction projects, and used to create a library of unit costs ahead of Final Proposals which can be used in conjunction with project-specific parameters to calculate an allowance specific to that project. This approach is complementary to that proposed in the calculation of revenue drivers for incremental capacity. Once created, the library of unit costs should be tested to the international benchmarking data to assess appropriateness and efficiency.

Our proposal will calculate appropriate funding once the required scope of works is known, with reference to a library of unit costs to be agreed ahead of the RIIO-T1 period. Such an approach would remove the potential for windfall gains and losses created by the methodology included in Initial Proposals, create transparency and provide an appropriate incentive for efficient delivery to a targeted cost.

Compressor unit costs

We were disappointed to see in Initial Proposals that Ofgem had created its own modelling of compressor unit costs based on a subset of historical outturn costs for recent compressor construction projects in Great Britain, and feasibility study estimates for new compressor units in Alaska which exclude a number of required cost items, which have not been built. We conclude this is not an appropriate data set on which to base our unit costs.

Ofgem's modelling is split into two distinct parts; one calculates a unit cost for electric-powered compressor units, the other for gas-powered units. This approach does not take account of the large degree of commonality between the two different types of compressor build, including (but not limited to) site preparation, civil works, safety systems, pipe work and security.

Our RIIO-T1 submission was based on the assumption of portfolio average unit costs (equivalent to the 'most likely' unit cost within the electricity TO submissions), reflective of the degree of complexity of works within the plan. Ofgem has responded with the provision of unit costs which can be considered equivalent to the 'lower' unit cost in the ETO submissions, which therefore takes no account of the differing levels of complexity inherent in similar types of construction projects.

On reviewing the assumptions which underpin the models, it is clear that Ofgem has created a model which attempts to estimate the cost for the simplest greenfield compressor construction projects. The historical data used has had cost elements removed which Ofgem considers to be 'exceptional' in nature (two thirds of the dataset used to calculate the unit cost included such elements), so by definition the resultant unit cost is suitable only for only the simplest of greenfield projects.

We agree that the approach taken for calculating the unit cost is suitable for such simple projects (once the input data has been corrected and a fixed element relating to Main Works Contractor and client costs is recognised), however we need to ensure that where the scope of any future project necessarily includes complexity as a consequence of scheme variation factors, driven by environmental requirements, site specific factors, duty volatility and expected operating envelope, we find a way to efficiently fund the required work. To assist in this work, we will provide Ofgem with further detail on our current expectations of the high level scope requirements for our emissions-related investments in the near future.

Below we set out more specific observations on each of Ofgem's two unit cost models. Detail supporting these observations is included in our supplementary information document, 'NGGT_unit_costs'.

Gas turbine compressor unit cost

The gas turbine compressor unit cost has been based on estimated costs sourced from a single feasibility study for new greenfield gas compressor units in Alaska. It is important to note three things:

- The compressor units have never been built, therefore it is not possible to validate the feasibility study cost estimates against an outturn cost, which would take into account any factors not fully considered in the study.
- The cost estimates are incomplete as they appear to exclude such items as security, backup generation, client costs. Correction for these excluded items could increase the unit cost by up to 100%.
- No account or consideration has been taken for differences in design, safety and environmental standards for the construction of compressor units between the US and those which currently apply in Great Britain. Without visibility of the detail behind the feasibility study we cannot quantify the potential effect, however it could be material.

We believe that if account is taken for the above factors, the resultant unit cost would be appropriate for use to fund a simple, greenfield project. We will continue working closely with Ofgem to reach a suitable base dataset based on their modelling upon which to agree a unit cost for constructing gas turbine compressor units in Great Britain.

Within Initial Proposals Ofgem, as an aside, there is a reference to a report on the approach to legislative compliance with the Industrial Emissions Directive (IED) taken by the German TSOs. This comparison is invalid as the level of investment and replacement activity over the last decade on the German fleet, driven by local legislative requirements which are more onerous than in the UK, has led to a very different starting point from which to meet compliance with the IED.

Further detail on this in included in our supplementary information document, 'NGGT_unit_costs'.

Electric drive compressor unit cost

Ofgem's electric drive unit cost is based on historical data from recent compressor unit construction projects, however it does include the use of an erroneous value for the calculation of Main Works Contractor costs (£5.5m too low) which was corrected post submission of our RIIO-T1 plan. From the historical data, Ofgem has removed all items it considers to be 'exceptional', such as long high voltage overhead line connections to the electricity network and associated substations. We agree it is appropriate to remove these items where they are not required (i.e. where only a short HV connection is required); however, it is inappropriate for situations where they are needed. The scope of many of our future projects demonstrably includes many of these items.

The unit cost included in Initial Proposals is a simple £/MW, with a fixed allowance where a new HV connection is required (but no allowance where an existing HV connection would require upgrading). Any compressor construction project will require a base amount of work including (but not limited to) site preparation, civil works, safety systems, pipe work and security, regardless of the size of the compressor unit to be installed. The simple £/MW approach will therefore always underestimate the cost of smaller units. This conclusion is supported by the Juran GTBI report included in our supplementary information document, 'NGGT_unit_costs' and mentioned below.

Such a simplistic approach does not work in reality; for example, the cost associated with the installation of two 8MW units will be larger than the cost of a single 16MW unit due to the additional infrastructure that two units require.

Comparable international compressor cost data

In order to inform Ofgem's assessment, we have collated a range of comparable data (for use as a benchmark) from a variety of new sources, which we detail in our supplementary information document, 'NGGT_unit_costs'. These sources include:

- European benchmarking data from the Gas Transmission Benchmarking Initiative (GTBI) for 67 new gas transmission compressor units
- Procurement data from three Original Equipment Manufacturers (OEMs) for compressor machinery trains, requested and received during the establishment of a commercial framework agreement
- Publicly available compressor construction costs
- Responses from an external costing exercise for the next compressor project driven by existing environmental legislation

This body of evidence demonstrates that the modelled unit costs for both gas turbine compressors and electric drive compressors included in Initial Proposals, as they stand, generate a significant shortfall when compared to outturn costs of a large number of new compressor units around Europe, and current market prices for delivery of such investments. It also clearly demonstrates that, at a component level, the unit costs are below the prices we would have to pay for the plant as quoted by OEMs for compressor machinery trains.

It is clear from this data that there is a very large disparity between many of the costs incurred in the construction of compressor units and the unit costs included within Initial Proposals. We believe, however, that given specific corrections to the input data to Ofgem's modelling detailed in our supplementary information document, 'NGGT_unit_costs', a realistic set of unit costs can be generated for simple, greenfield projects and that this data can form the basis of unit costs going forward.

Way forward

Agreement as to the scope and complexity of future projects is the key stumbling block, as Ofgem's model assumes future projects will be simple, greenfield compressors in close proximity to suitable HV supplies where necessary. In contrast, our model assumes historical levels of complexity, including intrusive development on existing operational sites, will continue. In reality, there is a material degree of uncertainty in the requisite scope for each of these sites as site specific requirements are ascertained during the Front End Engineering Design (FEED) stage of each project, and the technology solution required is agreed with the environmental regulators (through the assessment of Best Available Technique, or BAT).

The additional information we have agreed to provide to Ofgem on the high-level scope requirements for our emissions-related investments will demonstrate the potential range of complexity factors and requirements for future compression construction projects, and aid the creation of a menu approach to setting allowances for this necessary work, in a manner akin to that adopted for NGET in the use of unit and non-unit costs to reflect differing levels of complexity and scope for similar asset types, which would build on Ofgem's unit cost modelling.

We would like to work with Ofgem to develop and agree a methodology which will calculate appropriate funding once the required scope of works is known, with reference to a library of unit costs to be agreed ahead of Final Proposals. Such an approach will remove the potential for windfall gains and losses created by the proposed methodology, create transparency and provide an appropriate incentive for efficient delivery to a targeted cost.

Asset Health

To enable a full understanding of the asset health conclusions set out in the associated document: 'RIIO-T1 Summary report – GAS', a full version of the report produced by Pöyry was made available to NGGT. We have sourced additional new information in support of three secondary assets most materially impacted by the proposals, to further demonstrate the need case and requirement for sufficient allowances to perform essential works to maintain the safety and integrity of our assets. It remains our view that our RIIO-T1 submission represents an efficient balance of investment and network risk, and the reductions set out in Initial Proposals will impact our ability to meet our Network Output Measures targets, which are the measure of performance of our Reliability output.

We attach two independent external reports as further evidence of need case, and one file which contains photographic evidence of coating disbondment on some of our pipelines. These reports and photographs are referenced in the following section:

Below Ground Pipe & Coating:

Initial Proposals contains a 21% (£16.7m) reduction to our forecast for responding to defects (including corrosion damage) to our pipelines.

By 2021 an increased length[28] of our operational pipelines will be required to operate beyond their original design life. It is therefore essential that our pipeline coatings continue to perform effectively for as long as the pipeline is required. Coating degradation is more likely post design life of a pipeline; the tests within the 'Large-Scale Cathodic Disbondment Testing for Coal Tar Enamel' report prepared for the Pipeline Research Council International (PRCI) attached for completeness, concludes that aged coatings show more severe cathodic disbondment at all tested Cathodic Protection (CP) levels.

PRCI
PR-186-073502.pdf

Unlike the NTS pipeline feeders, buried pipework associated with our Above Ground Installations (AGIs) cannot be internally inspected and is therefore subject to external inspection via Close Interval Potential Surveys (CIPS) and Direct Current Voltage Gradient (DCVG) surveying. Our most recent CIPS and DCVG data for AGIs demonstrates that we can expect similar degradation and corrosion issues to those identified on our pipeline feeders; we have therefore planned to conduct a number of interventions at our AGI's each year. 168 of our AGI's have discreet CP systems, of which we expect approximately 120 of these to require some form of intervention (two or more interventions per site).

[28] Over 4,500km of pipeline will be over 41 years old as illustrated in Appendix E of the 'Detailed plan' annex.

The enhanced risk of corrosion, however, can be attributable to a number of causes as set out within the report on behalf of the European Pipeline Research Group (EPRG), titled: 'Coating degradation mechanisms and their impact on long term performance of external pipeline coatings'[29]. The report explains that whilst all coating systems have the general capability to provide effective corrosion control for an extended period, this is not always the case for every specific location and there are instances of premature coating degradation that will pose maintenance issues in regard to the long term integrity of a pipeline.

The Pöyry report suggested the assumptions made by National Grid with regards to the degradation of Coal Tar Enamel (CTE) were pessimistic and made reference to GL Noble Denton's experience working with other pipeline operators in North America and elsewhere in Europe, claiming this level of concern does not exist in other parts of the world.

We requested a copy of the literature/analysis that supported these statements to ensure suitable comparisons had been drawn. The evidence used to inform this assessment, however, was not comparable given it used through-wall incident frequency data for CTE coated pipe (collected from 'The UK Onshore Pipeline Operators Association' (UKOPA) and 'The European Gas Pipeline Incident Data Group' (EGIG)) to provide an indication of the rate of CTE coating degradation. This data is for through-wall defects only and does not include for part-wall corrosion defects.

The aim of our management of corrosion defects is to explicitly avoid through-wall defects, addressing the feature at an appropriate time prior to any loss of containment. A through-wall defect would have significant safety implications including the potential for significant loss of life. The failure would be a direct contravention of the Pipeline Safety Regulations, regulation 13: *'The operator shall ensure that a pipeline is maintained in an efficient state, in efficient working order and in good repair'*. For this reason, the use of GL Noble Denton's assessment is invalid and does not form a sound basis upon which to assess our volume requirements.

The level of interventions associated with the degradation of the thermoplastic coating Coal Tar Enamel is an increasingly common issue on our aged pipelines. Whilst CTE as a coating system has a low moisture permeability and high electrical resistivity, it is prone to splitting over time as a result of soil stressing, loss of adhesion and damage during construction (see section 4.2 'reported degradation' in EPRG report 121 attached below). The creep properties of CTE also gives rise to a number of issues[30], including deformation under point loads, stone penetration, wrinkling of the sides and cracking along the crown of large diameter pipes under the action of soil loads. Please see attached photo file of example National Grid feeders across the country that are experiencing degradation of CTE.

EPRG Project 121.pdf

NG Feeders - CTE disbondment.pdf

Whilst we utilise CP as the secondary protection method to shield exposed areas of the pipeline metal, it is has proven over time to enhance coating disbondment, the extent of which may increase should the current from the rectifier be increased to compensate for the extended damage (See the Large-Scale Cathodic Disbondment Testing for Coal Tar Enamel report prepared for the PRCI attached).

The external reports presented are aligned with the increased number of coating defects identified by our In-Line Inspections (ILIs) completed over the last few years and the actual number of interventions we are required to complete to ensure the safety and integrity of our

[29] http://www.apia.net.au/wp-content/uploads/2010/06/Paper-24-Jansen.pdf

[30] Section 4.3 'material properties' of the EPRG report 121

high pressure pipelines is maintained.

Approximately 60% of the pipelines due for In-Line Inspection in 2012/2013 are coated with CTE, of similar age and located in comparable areas of the UK (with respect to ground conditions) to CTE coated pipelines inspected during the last 5 years. The majority of these pipeline feeders have required remedial works to address external corrosion features associated with the damage to or deterioration of the coating system. Based upon the historical ILI data and current CIPS results, we anticipate performing a similar number of remedial/repair activities to address the features on the pipelines due for inspection in 2012/13.

We have completed circa 30% of this years scheduled ILI plan to date and based upon the results so far we will need to perform excavations and repair on 37 ILI features in 2013/14 with many more expected. In addition, we have 60 high priority CP faults that have been identified which need to be addressed to prevent active corrosion on the pipeline.

Our short term maintenance plan is based upon actual defects that have been identified by ILI and CP inspections. These results have identified intervention requirements which are significantly greater than the proposed TPCR4 averaged volumes that Ofgem has used to set our RIIO-T1 allowances.

Impact Protection:

Initial Proposals contains a 31% (£7.1m) reduction to our forecast cost for the necessary refurbishment of assets designed to protect our pipelines from impact.

The Pöyry report has proposed the lower end of our volume estimate, refurbishing a total of 160 sleeves in the period at a unit cost of [text deleted] per sleeve be used to form the basis of the RIIO-T1 allowance. This volume reduction places new challenges, given the total number of nitrogen sleeves quoted in Appendix E of the 'Detailed plan' included forged end-seals only and had incorrectly excluded epoxy end-seal nitrogen sleeves on the NTS. Our March 2012 submission was not updated to reflect this revision given it was not in response to Ofgem feedback, a result of wider stakeholder feedback or deemed to be a material error correction. Our total nitrogen sleeve population is, however, confirmed at 1,225.

In November 2011 our field force started using the Office in the Hand (OiTH) and associated Point of Work data collection capability, allowing us to accurately identify that 402 of our sleeves are leaking of which 296 have unacceptable pressure decay to below 0.1 bar, in accordance with our internal procedures. The remaining 106 sleeves still maintain a positive pressure although not to standard.

Type of Sleeve	Number of sleeves	Pressure in sleeve	Number confirmed leaking
Forged End-Seal	1099	<0.1 bar	231
		>0.1 <0.6 bar	98
Epoxy End-Seal	126	<0.1 bar	65
		>0.1 <0.6 bar	8

Of these leaking sleeves, 74[31] are located in high-density traffic routes and deemed priority projects, the remaining 222 are classified as Class 1[32] and must also be suitably replaced to render them compliant. Given the volume of leaking sleeves, we will prioritise those with an

[31] 65 Forged End-Seals & nine Epoxy End-Seals.
[32] Class 1 sleeves were required by IGE/TD/1 Edition 2 clauses 6.8.3.1, 6.8.3.2 and 6.10.1 in order to protect the public, or judged desirable to protect some other installation from the consequences of failure of the carrier pipe. Such sleeves also serve to protect the carrier pipe against external interference.

unacceptable pressure decay and manage the remainder through phased top ups. Introducing technologies to monitor the rate of decay will help assess the frequency of top ups required and the prioritisation of workloads.

Application of a [text deleted] unit cost for a standard sleeve crossing on a two-lane highway including excavation does not provide sufficient funding to manage more complicated[33] jobs. The allowance proposed has ignored the premium associated with completing more difficult crossings, however, 22% of those with an unacceptable pressure decay are considered more complex given their location and/or condition and will therefore attract additional costs.

Our plan detailed that these crossings could rise to [text deleted] per sleeve; to evidence our mid range price figure we have therefore priced some of the example works. In the table below, we have priced the shortest sleeve at 10m in length, the longest sleeve at 750m and a more typical length sleeve at 94m. These cost estimates are provided in 2009/10 prices.

Sleeve ref.	External coating	End Seal	Length (m)	Sleeve diameter (mm)	Annulus cross-sectional area (m3)	Volume of alternative fill (m3)	Cost of alternative fill[34] (£k)	Total cost[35] (£k)
NS Copthall Lane (Shortest)	Coal Tar	Epoxy	10	1050	0.21	2.20	[text deleted]	[text deleted]
NS A84 (Typical)	Coal Tar	Epoxy	94	1050	0.21	19.68	[text deleted]	[text deleted]
NS Longfield (Longest)	Coal Tar	Epoxy	750	1050	0.21	156.97	[text deleted]	[text deleted]

Whilst we will continue to bundle works where possible, our programme of works will address the priority locations in the first instance which may not necessarily be on the same pipeline feeders as other intervention and refurbishment activities.

We remain of the opinion that the refurbishment of 15% of our total volume of nitrogen sleeves is a deliverable volume, which will also minimise risk and reduce outage constraints. This equates to 184 sleeves in total across the RIIO-T1 period which is aligned to the mid-point of our annual volume range.

To be able to deliver this volume requirement, we require a reasonable unit cost which takes account of the proportion of more complex jobs, to ensure we can deliver the more complex sleeve refurbishment necessary over the RIIO-T1 period; the cost forecasts in our submission would provide sufficient funding to complete this work.

<u>Civil Assets (Access):</u>

Initial Proposals contains a 29% (£5.7m) reduction to our forecast cost for essential repairs to the access roads to our sites.

It is essential that we continue to maintain NGGT owned access and on-site roads (i.e. non-

[33] Epoxy End-Seals are considered more complicated jobs given the end-seals themselves leak and require modification. To accept an alternative inert gel type grout fill, each end of the sleeve will require modification to accept two fill and vent points together with a drain point. Longer sleeves may also require additional vents in the middle to accommodate changes in depth.
[34] The alternative fill is assumed to cost [text deleted]/Litre
[35] We have assumed [text deleted] is required to excavate and modify each epoxy end-seal given these seals require excavation at both ends of the pipe sleeve.

public highways) to ensure safe passage regardless of location (not only for our staff and contractors.

Initial Proposals argue that a reduced level of investment is appropriate as our sites are 'often remote rural locations'. Remote rural locations are often subject to more extreme climatic conditions and temperatures resulting in an accelerated rate of deterioration when compared to our more urban based sites. The greatest need for good access surfaces is during periods of extreme weather including snow, ice or flood, when site attendance is required in the event of a system failure. Coupled with remote rural locations typically having less if any background lighting compared to our urban sites, this would give rise to an increased safety risk.

The reduced allowance proposed does not facilitate a sustained programme of access road re-life, resulting in an increased frequency of complete access road rebuilds in the future, which can typically cost 3-4 times the cost of re-life.

Feeder 9

All parties are in agreement with regards to the need, however, there is degree of uncertainty that exists in the timing and scope of the project since it is has now been classed as a Nationally Significant Infrastructure Project (NSIP) and subject to the provisions of the Planning Act 2008.

We see merit in Ofgem's proposed treatment of this project which will move it to an uncertainty mechanism (UM) (a re-opener triggered in the re-opener window following granting of planning consent), as this would allow us to apply for an appropriate level of funding for construction activities upon receipt of planning permission by the Planning Inspectorate. We do not, however, agree that this alternative treatment of the uncertainty of this project should result in us being penalised under the Information Quality Incentive (IQI), as is currently the case in Initial Proposals. As detailed in our response to question two of the Overview document, the application of such a penalty is in direct contrast to Ofgem's March 2011 strategy document[36] (paragraph 6.30) and an adjustment should be made to the IQI calculation to remove this effect.

Ofgem's movement of ex ante funding (as requested in our RIIO-T1 submission) to an uncertainty mechanism creates a penalty under the IQI. Where it is clear that such a movement is as a result of a different legal interpretation (e.g. IED) or expectation of timing of planning consent approval (e.g. Feeder 9 replacement), rather than an alternative view of likely costs, it is inappropriate to assume that such a difference is 'inefficient' and that a penalty should apply. In these circumstances, an adjustment should be made to unwind the impact these alternative treatments have on the IQI assessment.

This approach being proposed by Ofgem is in direct contrast to that suggested in Ofgem's March 2011 strategy document[37] (paragraph 6.30): "*It is important that the comparisons between company forecasts and our own cost assessment that feed into the IQI are made on a like-for-like basis. In particular, there should be consistency in the set of outputs that the expenditure contributes towards. This may require adjustments as part of the IQI calculations.*". It is also inconsistent with the approach taken with NGET, where no such penalty applies for a movement of expenditure from 'best view' into an uncertainty mechanism.

[36] Decision on strategy for the next transmission and gas distribution price controls - RIIO-T1 and GD1 Business plans, innovation and efficiency incentives, 31st March 2011

[37] Decision on strategy for the next transmission and gas distribution price controls - RIIO-T1 and GD1 Business plans, innovation and efficiency incentives, 31st March 2011

Initial Proposals provide a £6.6m ex ante allowance for pre planning consent activity however, to maintain the project on the critical path it is necessary that we procure long lead time items in the year that the Development Consent Order (DCO) is submitted. The allowance proposed is approximately 50%[38] of that the forecast of what is necessary to complete the pre-consent work.

On 14th August, this uncertainty was discussed with Ofgem. It was suggested that should we need to procure long lead time items ahead of funding, these costs would be considered as part of the construction cost review when the uncertainty mechanism is triggered. Initial Proposals do not consider a logging up type mechanism to capture these costs. We seek confirmation of the proposal in this area, specifically that such long-lead item procurement costs will be considered in the uncertainty mechanism.

Consequential impact of environmental legislation-driven investment

Our asset health investment plan and prediction of Network Output Measures (NOMs) have been built on the common assumption underpinning our wider investment plan, in particular the replacement of a number of compressor units under environmental legislation. Where a unit is expected to be replaced, we would undertake minimal asset health works targeted on maintaining the asset only until it will cease operation. Should these replacements not be required or funded, the effect would be to increase the asset health investment requirements on the impacted units as we are required to maintain their operation into the future.

Greenhouse Gas Emissions (venting) abatement

Initial Proposals for the SO incentives suggest that NGGT TO has funding to incrementally reduce the venting of greenhouse gas emissions through normal compressor operation.

Ofgem was able to clarify, through subsequent discussions, that the only funding available was through the Network Innovation Allowance (NIA) (which is designed to fund small-scale innovative projects that are primarily in the early stages of development) or Network Innovation Competition (NIC) (which is based on competitive processes designed to cover a small number of large projects across the gas industry rather than NTS specific venting abatement), and that no other funding was included in Initial Proposals. Furthermore, Ofgem has yet to confirmed whether the SO will have access to the Innovation Rollout Mechanism (IRM), which is designed to fund the rollout of a proven solution with remuneration being considered in the two re-opener windows within the RIIO-T1 period. Therefore, there are no confirmed allowances at this point in time that would fund venting reduction techniques and as such it is inappropriate for the targets to reflect their implementation.

If NGGT are to deliver incremental reductions to the venting of greenhouse gas emissions, it would be appropriate for explicit funding to be made available to do this. We would welcome the opportunity to discuss this matter with Ofgem to clarify requirements ahead of Final Proposals.

Network Flexibility

We defined Network Flexibility as a requirement for additional operational capability driven by changing user behaviour; it is a complex area and one that we have worked very closely with stakeholders on throughout the RIIO-T1 process.

We were pleased to note that, within their final report to Ofgem, Ofgem's gas consultants

[38] An update to our forecast costs was included in the response to question RT1-Ph3-307

supported the concept of Network Flexibility:

"Pöyry confirms that in principle the general driver of the investment identified as network flexibility is reasonable. The behaviour of users has continued to change over the course of TPCR4, which precipitates the conclusion that capacity rights (especially entry capacity) and the gas behind those holdings are increasingly valued by shippers for the optionality and flexibility that they provide."

"Pöyry attended various stakeholder events over the period prior to the March re-submission, and observed that stakeholders had broad support for the concept of network flexibility investment and considered that if the problems imagined materialised unmitigated, it would result in inefficient outcomes"

As user behaviour continues to evolve over the RIIO-T1 period (in response to changes in both the gas market and wider energy sector) we believe that Network Flexibility will be an increasingly important concept. We recognise that we are at the beginning of understanding how user requirements are going to change over the coming period and we remain committed to continuing to work with stakeholders to ensure that we are able to offer the network capability that our users require going forward.

<u>Scottish 1 in 20</u>

We welcome Ofgem's recognition of the case for Network Flexibility investments in response to our customers' changing use of the network and specifically the decision to provide baseline funding for the 'Scottish 1 in 20' projects.

It is unclear, however, to what the £1m reduction relates within this allowance. Initial Proposals includes no information as to the rationale or justification for this reduction, therefore we cannot confirm whether this is an error or a modelling adjustment. We look forward to further clarity being provided.

We note that, as detailed in our March 2012 submission, as user requirements and thus gas flows continue to evolve there may be a requirement for additional capability to secure gas supplies to Scotland. We will continue to monitor this area and where, following suitable engagement with stakeholders, we believe that additional capability is required we will progress this through the Network Flexibility uncertainty mechanism (annual re-opener window).

<u>Lockerley</u>

We are disappointed that Ofgem's proposals do not provide baseline funding for Lockerley given this project is driven explicitly by 1 in 20 provision for the South West, and that we have recent operational evidence of the need for this investment. We note that the main operational tools that have been used historically to mitigate this issue will no longer be available following the implementation of Exit Reform, and are concerned that delaying this investment will result in constraint management costs that will impact network users and ultimately consumers. We continue to believe our proposals for Lockerley represent value for money for consumers and note Ofgem's comment within Initial Proposals regarding bringing this work forward for funding under the Network Flexibility uncertainty mechanism (annual re-opener window).

<u>Bacton Rationalisation</u>

The need to undertake works at the Bacton terminal is currently proposed under the Network Flexibility UM given that it will result in a change the capability of the network; however the bulk of the work required at Bacton is in response to significant and pressing Asset Health issues. Given the critically of the Bacton site, we are concerned that any asset failures may have the potential to significantly distort both the UK and wider European gas markets. We note explicitly that:

- this work has not been included in our baseline Asset Health funding requests, and
- it will not provide any incremental capacity

Based upon our conversations during the RIIO-T1 cost visits with both Ofgem and their consultants, we recognised that this project might need to be re-categorised as Asset Health works and funded on an ex ante basis. We note that within the Gas Consultant's final report, whilst there was confusion regarding the drivers for this project, the requirement to undertake the work was not challenged.

This specific project has not been captured by Initial Proposals, although we note that in subsequent discussions, Ofgem acknowledged this omission and committed to respond on their proposed treatment for the Bacton Rationalisation works. In conjunction with significant stakeholder engagement with existing and potential future[39] Bacton users we have now undertaken detailed feasibility studies of the work that is required to re-engineer the site to meet current and future requirements. We look forward to the opportunity to discuss this new data with Ofgem and their technical consultants in order to agree a suitable funding approach to allow us to deliver the necessary works in a timely manner.

<u>Seedcorn allowance</u>

As noted previously, Network Flexibility is a complex area and we welcome the proposed provision of an allowance ('seedcorn' funding) to allow us to instigate preliminary work on further identifying and quantifying the impact of changing user flow requirements on the NTS.

The provision of this funding was a concept that was supported by our stakeholders, therefore we are disappointed that Ofgem has chosen to reduce the level of funding by approximately 50%. This reduction in funding will necessarily require us to reduce work on some areas of investigation; a direct consequence of this will be to restrict our ability to develop solutions to emerging issues in a timely manner. We are concerned this in turn will lead to increased risk exposure to all parties in the form of constraint management costs which could otherwise have been mitigated through timely delivery of infrastructure solutions.

Appropriate funding for pre-capacity signal activities

Paragraph 3.11 of Ofgem's 'Outputs and Incentives supporting document' states that revenue recovery will be via a totex approach with consequential implications on funding release, but it provides no details on how or when that funding will be triggered.

Subsequent discussions with Ofgem has revealed that Ofgem proposes to release 20% of a calculated revenue allowance adjustment in year T-2 (where T is the year of capacity delivery) and 80% in year T-1. Although we recognise this is an improvement on the current funding arrangements (where funding is not released until capacity delivery), it still leaves NGGT in the position of having to fund the early years of work prior to revenue being released with consequential impacts on cash flow.

[39] We note that whilst there is the potential for additional capacity to be required at Bacton (we have discussed this with customers, but nothing has yet been signalled) we have, as a prudent operator, ensured that the proposed scope of works does not preclude these potential future connections, but nor does it directly enable them i.e. this work is 'no-regrets' with regard to future capacity requirements

Of particular concern is the impact of Ofgem's proposals if the customer pulls out of the project before making a formal capacity signal. In this situation, with the totex mechanism applied, NGGT will have been exposed to 45% of the expenditure in each year but will never have the allowed revenue adjusted to make NGGT 'whole'. The introduction of the Planning Act has changed the level of costs associated with, and the length of time required to complete, this pre-capacity signal activity.

It is clear that continuation of the TPCR4 arrangements whereby no explicit funding is provided to cover this type of activity is not appropriate going forwards, given the changes introduced by the Planning Act. We therefore suggest that funding arrangements for this pre-capacity signal activity is explicitly included within the regulatory settlement, such as provided for in the NGET control.

Direct opex:

Submission	£278m	**Initial Proposals**	£251m
Reasons given for disallowance	• Reductions in costs to rectify deterioration in Coal Tar Enamel (CTE)		
Action required	• Errors in calculations for the impact of CTE to be rectified • New evidence which shows deterioration of CTE is understated in Pöyry's assessment to be incorporated		

Our concerns with the baseline level of expenditure in direct opex focus on:

- **Errors in the calculation** used to reduce costs for CTE deterioration which overstate the impact of these costs
- **Providing new independent evidence** which shows that Pöyry's assumptions for deterioration of CTE are understated

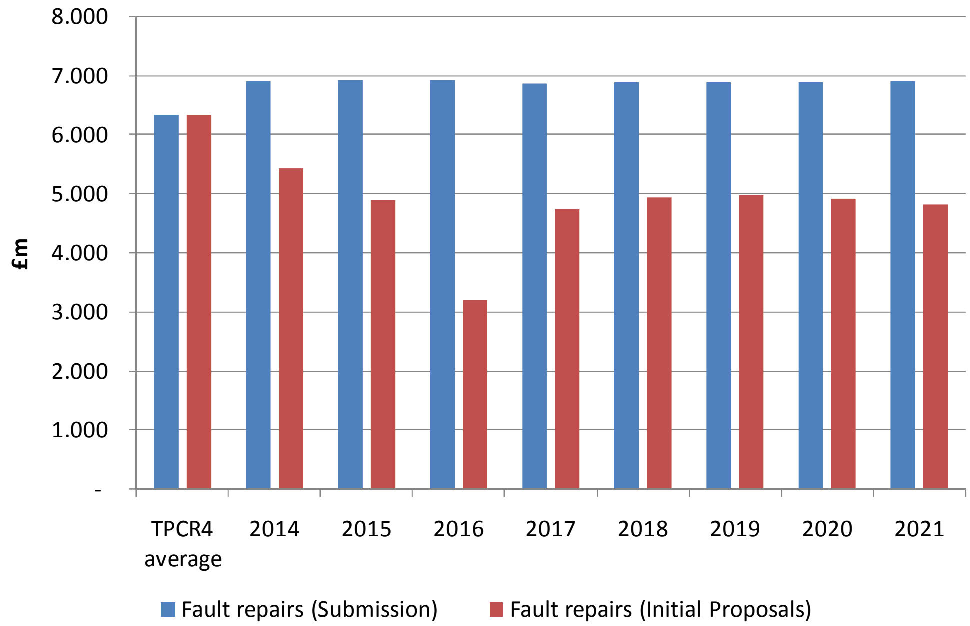
The Initial Proposals reduce our forecasts for fault repairs (unplanned maintenance) by £2.1m per annum based on Pöyry's inaccurate assessment of costs. In coming to their conclusions Pöyry suggest we are being pessimistic in our forecasts for remediation work related to Coal Tar Enamel (CTE) coated pipelines including levels of In Line Inspections (ILIs) and Cathodic Protection (CP) work. This view is based on errors in calculation and volume requirements as outlined below:

- ***Volume assumptions on interventions***: Pöyry have assumed that there will be no increase in the number of interventions per annum for CTE pipeline from the TPCR4 period. This is based on '*a review of relevant literature'.* This same assumption has been used to reduce asset health capex in this area where there are similar upward pressures as some of the interventions will be capex in nature, some opex. We outline evidence why there will be a volume increase in this activity within the Asset Health capex section of this question. This includes the safety concerns of basing the assumption on literature which refers to complete through wall defects (rather than partial which our work is rectifying) and research from the Pipeline Research Council International (PRCI) and the European Pipeline Research Group (EPRG) which counters the claims from Pöyry. This evidence should be factored into the allowances in this opex area as well.
- ***Erroneous application of volume reduction:*** The method used by Pöyry to reduce the level of CTE remediation work is incorrect. The reduction has been applied to the totality of the fault repairs activity, assuming that CTE work is the only work contained in this category. This is not true and therefore overstates the reduction which would arise from lower levels of interventions.

  Pöyry's workings state that 48 opex interventions would equate to £4.8m per annum and compare this to the overall fault repairs costs (excluding decommissioning costs and insurance proceeds) of ~£7m per annum to derive the £2.1m reduction. This would be correct if the only costs within the £7m relate to CTE remediation work but they do not and in fact CTE work is only a small proportion of this cost.

This incorrect application could arise because Pöyry is confusing the fact that CTE remediation work is the principal upward pressure we have going into the RIIO-T1 period rather than the principal cost in this area. Underlying work in this activity which has been undertaken in the TPCR4 period will still be required in the RIIO-T1 period. This is illustrated in the graph below which shows fault repairs expenditure in the TPCR4 period versus the Initial Proposals allowances and our forecasts for the RIIO-T1 period. According to their report, all Pöyry wants to achieve with their proposed reduction is to give an allowance which is the average of the TPCR4 period. In fact the graph highlights that the majority of the £2.1m is an actual cost reduction compared to the levels of TPCR4 in this category, rather than just a reduction in any increase proposed by ourselves in the RIIO-T1 period.

Fault repairs: submission versus Initial Proposals



Overall costs within the fault repairs category include all unplanned maintenance work on pipelines, compressors and Above Ground Installations (AGIs). As is the nature of unplanned work the constituent parts of the work undertaken over the TPCR4 period vary by year but overall costs have been consistent at ~£6.3m per annum. CTE remediation work in the form of cathodic protection and ILIs only accounts for ~£1.1m of the annual cost during the TPCR4 period. Costs outside of CTE remediation work include:

- Field force time rectifying defects on the network within all asset categories
- Third party costs for breakdown activities on compressors
- Overhead costs for defect triggered maintenance of asset components including: compressor seals, pressure systems, exhausts and air intakes, valves and actuators, and telemetry units

The proposed increase in fault repair costs from TPCR4 average costs is only £0.6m per annum, so this is the maximum value per annum that could be removed from our forecasts to return levels to that spent in the TPCR4 period. This maximum adjustment would only apply if there is proven to be no justified increase in CTE remediation work, however any reduction would have to be tempered by the evidence given in relation to the volume of interventions outlined above.

In summary, the error in the calculation to set allowances should be rectified adding £1.5m per annum to the allowances and volume increases in the work of £0.6m per annum should be allowed, based on external evidence of the requirement

Closely associated indirect opex

Submission	£124m	**Initial Proposals**	£118m
Reasons given for disallowance	• Reductions in operational IT costs as Ofgem do not believe new IT systems will increase support costs • Unexplained reductions in other categories		
Action required	• New evidence on our SAM investment shows that this will increase IT support costs reduction should be reversed • Arbitrary reductions with no justification should be reversed		

We have two concerns with the baseline proposals for Closely Associated Indirect (CAI) opex given the view of Ofgem's consultant Pöyry and the strength of evidence submitted by ourselves. These relate to operational IT costs and arbitrary reductions in other categories.

- ***Operational IT***: This activity contains the IT support costs for our TO operational IT systems. We forecast that these costs will marginally increase in the RIIO-T1 period due to the costs of additional servers and communication links required for new systems, partially offset by efficiencies.

  In their consultants' report Pöyry support both the underlying investments triggering these increases and the opex increases themselves stating that "*we agree with the proposed allowance for operational IT and telecoms, in particular to enable operational benefits arising from new IT systems to be fully realised".* This is contrary to the Initial Proposals where Ofgem state that: "*we do not accept that new systems will lead to increases in support costs".*

  This means that despite Pöyry being engaged in this area specifically for their expertise their viewpoint has been ignored. Quite correctly Pöyry have identified that any reduction in this expenditure would impact on the outputs of the key Transmission Front Office (TFO) and Strategic Asset Management (SAM) investments which would be to the detriment of customers and consumers (as detailed in the non-operational capex section below). Pöyry have also correctly identified that: "*…should new IT systems not be implemented then we consider that requirements to maintain existing systems would probably increase…*" The application of an additional reduction in this area by Ofgem therefore seems to undermine the greater expertise of their consultants in this area.

To further explain the reason for the increase in costs in this area a case study on the SAM investments that are currently in development is attached below. This highlights why the new systems will increase IT support costs, with SAM just one of several systems which will cause upward pressure on IS costs in the RIIO-T1 period.

SAM case study.docx

- ***Arbitrary reductions***: As with operational IT costs Pöyry fully support our forecasts for the other CAI opex costs. The Initial Proposals documents also seem to suggest their support in these areas but despite this then make a 1.3% reduction to each of the categories of expenditure. It is not clear what this adjustment is for, with the only potential link being a comment that the general efficiency assumption of 1.5% per annum has been applied to CAI costs.

  If this is the reason for the reduction then this has been actioned erroneously because – as stated in paragraph 1219 of our 'Detailed plan' annex - CAI opex has efficiencies of ~3% per annum already included in our plan figures. It could be that the overall NGGT figure (inclusive of all categories of opex in GTO and GSO) of 1.3% has been compared to the 1.5% with the difference applied in CAI costs. This is incorrect because the 1.3% per annum figure is the overall level of efficiency embedded into opex, not the level specific to CAI opex which is being reviewed here.

Business support opex

Submission	£144m	**Initial Proposals**	£113m
Reasons given for disallowance	• Benchmarking of 2010/11 costs versus other networks and independent data set		
Action required	• Use future FTE and revenue metrics rather than 2010/11 figures • Include Transmission submitted benchmarking and market testing evidence in assessment • Non-normalised costs for regulation and more automated IT approach should be adjusted		

The Initial Proposals used cross-network benchmarking for business support costs with reference to data from Hackett to produce a reference point outside of the utility sector. As stated in our submission, if costs are adequately normalised and the methods used are applied consistently, the use of such benchmarking for business support costs is a valid assessment method. The issue with the use of such benchmarking in Initial Proposals is that neither of these conditions have always been adhered to, giving rise to logic flaws in the methodology used and a deflated resulting allowance.

Benchmarking of business support costs purely on 2010/11 costs and metrics such as FTEs and revenue represents a material departure from Ofgem's published RIIO principles which favoured benchmarking future, not historical costs. The analysis underestimates the impact of Transmission workload growth over the next decade giving rise to wholly inappropriately low allowances. Errors in the calculations and unsound logic in the assessment compound this position, leaving untenable targets which will inhibit areas such as IS innovation and skills development.

Reversing the analysis and logic errors in the benchmarking would increase combined allowances for Transmission and Distribution by approximately £94m. This is even before adjusting the benchmarking to only refer to Networks' levels of performance due to lack of comparability with the Hackett data.

As they stand we have concerns around the suitability of the Initial Proposals in the these key areas:

- **Future benchmarking:** The lack of benchmarking based on future metrics contradicts Ofgem's published RIIO principles, with Ofgem stating: "*We will place much more emphasis on the benchmarking of forecasts (as opposed to historic costs) as these are likely to be more relevant in the context of our sustainable development duties and the introduction of new output measures.*" We have been unable to ascertain whether any such benchmarking has taken place but are aware that our costs have been benchmarked based solely on 2010/11 metrics such as FTEs or revenue, rather than considering the impact of forecast increases in these over the RIIO-T1 period reflecting growth. This is inconsistent and demonstrates a departure away from the RIIO core principles.
- **Ignoring our benchmarking and market testing evidence**: We agree that including efficiency additions based on the strength of independent benchmarking in the business plans is a positive step. However several of the benchmarking results and market testing evidence submitted by us has been ignored by Ofgem's own admission, creating artificially low allowances.
- **Non-normalisation of costs**: Regulation costs have been benchmarked against a comparator set of data which contains no regulated entities. Hackett data has been used to set a target in several activities despite specific guidance from Hackett not to do this. In addition, there has been no account taken of the benefit of us having more automated (and hence more IT led) processes than those we have been benchmarked against, despite Hackett themselves stating this needs to be performed.

The resulting impact of these errors and inadequate analysis is a set of allowances which do not reflect an accurate assessment of the costs in this area and would introduce unachievable targets that would inhibit investment in key areas such as IS innovation and skills development through the period.

We provide supplementary detail and evidence in **Supplementary information document – business support benchmarking**.

Non-operational capex:

Non-operational capex investments are key to maintain and improve safety and reliability outputs over the RIIO-T1 period, however:

- **Arbitrarily reducing IS projects by 50% will hit key outputs and mean we have to keep ageing systems on line for eight to twelve years**
- **Disallowing 15% of unsanctioned SAM and TFO investments will erode benefits delivered and is based on no justification**

For completeness, we have duplicated the following information on non-operational capex in our responses to both this question and the equivalent question for NGET (SO).

Within non-operational capex the assessment of our Strategic Asset Management (SAM) and Transmission Front Office (TFO) systems has been performed separately from the other investments within our forecasts. The SAM and TFO assessment have been performed by Pöyry with the other investments assessed by Ofgem. There is a marked difference in approach between the two with the Pöyry assessment being more considered as it was based on more interaction with ourselves. By contrast, the assessment for the other investments does not consider the impacts of the proposal made on other areas of the plan and proposes an arbitrary, unjustified reduction. We will discuss both of these assessments in turn below giving more evidence why the expenditure levels proposed in our plan are justified.

In summary the main concerns we have with the Initial Proposals are:

- **Arbitrary 50% reduction in other schemes**: The 50% reduction in other investments is wholly inappropriate and premised upon ill-founded and unsupported assumptions. A reduction of this scale will mean that thirteen projects delivering safety related outputs will be put at risk, and a further eighteen initiatives delivering capital and reliability related outputs will be compromised, including refresh of essential network analysis capabilities, field user device refresh and remote site communication infrastructure upgrades, essential to realise SAM benefits. Implementing this reduction will force us to leave IS systems in service for at least eight years and in some cases up to twelve years which will not only compromise safety and system reliability, but will increase totex costs due to incremental support costs and embedded efficiencies we would no longer be able to deliver
- **Lower outputs**: The 15% reduction on unsanctioned TFO and SAM work is arbitrary and incentivises us not to integrate and extend the capability across all of our network giving a diminution in output benefits (i.e. we will not get all the safety, reliability environmental and customer outputs envisaged). Forecast costs for TFO and SAM have been refined as the programme has matured, and have been tested against available external comparators. We believe that our implementation costs are challenging, offering value for money when compared to other implementations of a similar scope, scale and complexity.
- **Erosion of SAM and TFO benefits:** One of the justifications used by Pöyry and supported by Ofgem for proposing lower direct opex allowances is higher expected benefits from SAM / TFO than those included in our plan. The proposed reduction in non-operational capex will reduce opportunities for investments that deliver direct opex efficiencies, and is inconsistent with this position. TFO and SAM investments must be maintained at our plan levels if the associated direct opex benefits are to be achieved.
- **Ignoring flexible IS delivery model**: Our flexible IS delivery model which enables demand to be met across National Grid using external resource where required has been ignored in assuming that our IS department will be too busy with TFO and SAM investments to work on other projects. In addition, the competitively tendered arrangements put in place with our delivery partners include provision for annual external benchmarking, to ensure value for money for National Grid and our customers.

Other investments:

The Initial Proposals recognise that IT expenditure (outside of SAM and TFO) is spread over a number of systems which are proposed to be enhanced or refreshed at differing times over the RIIO-T1 period. Investments in this category are necessary to replace/refresh existing systems at end of life essential for asset maintenance and capital commissioning supporting network planning and efficient capital investment.

A number of proposed investments are to replace systems which are at end of life within the early years of the RIIO-T1 period, (e.g. HEAT Alarm Response, Safe Control of Operations and Transmission Test Laptops). Failure to replace these systems as planned will mean that we will have to maintain some systems in service for at least eight years, and in some cases up to twelve years, which will not only compromise safety and system reliability, but increase totex costs due to incremental support costs and embedded efficiencies we will no longer be able to deliver.

Enterprise Content Management is an essential enterprise wide application that will require replacement in the middle of the RIIO-T1 period. This application manages operational drawings and documentation, essential to the safe and reliable operation of the electricity and gas transmission systems, and to the delivery of our capital plan. Failure to maintain this system will expose us and our customers to an unacceptable level of risk.

Other investments, e.g. Operational Site Communications Infrastructure and Field Device Replacement are essential to the delivery and maintenance of SAM and TFO respectively. The breakdown of Other investments by RIIO output for NGGT is set out below:

RIIO Output	NGGT (No of Projects)
Safety	4
Reliability	7
Environment	4
Customer	5
Customer Connections	3

A 50% reduction in other investments will clearly have a significant impact on our ability to deliver RIIO outcomes, and in some cases will expose us and our customers to an unacceptable level of risk. We maintain that these planned investments are an essential and well-justified component of our overall non-operational capex investment strategy, which has been structured to optimise IT asset lifecycle and deliverability.

Asset refresh and deliverability:

Within either Pöyry's report or the Initial Proposals there are several statements regarding delaying asset refresh work:

> *"…application refreshes planned for the end of RIIO-T1 could be delayed until RIIO-T2"* [in relation to TFO]
>
> *"…we consider that some of the proposed system refreshes in the NGET business plan will not take place within the RIIO-T1 period"* [in relation to other investments]
>
> *"With respect to system refreshes, our Initial Proposals assume are based on the view that whilst IT system will be reviewed regularly (maybe every 5 years) to ensure they are up to date, system refreshes will not happen every time such a review is taken."* [in relation to other investments]

We are compelled to provide further background to the plans set out in our original submission regarding asset refresh and replacement, which are integral to our ability to operate in a safe and efficient manner in the coming RIIO-T1 period.

In parallel with the capability-related activities, a review of the current system landscape, which considered system constraints and dependencies, was completed. The key observation taken from the assessment was that an asset refresh/replacement programme to address ageing systems and infrastructure as well as known support constraints is required.

Whilst we looked across the Transmission applications landscape on an application by application basis (as set out in our submitted March 2012 Business Plan) to assess when a refresh or replacement would be required, we also verified this against our asset refresh policy, as described in some detail in the 'IS Strategy' annex of our March 2012 submission. A final step that we took was to re-test our intended approach against IT Industry benchmarks. This found that we are seeking to execute our refresh and replacement activities in line with common IT Industry practice in the UK:

- **UK High Street and Global Bank** – For leading edge applications (e.g. city, treasury systems etc) they had a 3-year asset refresh cycle, for the branch network it was 5 but some corporate applications it went up to 7 years because of the cost/complexity of replacement
- **Insurance organisation** – Typically between 3-5 years refresh across infrastructure
- **Telecoms & Networks** – Have a number of different refresh policies across their asset base; most fall within a 5-year refresh cycle
- **Government** – 5-7 years on large government procurements, including interim refreshes – sometimes based on Moore's law[40] for infrastructure/hardware to show "innovation" against e.g. green targets

The key driver for delivering a regular refresh of systems (without changing functionality) is ensuring that systems are supported by vendors so that spare parts are available and software patches can be applied to fix faults and resolve security risks. It must be stressed that we have assessed our requirements on an application by application basis, as opposed to applying a broad principle-led approach to application refresh or replacement.

Although extended support may be available, it is expensive (first year increase is approximately 60%, with 20% increases applied for each subsequent year) and would be time limited. As the rate of technology change is accelerating, the availability of skills to support older software and hardware declines. This is a challenge that we face with our Transmission application landscape, with applications such as Office in the Hand (OiTH).

We are moving towards purchasing more off-the-shelf applications as this is a more economic option, but these economies can only be maintained if we remain close to the manufacturer's upgrade path. Falling behind will lead to increased costs for future refreshes.

Ofgem's suggestion that the refresh approach could be extended to 12 years. Based on their reduction in other investment expenditure of 50% is substantially out of alignment with the normal IT market, it would increase opex and force us to operate inefficiently and at increased risk, relying on manual workarounds and spreadsheets to replace what would be unreliable and inoperable systems.

Ofgem's consultants state a further assumption, relating to deliverability, in support of a proposed reduction of 50% to 'other' IT systems expenditure: *"…a lot of IS resources within National Grid's IT department will be consumed in ensuring TFO and SAM are delivered."* This statement does not take into account our flexible IS delivery model which covers all of National Grid's forms of control, not just GTO, and means we have access to significant levels of external resource so that we can deliver all required business IS requirements rather than be limited by internal resource levels.

Over the TPCR4 period National Grid IS have delivered an average of ~£80m of capex projects per annum across our UK Electricity and Gas Transmission, Gas Distribution and Business Support businesses. During this period expenditure has been highest in our Gas Distribution business reflecting the changes in that sector of the industry. Correspondingly, expenditure in our Transmission businesses has been comparatively lower.

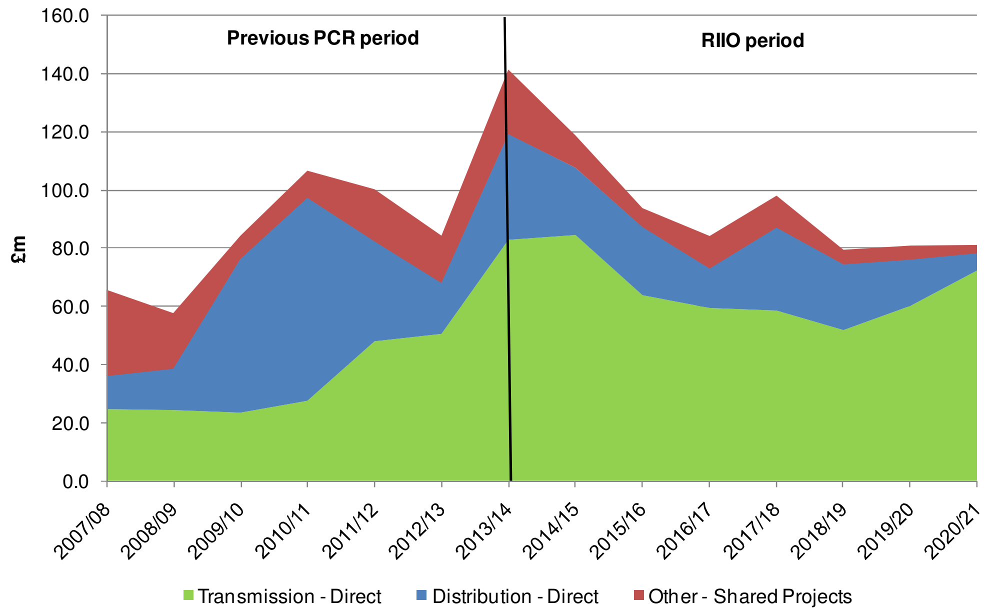
In the RIIO-T1 and GD1 period however these relative expenditures are reversed. This is to be expected as our Gas Distribution business leverages the IS investments of the previous period. Our Transmission businesses correspondingly enter a period of significant change and the systems which have supported them in the earlier period require refresh or replacement.

Our combined UK IS capex expenditure during this previous period compares favourably with

[40] States that processor speeds, or overall processing power for computers will double every two years

our proposed expenditure in RIIO-T1/GD1 period. This is illustrated in the following figure:

IS capex 2007 to 2021



The peak in 2013/14 results from the deferral of Transmission expenditure from the Rollover year, necessitated by the reduced allowances provided through the TPCR4 Rollover review.

Our IS department is a Global function and supports all of our businesses in both the UK and US. As such we are able to concentrate our resources towards those areas with greatest demand at any given point in time. A key benefit of this approach is that these resources are able to bring the learning and experience from one area of our business and apply it on other areas. Also, given our strategy to adopt Commercial-Off-The-Shelf (COTS) applications across our organisation wherever appropriate, these resources are able to bring specific application expertise from previous projects to our current initiatives, promoting efficiency and exploiting learning. A prime example of this is the transfer of many IS resources from the Gas Distribution Front Office program onto our Transmission TFO program.

We acknowledge that there is an increase in our total UK IS project planned expenditure for the RIIO period as compared with the previous period. The average UK annual expenditure for 2007/08 to 2012/13 was £83m per annum compared with £97m for the RIIO period. This was clear to us a number of years ago through our business planning activities and was one of the key factors in development of our IS Strategy and IS Transformation programme.

Two key features of our strategy and Transformation programme are specifically targeted at this overall increase and securing our ability to deliver our plans;

- Our strategy of adopting common applications across our organisation and moving towards COTS solutions supports deliverability of our plans through;
    - Enabling us to build knowledge, expertise and learning in a reduced number of applications which can be applied across our entire organisation as each area reaches its period of need
    - Deploying COTS applications which are leading solutions in their respective capability areas for which there is an established and sizeable pool of qualified and knowledgeable resources in the open market
    - Providing the potential for re-use of solution components or designs, developed in one area of our business and exploited in other areas thereby reducing design and build (configuration) effort on subsequent

deployments.

- Our IS Transformation programme includes a number of elements designed to bring efficiency and scalability to our programme/project delivery capability. These include;
    - Centralising all programme/project delivery into a single IS departmental function. This promotes consistency and familiarity of process and more granular and effective planning and allocation of resources
    - Consolidation of projects into programmes of related work. This promotes re-use, increases efficiency of governance and allows for more fluid management of priorities within programmes. This approach is evidenced in our 'IS Strategy' annex and supporting 'IS Investment Descriptions'.
    - Appointment of two external Solution Delivery Partners, IBM and Wipro through competitive tendering. Key factors in our evaluation of these partners (prior to appointment) included clear capability within;
        - Relevant experience; evidence that the partners had a track record of direct experience in successfully delivering solutions similar to those that are required in National Grid
        - Scale; evidence that they had the have the volume of suitably qualified and experienced staff to support delivery of our Investment Plans

Furthermore, the McKinsey Benchmarking shows that we have achieved 'A' Utility status in the capability area of 'Set up centralised skills and establish a vendor partnership model'. This is evidence that we are demonstrating best practice in this area and is further illustrated through the ramp up in delivered capex over the period since 2009/10.

In summary therefore, whilst the planned increase in Transmission IS investment during the RIIO-T1 period (compared with TPCR4) is significant, this represents a much smaller increase in our overall IS programme demand when viewed for the UK as a whole. Acknowledging this increase we have taken measures to ensure that we have both the capability and capacity to deliver our plans and to leverage the knowledge, experience and learning from previous related investments elsewhere in our business.

SAM / TFO

Following the review of the Initial Proposals we note that Ofgem's consultants agree with the need for TFO and SAM, stating that '*these developments will enable NGET (and NGGT) to deliver further efficiencies within direct opex and non-load related capex*'. However, in light of the reduced cost expenditure forecasts proposed of 15% for unsanctioned elements which incentivises us to reduce work and hence outputs in this area, we feel compelled to provide greater insight to the challenges that we are facing and the resulting transformation that is required to meet these challenges. This will demonstrate the origins of our requirements, the background to our funding requests, and how Ofgem's suggestions will limit our ability to deliver the required benefits and hence our proposed plan.

With the introduction of RIIO and the move to a low carbon economy, set against a background of significant change involving workforce renewal, infrastructure renewal and increased levels of supply and demand volatility, the UK TFO systems landscape faces a number of key challenges:

- **Increase in capital investment:** Significant volume increases in capital delivery are required over the RIIO period in order to maintain network reliability and meet changing customer needs and energy sources. New capabilities will be required to support this increase in the capital plan, as well as the enhancement of existing tools and processes.

- **Changing network environment**: The expected evolution in the network, including changing supply and demand patterns, and the increasing influence of the low carbon agenda will introduce changes to our business environment requiring new capabilities to maintain business continuity and delivery to our customers
- **New technologies**: The challenge of adapting to the introduction of new technologies will represent opportunities for new capability development focused on enhancing the safety, reliability and deliverability of our business outputs through the RIIO period
- **IS Asset Health:** Ageing TFO system infrastructure and operating systems must be optimised with the release of new capabilities in order to maintain effective support arrangements and ensure ongoing system asset reliability

In addition to these challenges above, we need to address further capability-related challenges posed by the existing IT system and process landscape. Over the past decade we have introduced a series of efficiency saving programmes, including 'Staying Ahead' and 'Ways of Working', delivering industry-leading capabilities in work delivery and asset management. Whilst these capabilities have been enhanced over time through subsequent refresh and change initiatives, they were delivered to a very different business and technology landscape to that facing us today.

Against this background, a capability maturity assessment using an industry-specific model (Accenture's High Performance Utility Model, HPUM), was undertaken to explicitly position as-is capability, and identify the required future business capabilities that would address the key challenges to be faced (to-be capability), and also to provide insight into the level of change required to be delivered during the next regulatory period.

The outputs from this assessment highlighted a significant journey that we will need to undertake to deliver the required capabilities to meet our challenges in the coming period. In particular, a series of new capabilities have been identified as being essential to business requirements with regards to: delivering the augmented capital plan; implementing enhanced work delivery capabilities; and supporting workforce flexibility and customer service. Underpinning these areas will need to be a focused effort on data quality and data management frameworks. The gap in maturity between the as-is and required to-be states is depicted in the diagrams below (full-scale versions of each of the below have been included in an attachment):

To-be and as-is capabilities

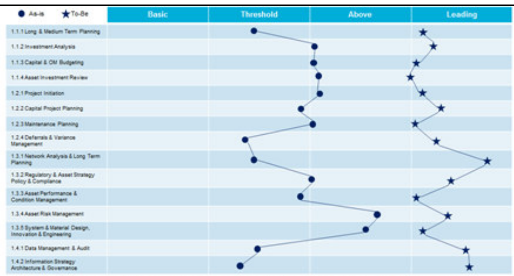


Figure 1: Manage the Asset Infrastructure (Electricity)

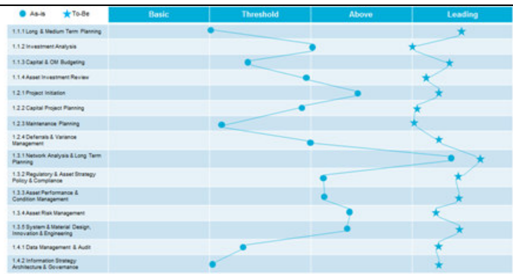


Figure 2: Manage the Asset Infrastructure (Gas)

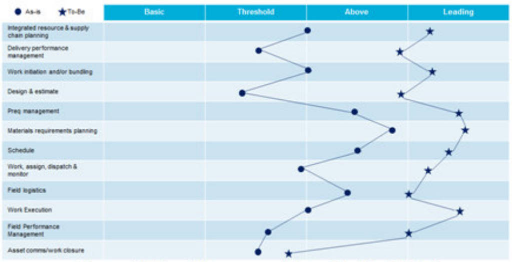


Figure 3: Plan, Manage and Execute (Electricity)

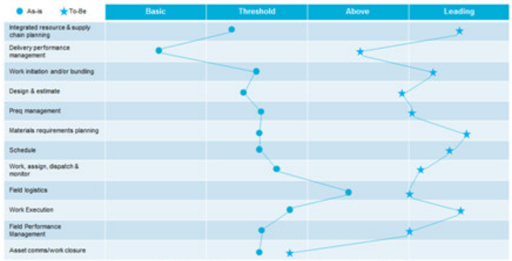


Figure 4: Plan, Manage and Execute (Gas)

TFO as-is and to-be.docx

These diagrams highlight not only the gap between the current state and the required future state, but also the pressure that the business challenges are placing on us to be at or near to the 'leading' end of the capability scale across areas relating to capital delivery, asset management, work delivery and execution. It is clear that minor and incremental enhancements to existing systems and processes would be insufficient to deliver the level of change required.

Our commitment to the TFO and SAM (including RAMM) programmes has been demonstrated during the TPCR4 Rollover period, where required expenditure in excess of £10m has been committed against a Rollover 'allowance' of £4.2m (for NGET and NGGT together). During this period, the TFO programme has further developed understanding of the scale and complexity of the transformation that it is seeking to undertake. It is from this more mature position that we now understand that the original cost case - which already included an embedded cost challenge of 10% - represents a genuine stretch target.

TFO and SAM forecast costs have been tested against available comparator information from other front-office transformation programmes. As a result of this comparative analysis, we have concluded that whilst there is evidence to support that some non-complex, small scale asset refreshes have out-turned in the range £20-40m, other larger scale complex implementations, similar to our requirements, are more typically in the range £70-100m.

Pöyry recognise the scale and complexity challenge and state in the case of SAM: *"In view of the innovative and "leading edge" nature of this activity there is some risk the necessary expenditure to complete the work may out-turn at a higher figure than expected.'* The same could be said of TFO. Any reduction in expenditure in this area is therefore questionable given that they recognise the challenge and support the outputs.

We therefore believe that Ofgem's proposed cost expenditure reductions will mean that we will be unable to fully deliver planned systems enhancements through TFO and SAM, thereby compromising our ability to meet the challenges of delivering RIIO outputs and efficiencies across the period. The reductions in these areas for unsanctioned projects should therefore be reversed.

Question 8: Do you consider that our proposed uncertainty mechanisms for NGGT (TO) are appropriate?

National Grid response:

As an eight-year price control, RIIO-T1 requires a different approach to a more traditional five-year control. Whilst we accept that a longer price control brings benefits in terms of incentivising the network company to made efficient decisions beyond the shorter five-year horizon, the longer period has inevitable consequences for the form of the control, including greater utilisation of uncertainty mechanisms.

We note that the Finance Supporting Document (para 2.16) states that the "The NGGT expenditure to which the "uncertainty" capitalisation rate would be applied is that which is included in the uncertainty mechanisms detailed in the Cost assessment and uncertainty Supporting Document". There are a number of areas of expenditure contained within these mechanisms, (including, for example, constraint management costs) to which it appears illogical to apply this capitalisation rate. We would therefore welcome clarity regarding to which uncertainty mechanisms the uncertainty capitalisation rate will apply.

We are very concerned that costs to be considered in the re-opener windows or mid-period review materially add to the financeability issue detailed in our 'Financeability' supplementary information document. Ofgem's own best view modelling anticipates us incurring over £0.5bn on costs covered by such schemes in the first three or four years of RIIO-T1. This expenditure will be incurred before any revenues are received to finance them. We provide further detail on this in the 'Financeability' supplementary information document.

There are a number of areas Ofgem has proposed alternate mechanisms to manage the uncertainty which is evident over the RIIO-T1 period, and other areas where Ofgem is not proposing any mechanism at all. We address each of these in turn below.

Information Quality Incentive (IQI)

For NGGT, Ofgem's movement of ex ante funding (as requested in our RIIO-T1 submission) to an uncertainty mechanism creates a penalty under the Information Quality Incentive (IQI). This is in direct contrast to Ofgem's March 2011 strategy document[41] (paragraph 6.30): "*It is important that the comparisons between company forecasts and our own cost assessment that feed into the IQI are made on a like-for-like basis. In particular, there should be consistency in the set of outputs that the expenditure contributes towards. This may require adjustments as part of the IQI calculations.*". It is also inconsistent with the approach taken with NGET, where no such penalty applies for a movement of expenditure from 'best view' into an uncertainty mechanism.

The impact of this penalty can be seen most notably in the case of the IED and Feeder 9 mechanisms introduced in Initial Proposals. Where it is clear that such a movement is as a result of a different legal interpretation or expectation of timing of planning consent approval, rather than an alternative view of likely costs, it is inappropriate to assume that such a difference is 'inefficient' and that a penalty should apply.

In the case of the IED, Ofgem has raised a question over our interpretation of the legislation. We have shared QC advice we have received which supports our view. In the event that the QC advice is proven to be correct once this legislation is transposed into UK law next year,

[41] Decision on strategy for the next transmission and gas distribution price controls - RIIO-T1 and GD1 Business plans, innovation and efficiency incentives, 31st March 2011

the uncertainty mechanism will trigger and provide funding. There is a clear difference in outputs that each interpretation delivers, and therefore an adjustment is required to the IQI calculations. We have not acted inefficiently at any point in this process, and therefore a penalty is unwarranted.

For Feeder 9, Ofgem accepts the need case for this work however due to the uncertainty of timing of planning consent, have proposed an uncertainty mechanism to be triggered in the re-opener window following granting of consent. There is a clear difference in outputs that each interpretation delivers, and therefore an adjustment is required to the IQI calculations. Again, we have not acted inefficiently and it is therefore unreasonable for such an approach to penalise us.

In these circumstances, an adjustment should be made to unwind the impact these alternative treatments have on the IQI assessment.

Enhanced security re-opener

The Initial Proposals do not include any baseline funding for NGGT TO physical security costs (either capex or opex) and instead propose that funding will only be triggered in 2016 and 2019 by separate submissions under the re-opener uncertainty mechanism. Whilst we agree with the proposal for re-openers in this area due to the uncertainty involved, Initial Proposals do not fund the significant levels of expenditure we have already incurred to date for completed projects and those which are backed up by value for money audits, adding to the financeability issue detailed in our response to the Finance Support Document. The Initial Proposals baseline should be updated to reflect these costs and include all opex costs on an ex ante basis, with the re-openers used to adjust from this baseline position if required. This would represent a more balanced view of the uncertainty and our cashflow risk in this activity, as well as ensuring adherence to the logging up principles from TPCR4.

We therefore propose the following, more reasonable position for capex schemes on an ex ante basis:

- Schemes which have had a Value For Money 2 audit (VFM2) to be funded at the level within the VFM2
- Completed projects which have not yet had a VFM2 but are just awaiting commercial completion with the contractors to be funded at the forecast level for 31st March 2013

All these costs should be entered into the Final Proposals base revenue allowances from 1st April 2013.

In addition, opex costs should be funded on an ex ante basis in their entirety. These costs are a function of the Post Delivery Support Agreement (PDSA) contract unit cost multiplied by the number and type of sites, and costs of the Alarm Receiving Centre (ARC). Information required to assess the efficiency of the PDSA unit costs have already been sent to Ofgem and the ARC is already in place, again with details already sent to Ofgem. The only variable that is subject to any uncertainty is the timing of when sites will be commissioned but there are defined dates which set this point so funding the relevant costs on an ex ante basis seems the most appropriate approach.

Ex ante funding on this basis would create baseline expenditure as outlined in the table below:

	£m

Capex	[text deleted]
Opex[42]	[text deleted]
Total	[text deleted]

This compares to a current forecast of expenditure by the end of 2012/13 of [text deleted] ([text deleted] of capex and [text deleted] of opex), and a total expected cost for the projects currently required of [text deleted] ([text deleted] of capex and [text deleted] of opex). At approximately half of this total expected spend, it represents a more balanced level at which to set the as a baseline.

From a process perspective, the use of re-openers would work more efficiently if there was sign off from Ofgem on each of the VFM2 audits as they were completed during the RIIO-T1 period, with any further work required completed at this point. This would ensure both that the review occurs in a timely manner thus allowing for any key issues to be resolved in readiness for future projects, and that regulatory burden is minimised. If this sign off was not finalised until the re-opener windows, necessary information to support the analysis is unlikely to be readily available for those projects which had closed years earlier, and teams would need to be remobilised to answer questions, diverting resources from other projects and increasing costs overall.

Ofgem recognised we need to discuss the funding in this area, and we are currently in dialogue with them.

In relation to the costs associated with our data centre strategy, the scope of which is currently under development in conjunction with the Centre for the Protection of National Infrastructure (CPNI) and is discussed in more detail in response to question 13 below, the re-opener windows are too late in the delivery schedule to provide timely funding, and demobilisation of the current work to await the re-opener window would drive total costs up and prove inefficient.

Given the first re-opener window is after we expect to have delivered the strategy, we propose that the re-opener window explicitly considers historical costs incurred in the delivery of the project to that date.

Re-opener windows
Initial Proposals include for the consideration of specific uncertain costs during the two re-opener windows. These are considered individually in our response to question nine below.

Mid-period review
From Initial Proposals, we understand that the mid-period review has been expanded from the original remit of consideration of the continued appropriateness of Outputs, and the impact of new legislation. It is proposed that this review will now include:

- An evaluation of the need case for investments required to meet the Industrial Emissions Directive following clarification of the applicability of the ‘emergency use’ clause to some of our plant contained within the Directive.

- Consideration of network flexibility expenditure intended to assist with “commercial obligations”. We would like to seek clarity on whether “commercial obligations” relate to the introduction of new commercial products, or network flexibility requirements to support the different use of existing capacity outside the definition of ‘future peak day requirements’.

[42] Includes £7.5m opex to the end of 2012/13 and £41.9m forecast for the RIIO-T1 period.

We do not agree the evaluation of the IED need case should form part of the mid-period review, as we believe this is too late to provide timely funding to ensure the safe, efficient delivery of the necessary works. The potential for a different interpretation of the Industrial Emissions Directive does suggest that a mechanism is warranted to release appropriate funding in a timely manner to ensure delivery of any necessary works once the need case is proven, and we propose that such a mechanism can and should be triggered at the point clarity is received. As set out in our response to question three of Chapter two of the Overview document, we hope clarity will be forthcoming as the Directive is transposed into UK law early next year. In the event the legislation does impact our plant, waiting until the mid-period review in 2017 before starting the necessary replacement works will render the replacement programme undeliverable. Evaluation of the need case should therefore be completed when clarity is provided on the requirements of the legislation, either through the provision of guidance from DEFRA and the Scottish Parliament, or agreement with the environmental regulators.

This mechanism must allow reconsideration of the asset health investment requirements in relation to specific compressor units in the event they do not require replacement, given the age and condition of the affected assets. As stated in our response to question seven above, our asset health investment plan and prediction of Network Output Measures (NOMs) has been built on the assumption that a number of compressor units require replacement under environmental legislation. Where a unit is expected to be replaced, we would undertake minimal asset health works targeted on maintaining the asset only until it will cease operation. Should these replacements not be required or funded, the effect would be to increase the asset health investment requirements on the impacted units as we are required to maintain their operation into the future. This consequential increase in investment requirement must be considered alongside the evaluation of the need case.

Such a mechanism also provides the opportunity to ensure that, once the need case is clarified, the scope of required works is understood and that a suitable allowance can be agreed. As noted in our response to question 7 above, we propose to agree a library of unit costs ahead of the RIIO-T1 period which can be used to set an allowance for specific works once the required scope is clarified. This treatment is predicated on the ex ante funding of the necessary Front End Engineering Design (FEED) to ensure the projects can progress to provide the required clarity of scope in a timely manner.

Initial Proposals also includes a view of incremental capacity signals and the reinforcements which may be triggered in the assessment of the impact of a new uncertainty mechanism in this area. Placing reliance on a potential signal for incremental capacity to deliver a legislative requirement is inappropriate, so the need case for such investment must be considered against the known environment at that time. We can be certain that such investment will never be funded more than once as revenue drivers for incremental capacity will be calculated as and when they are required, and will therefore take into consideration any new environmental legislation-driven infrastructure already provided for.

We note also that within Initial Proposals, for a number of future emissions driven compression projects related to both IPPC and IED, Ofgem has proposed reductions in the amount of compression power required at certain sites. When, subsequently, details of the network analysis Ofgem (or their technical consultants) had undertaken supporting these reductions was requested, Ofgem responded that the reduced powers were based solely on the current level of compression used at each site and the requirement to maintain the appropriate level of backup capability. This reasoning is fundamentally flawed as the level of compression power that will be required at each site will reflect the Best Available Technique (BAT) agreed for that site with the appropriate environmental regulator. The BAT decision will include an assessment of the expected future operating duty of that site which may of necessity drive a different power level to that currently installed. It is this requirement that will then in turn, drive an assessment of the appropriate provision of backup required to maintain our safety obligations. Any correction to IQI in respect of negating the impact of moving compression projects to an uncertainty mechanism also needs to correct for this erroneous re-sizing.

Regarding consideration of network flexibility expenditure in the mid-period review, delaying funding until 2017 will create a disincentive to act in a timely manner to provide pro-active solutions to emerging network issues. This is turn will lead to increased risk exposure to all parties in the form of constraint management costs which could otherwise have been mitigated through timely delivery of infrastructure solutions.

We propose that a single uncertainty mechanism covering both 1 in 20 obligations and 'commercial obligations' remains the best solution to the challenges posed by network flexibility; specifically we propose merging the assessment/provision of 'commercial obligations' with Ofgem's proposed mechanism to address '1 in 20 obligations'. With an annual process being implemented to assess Network Flexibility projects required to meet '1 in 20 obligations' we struggle to understand why an efficient solution would not be to use the same process to evaluate projects driven by 'commercial obligations'.

We would envisage that any such proposals brought forward (to meet 'commercial obligations') would as a pre-requisite require significant stakeholder consultation on both specific deliverable outputs and need case, and would thus be sufficiently well developed to allow Ofgem to evaluate their suitability for funding. This single mechanism would best facilitate the timely assessment of issues as and when they become evident and support the delivery of any necessary solutions, investment or otherwise, in a timely manner.

An alternative solution, though not our preferred option, would be a simple expansion of the mid-period review to consider efficient actual costs incurred in the first half of the period (in the form of a logging-up mechanism) incurred to assist with "commercial obligations". This mechanism would also tend to mitigate against this disincentive to act, although not, we believe, as effectively as the single uncertainty mechanism.

Innovation roll-out mechanism

We have provided comments on this mechanism in our response to question three of Chapter three of this Cost assessment and uncertainty Supporting Document above.

Revenue driver

We have provided comments on this mechanism in our response to question three of Chapter three of the Outputs, incentives and innovation Supporting Document above.

Constraint management / buyback

We have provided comments on this mechanism in our response to question five of Chapter three of the Outputs, incentives and innovation Supporting Document above.

Network flexibility

We welcome Ofgem's inclusion within Initial Proposals of a mechanism in the form of an annual re-opener window where NGG may apply for additional projects that need to be undertaken to meet peak day requirements although we have serious concerns, detailed below, regarding some of the detail of how this mechanism will operate. We note Ofgem's proposals to treat expenditure associated with meeting ‘commercial obligations’ separately, however we are not clear as to specifically what Ofgem would include within this category and require Ofgem to provide further clarification in this area.

Notwithstanding this, as noted above, we believe that having a single mechanism to include assessment of Network Flexibility issues related to both ‘1 in 20 obligations’ and ‘commercial obligations’ would be more efficient and would offer benefits to users by ensuring that NGGT is correctly incentivised to progress these issues in a timely manner.

We are aware of Ofgem’s concerns regarding a requirement to define a specific output in advance for actions to meet ‘commercial obligations’. We also note, however, the conclusions of Ofgem’s consultants[43] which support our position that, due to the very nature of these issues, it is inherently difficult, if not impossible, to define specific outputs in advance of identifying and understanding specific options.

As already noted in our response to question seven above, where a need case has been identified that merits action under the ‘commercial obligations’ category, we would fully expect by the point of applying for funding to have undertaken sufficient analysis and stakeholder engagement to be able to clearly define both the problem itself and the expected specific outputs to be delivered by any solution.

We are very concerned with Ofgem’s proposal to apply a materiality threshold of 2 per cent per project to the proposed Network Flexibility uncertainty mechanisms, in particular due to the lack of information provided by Ofgem on how they propose that this threshold would be applied in practice. The majority of network flexibility investments identified so far involve additions or enhancements to existing network infrastructure for example, modifications to compressor station pipework to permit the reversal of flows, or the re-wheeling of compressors to provide compression capability over differing flow ranges. By their nature these projects are individually of relatively low value and would not trigger the proposed 2 percent materiality threshold. A prime example of this is the Scottish 1 in 20 investments, which whilst supported by stakeholders and Ofgem’s consultants (and implicitly by Ofgem as Initial Proposals contain a baseline allowance to fund these projects), would not individually or in aggregate exceed the current proposed uncertainty mechanism materiality threshold.

Having identified Network Flexibility as an area of significant concern to merit an uncertainty mechanism, it is surprising that Ofgem is proposing to define the mechanism so as to exclude the provision of funding within the most likely range of materiality to be applied for. We could envisage this issue being overcome by the introduction of a logging up or aggregation facility within the Network Flexibility mechanism to allow multiple projects to count towards the trigger threshold, and applying the 1 per cent threshold applicable to the majority of other re-openers. Subject to agreeing appropriate rules/levels in either case we are indifferent to which mechanism is chosen and we look forward to Ofgem providing further clarity in this area.

We note Ofgem’s comment regarding any such future application requiring consideration of “why the need for this expenditure has not been previously identified”. We fully support the requirement to ensure that investment decisions are identified and assessed efficiently; however we would expect this consideration to include an assessment of whether, even if projects were correctly identified at an earlier date, it would have been efficient to have undertaken them at that point in time. In any such historical evaluation care must always be taken to ensure an unbiased assessment based on the information available at the time rather than using ’20:20 hindsight’.

[43] Within section 4.1 of the ‘RIIO-T1 Gas Consultant’s Stage 4 Report’ Pöyry consider in significant detail the difficulty of determining specific Network Flexibility outputs in advance of identifying specific problems

Income Adjusting Event provision

As detailed in our response to question four above, we are concerned that Initial Proposals remove the general Income Adjusting Event (IAE) provision from the licence and replace it with a specified 'uncertain cost' term. Recent feedback from stakeholders has revealed concerns that they were not aware of the potential for this provision to be removed and do not support this approach, although one stakeholder did question whether the current materiality threshold was still appropriate. As communicated in previous meetings with Ofgem, with the extension of the price control period to eight years, there is an increased likelihood of events occurring within that period that could affect costs or benefits that we are unable to predict now. The general Income Adjusting Event term provides a method to address this.

Of more concern is the fact that the current IAE terms allow for third parties to question whether there should be an adjustment to our allowed revenue; this is a facility that has been utilised within the TPCR4 period. We note that the uncertain cost licence conditions, which are intended to replace the IAE terms, do not contain similar provisions and so the ability for a third party to question whether there should be an adjustment to our allowed revenue has been removed. This has not been consulted on in Ofgem's previous strategy documents and the effect on third parties is not specifically drawn out in Ofgem's Initial Proposals. We note that Ofgem do express concern that a general IAE is too broad and could be used in too many situations but we contend that this can be controlled by retaining the existing form of licence drafting that clarifies a strict process for assessing requests. We note that IAEs have only been raised twice in the TPCR4 period, with one occurrence being rejected. The general IAE provision should therefore be maintained.

Question 9: Do you agree with our proposals to expand the provisions of the re-opener mechanism for NGGT to cover a number of additional cost areas?

National Grid response:

We comment on each element of the expansion of the provisions of the re-opener mechanism below:

Asset Health shocks

We welcome the inclusion of an uncertainty mechanism to manage the uncertainty of material 'shock' events, such as a significant type-fault on an asset or the necessary replacement of a material length of pipeline.

Feeder 9

We understand the rationale for moving the ex ante funding to an uncertainty mechanism to be triggered on receipt of planning consent. However, we are concerned that restricting the release of necessary funding to the re-opener windows has the potential to delay a critical asset health investment thereby increasing the risk of failure of a key pipeline which, as we set out in our RIIO-T1 submission, would lead to very material constraint costs. We propose that the mechanism is designed to trigger on receipt of planning consent, regardless of when that would be to ensure timely delivery of this critical investment.

In a similar manner to the newly proposed uncertainty mechanism for environmental legislation-driven investment, the movement of the requested ex ante funding for the replacement of the Feeder 9 crossing of the Humber estuary has created a penalty resulting from the IQI mechanism. This is detailed above.

Pipeline diversion costs
We welcome the inclusion of an uncertainty mechanism to manage the uncertainty over legacy arrangements relating to pipeline diversion costs. We are concerned that, as currently worded in Initial Proposals, the mechanism could be interpreted too widely (i.e. it could be understood to include all pipeline diversion costs, which would lead to over-recovery of revenues as most diversions are customer funded), and therefore need to work with Ofgem to ensure it is correctly included in licence drafting.

Environmental legislation-driven investment
In addition to the new IED legislation, existing environmental legislation perseveres in the form of the Integrated Pollution Prevention and Control Directive. The use of a re-opener window has been proposed for IPPC Phase 4 projects following the commissioning of projects within Phase 3. Whilst we recognise that Ofgem has proposed this approach given the time delays we have incurred on Phases 1 and 2 to avoid providing advanced investment unnecessarily, triggering funding in the re-opener window following commissioning of Phase 3 will not align with the legislative requirement triggered by the annual Network Review process earlier this year.

Phases 1 and 2 were run in parallel as part of our continuous improvement to fleet emissions reduction performance and were aligned with the overarching strategy agreed with the EA/SEPA to achieve legislative compliance. The delay introduced by triggering investment on commissioning of the previous project will therefore counteract the strategy agreed with our environmental regulators. Should Ofgem continue to propose this treatment for IPPC phase 4 investment, the need case should be considered in the two re-opener windows (2016 and 2019) and costed using the library of unit costs once scope is confirmed to ensure timely delivery against the environmental legislation is possible.

In both cases above, to enable generation of a scope of works to be agreed with the environmental regulator as Best Available Technique (BAT), we must progress Front End Engineering Design (FEED) for each impacted compressor unit. Such work is certain and required ahead of confirmation of scope for use in the calculation of an appropriate allowance, and should therefore be funded on an ex ante basis. FEED work represents a small proportion of the overall investment cost.

It is also important to avoid unintended consequences under IQI of the movement of funding from ex ante to an uncertainty mechanism; this is detailed above.

Quarry and loss of development claims
Quarry and loss of development claims are currently managed on a pass-through basis as these exceptional costs are largely outside of our control. Ofgem are proposing to change these arrangements such that these costs will be considered in the two re-opener windows. Provided historical, actual costs incurred can be considered in these re-opener windows we agree with this proposal, however note that it delivers little benefit over the current arrangements.

Question 10:	Do you agree with our proposed materiality thresholds of 2 per cent (subject to the efficiency incentive rate) for the re-opener mechanism in relation to asset health shocks?

National Grid response:

The intention of this mechanism is to provide funding to manage the impact of low probability high impact unexpected events and as such, we agree with Ofgem's proposal for a higher 2 per cent (subject to the efficiency incentive rate) materiality threshold.

We note that the Initial Proposals do not provide clarity on whether this threshold level will apply on an annual basis or whether costs can be carried over from year to year and the total is compared with the materiality threshold. As the majority of potential items covered by this re-opener mechanism will incur costs over more than one Formula Year, it would seem appropriate for the total to be compared to the materiality threshold. We look forward to this being clarified within the licence drafting consultation in October.

We also note that the Overview Document (table 3.6) states that Ofgem are proposing the materiality threshold for asset health at £50m, and from the wording of this question 10 believe this inconsistency is an error. We would welcome confirmation that this is the case.

Chapter: Eight

Question 11:	Do you consider that our proposed baseline for NGET (SO) has been set at an appropriate level?

National Grid response:

Efficient operation of the transmission network and UK electricity market is dependent on the timely provision of required capabilities within the System Operator (SO), however

- **Initial Proposals reduce allowances due to uncertainty, but do not include any mechanism to manage that uncertainty, in direct contrast to Ofgem's consultant's recommendation which will result in overall SO costs increasing**
- **Errors in calculations for opex allowances incorrectly assume that these costs are linear to capex**
- **Market facilitation has been reduced to 2010/11 expenditure levels despite the growing influence of European energy policy**

The changing mix of generation to less predictable sources, coupled with the growing influence of interconnections, EU energy policy and demand side participation is driving a requirement to enhance our System Operation capabilities to operate the power network securely and safely. We will develop these capabilities through a mixture of investing in IT systems (capex) and adapting our operational processes and facilitating the market to deliver solutions (opex) that minimise the external costs of balancing the network. Without these investments balancing and constraint costs will increase significantly, as we have to run the system more conservatively, far outweighing the costs of the proposed investments.

We are therefore concerned with the Initial Proposals in this area. There seems to be little focus on total SO costs or risk within the assessment, instead the focus is on reducing internal SO costs without taking into account the detrimental impact on balancing and constraint management costs that these reductions will create, which have a much larger potential impact on total operating costs.

Our main concerns are summarised within this section with further detail available within the supplementary information: SO costs document and supplementary information: market facilitation paper.

Capex

PPA's approach in reviewing the RIIO-T1 capex programme for the ESO, which is stated in the PPA report was to:

- Critically appraise enhancement projects
- Defer the more speculative enhancement projects pending clarity of need and requirements
- Taking a conservative view of the rate of expansion of wind capacity
- Identifying those developments likely to provide most benefit to consumers

Where PPA's approach is perhaps most surprising is the explicit focus on deferral of projects with no consideration of the consequence this brings.

We recognise that as a natural consequence of the combination of the longer eight year RIIO-T1 control period and the increasingly dynamic operational and regulatory environment that there would be greater uncertainty when forecasting investment requirements for the latter half of the plan period. This is compounded for SO capex due to the reliance on information technology to deliver many of the enhanced capabilities required in the future, where advancements in technology make forecasting up to eight years into the future with certainty an impossible task. We recognise that absolute clarity over requirements and necessary functionality of SO capex projects in five to eight years time cannot therefore be provided, however we can be sure that there will be requirements.

We therefore requested funding for theme based investments such as integrating a wider variety of generation technologies, further demand side integration impacts and greater SO to SO interactions. Whilst there is uncertainty to the precise requirements there is certainty that we will need to make changes to our system architecture to adapt to the changes to the system operator environment.

Notwithstanding this, ex ante reductions should be corrected as the methodology that PPA use fails to appreciate the following:

- Whilst wind is a dominant factor in requiring us to enhance our capabilities, near term increases in DSR, Interconnection and the introduction of physical assets such as series compensation and embedded HVDC, is also driving the requirement for investments.
- The proposed reductions delay schemes that can add tangible benefits to consumers such as EBS phase 2 which from the adoption of AGC alone could save £25m per annum

What follows is further details of the needs case and rationale for ex ante funding for certain schemes illustrating the value they deliver to the end consumer. The table below summarises these schemes

Scheme Name	March Submission	Ofgem Initial Proposals	Revised request	Reason
Stability Control System	[text removed]	[text removed]	[text removed]	Provision of funding for least regrets stability monitoring capability to monitor reliability of network and minimise reserve holding requirements
EBS Phase 2	[text removed]	[text removed]	[text removed]	Incorporation of stakeholder-led developments that were requested

				for phase 1, including provision of industry standard AGC technology
Wokingham Smart Workplace	[text removed]	[text removed]	[text removed]	Initial Proposals disallow to allow more research but concept has already been proven in Warwick office
Improved Modelling	[text removed]	[text removed]	[text removed]	Enhanced capability to optimise network configuration, reducing balancing costs
OLTA Hardware refresh	[text removed]	[text removed]	[text removed]	Maintains ability to study more network configurations, a process which was supported by PPA
IEMS Future upgrade	[text removed]	[text removed]	[text removed]	Funding to allow change to a more efficient modular upgrade of the core CNI system
Infrastructure for business systems	[text removed]	[text removed]	[text removed]	Increased costs compared to TPCR4 period driven by headcount allocations
SMART Demand	[text removed]	[text removed]	[text removed]	Required to be able to forecast shifting intraday demand patterns and facilitate greater demand side response provision

Stability Control System

Whilst we recognise Ofgem's concerns around the degree of uncertainty around the requirement and cost of implementing such an innovative and complex system, it needs recognising that there is short term certainty around the requirement for us to enhance our stability monitoring capability. Correspondingly, we are requesting ex ante funding for the 'no regrets' stability monitoring capability and for the iterative parts of the investment that would provide the appropriate level of system safety to manage the risk of instability. These investments in monitoring capability will allow us to maximise the benefit of the existing capacity on the network without having to run the system more conservatively. There are four subcomponents for which we are requesting ex ante funding of [text removed]. These are explained further in the supplementary document but in summary are:

Stability Monitoring - This work stream will expand the breadth of coverage of our capability for wide area stability monitoring allowing us to utilise the maximum capacity of the existing systems.

Disaster Recovery and Data Management - The existing IT infrastructure was not designed to support the increasing data volumes or the renewed scope of stability monitoring and ultimately control. This investment will build in the capacity and redundancy required for the broadening stability monitoring system.

Stability Analysis - This work stream will build on the current in-flight project of our online stability analysis project (which has been funded) and provide our planners and control engineers with advice on how Inter-trip schemes should be set to take account of actual generator outputs in order to maximise network utilisation. This will help maximise the benefit of intertrip schemes in helping to reduce stability related constraint costs

Voltage Stability Assessment – We need to develop our voltage assessment capability through a tool for offline voltage collapse assessment taking into account the increase dynamism of system voltage and load

EBS Phase 2

PPA has stated that EBS Phase 2 should be delayed by two years, allowing more time to clarify requirements against the build up of wind. This reduction moves £3.8m out of the RIIO-T1 period. Without the timely investment in the second phase of this project, our ability to optimise the economic despatch of the broadest set of market participants will be compromised leading to sub optimal economic despatch and higher balancing costs that will be passed on to consumers.

Our primary aim as SO is to maintain security of supply. EBS Phase 2 will allow the analysis of a range of credible scenarios, assessing the impact on security and balancing costs. By ensuring we remain in an acceptable operating environment for credible inputs we will be able to make the best decisions to minimise costs and protect system security.

In the stakeholder engagement we undertook in advance of phase 1 of the EBS replacement stakeholders proposed several improvements which we were not able to incorporate. The second phase allows these improvements to be put into operation, such as Automatic Generator Control (AGC). It is estimated that on average £25m per annum of response costs are needed due to the current absence of such a system.

The development of this second phase will also deliver automatic bid-offer acceptance capability and the ability to develop the network secured functionality to assess voltage constraints. These are a growing cost driver and it is essential that we develop the capability to mitigate the cost of these. This aligns with stakeholder views expressed at the London workshop on 4th September, suggesting that investments that reduced constraint costs were an entirely appropriate focus.

<u>Wokingham Smart Workplace sharing</u>

As the size of our workforce increases to meet the operational challenges of the next decade we aim to increase the utilisation of our existing office space and rationalise where possible thus avoiding taking any new space. Through this concept we reduce the amount of space per person from ~100 sq ft (the current industry benchmark) to 50 – 60 sq ft.

The Smart Workspace concept provides an increase in capacity in the order of 20% to 30% with no significant increases in operational costs. To date at Warwick we have converted six floor plates into smart workspaces. The cost to complete the Warwick scheme is fully sanctioned. The scheme to increase capacity at Wokingham from 574 to 699 was sanctioned in September. The increase in capacity delivered at existing cost is equivalent to operating expenditure in the order of £0.6m per annum at an additional location.

Ofgem reduced funding for this scheme pending further research to demonstrate the benefits. These have already been effectively demonstrated through the roll out of the concept in Warwick so there is no requirement for further research into the concept in our Wokingham office as suggested by PPA. With the benefits that arise from the investment the full [text removed] should be allowed on an ex ante basis.

<u>Improved Modelling and OLTA Hardware refresh</u>

These investments support our ability to analyse the transmission system from seven years ahead right through to real time and post event. They support the automation of system studies that allow us to plan and run the system in the most economic and reliable manner. Changes to the physical network and the increasing variability of generation and demand over the RIIO-T1 period will require us to increase the number of scenarios that we run.

Without funding for these investments:

- We will not be able to refresh the hardware that delivers the processing power to undertake the volume of scenarios that we will need to run in a timely manner in the future
- Have the capability to create accurate outage and network constraint plans to be able

to facilitate the customer connections and maintain our obligations for system operation.

IEMS Future Upgrade

The IEMS is our most operationally critical IT system which underpins our capability of operational control. This system covers both the NETSO and the TO roles for monitoring, control, data provision and management of the work-flow for issuing of safety permits to enable maintenance work on the transmission network.

We expect that requirements for changes on the IEMS to be more prevalent with the introduction of changes such as electric vehicles, increased impact of smarter networks and DSR services, offshore grids and the level of European interconnection. With these changes impacting our operations at different times, we are proposing to move away from the standard five year project delivery to enhance our capability to a more agile, modular based approach. This approach of making annual investments to provide the required enhancements will ensure that we are able to implement changes more rapidly to meet the needs of our customers and the external environment, whilst still maintaining the health of this critical CNI system.

Infrastructure for business systems

Ofgem has proposed reducing ESO expenditure on Infrastructure for business systems because the expenditure is higher than during TPCR4. Our overall spend in this area in the UK is planned to reduce to an average of £6.5m per annum during the RIIO-T1 period compared to an average of £9.6m per annum in TPCR4. It is the allocation of costs to ESO that has increased due to a change in our infrastructure allocation driver. This driver uses the number and complexity of servers used by the applications owned by each business area to determine the share of costs for each form of control. Through IS Transformation more granular information about applications and their associated infrastructure is becoming available which has led to a greater proportion of these costs being allocated to ESO. The increase in capex costs for ESO in this area is therefore a better reflection of the costs applicable for ESO.

These investments are required to support the commodity IT systems such as e-mail and desktop applications and the associated hardware and infrastructure such as servers, storage, firewalls and desktop PC's or laptops. These infrastructure items may not be critical individually but are key enablers for all of our business capabilities. 94% of investments in this area relate to maintaining and refreshing our existing capability rather than further developments.

SMART Demand

Since our initial submission, the momentum behind the uptake of Demand Side response and Smart network services has increased. DECC indicated in their conclusions of the (Electricity System: Assessment of Future Challenges Summary, August 2012) that market arrangements need to be fit for purpose and able to support the development of key balancing technologies. The report continues to promote investment in smarter network technologies. These will be critical to support the increasing roll out of smart meters and a number of SMART grid solutions being trialled by utilities. Our current market view is that 85% of commercial and households will have smart meter installations by 2017.

SMART grid solutions will change the demand profile and how we can actively forecast the shift in demand patterns. This will become more central to decision making since the future scenarios are expected to be very different to current trends. This investment will support predictive tools which will be used in the planning stage to ensure proactive analysis and actions can be taken to preserve system security and minimise balancing costs. Collecting and assessing this data will form an important base for our forecasting and planning functions creating a positive impact on the amount of operating margins we require.

SO Opex

We have several issues with the baseline expenditure for SO opex including:

- **Calculations for opex allowances incorrectly assume that these costs are linear to capex**
- **Market facilitation has been reduced to 2010/11 expenditure levels despite the growing influence of European energy policy**

The assessment of our forecasts undertaken by Ofgem and its consultants PPA have reduced opex allowances for ESO by £112m across the RIIO-T1 period. These reductions in opex allowances are wholly inappropriate and have been based on ill-founded logic that incorrectly assumes that these costs are linear to capex with lack of justification for the depth of the funding reductions.

As currently proposed the total level of opex for 2013/14 of £62.7m falls significantly below the allowances allowed for rollover of £65.4m, despite the necessary volume of work we need to undertake continues to increase over the RIIO-T1 period. This gap is compounded by the fact that there is an allocation change of £4.3m for Optel costs from ETO in 2013/14. This has been removed from ETO allowances but not included in these ESO costs.

Not undertaking the extra work – which the Initial Proposals incentivise us to do – would have detrimental impacts on IS system security leading to reduced network reliability and/or higher balancing costs. More specifically they jeopardise our ability to:

- Play our full part in European energy policy development
- Recruit and train the necessary skills for critical operational roles which are on UK government shortage lists
- Support the existing IT systems, let alone the necessary future expansion of the portfolio

Whilst we respond to these concerns below, greater detail can be found in the supplementary documents: 'SO_costs' and 'Market_facilitation' where each activity line of our direct and business support opex costs is critiqued individually.

Market Facilitation

Initial Proposals reduce market facilitation costs to 2010/11 expenditure levels based on analysis errors and despite the growing influence of European energy policy. This unjustified reduction means that mandated European work cannot be undertaken and we will not be able to play our full part in Europe which Ofgem has stated they want us to do. In addition, disallowances have been triggered based on an unsound link through to capex workloads which fails to understand the nature of the fundamental work undertaken in this activity which benefits the wider energy industry.

The impact of the Initial Proposals would result in:

- **Mandated costs disallowed**: Much of the European work such as development of joint EU codes and membership of TSO bodies are mandated by EU law. Reductions to forecasts disallow costs which European regulations state must be funded through local regulatory allowances.

- **Minimal European interaction:** We will not be able to play the role expected of us within European interaction. Ofgem recognise that we need to be at the heart of this work, stating that they want us to 'play our full part', however, all of the increased workload from 2010/11 – which is virtually all due to European activity - has been disallowed.
- **Higher industry costs due to no proactive work**: Limiting our role within Europe will lead to higher industry cost overall because we are helping stakeholders understand the impacts of proposed changes. The result of disallowing costs of this stakeholder engagement would be a reactive, rather than proactive approach for us and the UK energy industry. This would increase long term costs due to European codes being less like the UK, resulting in higher implementation costs.

The reductions themselves are based on unsound logic with Ofgem's consultants using the following arguments to reduce expenditure:

- **Reductions linked to capex levels**: which have no relationship to the activity
- **Direct billing of above license requirement:** We strongly disagree with this as such a proposal would increase transaction costs, reduce the level of competition and introduce a two-tiered market structure with parties willing and able to pay for specific services gaining advantage over others

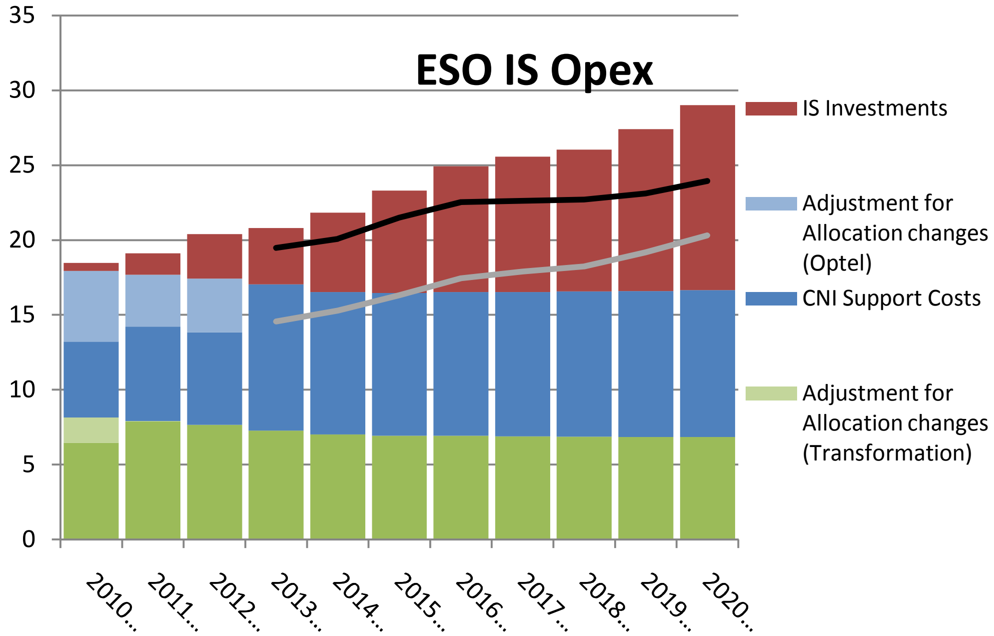
Subsequent to Initial Proposals, Ofgem has stated that their consultants thought we were trying to take on Ofgem or DECC's role in Europe but this is not the case. We are in regular dialogue with both Ofgem and DECC to ensure that we understand the role these key stakeholders want to undertake and that we work together for the benefit of UK consumers. However without the proposed funding this work would have to reduce.

Reductions linked to capex

PPA have justified the volume of opex reductions based on the corresponding capex reductions for all aspects of our opex plan apart for market facilitation. The logic that has been applied to reducing our allowances assumes that there is perfect linearity between the two which is ill founded. In addition, the assessment does not take into account that capex reductions are mostly at the latter end of the plan. As they currently stand, opex reductions are phased proportionately across all years of the RIIO-T1 period.

The result of this methodology and how it has been incorrectly applied is illustrated by the reduction in engineering support costs. The majority of these costs are for the recruitment and training of 38 new hires that are vital to support increasing work load requirements and are in areas where there are specific UK skills shortages. The recruits required for our near term planning functions and control room teams to replace people expect to retire and leave. This impact has nothing whatsoever to do with capex volumes yet expenditure has been reduced based on PPA's methodology.

PPA have reduced the SO capex forecasts based mainly on the uncertainty of the requirement for these schemes. In removing these schemes from the capex plan, there is a knock on impact to the support costs for our IT portfolio. However, instead of removing the opex for the projects that they have deducted, PPA have assumed that the opex impacts are linear with the capex reductions and have removed 30% of the IS opex business support costs. In doing so they have removed over double the opex they should have to the extent that in the near term we do not even have enough opex allowances to support the existing suite of IT systems. We have calculated that for IS and Telecoms cost the adjustments should be reduced from the £61.6m in Initial Proposals to £21.8m. The error in this area is illustrated by the graph below which shows the Initial Proposals (grey line) compared to the reduction that should have taken place given the SO capex disallowances (black line)



IS Business Resources

Funding on IS business resources has been reduced in line with the proposed reductions in SO capex allowances. These resources are there to support the development of the IS schemes that we require to manage the system of the future and are vital in the creating the right solutions to the challenges we face. Within their report Ofgem's consultants recognised the need for IS business resources and went as far as to highlight that there was a risk that we did not have enough resources to deliver the projects. We are therefore confused as to the rationale for the cut in these resources when it was believed that we did not have enough individuals in our plan to start with.

Data centres

The costs apportioned to our data centres are shared between the ESO and GSO functions as well as our gas distribution business. We have responded to the proposed data centre allowances in Chapter 8, Question 13.

Question 12: Do you consider that our proposed uncertainty mechanisms for NGET (SO) are appropriate?

National Grid response:

There are three key areas where uncertainty mechanisms are important for NGET (SO) direct costs:

- Capability enhancements towards the end of the RIIO-T1 period
- EU/GB regulatory and market driven change
- SO security enhancement costs (data centres)

We present our views on each in turn below, with supplementary information contained within the stand alone supplementary documents: 'SO_costs' and 'Market_facilitation'.

Capability enhancements towards the end of the RIIO-T1 period

In its report Ofgem's consultants (PPA) stated that there was a large degree of uncertainty over the requirements for future systems developments to provide enhanced capabilities to support the operation of the electricity transmission network.

They went on to reflect that this was unsurprising given an eight year price control, and that ex ante funding should be removed and an uncertainty mechanism be considered to allow access to that funding once the need case was more certain.

"It is therefore proposed that an uncertainty mechanism is introduced that provides for further allowances"

As we move into a longer term price control there is inherently a greater level of uncertainty and risk that we face in terms of how we will overcome the future challenges of system operation. We were initially comfortable that this symmetrical risk was something that we were best placed to control and that minimising the number of uncertainty mechanisms was beneficial in reducing the regulatory burden and increasing transparency. However, with the implied reduction in funding for investments in the latter half of the plan, the risk is now asymmetric and in our view this currently does not best protect the interests of consumers.

Without an uncertainty mechanism that allows for funding of necessary investments to manage the challenges of an evolving system operation environment we will end up running the system in a more conservative manner so as not to jeopardise system reliability. This will not be in the best interests of consumers, contrary to Ofgem's statement, as we will be less able to reduce the forecast increase in external balancing costs. As depicted within the analysis that we undertook within our March submission these are forecast to be far in excess of the cost of implementing systems that would allow us to fully optimise system operation in the future. We therefore believe that the interests of consumers are now best protected by the introduction of an uncertainty mechanism to give access to further funding within the RIIO-T1 period.

Whilst recent conversations with Ofgem suggest that some of this risk can be covered by an uncertainty mechanism based around the mid-period review, this is neither explicit in the Initial Proposals nor adequately defined for us to be comfortable with this approach. If Ofgem believes - as its consultants propose - that all allowances cannot be set on an ex ante basis in such a dynamic operational environment, we need to work with Ofgem to develop an appropriate mechanism.

We therefore believe that future SO investments should be triggered by changes to our operating environment, which rely on us justifying the requirements for the 'new' schemes rather than a review of outputs. We therefore propose that there should be a specific uncertainty mechanism that is assessed at the mid period review, when external driving factors will be much clearer.

In conclusion, having a suitable funding mechanism will deliver against Ofgem's principles around uncertainty mechanisms. It will protect consumers through minimising proposed SO investments and also protects them by allowing us to provide an evidence based case for future investments that will maintain the delivery of outputs whilst minimising increasing balancing costs.

EU/GB regulatory and market driven change

Within our March submission we requested the creation of an uncertainty mechanism, for NGET to cover us for the risk that the workload associated with changes to GB and EU markets increased above our baseline workload assumptions. The risk we face is that the required changes are more fundamental than currently envisaged and that unforeseen developments could arise over the RIIO-T1 period such as a Fourth Energy Package.

In response to the proposals put forward by ourselves, Ofgem has deemed it more appropriate that requests for additional funding during the price control should be subsumed within the scope of the mid period review. We do not agree with the proposal to use the mid-period review to cover the uncertainty in relation to GB and EU market change, with an extension of the re-opener mechanism seemingly a better fit for this risk.

There are two problems with the current proposal:

(a) The difficulty in defining outputs resulting from market change
(b) The incentive to defer change which the proposals introduce due to higher cashflow risk

Whilst changes in the GB and EU markets will necessarily trigger changes to our processes or systems it is not possible to measure the impact that those changes have on outputs, even in hindsight. To illustrate this point we have previously undertaken investment in our IS systems triggered by required improvements to cross border balancing data (across Europe). This change was triggered by a legislated EU change (which would fall within the remit of this uncertainty mechanism in the RIIO-T1 period) and meant alterations to several of our IS systems to implement the mandated change.

The uncertainty for GB and EU market change is not around the outputs that the work delivers, but rather nobody knows in advance of any period what work will actually arise from market change. For example we cannot say what the impacts of European code developments will be until they are finalised and we can assess the change impacts. To try to do so now would be guessing and give rise to windfall gains or losses. We therefore did not include such estimates in our submission. By the time of the mid period review we will have no more of a defined answer for the changes that will occur in the future four years, or indeed what outputs the work undertaken in the first four years of the plan has delivered, than we do now.

Given the low chance of forecasting costs in this area correctly any uncertainty mechanism is effectively adjusting allowances on an ex-post basis rather than giving the potential for windfall gains and losses. This is therefore like logging up expenditure which Ofgem wanted to keep outside of the scope of the mid-period review. Such expenditure is however covered by re-openers in the Initial Proposals (for example physical security works).

Without changing the uncertainty mechanism to a re-opener - even if we could define outputs so funding was received under the mid-period review - the time between expenditure and funding would be up to four years. This could introduce significant cashflow risk for us. Use of the mid-period review – along with reduced baseline allowances in this area - therefore incentivises us to defer market change wherever possible, rather than to keep developing changes with the rest of the industry. Elsewhere in the Initial Proposals Ofgem state that we will be incentivised to play our full part in these developments, especially regarding European change, but the proposal in this area seems to run counter to their wishes.

SO security enhancement costs

Initial Proposals only allow funding for tactical refurbishment of our existing data centre estate and propose a mechanism, based on the re-opener windows in 2016 and 2019, which can trigger additional funding in the event it is required to go further to meet the requirements of HM Government for security and resilience to support our CNI systems. As stated in our RIIO-T1 submission, our data centre strategy requires the construction of new data centres to meet our expectation of these requirements. As construction is expected to be complete in 2014/15, however, the re-opener windows (the first of which is 2016) are too late to provide timely funding, and demobilisation of the current work to await the re-opener window would drive total costs up, introducing inefficiency and exposing end consumers to an increased risk of failure of the CNI systems for longer than is necessary. We will therefore be required to incur unremunerated costs.

Given the timing of this first window, we propose that the re-opener window explicitly considers historical costs incurred in the delivery of the project to that date, includes a materiality threshold that is proportionate to the likely costs, and that account is taken of this cash risk in the wider finance package.

Question 13: Do you consider that our proposed baseline for NGGT (SO) has been set at an appropriate level?

National Grid response:

SO capex

Initial Proposal includes a baseline for NGGT (SO) which is significantly lower than we believe will be required to meet our obligations and the challenges of the RIIO-T1 period (particularly for the second half of the period), and to deliver a strong performance against the RIIO outputs.

Approach

Over the early years of the RIIO-T1 period, there is strong alignment between our submission and Ofgem's Initial Proposals. This is as a result of reasonable clarity over near-term capability requirements and implicit agreement by Ofgem and its consultants (PPA) on our asset refresh policy. The majority of funding in the latter half of the period, however, has not been allowed. This is unsurprising, given PPA's approach in reviewing the RIIO-T1 capex programme for the GSO, which is stated in the PPA report as:

- Critically appraise enhancement projects
- Identify opportunities to delay enhancement projects (for example, relating to addressing intermittent CCGT demand, assuming slower wind capacity build up)
- Defer the more speculative enhancement projects pending clarity of need and requirements
- Defer IT refreshes where they appear to commence sooner than the asset health policy and/or they take place late in the RIIO-T1 period.

Critical appraisal of projects is a reasonable and expected activity in the assessment of a price control submission. Where PPA's approach is perhaps most surprising is the explicit focus on deferral of projects with no consideration of the consequence this brings.

It must be recognised as a natural consequence of the combination of the longer 8 yr RIIO-T1 control period and the increasingly dynamic operational and regulatory environment that there would be greater uncertainty when forecasting investment requirements for the latter half of the plan period. This is compounded for SO capex due to the reliance on information technology to deliver many of the enhanced capabilities required in the future, where advancements in technology make forecasting up to eight years into the future with certainty an impossible task. We recognise that absolute clarity over requirements and necessary functionality of SO capex projects in five to eight years time cannot therefore be provided, however we can be sure that there will be requirements.

We do not believe, however, that the most appropriate method of managing this uncertainty is to remove funding due to lack of specific justification for individual projects in the second half of the plan period. Both historical expenditure profiles and future requirements to enhance capability to facilitate evolving gas flows, UK decarbonisation targets and new sources of supply suggest that more funding than allowed within Initial Proposals will be required in the RIIO-T1 period and we discuss in more detail below specific issues and how we believe they should be addressed.

In parallel, we welcome Ofgem (and PPA's) implicit acceptance of our asset health policy for investments planned in the first half of the RIIO-T1 period, however cannot understand the inconsistent approach taken to asset health investments in the second half. Deferring asset health investment simply because is falls "late in the RIIO-T1 period", without taking any account of the potential consequences of these actions, is an irresponsible approach to assessment of a price control submission and risks the reliable operation of systems which are key to the operation of the UK gas market.

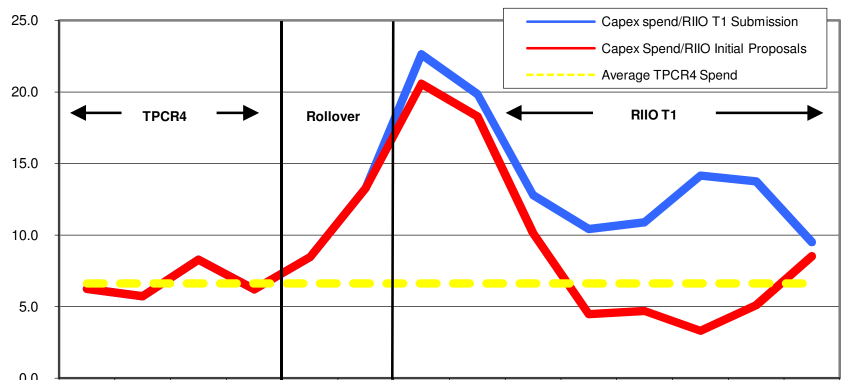
Comparison to historical investment requirement

From 2016/17 onwards, the funding levels included in Initial Proposals are substantially below our submission requirements. From our analysis of the proposals, and the associated PPA report which underpins them, we believe the most significant reductions are primarily due to:

- removal of the majority of funding for new and enhanced operational capability
- halving of funding to support obligated UK and EU regulatory driven changes
- deferment of the majority of IS asset health related investment towards the end of the period

The resultant overall level of funding, over the second half of the RIIO-T1 period, falls below the level of annual expenditure that has been required through the TPCR4 period (see graph below). This funding level is contradictory to the level of challenge that is being faced through the RIIO-T1 period and to Ofgem's clear statement that it expects network companies to play a full role in supporting decarbonisation of the energy sector, particularly when compared to the level of funding needed in the relatively less challenging TPCR4 period.

TPCR4 Spend and RIIO T1 Submission v Initial Proposals (Direct SO Capex)



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capex spend/RIIO T1 Submission	6.2	5.7	8.3	6.2	8.5	13.3	22.6	19.8	12.8	10.4	10.9	14.2	13.7	9.5
Capex Spend/RIIO Initial Proposals	6.2	5.7	8.3	6.2	8.5	13.3	20.6	18.3	10.1	4.5	4.7	3.3	5.1	8.5
Average TPCR4 Spend	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6

New capability / enhanced functionality

Of the £17.2m of investments for enhanced capability to support the processes required to manage the changing operational environment for the years between 2016 and 2021, £14.9m has been disallowed in Initial Proposals. This partially aligns with the recommendations from PPA who proposed that, as these investments could not be sufficiently justified at this time, they should instead be included in a new uncertainty mechanism to be triggered once the need case could be proven, but with sufficient ex ante funding to allow research to be carried out to develop the need case. Even within PPA's low case (Case 1), it does not state that these investments are not necessary, rather that more work is required to ensure they are fully justified.

Initial Proposals however reduce the funding to the research funding levels proposed by PPA, with no mention of an uncertainty mechanism that would allow funding (to ensure effective operation of the NTS in line with expected outputs and customer expectations) once the need case for the related capability enhancements is confirmed.

Whilst we maintain that the business plan requirements submitted in this area are appropriate for the increased level of operational challenge we expect to experience, we have always accepted that other credible scenarios to 'gone green' exist. Under most credible scenarios, we believe we will need to enhance our capabilities as System Operator to support both the efficient operation of the NTS, and the decarbonisation of the energy sector - the key issue is the timing of this requirement. We recognise that an uncertainty mechanism to trigger enhanced capability funding, as proposed by PPA, could provide a reasonable tool to help manage this timing uncertainty. If Ofgem is to maintain the reductions to ex ante allowances as set out in Initial Proposals, we consider it essential to develop an appropriate uncertainty mechanism in this area.

Failure to maintain and develop operational systems to meet the needs of an evolving operational environment will lead to higher costs and operational restrictions for both NGGT and customers. Should we be required to use greater manual effort in place of systems enhancements, the processes required to ensure safe operation of the NTS would be slower, cover a narrower range of credible scenarios and be more prone to human error. As a direct consequence, we would necessarily have to take a more conservative approach to system operation than if the developments we have proposed were in place. This would undoubtedly lead to a reduction in the flexibility we could provide to customers and an increase in the use of constraint management and balancing tools, leading to higher costs for our customers and ultimately consumers.

This approach is also likely to have a detrimental effect on the free operation of the electricity market. If we do not have the operational capability to allow CCGT generation to operate as flexibly as it will need to, to mitigate wind intermittency issues on the electricity system, then renewable generation would have to be constrained off which will increase the risk of the UK missing its obligated renewables targets.

Through Initial Proposals we are effectively incentivised to stand still, while the operating environment, renewable generation landscape and market change around us. Development is being deferred until after 2020, rather than allowing its delivery ahead of the 2020 deadline to facilitate the necessary changes to the operation of the gas market.

Specific examples of investments that have not been funded and the implications this will have are included in our supplementary information document, 'SO_costs'.

Our preferred option is for the proposed funding in our business plan submission in this area to be reinstated in final proposals. The only viable alternative is the movement of this funding into an uncertainty mechanism which will be reviewed during the re-opener windows (2016 and 2019) on demonstration of the need case, using a combination of actual spend to date, latest views of requirements based on growth of renewable energy, challenges in system operation and market balancing, and volatility of NTS flows.

Asset Health

Of the £60.4m included within our submission for asset health related investment on our operational systems, £10.6m has been deferred or removed in Initial Proposals. Virtually all asset health investment required in the first four years of the RIIO-T1 period has been allowed and this reduction almost exclusively relates to the last four years. As with any business which is reliant on complex IT systems, our systems require investment to ensure their ongoing reliability, however but very little funding is provided for this in these years.

Initial Proposals support our planned asset health investment strategy in the first half of the RIIO-T1 period by allowing a number of investments in line with the above policy, but have deferred or removed most asset health investments in the later phases; this inconsistent approach appears to have been adopted to allow expenditure to be deferred to the RIIO-T2 period rather than based upon the IT Asset Health policy and creates the risk that necessary system health investment for critical operational systems would not be carried out at the most cost efficient time. This has implications on the reliability of service to customers and the opex costs associated with ensuring the systems are maintained and managed effectively.

The processes we follow to manage the asset health of our systems are risk based, as outlined in the 'Information Services strategy' annex of our March 2012 submission. For business planning purposes, we assume that each system will need refreshing every five years (for Critical National Infrastructure (CNI) systems and their supporting infrastructure) or six years (for other non-CNI systems), in the absence of any other change. Our approach to determining the timing for IT asset health investments seeks to combine IT asset health investments with additional capabilities driven by the changing operating environment and regulatory driven changes. Where possible these have been aligned within our business plan to achieve the most efficient and cost effective solution.

By deferring funding for a number of asset health investment areas by at least two years, Initial Proposals extend the planned operational life of our operational systems from five / six years to at least seven / eight years with no assessment of the impact of this change on the reliability of these systems and the knock on impact on support requirements and costs. Our assessment of the additional opex support costs for the proposed deferral of two years to iGMS asset health refresh costs alone is approximately [text deleted], predominantly due to the increased costs of vendor support once standard warranty periods have been exceeded. This indicates the financial cost of deferral beyond the optimum refresh point, onto which the risk of service failure needs to be added.

It is possible that this deferral may be due to a misunderstanding of our policy and its application by PPA Energy. Their review of our plan (RIIO-T1 Stage 4 National Grid System Operator Electricity and Gas Capex and Opex Initial Assessment) suggested that a number of our proposed investments "appear to be commencing sooner than the five year refresh policy". This is incorrect; all investments in this area are timed to ensure that the refresh is delivered in the appropriate number of years after the previous investment – it is the period between system deliveries that is important, not the period between years in which spend is incurred – as an asset refresh may have spend across more than one year.

Specific examples of investments that have not been funded and the implications this will have are discussed in our supplementary information document, 'SO_costs'.

iGMS Network Security

Initial Proposals remove funding for investment designed to ensure that the security infrastructure around our iGMS system is maintained at an appropriate level to meet increasing cyber risk (INVP 1050). This approach aligns with proposals by PPA, however PPA do not provide any justification for the removal of this funding line in their low case (Case 1), nor for its reinstatement in their high case (Case 2), and we therefore believe this may have been an oversight or error.

Protecting our CNI systems from cyber terrorism and malicious attack is essential to ensure safety, security of supply and a reliable service to customers. The standards and best practice we comply with are appropriate for the criticality of a CNI system, and we undertake regular reviews with the Centre for the Protection of National Infrastructure (CPNI) to ensure this is the case. As with any other organisation exposed to cyber threats, the ever changing nature of these threats means ongoing enhancement and testing is required to maintain the security of our systems.

Our forecast of increasing threat is evidenced by recent events. We were warned of a likely cyber attack during the Olympic opening ceremony by Government bodies, as reported in the press: http://www.guardian.co.uk/sport/2012/aug/15/london-2012-cyber-attack-warning. Our forensic analysis confirmed that an attack was launched, but that it did not penetrate our perimeter protection as our network security is current and maintained.

Monitoring of our CNI network (though BT Counterpane service) further supports this view. Last month showed that of the over two billion CNI network events analysed, 98,000 were potential security events of which 500 were classified as suspicious and potentially malicious actions. None of these events penetrated our CNI system protections.

Initial Proposals remove planned investment to evolve our security around iGMS to keep up with the threat of cyber attack, in line with industry best practice. As this disincentivises us to develop this security, it places a materially increased risk of disruption of operational control and market services to our customers due to cyber attack. Accordingly, this funding should be reinstated in full.

Information Provision

Market Information Provision plays a vital role in the effective and efficient operation of the UK gas market. We support this through the timely and accurate provision of appropriate information, and are considered by market participants in the UK and across the EU as a forerunner in this area.

Our submission reflects the need to maintain existing capability through a refresh of the existing MIPI system assets by 2014/15, which was accepted by PPA and Ofgem has provided funding in Initial Proposals. Our submission also includes plans to enhance the capability of the system to react to forecasts of increasing demand from customers for more information at greater frequency, especially within day information, as well as demands for that information to be published in ways that allow customers to access and manipulate the information in the ways that they want to. This enhancement funding to deliver phased investments from 2016 through to 2020 to align with the increasingly volatile operation of the NTS was not funded in Initial Proposals, suggesting that enhancement of this capability is not believed by Ofgem to be valued by the market. A further asset refresh of the system, commencing in 2020/21 in line with asset health policy was also not funded.

Through the latter years of the TPCR4 period we have seen exponential user growth, and therefore load, on the MIPI system. The system is now running at between six and eight times its design capacity and we are having to undertake unfunded tactical spend in this year to allow us to manage this in the short term.

Recent press reports reflect the continued importance of our information publications systems and the value to stakeholders and the issues caused by increased load (ICIS Heren 24th August 2012) http://www.icis.com/heren/articles/2012/08/23/9589610/national-grid-data-issues impeding-british-natural-gas-market.html.

Investment in MIPI Infrastructure Refresh (INVP 0229 MIPI Infrastructure Refresh) will refresh the current infrastructure but will not provide any additional information or improved functionality, and whilst the new hardware and software will provide greater performance than what it replaces and the capability to extend this further, this investment in itself will not provide additional capacity to meet further increases in user load.

Maintaining our current level of capability in information provision against anticipated increasing load requirements as more information is sought by more parties will result in decreasing performance for our customers and other stakeholders. At the same time, we will not be funded to respond to customer requirements for new data and functionality that is required to support efficient market operation. Initial Proposals significantly constrain our plans to support all of these drivers and customer needs for information provision over the RIIO-T1 period.

The proposal to reduce by 50% funding to deliver regulatory requirements (INVP 2401-

Regulatory Driven GSO System Enhancements (EU) & INVP 1436 - Regulatory Driven GSO System Enhancements (GB)) will also constrain our ability to meet customer requirements for regulatory enhancements in information provision. Whilst we will always strive to meet our obligations by publishing the information we are obliged to, reduced funding will constrain our ability to meet customer requirements to publish information in different ways and support increasing load.

Given the value the market demonstrably places on information provision, funding should be included in Final Proposals to allow these developments to be delivered through the second half of the RIIO-T1 period. If requirements are considered to be insufficiently defined at this time, this funding should be considered directly within an uncertainty mechanism however this level of micro-regulation is unwarranted in this area.

We are developing options in this area with the intention to carry out further stakeholder engagement to support developments and we would welcome discussion about how this might be carried out and developments funded.

Regulatory

Within our RIIO-T1 submission, we proposed a baseline of ex ante funding appropriate to deliver the regulatory changes we can reasonably foresee in the near future, and an extrapolated view of requirements towards the later end of the RIIO-T1 period. In recognition of the uncertainty in this area, we also proposed an uncertainty mechanism which would trigger where costs were either 10% above or 10% below this baseline funding. The intention was to protect both National Grid and end consumers from the uncertainty of expected changes. Initial Proposals have reduced the allowance by an unsubstantiated 50% and removed the proposed uncertainty mechanism. Instead, Ofgem proposes to further consider the requirements at the mid-period review.

Given the increasing certainty for investment in the early years of the RIIO-T1 period to deliver evolving EU codes (such as Congestion Management Principles, Capacity Allocation Methodology and Balancing), and Ofgem's stated requirement for us to also fund any systems changes resulting from its ongoing Significant Code Review (SCR) from the Regulatory Change allowance we submitted in March (which has been reduced by 50% in Initial Proposals), the need case is stronger than ever and funding should be provided in full for at least the first half of the period.

Ofgem has proposed that funding for these activities will be considered though the mid-period review. The timing of this ill-defined review means these activities, many of which will be delivered or under development by 2015, will be considered in 2017. This creates a cashflow issue and brings into question the validity of this proposal. Given the increasing momentum of the European regulatory framework and the changes this will require, coupled with the requirement for us to fund SCR-related changes, a more reasonable approach would be to provide the required funding as requested for the RIIO-T1 period and review this in the re-opener windows. This approach provides protection from any potential for windfall gain or loss, and avoids the financeability issue in this area created by Initial Proposals.

The first of these windows occurs at a time when Congestion Management Principles will have been implemented (comitology has completed and we have an obligation to implement by October 2013), Capacity Allocation Methodology (EU Commission have stated this should be fully implemented by October 2016), Balancing, Tariffs and Interoperability will be in final delivery, the remaining European codes will be at some point in development and clarity should be available on Ofgem's SCR requirements. The financial regulations (such as the Wholesale Energy Market Integrity and Transparency (REMIT), which has been defined in law since December 2011, and the Market in Financial Instruments Directive 2 (MIFID2)) should also be in phased delivery at this time. This will allow a high degree of clarity over expenditure requirements for the first half of the RIIO-T1 period, and ensure that any over/under funding is dealt within an appropriate timescale rather than allowed to accrue and compound the financeability issue. The second re-opener window would allow a review of actual costs for all of the implementations that have taken place for the envisaged EU codes and regulations that are currently under development, and a review of forecast costs to deliver the requirements for other changes, such as the foreseen EU 4th package.

The current position on developments required for the regulations and codes that are significantly developed and likely to require implementation prior to the mid period review are covered in our supplementary information document, 'SO_costs'.

In summary we believe that NGGT should be fully funded in line with business plan requirements for the RIIO-T1 period, with the initial re-opener window used to resolve any material variance from allowances up to that period and to define funding allowances through to 2018/19 when a further review can be carried out.

<u>SO opex</u>

We have several issues with the baseline expenditure for SO opex including:

- **Calculations for opex allowances incorrectly assume that these costs are linear to capex**
- **Market facilitation has been reduced to 2010/11 expenditure levels despite the growing influence of European energy policy**

The assessment of our forecasts undertaken by Ofgem and its consultants PPA has reduced opex allowances for GSO by £79m across the RIIO-T1 period. These reductions in opex allowances are inappropriate and have been based on ill-founded logic that incorrectly assumes these costs are linear to capex. There is a lack of justification for the depth of the funding reductions.

As currently proposed the total level of opex for 2013/14 of £30.6m falls significantly below the allowances allowed for rollover of £34.9m, despite the necessary volume of work we need to undertake continues to increase over the RIIO-T1 period. Not undertaking the extra work – which the Initial Proposals attempt to incentivise us to do – would have detrimental impacts on IS system security leading to reduced network reliability and/or higher balancing costs. More specifically they jeopardise our ability to:

- Play our full part in European energy policy development
- Recruit and train the necessary skills for critical operational roles
- Support the existing IT systems, let alone the necessary future expansion of the portfolio

Whilst we respond to these concerns below, greater detail can be found in our supplementary information documents, 'SO_costs' and 'Market_facilitation', where each activity line of our direct and business support opex costs is critiqued individually.

Market Facilitation

Initial Proposals reduce market facilitation costs to 2010/11 expenditure levels based on analysis errors, and are contradictory to the growing influence of European energy policy. This unjustified reduction means that mandated European work cannot be undertaken and we will not be able to play our full part in Europe, which Ofgem has stated they want us to do. Disallowances have been triggered based on an unsound link through to capex workloads which fails to understand the nature of the fundamental work undertaken in this activity that benefits the wider energy industry.

The impact of the Initial Proposals would result in:

- **Mandated costs disallowed**: Much of the European work such as development of joint EU codes and membership of TSO bodies are mandated by EU law. Reductions to forecasts disallow costs which European regulations state must be funded through local regulatory allowances.
- **Minimal European interaction:** We will not be able to play the role expected of us within European interaction. Ofgem recognise that we need to be at the heart of this work, stating that they want us to 'play our full part'; however, all of the increased workload from 2010/11 – which is virtually all due to European activity - has been disallowed.
- **Higher industry costs due to no proactive work**: Limiting our role within Europe will lead to higher industry cost overall because we are helping stakeholders understand the impacts of proposed changes. The result of disallowing costs of this stakeholder engagement would be a reactive, rather than proactive approach for us and the UK energy industry. This would increase long term costs due to European codes being less like the UK, resulting in higher implementation costs.

The reductions themselves are based on unsound logic with Ofgem's consultants using the following arguments to reduce expenditure:

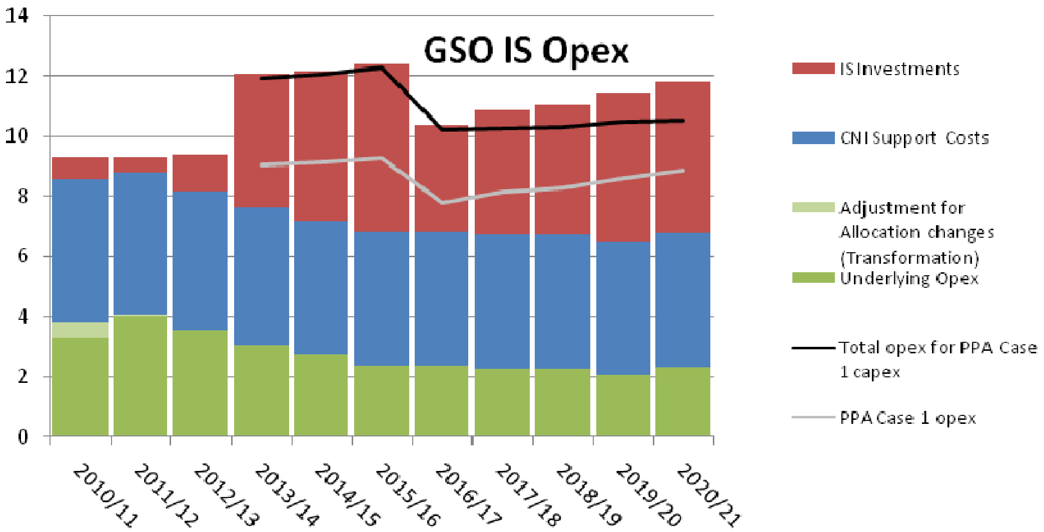
- **Reductions linked to capex levels**: which have no relationship to the activity
- **Direct billing of above license requirement:** We strongly disagree with this as such a proposal would increase transaction costs, reduce the level of competition and introduce a two-tiered market structure with parties willing and able to pay for specific services gaining advantage over others. This view was echoed by stakeholders at a recent Talking Networks stakeholder engagement event.

Subsequent to Initial Proposals, Ofgem has stated that their consultants thought we were trying to take on Ofgem or DECC's role in Europe but this is not the case. We are in regular dialogue with both Ofgem and DECC to ensure that we understand the role these key stakeholders want to undertake and that we work together for the benefit of UK consumers. However without the proposed funding this work would have to reduce.

Reductions linked to capex

PPA has justified the volume of opex reductions based on the corresponding capex reductions for all aspects of our opex plan. The logic that has been applied to reducing our allowances assumes that there is perfect linearity between the two. This is demonstrably not the case. In addition, the assessment does not take into account that capex reductions are mostly at the latter end of the plan. As they currently stand, opex reductions are phased proportionately across all years of the RIIO-T1 period, whilst the capex reductions they purport to fall largely over the last four years of the RIIO-T1 period.

PPA has reduced the SO capex forecasts based mainly on the uncertainty of the requirement for these schemes. In removing these schemes from the capex plan, there is a knock on impact to the support costs for our IT portfolio. However, instead of removing the opex for the projects that they have deducted, PPA have assumed that the opex impacts are linear with the capex reductions and have removed 25% of the IS opex business support costs. In doing so they have removed over double the opex they should have to the extent that in the near term we do not have enough opex allowances to support the existing suite of IT systems. We have calculated that for IS and Telecoms costs the adjustments should be reduced from the £21.7m reduction in Initial Proposals to £4.9m. The error in this area is illustrated by the graph below which shows the Initial Proposals (grey line) compared to the reduction that should have taken place given the SO capex disallowances (black line).



Data centres

We have undertaken comprehensive optioneering, both utilising internal resource and by engaging external consultants. We continue to work closely with both the Department of Energy and Climate Change (DECC) and the Centre for the Protection of National Infrastructure (CPNI) to develop the most appropriate strategy to protect our CNI systems from increasing security threat levels and the implications of ageing support infrastructure, the failure of which would have material implications for the operation of our gas and electricity networks. Development of the requirements and design of the final solution are well underway, however we will not have tender responses to assess the efficient cost of delivering this scope before Final Proposals.

Construction of new data centres is not part of our core regulated business, and it would therefore be inappropriate to incentivise us on scope of necessary works especially given this scope is being developed with the guidance and input from CPNI. We therefore agree that an uncertainty mechanism should be developed to set a target for only those works absolutely necessary to protect end consumers from the impact of failure of our most important systems, and that this should be done when efficient costs are understood. As construction is expected to be complete by the end of 2014, however, the re-opener windows (the first of which is 2016) are too late to provide timely funding, and demobilisation of the current work to await the re-opener window would drive total costs up, introducing inefficiency and exposing end consumers to an increased risk of failure of the CNI systems for longer than is necessary.

Given the timing of the re-opener window, we propose that the re-opener window explicitly considers historical costs incurred in the delivery of the project to that date and includes a materiality threshold that is proportionate to the likely costs.

We note that, if we were to only complete the tactical investments funded through Initial Proposals, this would deliver an inefficient, higher risk and short term solution, which would not deliver value for money. Refurbishment would have to be conducted in a live environment, risking CNI system outages whilst enhancements to cooling and power supplies are completed however this would still retain some existing issues. Security concerns cannot be mitigated, and the level of funding suggested would be insufficient to migrate systems and consolidate the data centre estate, thereby preventing opex efficiencies from being delivered.

Question 14: Do you consider that our proposed uncertainty mechanisms for NGGT (SO)

	are appropriate?

National Grid response:

There are three key areas where uncertainty mechanisms are important for NGGT (SO) direct costs:

- EU/GB regulatory and market driven change
- Capability enhancements towards the end of the RIIO-T1 period
- SO security enhancement costs (data centres)

We present our views on each in turn below.

We are very concerned that costs to be considered in the re-opener windows or mid-period review materially add to the financeability issue detailed in our Financeability Supporting Document. Ofgem's own best view modelling anticipates us incurring over £0.5bn on costs covered by such schemes in the first three or four years of RIIO-T1. This expenditure will be incurred before any revenues are received to finance them. We provide further detail on this in the 'Financeability' supplementary information document.

EU/GB regulatory and market driven change

Within our RIIO-T1 submission, we proposed an ex ante allowance to provide sufficient funding for our reasonable expectation of necessary IS system developments driven by regulatory and market-driven changes, both from within GB and EU. Our forecast was based on the demonstrable assumption that the cost of a system release to enhance functionality has a large fixed element and that total expected cost on delivering a change can therefore be forecast with a degree of confidence. In recognition of the uncertainty around future requirements, we also proposed an uncertainty mechanism which would trigger on actual costs differing from the ex ante allowance by more than 10%, to protect both ourselves and end consumers from windfall gains or losses.

Initial Proposals reduces the ex ante funding by 50% without any justification other than it was the low case used in our own risk modelling. Ofgem also have rejected our proposed uncertainty mechanism, and instead propose to consider this issue in the mid-period review in 2017.

This is inappropriate, given the scale of workload already in flight, which will require delivery in the first few years of the RIIO-T1 period, which includes:

- EU-led codes
  - Congestion Management Principles will have been implemented
  - Capacity Allocation Methodology will have been implemented
  - Balancing will have been implemented
  - Tariffs will have been implemented
  - Interoperability will have been implemented
  - The remaining European codes will be at some point in development
- Ofgem's Significant Code Review – since the publication of Initial Proposals, Ofgem has confirmed that they expect consequential systems changes to be funded by the Regulatory change allowance, the forecast for which was submitted before this was known
- Financial regulations
  - Wholesale Energy Market Integrity and Transparency (REMIT) should be implemented or in final phases of delivery

- Market in Financial Instruments Directive 2 (MIFID2)) should be implemented or in final phases of delivery

The timing of the mid-period review means these activities, many of which will be delivered or under development by 2015, will be considered in 2017. This creates a cashflow issue and brings into question the validity of this proposal, as this level of under-funding for the first half of the RIIO-T1 period contributes to the financeability issue highlighted in our response to the Finance Supporting Document.

We propose that the ex ante funding as allowed in full, in recognition of the justification we have provided for our cost assessments to enable us to deliver the necessary changes listed above. We also propose that the re-opener windows (2016 and 2019) are used to validate this and, if necessary, adjust allowances. This will allow a high degree of clarity over expenditure requirements during the RIIO-T1 period, and ensure that any over/under funding is dealt within an appropriate timescale rather than allowed to accrue. This approach also provides protection from any potential for windfall gain or loss, and avoids the financeability issue in this area created by Initial Proposals.

Capability enhancements towards the end of the RIIO-T1 period

In its report Ofgem's consultants (PPA) stated that there was a large degree of uncertainty over the requirements for future systems developments to provide enhanced capabilities to support the operation of the NTS and gas market. They went on to reflect that this was unsurprising given an eight year price control, and that ex ante funding should be removed and an uncertainty mechanism be considered to allow access to that funding once the need case was more certain.

Initial Proposals removed the funding, in line with PPA's report, however failed to include any reference to an uncertainty mechanism to allow access to funding in the future. This very significantly curtails our ability to develop the capabilities we need to perform in the future operational environment. This is discussed in more detail in our response to question 13 above.

We have noted elsewhere that a different approach is required for an eight year price control when compared to a five year control, including a greater use of uncertainty mechanisms. Ofgem has stated that they expect us to play our full part in supporting the decarbonisation of the UK energy sector; however its Initial Proposals are in direct contrast to this. As we have stated before, without the ability to develop capabilities we will be unable to support, among others, the dynamic operation of CCGTs to support renewable generation on the electricity network, and unable to support flexibility in the supply of gas to the UK.

We propose that funding is allowed to the extent detailed in our RIIO-T1 submission, and the mid-period review is used to review the appropriateness of this using a combination of actual spend to date, latest views of requirements based on growth of renewable energy, challenges in system operation and market balancing, and volatility of NTS flows. Reductions in the ex ante allowance will exacerbate the financeability issue we currently face with Initial Proposals.

SO security enhancement costs

Initial Proposals only allow funding for tactical refurbishment of our existing data centre estate and propose a mechanism, based on the re-opener windows in 2016 and 2019, which can trigger additional funding in the event it is required to go further to meet the requirements of HM Government for security and resilience to support our CNI systems. As stated in our RIIO-T1 submission, our data centre strategy requires the construction of new data centres to meet our expectation of these requirements. As construction is expected to be complete in 2014/15, however, the re-opener windows (the first of which is 2016) are too late to provide timely funding, and demobilisation of the current work to await the re-opener window would drive total costs up, introducing inefficiency and exposing end consumers to an increased risk of failure of the CNI systems for longer than is necessary. We will therefore be required to incur unremunerated costs, worsening the financeability issue detailed in our Finance response.

Given the timing of this first window, we propose that the re-opener window explicitly considers historical costs incurred in the delivery of the project to that date and includes a materiality threshold that is proportionate to the likely costs, and that account is taken of this cash risk in the wider finance package.

Question 15: Do you agree with our proposals in relation to uncertainty with respect to Xoserve's costs?

National Grid response:

Given the very limited information provided in Initial Proposals, we are unable to form an opinion on the proposed treatment of funding for the Gemini system which is owned by NGGT but operated and managed by Xoserve.

We agree that funding should be reviewed once the Xoserve review is concluded and welcome the proposal to provide ex ante funding based on current arrangements; however we are unclear on what this funding will include. Given there is potential for significant expenditure on the Gemini system over the next two years to meet developments in both UK and EU regulatory requirements, we need further clarity on what level of funding is going to be allowed for this period and how this will be provided before we can comment on its appropriateness.

We are also concerned over the lack of clarity of what is meant by the statement "The review will allow us to alter this funding once a decision has been reached on the final funding decision" in paragraph 8.45 of the 'Cost assessment and uncertainty supporting document'. Until we understand the alterations to which Ofgem refer, we are unable to comment on their validity.

We note that Ofgem's licence drafting includes provision to direct a variable to include within the Price Control Finance Model (PCFM) which would adjust allowances in relation to Xoserve costs; however it is unclear whether this direction would allow for retrospective changes in addition to prospective ones. We also note that opex in relation to Xoserve costs is classified within the PCFM as non-controllable opex, which suggests a pass-through treatment, however this appears to be at odds with paragraph 8.45 of the 'Cost assessment and uncertainty Supporting Document' which suggests all funding will be provided on an ex ante basis and will be subject to the Totex Incentive Mechanism. We would welcome further discussions with Ofgem to clarify the treatment of these costs.

Finance Supporting Document

Chapter: Three

Question 1: Do you have any comments on our relative risk assessment?

National Grid response:

Companies within the same sector have traditionally been given the same financial package. One of the principles of RIIO is that the allowed return can differ across sectors and within sectors if there are material differences in cash flow risk. This approach is appropriate provided there is robust evidence of material differences in business risk.

National Grid provided detailed risk modelling as part of our business plan. This modelling quantified the uncontrollable risks facing the networks relative to TPCR4 and demonstrated an increase in risk relative to TPCR4. This would indicate an increase in the asset beta and a requirement for an increase in the WACC relative to TPCR4 (for a given cost of debt). Indeed the Final Proposals for the fast tracked networks did imply an increase in asset beta from 0.40 to 0.43, consistent with expectation.

Ofgem has not engaged with us on the detail of our modelling so the Initial Proposals represent our first opportunity to gauge Ofgem's views on risk.

Results of the risk assessment (Asset beta)

The Energy Networks Association commissioned Oxera to review the Initial Proposals and their report is provided alongside our response. Their report shows that changes in risk should first be considered at the business risk or asset beta level. It then reviews the financial proposals from the perspective of the implied changes in asset beta, relative to both TPCR4 and the Final Proposals for both fast tracked networks. The resulting implied asset betas are as follows:

	Electricity Transmission		Gas Transmission	Gas Distribution
	SHETL & SPTL	NGET	NGGT	GDNs
Asset beta, RIIO	0.43	0.38	0.34	0.32
Asset beta, previous price control	0.40	0.40	0.40	0.38

Key observations to note are that:

- The asset betas for all non fast tracked networks are assumed to have decreased compared to the previous price controls. The asset betas for gas transmission and distribution are now assumed to be 15% lower.
- The asset beta of NGET is deemed to have fallen relative to TPCR4 despite being in the same industry as SHETL and SPTL for whom the asset beta is deemed to have increased.

Oxera discuss both Ofgem's risk assessment and their own views on changes in asset risk before concluding that the changes in asset beta implied by the combination of equity return and notional gearing proposed by Ofgem are disproportionate and not supported by the changes in business risk faced by the networks. Their findings are summarised in more detail in our supplementary information document: 'Relative_risk_assessment' that accompanies this response.

<u>Detail of the risk assessment</u>

Ofgem has not performed any substantive evidence based modelling to support their conclusions on relative risk. However the Initial Proposals do provide tables summarising Ofgem's relative risk assessment.

We have reviewed these tables in our separate paper on the relative risk assessment. In reviewing the subjective risk assessment we find that a number of important risk factors have been omitted such as:

- The difference between ex ante allowances and within period determinations
- The risks associated with the System Operator activities
- Cash flow duration, and
- The notional level of gearing (for a consideration of equity risk)

In addition, we have reviewed the substance of the risk assessment for the risk factors that are used by Ofgem. While we agree with the assessment in many instances, there are a large number where the assessment either double counts elements of the Initial Proposals or does not adequately reflect the detail of the Initial Proposals.

Our paper builds on Ofgem's analysis, but better identifies the separate underlying drivers of risk, and more accurately considers the detail of the Initial Proposals. As Ofgem has noted (footnote 15), *"the fast-track decision is particularly useful as it provides a benchmark of what investors consider an acceptable financial package given the cash flow risk of SHETL and SPTL in RIIO-T1.*" Once the separate underlying drivers of risk are identified and considered, we find that risk is higher both for NGET and NGGT than SHETL and SPTL and higher relative to TPCR4. We certainly do not consider Ofgem's conclusions that NGET and NGGT are lower risk than both SHETL and SPTL and, in the case of NGGT, lower than TPCR4, to be supported by the evidence available.

The increase in risk relative to TPCR4 is consistent with our previous risk modelling, and with the intent of RIIO which is to increase both the accountability of the networks to deliver outputs and the power of the incentives they face.

<u>RORE</u>

In the Initial Proposals, Ofgem use RORE analysis as a sense check that the financial package is appropriately calibrated. On reviewing the RORE analysis we identified a number of issues as follows:

- Incentives which have been omitted from the analysis
- Incentives which have been modelled incorrectly in that the modelling is inconsistent with the Initial Proposals
- Errors and inconsistencies in the modelling of the two fast track networks which has been used as the comparator against which the proposed packages have been judged

Our separate supplementary information document: 'Relative_risk_assessment' presents an updated set of RORE analysis which demonstrates that, once the appropriate corrections have been made, the currently proposed financial packages result in a range of RORE outcomes that is far wider for NGET and NGGT than the fast track networks. Reducing gearing narrows the range of outcomes to make them more consistent.

If gearing is set at 55% for each of NGET and NGGT the range of RORE outcomes is still higher than both fast track networks for the 'base view'. For the 'best view, the range is lower than that for SHETL but considerably higher than for SPTL.

Overall comments on relative risk assessment

Ofgem has not performed any detailed Excel based modelling of cash flow risk to substantiate their conclusions on relative risk. Nor have they engaged with National Grid on the detail of the risk modelling provided as part of our business plan despite the fact that their own unsubstantiated conclusions differ from ours.

When the underlying drivers of risk are considered in detail, the relative risk of both NGET and NGGT is higher than TPCR4 indicating that the asset beta should be higher, not lower. We also find that risk is higher than both SHETL and SPTL.

The combination of cost of equity and notional gearing proposed for NGGT and NGET do not adequately compensate equity investors for the risk they will face under RIIO-T1. This could be addressed by increasing the allowed equity return, reducing gearing, or a combination of both. Based on the RORE analysis, both NGET and NGGT face a higher dispersion of results than SPTL under both the base and best views if gearing is set to 55%. Consequently, the WACC awarded to SPTL of 4.82% (assuming 3% cost of debt) should be considered the minimum requirement.

Further detail, evidence and analysis to support the arguments summarised in this response can be found in our separate paper on the relative risk assessment. That paper is included as part of this consultation response.

Question 2: Do you agree with our proposed elements of the allowed return?

National Grid response:

There are three main elements that feed into the overall allowed return: cost of equity, cost of debt, and gearing. We have concerns with each of these (as well as several other financial elements of the proposals). We consider that the financing packages proposed in the Initial Proposals for both NGGT and NGET do not, on a standalone basis or in comparison to both TPCR4 and the Final Proposals for both RIIO-T1 fast-tracked networks, adequately reflect the risks faced by the networks or provide a sufficiently robust financeable package.

We consider each of the three elements of allowed return in this question response. We also consider the inconsistency between Ofgem's proposals for the cost of debt index and the results of the financeability assessment. Finally we request a re-opener uncertainty mechanism be developed to reflect the uncertainty created by the ONS's decision to consult on changes to the RPI measure of inflation.

The balance of this response is weighted towards concerns with the cost of debt index but this is only because we provide more detailed comments and evidence on the cost of equity and gearing elements within the separate supplementary information documents: 'Financeability' and 'Relative_risk_assessment' that accompany this response.

Cost of Equity

Risk free rate and equity risk premium

In relation to cost of equity, we are broadly in agreement with the proposed long-run values of risk free rate and equity risk premium that have been used in the Initial Proposals for the eight year control.

We enclose with this response a report prepared by Oxera for the ENA which, amongst other things, considers the component elements of the cost of equity under the CAPM framework.

The report concludes that the approach taken in the Initial Proposals to the risk-free rate and ERP is reasonable in the context of the RIIO framework and we refer Ofgem to this report for further supporting comment in support of this conclusion.

Level of cost of equity

For a given risk free rate and equity risk premium, the cost of equity is determined by the equity beta. This can be further broken down into an asset beta and notional gearing assumption.

Our response to question 1 above explains that Ofgem's risk assessment and the implied movements in asset beta are poorly substantiated and do not completely or accurately reflect the detail of the underlying risk drivers under RIIO-T1. Based on detailed risk modelling, a corrected relative risk assessment, and updated RORE analysis, both NGET and NGGT face higher risk than in TPCR4 and higher risk than the two fast tracked networks, particularly SPTL. The WACC should reflect this differential in risk.

If gearing is set at 55% this would indicate a requirement for a cost of equity above 7%. If gearing is set at the currently proposed levels, the cost of equity would need to be set above 7.5%.

Assumed Notional Gearing

As part of our consultation response we have provided a detailed supplementary information document: 'Financeability' addressing our concerns in this area.

We are concerned that Ofgem's financeability assessment has been misinformed as a result of accounting errors in the financial model such that the model generates incorrect financial statement data. This issue is compounded by a failure to reflect the actual detail of the Initial Proposals in a number of important respects, the most material of which are a failure to reflect the difference in timing between expenditure and the setting of allowances under uncertainty mechanisms, and a failure to reflect certain material cash payments in the assessment.

Alternatively, we fear that the credit metrics observed, lack of transparency over Ofgem's calculations in the face of heightened interest, limited stress testing of the financial package and apparent complacency towards the needs of equity investors may indicate a reduction in Ofgem's focus on matters of financeability.

For NGGT we find the credit metrics to be particularly poor and certainly not what would be expected for a network to achieve a comfortable investment grade. Ultimately, a real asset life of 45 years and equity return of 6.8% cannot support a notional level of gearing of 62.5% either during the RIIO-T1 period or on a longer term sustainable basis. Gearing therefore needs to fall to achieve a more financeable network and, as mentioned above, a rate of 55% would appear to generate a more appropriately calibrated financial package from a risk-reward and RORE perspective.

Further details can be found in the separate supplementary information document: 'Financeability' and our response to question 11.

Cost of Debt risk borne by equity under RIIO-T1

Ofgem's proposals increase the cost of debt risk borne by equity in two respects:

- The removal of headroom in the allowance leaves unfunded risk
- A cost of debt index increases the procyclicality of returns which will increase beta

The removal of headroom in the allowance leaves unfunded risk

The allowed cost of equity needs to be set to reflect the risks that will be faced by the network, and these include the exposure of equity returns to risks related to the proposed cost of debt allowance. As equity holders have in the past been rewarded for facing these risks through a headroom allowance on the cost of debt, it is easier to consider the appropriate impact on required equity return separate from the main risk assessment discussed above.

In our March Business Plan, National Grid showed that although the introduction of the cost of debt index will reduce the transmission networks' exposure to changes in the cost of debt and the risk that the allowed cost of debt will be too low (the "cost of debt matching risk") this risk is not eliminated.

In previous price controls (including TPCR4), this risk was not allowed for in setting the cost of equity but by Ofgem adding c.30 bps "headroom" to the estimated cost of debt (informed or based on a trailing index average)[44]. Clearly, with reduced matching risk the headroom needed will be reduced, but under RIIO this headroom has been removed from the cost of debt altogether.

Consequently, in our Business Plan National Grid proposed that a corresponding allowance should be added to the cost of equity, to compensate the networks for the "cost of debt matching risk" that was not otherwise being provided for. For NGET and NGGT this increase was 13bps and 12bps respectively at 55% gearing, which in each case would be equivalent to c.16½bps at 60% and 62.5% gearing respectively.

In the Initial Proposals, Ofgem does not directly address this approach, but instead merely notes that the risk is reduced (but not removed) by the debt indexation mechanism. Ofgem's relative risk assessment in tables 3.3 and 3.4 then notes that the business risk is reduced but critically overlooks the fact that there was previously an allowance for this risk through the cost of debt headroom. As a result, Ofgem's assessment of equity risk is incomplete.

In the FTI Consulting report, the issue is considered more explicitly in paragraph 8.17 and 8.21 to 8.33. FTI confirm (in paragraph 8.27) that indexation does not remove all the risk (albeit they fail to recognise that in some circumstances, particularly where the amount of new debt that needs to be raised is low, the risk is actually increased under the index approach).

Paragraph 8.28 of the FTI report then suggests that the premise that "*the headroom allowed in previous price controls represented a return for the risk borne by equity holders*" may be wrong, on the grounds that "*Ofgem's decision in the consultation process for the 2013/21 Price Controls was not intended to remove all risk faced by the network companies. Therefore, it is not clear to us [FTI] that this is the correct interpretation of the margin applied*." The argument here seems to be that because some of the risk remains under RIIO, the headroom in previous price controls cannot have been a compensation for the risk that the cost for debt allowance proved to be too low, which would suppress the equity returns that could be achieved. However, this thinking lacks logic and is clearly wrong, but in any case the RIIO Strategy Decision was to adopt an approach under which the network companies can propose a financial package in their business plans (including cost of equity, gearing, and uncertainty mechanisms as appropriate and justified), and does not preclude including an allowance in the cost of equity for the residual cost of debt matching risk.

Supportive of this latter view, Paragraph 8.29 in the FTI report continues "*According to Ofgem, the headroom allowed above the trailing average index value in previous determinations represented an allowance for changes in the cost of debt after the time of the determination. That is an allowance for the chance that the value of the trailing average index (that was used at the time the price control was set) was not a representative estimate of the cost of debt over the price control period*." Clearly, this explanation from Ofgem actually confirms the networks' interpretation of the headroom in previous controls, and thus supports the case that, to the extent that the risk is only reduced by the new index (and not eliminated),

[44] In paragraph 8.9 of the FTI Consulting report, FTI say that Ofgem has informed them that although headroom against the Bloomberg index was 30 basis points, against the iBoxx index historical headroom would only be 20 bps. This is not correct, and in almost all previous controls the headroom against the iBoxx index would have been at least as great as against the Bloomberg index: the iBoxx index was only introduced in 1998, and an average of the iBoxx index from 1998 onwards is actually below a corresponding average of the Bloomberg index until 2003, and only starts to rise slightly above it from 2009 onwards.

an allowance needs to be made under RIIO-T1 for this risk.

As noted above, differences between the actual cost of debt and the cost of debt allowance feed through to the equity returns that can be achieved, and so the approach of adding a corresponding margin to the cost of equity to allow for the residual risk, as in our March Business Plan, is completely appropriate.

Finally, in paragraph 8.33, FTI suggest that (i) provision of headroom and (ii) use of an indexation mechanism are both ways of providing protection against a rising cost of debt, and that "*providing two forms of protection against the same risk would effectively transfer risk from shareholders of network companies to consumers*." It is on this basis that FTI consider that providing an allowance for headroom in the RIIO-T1 controls (whether in the cost of debt or the cost of equity) may be duplicative of the protection that an indexed allowance provides against rising interest rates. It is self evident that the logic here is again flawed: such duplication would apply if all risk was removed by the indexation approach (or if the headroom was big enough that, together with the partial protection of indexation, all risk was eliminated), but as the headroom that we have proposed under RIIO-T1 corresponds only to the residual risk that will still remain even after the indexation mechanism has been introduced there can be no such duplication.

In conclusion, therefore, it can be seen that neither the Initial Proposals document nor the supporting FTI Consulting report provides any valid reason why an allowance for the remaining cost of debt matching risk should not be included in the allowed cost of equity, as National Grid proposed in its RIIO-T1 Business Plan.

A cost of debt index increases the procyclicality of returns which will increase beta

Paragraphs 3.56 and 3.57 of the Initial Proposals Finance supporting document considers the argument that the move to the cost of debt index approach will make network companies' returns more procyclical (and thus tend to increase equity beta) than if the previous fixed cost of debt allowance had been retained.

As an initial comment, we note that although this issue has been considered in the Initial Proposals in the cost of debt section, it is actually an issue that relates to the cost of equity. Turning to the substance of the issue, Paragraph 3.57 claims two counter arguments:

- The relationships are not as clear cut as has been claimed by network companies
- Networks' EV is underpinned by other factors (including the RAV) which would continue to make them a counter-cyclical hedge.

Both these factors are, at most, partially mitigating factors, so increased procyclicality of returns as a result of the introduction of the cost of debt index is not denied.

Moreover, FTI Consulting in fact conclude (in paragraph 8.38 of their report) that "*cost of debt indexation may have a procyclical effect on returns and so increase the beta of the network companies*", although they consider the effect may be reduced by various factors they discuss and so may not have a material effect. In this regard, however, FTI overlooked that the current fixed cost of debt allowance is of itself counter-cyclical, so even if the new positively procyclical effect is mitigated there is still a material change from counter- to pro-cyclical from previous price controls as a result of the new approach to cost of debt.

In conclusion, therefore, this consideration will increase the asset and equity beta of the network companies under RIIO, both in absolute terms and also in comparison to TPCR4.

Summary on impact of debt risk on equity returns

The implementation of a cost of debt index and removal of the headroom in the debt allowance generates a requirement to increase the cost of equity from two perspectives:

- Removing the headroom in the cost of debt allowance without adding a premium to the cost of equity (relative to TPCR4) means the risks associated with debt matching risk (which may be reduced but are certainly not eliminated) are not funded.

- The index replaces a countercyclical debt allowance with a procyclical one. This will increase beta and the required cost of equity.

Cost of debt allowance

The remainder of this question response considers a number of issues regarding the index-based cost of debt allowance. In doing so this section sets out Ofgem's reasons for not making any adjustments to allow for additional debt costs not covered by the index, as well as addressing certain other issues and concerns with the index that have been raised by the network companies.

In dismissing these arguments Ofgem has overlooked some important considerations, even where these have been supported by their own consultants, FTI Consulting, and in a some cases Ofgem has misunderstood issues and concerns raised by the networks, or have made errors in their analysis, such that they are not properly considered in the discussion.

<u>Calculation of the index</u>

In paragraphs 3.42 to 3.58 of the Initial Proposals Finance supporting document Ofgem confirm their intention to apply the proposed cost of debt index. Ofgem now propose to make a slight adjustment to the way in which the index is calculated (described in Appendix 2 of the Finance supporting document), and we support this change as it appears to be a small change which is technically and logically correct.

<u>Embedded Debt Costs</u>

In paragraphs 3.44 to 3.48 of the Initial Proposals Finance supporting document, Ofgem consider the potential divergence between the cost of embedded and new debt costs, and between the proposed cost of debt allowance (the 10 year trailing average of the index) and a network's actual cost of debt.

We agree with Ofgem's conclusion in paragraph 3.48 that no adjustment should be made for embedded costs: this would represent a break with regulatory precedent which should be avoided, and would be inconsistent with the overall basis of price controls under RIIO, which is to set a price control on a "notional network" basis.

Further, we agree that the potential for actual debt costs, even if efficiently incurred, to exceed the allowance calculated from the trailing average of the index does need to be recognised and taken into account in assessing financeability.

However, for consistency with the overall approach to setting the RIIO price controls, as well as with past precedent, this assessment should consider potential variances in debt costs for the "notional" network (e.g. using assumptions that are consistent with those adopted in setting the WACC), rather than starting from actual network interest costs as described in paragraph 3.48. If a network's actual debt costs were higher on an actual rather than notional basis, Ofgem would be unlikely to allow these higher costs in setting allowed revenues: it would therefore be asymmetric "cherry picking", in assessing financeability, to include the benefit of lower actual interest costs that have, with the benefit of hindsight, resulted from past financing decisions.

<u>Transaction costs may not be fully funded – an uncertainty mechanism could resolve this</u>

The proposed cost of debt index does not explicitly fund certain unavoidable transaction and other costs associated with raising debt, including debt issuance fees, new issue premia, bank facility fees, credit rating agency fees, commitment fees, and the costs of carrying cash. Ofgem does not deny that these costs exist, but has claimed that networks are able to outperform the proposed cost of debt index by 30 basis points or more, and this margin will be sufficient to fund these additional costs.

Ofgem's assumption that networks will be able to outperform the index is based on a comparison of a graph of the spot values of the cost of debt index (average of BBB and A) with the coupon rates on utility bond issues from January 1998 onwards. However, this comparison is subject to certain factors which reduce its relevance: for example, the yield on new issuances exceeds the coupon rate by up to 0.125% (as coupon rates on new issuances are rounded down to the next 1/8 %); where debt is issued at group or plc level this is not relevant to the cost of debt of a licensee (i.e. the notional company); and even for debt issuance by NWOs the gearing of the network companies will often have been lower than the proposed notional gearing under RIIO such that the comparison to the index is not relevant.

Further, where the majority of actual issuances have been at 'A' rating rather than 'BBB', it would be expected that the graph would apparently show an ability to outperform a proposed average index which is calculated from separate A and BBB indices. However, our financeability assessment indicates that Ofgem are not designing the RIIO-T1 packages to enable the notional networks (for which the price control is designed and set) to achieve a credit rating consistent with the index. Consequently the apparent outperformance in the past is meaningless as it does not apply to the circumstances of the notional networks under the proposed price control.

Even more fundamentally, such a historical comparison of past debt new issuances does not imply that networks will be able to issue debt more cheaply than the index in the future. This is because of the change in the regulatory regime. In the past, networks have shown strong operational performance, and the continuation of such outperformance has been assumed by rating agencies and investors, leading to stronger projected credit metrics and a lower cost of debt than would otherwise have been the case. However, under RIIO the regulatory framework has now been fundamentally reset, for example with increases in asset lives, increased exposure to the delivery of outputs, a new approach to cost of debt and a lower WACC, introduction of the totex approach, and stringent opex and capex targets. In addition, the demands on the networks are changing fundamentally (as evidenced by the increases in Capex / RAV for example). As a result, neither the agencies nor investors can expect past performance to be a guide to the future, reducing the potential to issue debt more cheaply than the index.

In paragraph 3.50 of the Initial Proposals supporting document, Ofgem point to certain factors that are innate to network companies which should enable them to raise debt more cheaply than other companies of similar credit ratings. This discussion is misplaced, as it fails to recognise that these characteristics are already taken into account in setting the network companies credit ratings, and so enable the companies to achieve the same credit ratings as companies in other sectors at far higher gearing (for example). Moreover, although these factors may still be present under RIIO, because they continue unchanged they cannot offset the fundamental change noted in the preceding paragraph.

In addition, as Oxera have noted in their new report[45], utility bonds are forming an increasing and very significant share of the overall composition of both the A and BBB iBoxx indices (now forming 60% of the A index and 48% of the BBB index). Consequently any historic ability of networks to outperform the proposed index would inherently be progressively reducing even in the absence of the other factors that have already been described.

FTI Consulting note in their report that the apparent outperformance of the cost of debt index by network companies appears to have reduced significantly in 2010 and 2011. They identify market considerations which might have led to this change, and whilst noting that it is uncertain whether these effects will persist, these are merely additional to the effect of the fundamental change in regulatory regime under RIIO noted above. Indeed, the reduced outperformance of the debt index in 2010 and 2011 may well be associated with the development and announcement of the new RIIO framework.

[45] "RIIO-T1 and GD1 Initial Proposals - Financial Issues", Oxera, September 2012

Ofgem recognise this reduced margin between network company bonds and the iBoxx index in 2010 and 2011 in paragraph 3.51, and suggest that this matter should be kept under review until Final Proposals although "*at present there does not seem to be sufficient evidence to change our approach*".

The FTI Consulting report suggested that because of the uncertainty surrounding the ability in the future of the networks to outperform the cost of debt index – which Ofgem rely on to fund the transaction costs of issuing debt - Ofgem should review the issue at the mid-period review. However, we recognise that this mid-period review is not intended to redesign the price control or adjust the financial package, and so in our March Business Plan (paragraphs A40 to A51), National Grid proposed a new uncertainty mechanism instead.

Under our proposed mechanism, if the differential between the index and utility issues is below 30 bps, the cost of debt index should be increased to restore the differential. At paragraph 3.44 to 3.45, Ofgem suggest that this mechanism sought to address the risk of "*efficiently incurred past debt not being fully funded as the value of the cost of debt index declines faster than the companies average cost of debt falls*", and so dismiss this proposed uncertainty mechanism on the grounds that the "*potential for embedded and new debt costs to diverge is an issue that crops up in every price control review*".

However, this misunderstands our proposed mechanism and the issue it addresses, and so does not address the point. The mechanism is not designed to address the risks associated with the lagging effect in the 10 year trailing average index. The mechanism is designed to ensure the cost of debt index adequately funds transaction costs in the manner that Ofgem has said it should, namely through a difference between the spot rate at which efficient networks can raise debt and the spot rates going into the index. The mechanism is designed to ensure the continued observation of the margin between new utility debt issuances and the index on a spot value basis[46] which Ofgem is now relying on to fund these costs.

The additional uncertainty mechanism that we have proposed should therefore be adopted in Final Proposals, given

- Ofgem's financing duty requires Ofgem to fund efficient and unavoidable network costs,
- Ofgem rely on a margin of at least 30 bps between utility issues and the index to fund the otherwise unfunded costs of issuing debt,
- The reduced margin seen in 2010 and 2011 as noted by FTI Consulting, and
- The fact that Ofgem misunderstood the proposed mechanism and so have not provided any reason why it should not be introduced.

Allowance needs to be made for the Inflation Risk Premium

As Ofgem note in paragraphs 3.52 of the Initial Proposals Finance supporting document, network companies have argued that the "breakeven inflation" figures that will be used to deflate the iBoxx index contain an inflation risk premium, and as a result the allowed cost of debt (on a real basis) will be lower than it should be.

In the following paragraph 3.53, Ofgem take comfort from "*the fact that, when averaged since the Bank of England began targeting inflation (May 1997), the 10 year break-even inflation figure we [Ofgem] use matches the sum of the Bank's inflation target (two per cent) and the difference between RPI and CPI inflation. The network companies have not refuted this point of our argument.*" As a result, in the Initial Proposals Ofgem do not propose to make any changes to the index to account for the Inflation Risk Premium.

[46] Given that utility issues do not take place on a continual basis or every day, we would suggest that the potential outperformance of the cost of debt index by utilities could be assessed either (i) by comparing the iBoxx non-financial index with the corresponding iBoxx utilities index, where an adjustment would be made if the differential falls below 30 bps, or (iii) if in each calendar year the average headroom of all utility issues in the year was less than 30 bps, the daily values of the index across that year should increased to restore this 30 bps differential.

It may be the case that this specific point has not been refuted by the networks, but this merely reflects the fact that the observation that Ofgem rely on is merely coincidence. The irrelevance of the observation is confirmed by FTI Consulting, in their report in paragraph 11.20, which notes that (i) averaging over slightly different time periods than the specific timeframe Ofgem chose to rely on would give significantly different results, and (ii) market expectations of RPI are in any case likely to differ from the CPI target plus the average difference between CPI and RPI.

Moreover, Ofgem are wrong to imply that the Bank of England has had an inflation target of 2% since May 1997. From May 1997 to December 2003, the target was 2.5%, using the RPIX measure of inflation[47], and during this period RPI was on average less than 0.1% above RPIX (and CPI was on average 1.1% below RPIX). It is the case that from January 2004 the Bank of England's inflation target has been 2% CPI, but during this time RPI has exceeded CPI by 0.6% on average.

Thus, during both timeframes (May 1997 to 2003 and 2004 onwards) the Bank's inflation target plus the average difference between the relevant measure (RPIX or CPI) and RPI is around or just under 2.6%, which is c.30bps below the average 10 year break-even inflation over the whole period (May 1997 onwards). Therefore, applying Ofgem's own logic and approach, the data would support an average inflation risk premium of around 30bps which should be taken into account in calculating the cost of debt allowance (real) from the iBoxx index.

Ofgem has previously accepted that an Inflation Risk Premium exists but have merely questioned whether it is material. Given the result above, more attention should be given to the positive arguments that have been made by the networks to support the existence of a material Inflation Risk Premium (which should not be disregarded), rather than any failure to refute Ofgem's (incorrect) observation about the relative levels of breakeven inflation and the Bank of England's inflation target.

Moreover, the FTI Consulting report provides further evidence to support the existence of an Inflation Risk Premium and that an allowance should be made for this.

- In paragraph 11.10 (and 11.1) FTI explain that Ofgem's justification for not adjusting for the inflation risk premium is that this is "*sufficiently offset*" by a "*liquidity risk premium*".
- However, in their conclusions in paragraph 11.23, FTI find that whilst "*there is enough evidence to presume the existence of an inflation risk premium*" they merely suggest there is "*possible existence of a liquidity risk premium*". This does not support the view that the offsetting effect that Ofgem has suggested can, in fact be relied upon, as noted by FTI in paragraph 11.21: "*Consequently, we do not consider that one can conclude definitively …. that the inflation risk premium is entirely offset by a liquidity premium.*" and in paragraph 11.23 "*The net effect of the two premia is unclear. Although it seems likely that the inflation risk premium is larger than the liquidity premium.*" Of course, even if the exact size of the effect is unclear, that is no justification for Ofgem to fail to make any allowance for it: rather, a fair estimate of the effect should be made and taken into account.
- It is possible that quantitative easing may have given rise to a liquidity premium, but even if this is the case it would be expected to be a temporary effect and as such should not be given any significant weight in setting the cost of debt mechanism for RIIO-T1 (and beyond).
- Further, on examination, any evidence for a liquidity premium in the UK is seen to be weak. FTI note (in paragraph 11.14) that relatively few estimates exist for the liquidity

[47] "The New Inflation Target", speech by the Governor of the Bank of England, January 2004

risk premium for UK index-linked gilts, but suggest (in paragraph 11.13) that if bid-ask spreads are wider for ILGs than conventional bonds that would provide some evidence for the existence of a premium. This is reported to be the case in some of the papers that FTI have reviewed, but these papers have often looked at other markets (particularly the US) or, even in some recent papers, have drawn on data from some time ago (e.g. the 1990s). It is, in fact, recognised in the papers that any liquidity premium is likely to be much lower in the UK than in the US, because ILGs form a larger fraction of total government debt in the UK, and because these instruments have a longer track record in the UK, both of which would tend to increase their liquidity.

- Moreover, on looking at actual bid-ask spreads as suggested by FTI, the data does not support a material Liquidity Premium for Index-Linked Gilts in the UK. Although these spreads are higher than on conventional gilts, they are only around 1.5 to 2 bps on 10 year index-linked gilts (and have been around this level for some time). Given this, in the context of an Inflation Risk Premium of around 30 bps, no material offsetting of the Inflation Risk Premium by the Liquidity Premium can reasonably be claimed.

In conclusion, the available evidence points to the existence of a material Inflation Risk Premium, which is not offset to any significant extent by a Liquidity Risk Premium, such that the break-even inflation values include a net "Inflation-Liquidity" Risk Premium of around 30bps on average. This is supported by

- The evidence provided by the networks,
- Ofgem's own logic and approach based on the Bank of England inflation target (once the errors made by Ofgem has been corrected), and
- The assessment of Ofgem's consultants.

This average 30bps should therefore be subtracted from the break-even inflation figure used to convert the iBoxx index from nominal to real, in calculating the cost of debt allowance under RIIO-T1.

Basel III and Solvency II could increase utility debt costs relative to the debt allowance

In paragraph 3.54 and 3.55 Ofgem consider whether the Basel III and Solvency II regulations will increase network companies' debt (interest) and liquidity costs.

In relation to Solvency II, the discussion does not address the key point we have previously made, which is a differential effect on bonds which, in the future, are likely to be issued by other companies in the iBoxx index and those which will be issued by network companies, which will tend to be of longer tenor (consistent with the long lives of energy network assets). This differential effect is the result of reduced demand for longer term debt which may be expected following introduction of the Solvency II rules.

The FTI Consulting report provides support for this differential impact in paragraph 9.14 to 9.16, based on public statements by ratings agencies. Whilst the FTI report then notes that the timing of the regulations is unclear and there are mitigating impacts, it does conclude that "*A risk that does remain is that there will simply not be sufficient demand for the longer-dated debt typically issued by infrastructure companies to fund their asset investments. It seems likely that there will be some reduced demand from insurers due to the increased capital charges envisioned but the impact of the reduced demand is not clear.*"

FTI further conclude that at the mid-period review the extent to which companies have been affected by Solvency II should be reviewed, although we understand that the mid-period review is not intended to review financial parameters or the overall financial package. Instead, therefore, a reasonable estimate of the effect should be factored into Final

Proposals, given that as we have previously noted a difficulty in estimating the scale of the impact is no justification for ignoring it altogether and making no corresponding cost allowances at all.

Furthermore, the FTI report shows that the impact on BBB debt is likely to be materially greater than on A-rated. Given our significant concerns regarding the financeability assessment that has been carried out by Ofgem as input to the Initial Proposals, and the fact that the credit metrics for NGGT resulting from the Initial Proposals only appear to be at BBB level at best, for consistency with this assessment it is this more significant impact on BBB debt that should be taken into account in making an allowance for the future impact of Solvency II.

Turning to consider Basel III, the Initial Proposals in paragraph 3.54 does not argue that the cost of liquidity facilities will not increase, although Paragraph 3.55 does refer to the observation in the FTI report that "*network companies should be able to access funds from sources that are not affected by these regulations, such as dedicated liquidity facilities*."

It may be the case that there are other sources of liquidity facilities, but the relevant points are (i) that these alternatives are more expensive than the arrangements that networks currently use and (ii) we are unaware of any liquidity facilities which would not be affected by Basel III, and thus networks' will not be able to avoid an increase in costs following Basel III. Specifically, FTI suggest that network companies could use:

- General purpose credit facilities
- Raising additional debt on the capital markets

Of these, the former is an example of bank credit facilities and as such it will be affected by Basel III.

The latter option would lead to a very significant increase in network companies overall borrowing costs through an increase in the "cost of carry" to maintain liquidity. This is because both to satisfy credit rating agencies and to satisfy the companies' auditors, the networks need to have in place sufficient finance (or back-up facilities) to be able to meet all funding requirements for the next 12 months at least. In practice, the need may be greater, for example at financial year-end the requirement is effectively for the next 13-14 months. If, as FTI suggest, it will be cheaper in the future to raise additional debt to satisfy this requirement than to use back-up facilities, Ofgem need, in effect to fund not just the RAV at any point in time but the expected RAV at least 12 months hence. On this basis, with a rapidly growing RAV during RIIO-T1, NGET's and NGGT's borrowing requirements under Ofgem's "best case" will be on average c.£1.1bn and c.£0.5bn respectively higher throughout RIIO-T1 than Ofgem has assumed in Initial Proposals, and allowed revenues need to be increased to fund the corresponding increase in overall borrowing costs.

Alternatively, if Ofgem prefer to fund back-up facilities (rather than interest on a much higher level of debt), the increased costs of these following the introduction of Basel III needs to be funded through allowed revenues. With the increase in these costs under Basel III, they cannot be assumed to be covered by a margin between utility new issues and the (spot rather than trailing average) cost of debt index, which as noted above has been much lower than previously since 2010.

<u>Conclusions on Cost of Debt Allowance and Mechanism</u>

In the Initial Proposals Ofgem has failed to recognise that although, at least for the transmission networks under RIIO-T1, the proposed indexation mechanism reduces cost of debt risk, some risk remains. In previous controls, networks were compensated for this risk through the provision of "headroom" in the allowed cost of debt. Since not all the risk is removed through the new mechanism but no headroom is now being provided, the unrewarded risks to equity have actually increased and so a corresponding increase now needs to be made to the allowed cost of equity.

National Grid and other networks have identified a number of other concerns with the proposed cost of debt index allowance:

- Any future outperformance of the cost of debt index by network companies is likely to be insufficient to fund transaction costs, new issue premia, carry costs, and other debt-related costs.
- In part, this is because the apparent outperformance (as indicated by Figure 3.9 in the March 2011 RIIO Strategy Decision finance document) has been much lower since the start of 2010 than previously.
- The resulting allowance is too low because the "break-even" inflation values used to deflate the nominal iBoxx index contains an Inflation Risk Premium
- At the same time, Basel III and Solvency II are likely to increase the level of transaction and other costs

In the Initial Proposals, Ofgem has failed to make any provision for break-even inflation or these other costs. We have shown above that Ofgem's basis for ignoring the inflation risk premium is ill-founded.

Not only has the apparent outperformance of the cost of debt index by networks been lower since the start of 2010 than previously, but there are also other reasons, as explained above, why any past ability of networks to outperform this index cannot be expected to continue in the future under RIIO.

Ofgem also misunderstood the uncertainty mechanism which National Grid had proposed in relation to debt index outperformance. However, there is now further evidence, including that in the FTI Consulting report, which supports the case that they need to be taken into account in setting allowances for RIIO-T1.

As a result there are transaction, liquidity and other debt-related costs (e.g. carry costs) which will not be funded through the proposed index-based allowance. In each case, FTI's report provides support for this view, and FTI propose that Ofgem should review the evidence again at the mid-period review to see whether allowance should be made for the costs faced by the networks. We recognise that the mid-period review is not intended to review the financial package but this is not a reason to ignore the arguments and concerns raised both by networks and Ofgem's own consultants.

Given the evidence that in both areas the networks will face costs that are not funded through the proposed index mechanism as it currently stands, the Final Proposals allowances cannot ignore both of these factors:

- To allow for the Inflation Risk Premium, the break-even inflation should be reduced by 30bps before these break-even inflation values are used to convert the iBoxx index values from nominal to real;
- In recognition of the otherwise unfunded debt costs, Ofgem should introduce an uncertainty mechanism under which, for those periods in which the apparent outperformance between utility issues and the iBoxx index falls below 30 bps, the corresponding daily values of the iBoxx index should be increased to restore the differential.

The proposals on financeability and cost of debt index are inconsistent

The proposed financial package is inconsistent with the cost of debt allowance. The proposed cost of debt index is based on an average of the iBoxx A and BBB indices, implying that the notional network should be rated around the threshold of A- and BBB+. In the case of NGGT at least, the credit metrics are well below this level. Our separate paper on financeability explains that a combination of accounting errors and a failure to reflect the timing of uncertainty mechanism funding arrangements has resulted in a misinformed financeability assessment. As things stand the proposed package for NGGT will result in credit metrics that are either below investment grade or low BBB.

The cost of debt finance is related to the credit rating of the issuer. Faced with the currently proposed financial package it is highly unlikely that the cost of debt index would fund the interest costs of NGGT. If the index is insufficient to fund the debt costs this will place additional pressure on the credit metrics causing a downward spiral in performance and financial stability.

Ofgem may seek to rely on the past experience of networks being able to raise debt more cheaply than the value of the index for a given credit rating. This would be inappropriate however because:

- Ofgem is already utilising this observed outperformance to fund transaction costs such as new issue premia and bank fees.
- It is by no means certain that this outperformance will continue in to the future such that there may not even be enough performance to fund these transactions costs let alone accommodate a downgrade caused by a deficient financial package

Informal dialogue implies that Ofgem is applying a lesser requirement for the financeability of the network than that espoused by the networks. If, as expected, Ofgem considers BBB credit metrics to be sufficient then it follows that the cost of debt index should also be set based on the BBB iBoxx index only and not an average of A and BBB rated debt.

A downgrade of the network caused by a deficient financial package will increase the costs to consumers in several respects:

- A downgrade not only increases the cost of debt for the network but also makes it more difficult to raise the debt required to fund critical investment in the networks.
- Even if debt can be raised it will be more expensive, not least because investors would have already suffered a loss on their existing holdings. As explained in the accompanying report by Oxera, utilities now comprise 60% of the iBoxx index for A rated debt and 48% for BBB rated. Utility debt issuances are sufficiently large that the increase in costs will increase the value of the index and so increase the cost of capital.

ONS consultation on changes to RPI

We note the ONS consultation on possible changes to the RPI measure of inflation. These changes may be expected to introduce formula changes which would reduce the future reported rate of inflation and thereby reduce the rate at which the RAV and revenues increase. This has a profound impact on the regulated networks so we consider it necessary for the licence to include a re-opener provision such that the implications can be considered and addressed once they are fully understood. These implications are likely to be material. Investors (both debt and equity) typically require a nominal return so any reduction in the underlying return provided through price protection will need to be compensated for through a higher real return. This would require an upward adjustment to be made to both the equity return and cost of debt allowance. There are also likely to be implications for the real price effects included in cost allowances. This may need to cover both the base allowances and also the real price effects embedded in uncertainty mechanisms.

Chapter: Four

Question 3:	Do you agree with our proposal for eight-year transition on NGET's asset lives for assets constructed after the start of RIIO-T1?

National Grid response:

We agree that the new asset life should only apply to expenditure incurred after the start of RIIO-T1. We also agree that there is a financeability need case to change from the current 20 year life to a 45 year life gradually through the use of transitional measures. We do not agree that eight years is sufficiently long for this transition.

Ofgem's best view scenario assumes that equity investors will provide £1.3 billion of additional finance to fund investments in the network, of which £0.6bn is in 2016/17. Our separate paper on financeability demonstrates that once the timing impacts of uncertainty mechanism funding and RIIO-T2 output expenditure are factored into the analysis, the requirement for equity grows to £2.1 billion.

There is an assumption that this equity will be provided despite an expectation that earnings will fall significantly afterwards. It is not clear why equity investors would choose to do this and no explanation is offered by Ofgem in the Initial Proposals leading us to infer that the needs of equity investors have been afforded very little consideration.

Our financeability paper demonstrates that implementing the new asset life of 45 years over 16 rather than 8 years would represent a net present value neutral movement that would go a small way towards mitigating this concern and would make the financeability of NGET more plausible.

Chapter: Five

Question 4:	Do you agree that companies must demonstrate a robust approach as to how their de-risking strategies, especially if aggressive, are protecting future scheme funding and that they should clearly demonstrate the benefits that they expect to flow to consumers?

National Grid response:

We would agree that in order for Ofgem to allow the funding of de-risking strategies, a clear consumer benefit case should be presented by the relevant network. We would also expect that in the current regulatory environment networks are likely to require funding certainty from Ofgem prior to embarking on innovative or aggressive de-risking strategies. We would expect that Ofgem would be supportive of any such strategies that were in consumers' interests, and Ofgem are well placed to determine the level of evidence they require in advance of providing such support. Consumer interests would be best served in this area through early liaison between Ofgem and the relevant networks prior to innovative de-risking strategies being employed, with Ofgem determining in advance whether such a de-risking strategy was efficient. Needless to say it is imperative for the future success of de-risking strategies that once Ofgem has made such a determination, it then stands by that decision, rather than re-evaluating such strategies with the benefit of hindsight. Lack of such regulatory certainty is likely to incentivise networks to avoid the adoption of innovative de-risking strategies.

Question 5: Do you agree that the costs of contingent assets may be allowed if considered to be in consumers' interests?

National Grid response:

Ofgem state in Paragraph 5.7 of the Initial Proposals - Finance Supporting document that 'The costs of contingent assets may be allowed if considered to be in consumers' interests.' National Grid would concur with this statement and can see no reason why such costs would not be allowed. It appears to be essential that networks outline their proposals in regard to contingent assets to Ofgem in advance of agreement with scheme trustees, to ensure that Ofgem agree that the particular arrangements being proposed would be deemed efficient and would be funded. Needless to say we would expect Ofgem to stand by such decisions once such arrangements have been put in place.

Question 6: Do you agree with the thresholds for pension scheme administration costs and Pension Protection Fund levies?

National Grid response:

Admin and PPF costs are largely outside of networks' direct control and particularly in the case of PPF costs could be subject to significant fluctuations should the Pensions Regulator decide to change its charging methodology. Consequently, a fair full true up of these costs is essential to ensure that consumers fund only the relevant costs.

No rationale has been offered to support the proposed true-up thresholds and National Grid can see no reason to apply them, particularly since the actual costs will be available through the Regulatory Reporting Pack process and true-up calculations would consequently require no significant effort to produce. Therefore, it doesn't seem reasonable to expose consumers to this unnecessary risk of over / under funding.

Additionally the thresholds chosen are arbitrary and would create very different risks for each licensee. For example, for licensees whose PPF allowances were 100k per annum the threshold for true-up would be 1000% of the forecast cost. This would be both unnecessarily large and clearly present an asymmetric funding risk to those parties. Smaller licensees or those with low costs would be particularly punished by such a move. In the case of National Grid Gas, where funding is spread across two Transmission and four Distribution price controls, allowances could differ from costs by up to £12m p.a. before any true up was made. The application of these thresholds would have the likely impact on National Grid's four gas Distribution networks of exposing each network to the first £1m p.a. of PPF costs before any realistic prospect of true-up recovery. The creation of such a large asymmetric funding risk would clearly be hugely disproportionate to the current level of costs.

There would have to be an overwhelming need case to introduce such arbitrary and unfair thresholds, and National Grid is unaware of any need case at all for their existence.

Full true up (without thresholds):

- Ensures that customers are only exposed to the actual costs incurred by networks.
- Provides for consistent treatment across networks regardless of size.
- Avoids placing inefficient incentives on networks in allocating costs.
- Is easy to implement, and
- Is demonstrably the most equitable treatment for both customers and shareholders.

Chapter: Six

Question 7:	Do you agree with our amended treatment for modelling the cash flows of Corporation Tax payments?

National Grid response:

We agree with the proposed simplification for the modelling of cash flows for corporation tax payments.

We are however concerned that the financial model currently omits from the financeability analysis the cash flows associated with corporation tax payments on a number of legacy incentive arrangements such as the gas revenue driver income and on income relative to adjustments from previous price controls. These tax payments are significant and omitted from the financial modelling in error. We believe this to be because the model has been designed to calculate regulated revenues, for which the calculation of these payments would not ordinarily be required.

On a related point, the tax payments in the financial model are designed for the regulated income calculation and work on the basis of the cash tax charge applicable with the benefit of perfect hindsight, i.e. ignoring the impact of timing issues which are then captured through the annual iteration process of the financial model. However, for an assessment of financeability a separate tax calculation is required based on the tax payments expected to be incurred taking these timing issues fully into account. Additional functionality capturing the revenues, costs, cash flows, debt and interest etc that are expected to be incurred would need to be added to the model to calculate these tax payments

Our response to question 11 and separate supplementary information document: ‘Financeability’ discuss these issues in more detail.

Question 8:	Do you agree with conforming the revenue adjustment for tax clawback to be annually in line with the annual iteration process?

National Grid response:

We agree that the tax clawback should be updated and reset each year in line with the annual iteration process of the financial model.

We do not however agree with Ofgem’s statement that there is no need to introduce a tolerance to the mechanism if gearing exceeds the notional rate. Ofgem’s rationale for rejecting our proposal to include a tolerance is that their approach to financing allows for equity issuance costs to be funded as gearing rises.

The Ofgem approach to financing only allows for equity issuance if gearing exceeds the notional rate by a given tolerance (2.5% for NGET and 5% for NGGT). Under these circumstances we believe it is inconsistent and illogical not to apply the same tolerance to the tax clawback.

We continue to believe that the clawback mechanism should include a tolerance on the test of whether actual gearing exceeds the notional rate.

Question 9: Do you agree with our treatment of expenditure for tax modelling?
National Grid response: We agree with the treatment of expenditure for tax modelling for the purposes of calculating the tax allowance to be included in regulatory revenues. However, as mentioned in our response to question 7 above, an additional calculation is required for the purposes of assessing the financeability of the network. This would be to calculate the tax payments that are expected to be incurred which differ from the allowance in several respects: • The allowance ignores a number of regulated revenue schemes such as the gas revenue driver income • The allowance is not based on the expected timing of revenues received and costs incurred etc This additional tax calculation should be used to inform the financial statements in the model and the financeability assessment.

Chapter: Seven

Question 10: The annual iteration process does not currently include any adjustment to TIRG values. We propose to add an adjustment. Do you agree?
National Grid response: We agree with the proposal to include an adjustment for TIRG values.

Question 11: Do you have any views on the calculations and layout in the financial model?
National Grid response: The financial model is generally well laid out, clear and transparent. We have engaged constructively with Ofgem to develop the financial model in the lead up to Initial Proposals and will continue to do so. Consequently we have not included the detail of each and every adjustment that we believe needs to be made to the model in this response. With regard to other material issues we have specific concerns regarding: • The use of the financial model to inform the financeability assessment • The capitalisation rate used for the totex incentive mechanism in NGGT • The threshold for equity injections in the model • The RPI forecast in the financial model • The restriction on dividend payments in NGGT **Financial statements and financeability assessment** We are concerned with Ofgem's financeability assessment on several levels: • A lack of transparency with regard to the results of Ofgem's assessment and their calculations of the credit metrics • Accounting errors in the model such that credit metrics calculated based on the

financial statement data in the model will be incorrect and misleading

- A failure to reflect the detail of the regulatory package proposed in Initial Proposals in the financeability assessment
- The very poor credit metrics that we observe for NGGT
- The poor earnings profile observed for NGET despite a requirement to inject equity
- A failure to consider a broader range of scenarios when stress testing the financial package

Further details on these issues can be found in our separate paper on financeability. The first three relate to the calculations and layout of the financial model and so are summarised below.

Lack of transparency

Our separate supplementary information document: 'Financeability' refers to material concerns we have relating to Ofgem's financeability assessment and specifically the lack of any calculations of the credit and equity metrics in the financial model. Prior to the publication of the proposals we (and other networks) have engaged with Ofgem and expressed concerns that the metrics in previous versions of the model were calculated incorrectly. We do not understand how stakeholders can be expected to meaningfully comment on the proposals when such material information is deliberately withheld.

This issue is compounded by the fact that the RIIO regime changes the nature of the regulatory contract by introducing fundamental changes such as the totex approach. It is not necessarily clear how financeability should be assessed in the future in the light of these changes. Ofgem almost appear to acknowledge the uncertainty created in their decision to calculate financial statements on two bases, both a statutory financial and regulatory basis.

Ofgem has stated informally that stakeholders can use the financial model to perform their own assessment. Unfortunately, this misses the point which is that we do not understand the basis on which Ofgem has concluded the Initial Proposals are financeable. This conclusion is different to our own and it is not clear whether the differences are due to a very different interpretation of what makes a network financeable, or different results from the credit metrics as a result of the modelling errors that we have identified.

Accounting errors

The primary purpose and focus of the financial model is to calculate the base revenue allowances. This includes the initial calculations of base revenue to be included in the licence and then the functionality required to update those allowances as part of the annual iteration of the financial model.

The financial statements sheets have been added so that Ofgem (and other users of the model) can calculate a number of credit and equity metrics for the purposes of the financeability assessment. These financial statements are materially incorrect for any scenario where there is a permanent or temporary difference between allowances and costs. Permanent or temporary differences will arise if costs incurred differ from allowances or if there is any delay in when allowances are triggered under an uncertainty mechanism (e.g. a re-opener or mid-period review retrospectively setting allowances for the RIIO-T1 period). Any metrics calculated using the statements will therefore be incorrect and potentially misleading.

As part of the annual model iteration process, the model recalculates what the base revenue should have been for all eight years of RIIO-T1 and compares those revenues to the results from the iteration for the previous year. It then performs a net present value true up adjustment for all of the differences for earlier years in an adjustment to the revenue calculated for the current year. This approach is a sensible one and the model executes it appropriately.

The annual iteration process is designed, again by necessity, to compare actual costs and allowances with a time lag of two years, so costs for 2013/14 are compared to allowances for 2013/14 when calculating income for 2015/16. As stated above, the model calculates revenue for all eight years in each annual iteration so in calculating income for 2020/21 the model will compare costs to allowances for all years from 2013/14 to 2018/9.

Taking an example, the revenue calculation for 2018/19 will have used allowances for that (and all prior years) known by November 2017, and the costs incurred for all years to 2016/17. An assumption is made that costs equal allowances for 2017/18 and 2018/19. The resulting revenue will be the base revenue that the company is entitled to in that year and should be used to inform the financial statements. However, when a model calculation is performed for 2020/21, the recalculated base revenue for 2018/19 will include a comparison of costs for all years up to and including 2018/19, with an updated view of allowances for all years up to 2018/19 and beyond to 2020/21. The model will therefore calculate a new, different revenue number for 2018/19 using different inputs. This recalculated revenue number will not change the revenues actually received in 2018/19, it will change the revenues due in 2020/21.

Unfortunately, the formulae for the numbers in the financial statements of the model pull their inputs from the live revenue calculations. There is no process within the published model to capture the modelled financial statements for prior years as the user steps through and performs subsequent annual updates. This means that data such as revenue, debt balance, interest costs and tax do not include the correct values. Given the importance of each of these numbers to cash flows and credit metrics it is clear that the financial statements within the published model contain inaccurate and misleading data for any scenario where costs do not match allowances. This issue was verbally acknowledged by Ofgem in a discussion on 7th September 2012.

To compound this issue, the costs and cash flows for opex / capex or fast / slow money (depending on whether the regulatory or statutory financial statements are being reviewed) are taken from the base revenue calculation. What this means is that they take the value of the recalculated allowance post the application of the sharing factor. Where costs do not match allowances, the value included in the revenue calculation does not represent the costs expected to be incurred for two reasons:

- For the year for which revenues are being calculated, and the preceding year, the model simply assumes the allowances equal the costs and ignores any cost data entered into the model
- For previous years, the model treats the recalculated totex allowances as the costs in the financial statements even though it is already known that costs differed from allowances and the recalculated allowances represent an interpolation between initial allowance and actual costs based on the incentive sharing factor.

It is clear therefore that the model does not use the costs expected to be incurred in the financial statements. A financeability assessment cannot therefore be accurately performed based on the financial statements in the model. To address this issue requires either additional functionality to capture the relevant financial statement data, or a full set of offline calculations be performed outside the model.

For the reasons above, any financeability assessment for scenarios with costs different to allowances in the financial model alone will have been misinformed if it was based on financial statement data from the model.

This issue has been identified subsequent to the setting of Initial Proposals and so it is reasonable to believe that Ofgem's financeability assessment was materially impacted by this accounting error and that corrected analysis would generate different conclusions.

We have provided a separate financeability paper as part of our response. As part of developing that paper we have added the necessary functionality to the Ofgem model to capture the financial statements as they would be expected to be experienced for the notional networks. The paper presents the key credit metrics and results both for the ‘best’ and ‘base’ Initial Proposals views. It also demonstrates the impact of a number of other issues and sensitivities which need to be considered.

Not reflecting the detail of Initial Proposals

Perhaps the most significant of the issues discussed in the paper is that Ofgem’s financeability assessment does not actually appear to reflect the detail of the regulatory package proposed.

Several of the uncertainty mechanisms introduce timing delays between when costs are expected to be incurred and when allowances will be set and revenues received.

Some uncertainty mechanisms are based on re-opener windows. If funding is agreed at the first window in May 2015, allowances would be recalculated in time for the November 2015 iteration of the model and so would adjust revenues from 2016/17. Under the current proposals there is no way that revenues could be received until that date which is the fourth year of the RIIO-T1 period.

Other mechanisms use the mid period review. In those cases no funding will be provided until 2017/18 at the earliest.

The separate financeability paper demonstrates the materiality and impact of these funding delays under the Ofgem ‘best view’ scenario. In NGGT for example, over £0.5 billion of investment is expected to be incurred in Ofgem’s best view scenario during the first three or four years before any allowances or revenues are received.

The failure to reflect the detail of the Initial Proposals goes beyond uncertainty mechanisms. There are also a number of other material cash payments that the networks are expected to incur during RIIO-T1 which are excluded from the published model. These include:

- Expenditure will be incurred in NGET in RIIOT1 to deliver outputs in RIIO-T2 where no allowance (or revenues) will be received in RIIO-T1 for this expenditure
- Tax payments on a number of elements of regulated income, e.g. the revenue driver income in NGGT

Model related concerns with the financeability assessment

In the light of the findings above and other issues reported in the separate paper we cannot see how Ofgem can be deemed to have met their obligations to have regard to the financeability of the networks and can only draw one of two conclusions, either

- Accounting and modelling errors misinformed Ofgem’s assessment and an updated assessment would result in a different financial package, or
- Ofgem has been complacent in its approach to financeability. Such a message would be worrying for both debt and equity investors.

NGGT capitalisation rate

NGGT has a totex capitalisation rate of 53% on baseline allowances and 90% on most uncertainty mechanisms. Under the operation of the totex incentive mechanism, where costs differ from allowances, the adjustment to revenues does not use the two separate rates but, instead, uses a weighted average rate. We do not agree with this for three reasons:

- Inconsistency between the allowed revenue and revenue adjustments
- Charging volatility
- Distortion of incentives

The inconsistency between allowed revenues and revenue adjustments is such that an uncertainty mechanism may trigger additional revenues with 10% fast money but any subsequent variances in spend would use a different fast money rate (of between 19% and 39% based on Initial Proposals).

This discrepancy could also lead to charging volatility so, for example, if a gas revenue driver was triggered to release additional capacity, 10% of the anticipated costs would be funded as fast money increasing charges. If an innovative solution could be developed at significantly lower cost the reduction in charges under the incentive mechanism would return 55% of the variance in cost at a far higher fast money rate. It is possible for the reduction in charges to be higher than the initial increase in charges.

It is equally possible for investment under one of these schemes to significantly exceed allowances at which point additional revenues would be provided based on a fast money rate between two and four times larger than the rate initially used. Since these schemes typically (but not necessarily) involve capital expenditure we are not convinced that a fast money rate possibly as high as 39%, is appropriate due to the potential for it to increase charging volatility and unpredictability.

A variable fast money rate could also distort incentives. While the fast money rate makes no difference to economic value it does have an impact on reported financial results. Where the fast money rate progressively falls during the price control, a network has an earnings incentive to accelerate works to do them earlier and get a higher fast money rate knowing that an underspend in later years will involve a smaller return of fast money cash to consumers.

This distortion of incentives could be avoided by applying the split capitalisation rate approach to expenditure variances during the price control, i.e. use both rates in the Totex Incentive Mechanism.

Threshold for equity injections

The financial model includes functionality to automatically calculate equity injections if the opening net debt / RAV ratio exceeds the notional rate used in the WACC by a given tolerance. This tolerance is 5% for NGGT and 2.5% for NGET.

This tolerance has a direct impact on the financeability of the network as a higher tolerance allows debt and interest costs to rise to higher levels than a lower tolerance would. As our financeability paper makes clear, we have serious concerns about the credit metrics for NGGT and would propose that the equity injection threshold be reduced to 2.5% to match that of NGET or, preferably, be reduced even further (perhaps to 1%) for both networks.

RPI forecast in the financial model

The financial model includes a forecast of RPI for all years to 2020/21. This forecast is then used as part of the calculations for the tax allowance etc. Ofgem do not currently intend to update the forecast included in the model as part of the annual iteration process. This means that if inflation turns out to be different over the RIIO-T1 period than the forecast currently included, the tax allowance could be materially incorrect. We do not consider this to be appropriate and would encourage Ofgem to include the RPI data as part of the annual iteration process.

NGGT restriction on dividend payments

Ofgem explains in paragraph 3.64 of the Finance supporting document that it has chosen to restrict the notional dividend of NGGT to be based on the ‘base view’ RAV only. The rationale given for this approach is the sharp rise in investment levels.

This explanation demonstrates a marked lack of consistency within the Initial Proposals and between networks. Paragraph 3.17 refers to NGGT's investment rate as being "substantially lower" than the electricity networks where no such dividend restriction has been applied. That same paragraph goes as far as to say that NGGT's rate of investment is closer to that of the Gas Distribution networks where, again, no such dividend restriction has been applied. Based on Ofgem's own investment analysis NGGT falls in the pack as being lower than electricity and higher than distribution. The importance of dividends and rationale for the underlying 5% dividend assumption applies equally to NGGT as any other network. In this context it is both illogical and unjustified to apply a restriction to NGGT.

We would therefore encourage Ofgem to remove this restriction and to apply the same formula currently used for the other networks to NGGT as well. This issue is discussed further in our financeability paper.

Question 12: Should the financial model also capture, for presentational purposes only, the revenue from all incentive schemes?

National Grid response:

The scope of the financial model is currently restricted to setting the initial base revenue allowances and then calculating the adjustments to that base revenue required by the annual iteration process. The model does not cover the whole of the regulated income and does not cover the majority of incentive schemes.

We can see the benefit of extending the model to cover these items as memorandum entries only such that the model presents the whole picture in one place but this is not the true purpose of the model and care would need to be taken to ensure that the model does not mislead stakeholders by implying it is more than it really is. If the model is extended to incorporate other revenue terms we believe it would be appropriate to review the current revenue reporting rules to avoid a duplication of reporting and to reduce costs to consumers.

Regardless of Ofgem's decision in this regard it is vitally important that Ofgem clarify exactly what the data in the model represents.

Other Issues

Other Issues: The section below details a number of other comments and issues in relation to the Initial Proposals

Inputs to the financial model

There are a number of inputs to the financial model that still need to be agreed or updated before Final Proposals. We will work with Ofgem to do this over the coming weeks. By way of example, many of the inputs (including the opening RAV) have not yet been updated to reflect the costs incurred during 2011/12.

Risk Modelling

National Grid provided detailed risk modelling as part of its business plan and presented the results of Monte Carlo analysis of the risks faced by NGET and NGGT under RIIO-T1 and TPCR4. This modelling demonstrated an increase in risk during RIIO-T1 relative to TPCR4.

As we observe in our separate supplementary information document: 'Relative_risk_assessment', Ofgem has not engaged with us on the detail of our modelling. It has also not produced any substantive-based modelling of its own to either confirm the results of National Grid's modelling or to seek to put forward a different view.

Although Ofgem has not addressed our quantitative Monte Carlo risk modelling, it is considered in the FTI Consulting report which was commissioned by Ofgem. This report makes a number of observations on the approach, including "We [FTI] agree that probabilistic modelling is a reasonable approach to modelling the increase in risk" and "Monte Carlo simulation is a useful tool to obtain a probabilistic view of the impact of changes to a well specified operation model".

In their conclusions on the approach, FTI note that it appears that companies (including National Grid) "drew on their business models and experience to develop well specified models using reasonable inputs" but caution that "the Monte Carlo simulations are sensitive to multiple input assumptions for which there are likely to be equally reasonable alternative sets of assumptions that would affect the results." Consequently, FTI consider that "the results provide a useful indication of the extent of additional risk carried by the network companies during the 2013/21 controls" but "should not be used in a deterministic way".

In the quantitative risk modelling we presented in our March 2012 business plans, and to address a reservation expressed by Ofgem regarding the risk modelling we had previously included in our July 2011 business plans, National Grid applied a scaling factor to the results, in recognition that some of the risk factors that were being modelled were, in part, diversifiable. Whilst FTI do not appear to take issue with this approach in principle, their report suggests that the differences between National Grid and other business sectors from which this scaling factor was derived are too great for the resulting scaling factor to be considered accurate, and so applying the scaling factor to the results of the Monte Carlo simulation may not give a cost of equity which accurately reflects the increase in business risk. However, this reservation fails to recognise that the scaling factor was applied to the results of modelling the risks under both TPCR4 and RIIO, and so the end results of the quantitative analysis, which are the relative increase in non-diversifiable risk from TPCR4 to

RIIO and the corresponding cost of equity required under RIIO-T1, are little affected by the value of the scaling factor used.

Thus, the FTI report can be seen to provide support for the use of quantitative risk-based modelling, and whilst some reservations are expressed which might question whether such modelling should be used to derive a single cost of equity value in a deterministic way (rather than a range), this does not, in FTI's view, detract from the usefulness of the approach to give an indication of the increase in risk faced by the networks.

In the light of these conclusions, and given that Ofgem has not engaged with us on the detail of the risk modelling in our business plans, nor produced any equivalent analysis of their own, the indication of increased business risk for both NGGT and NGET during RIIO compared to TPCR4 cannot be disregarded. Furthermore, the reservations expressed by FTI apply principally to the level of non-diversifiable risk that is calculated in the modelling in each of TPCR4 and RIIO-T1 when considered separately, and are very much less relevant to the relative increase in risk between TPCR4 and RIIO-T1 that is demonstrated by the modelling.

NGET pension issues

The pension deficit allowances for NGET appear to be based on an incorrect ERDC amount which we would expect to be corrected for in the Final Proposals.

Pension true up numbers are based on calculations which employ assumed rather than actual tax rates for the TPCR4 period. Ofgem has agreed that actual rates should be used and we would expect this to be amended in the Final Proposals.

The description of the established deficit in Paragraph 5.2 of the Initial Proposals - Finance Supporting document is somewhat misleading and should be updated to avoid confusion in the future. The established deficit is the element of any future deficit that relates to service up to the ‘cut-off date’ as opposed to the deficit at the ‘cut-off date’.

NGGT pension issues

The pension allowances for NGGT may need to be updated in the Final Proposals since TPCR4 regulated fractions have been used to calculate deficit allowances in the Initial Proposals. We would expect that both the overall fraction and licensee splits would be updated at that time. PPF and pension admin allowances would also need to be updated in the Final Proposals assuming new regulatory fraction splits are agreed.

Ofgem state in Paragraph 5.16 of the Initial Proposals - Finance Supporting document, that there is an issue with agreeing ERDCs. Since ERDCs for NGGT are now zero, it isn’t obvious what the issue is, nor why we should need to wait until the first reset to resolve it.

A full response on the proposals in relation to the proposed review of the NTS recharge, (referenced in Paragraph 7.3 of the Initial Proposals - Finance Supporting document) is contained in National Grid’s response on the RIIO-GD1 Initial Proposals.

Ongoing pension cost issues

Overall reductions in opex allowances from those costs included in our submission are likely to overestimate potential ongoing pension cost savings that can be made through general efficiency savings. Any assumed reduction in overall headcount (through reduced recruitment) would only reduce pension costs at the defined contribution level (forecast at 11% of pensionable salary) rather than the average pension cost level which includes DB ongoing costs.

Deteriorations in bond yields since the business plans were submitted indicate that the level of DB ongoing pension costs in future are likely to be higher than forecast by perhaps 5-8% of pensionable salary. We would ask Ofgem to reflect these increased costs in the overall opex allowances that are set in the Final Proposals. Moreover, it would appear inappropriate to apply general efficiency assumptions to these costs given that they are largely outside of networks' control and there appears to be very little scope in the short or medium term for ongoing defined benefit contributions to reduce.

NGET capex

- Page 31, paragraph 4.42

  Ofgem state the reduction applied as being 11.1% for transformers. In subsequent discussion, Ofgem confirmed that they had only applied 11% reduction to transformers.

- Page 64, paragraph 4.184

  Ofgem do not define how they are going to assess shunt reactor requirements using the P/Q ratio, nor how they intend to verify the fault levels at substations.

- Page 73, table 5.3

  Ofgem state that the TPCR4 OHL conductor Volume for NLR Disposal + LR Disposal in Window as 543, we believe this number should be 714.

- Page 78, table 5.6

  Ofgem state that the RIIO-T1 OHL Fittings Volume for LR Disposal in Window as 575, we believe this number should be 580.