National Grid Transmission

TPCR4 rollover: Initial Proposals

Table of Contents

Responses to Ofgem's questions

Chapter: 2

Question 1: We invite stakeholders to comment on our proposed operating cost allowances for the transmission companies.

Summary

The opex initial proposals cover both controllable opex and non-operational capex in line with the methodology used in setting the TPCR4 allowances. Consistent with our rollover submission our thoughts on the initial proposals for opex are split between the two areas. This is because the drivers for each in 2012/13 are different, with controllable opex dominated by the requirement to recruit and train resources ahead of RIIO-T1 workloads and non-operational capex being akin to traditional capex in nature so should be viewed in this light.

Funding for the rollover year needs to adopt a proportionate approach which defers discussion of some issues into the RIIO-T1 process so long as it does not impact on stakeholder outputs either in 2012/13 or into the RIIO-T1 period. The aim for the rollover is to get to a position of adequate allowances to deliver stakeholder requirements and to move incrementally where volumes and costs are rising into the future in order to smooth the transition and make the step change more deliverable.

The signals given by Ofgem in the initial proposals indicate a desire to defer investments which may impact on the efficient delivery of network reliability and safety in the future. For example funding of half of the workforce growth and renewal costs would not allow us to keep to the same resource levels we have in place currently as, of the costs to be incurred in 2012/13, two thirds will be incurred to offset expected attrition and retirements. Not being able to respond to this would impact on the efficient delivery of future outputs.

We recognise that there are some specific areas where our proportionate approach to the rollover submission has meant that Ofgem have not got all the evidence they require in certain areas. We welcome the opportunity to provide new and improved information which enables a more detailed assessment of the opex costs.

We are strengthening the justification for each of the areas of upward cost increases between 2009/10 and 2012/13, providing more detail in the sections below and highlighting areas where our information may have been misinterpreted. For example we give new information on the efficiencies we have embedded into our plan which shows that the Initial Proposals include a double count of both 'catch up' efficiency and avoided cost efficiencies without allowing the related cost increases they offset.

Controllable opex

The initial proposals assess each of the upward cost drivers in opex from 2009/10 through to 2012/13. In many cases Ofgem outline that there is more justification required in each of the areas with either no allowance given for the forecast increase or half of the value included in the proposed allowance. Our response gives more justification for the increases focusing on the need for the investment and why this translates into a requirement for expenditure in 2012/13.

The main upward opex pressure between now and 2012/13 arises due to the need to recruit and train resources. This is both to renew the workforce in the face of attrition and retirements – i.e. to maintain current levels of fully trained, skilled employees – and to grow the workforce to help deliver the investments our stakeholders require in the RIIO-T1 period.

Both of these enable delivery of the outputs we detailed in our recent RIIO-T1 submission. With necessary training periods of up to four years to achieve required competency levels the work between now and 2012/13 is vital to deliver the capital and operating requirements in the RIIO-T1 period. Recognising the need to give more justification for the drivers and deliverability in this area we explore them below including evidence of:

- How we have already recruited nearly 300 FTEs in 2010/11 and are on track to recruit nearly 500 more in 2011/12 with 213 recruited by the end of September 2011. This shows we can both deliver the recruitment outlined in our rollover submission and are already undertaking some of the expenditure proposed for 2012/13 at our shareholders' expense due to the essential nature of the expenditure.

- How two-thirds of the recruitment and training burden is just to maintain the current levels of resource into the RIIO-T1 period in the face of attrition and retirements. This means that the current proposals of only allowing half of the expenditure for recruitment and training in 2012/13 would not enable us to remain at the level of employees we have in place today. With growing workloads - as evidenced by many industry commentators for example the Department of Energy and Climate Change (DECC)[1] – this would impact on the efficient delivery of network outputs that our stakeholders expect us to deliver in the RIIO-T1 period and could delay critical investment.

In addition to assessing each of the upward cost drivers, the initial proposals embed an efficiency target into the proposed allowances. This is stated as being 1.5% per annum for on-going efficiency. In reality for NGET and NGG the efficiency level applied has been based on the efficiency levels we included in our submission. These already totalled 3.7% per annum for ETO and 2.7% per annum for GTO. An additional £4m 'catch-up' efficiency has also been included by Ofgem for ETO because opex has been above TPCR4 allowances.

The NGET and NGG efficiencies already incorporate a 'catch-up' efficiency where benchmarking or market testing has shown that improvements can be made (for example, savings from our support function transformation programmes). Ofgem's £4m efficiency is therefore double counting this 'catch-up' efficiency. Outside of these areas our opex benchmarks well against our peers (for example under mature benchmarking studies ITOMS and GTBI).[2] Using the TPCR4 opex allowances for ETO - which have proved inadequate during the period - as a proxy for the efficient level of expenditure is too simple an assessment because several key cost drivers such as the price of on-going contracts (such as energy costs) and workforce attrition rates have changed since the allowances were set.[3]

The efficiency levels we embedded into our plan incorporated catch up efficiency, avoided cost efficiency (linked to specific upward cost pressures) and underlying efficiency equivalent to the levels any network should strive to deliver (sometimes called frontier shift):

- **Catch up efficiency:** Once the impact of the £4m of extra catch up efficiency is factored into the calculations the efficiency levels total 4.4% for ETO. This is in excess of the 1.5% levels in the TPCR4 allowances and our forecasts already incorporate £4.7m of catch up efficiency. We therefore propose that the double counted £4m efficiency is removed.

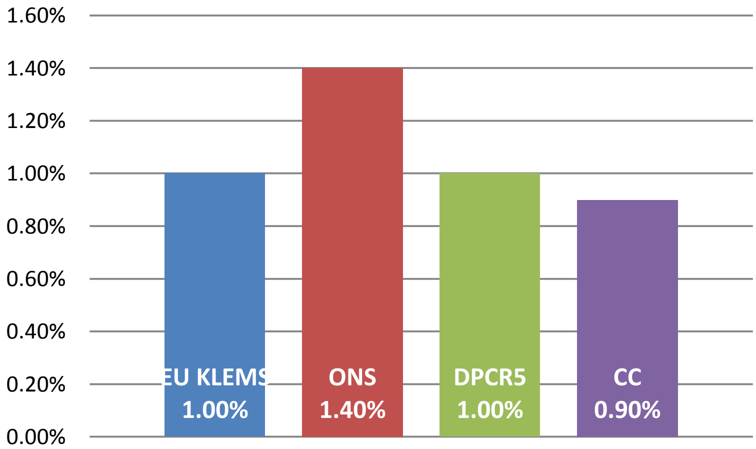
[1] See the overarching National Policy Statement for Energy (EN-1) where the government estimate £100 billion of investment required in the electricity sector by the end of this decade

[2] See the 'Innovation, efficiency and value for money' annex of our RIIO-T1 submission for the evidence and more detail in this area

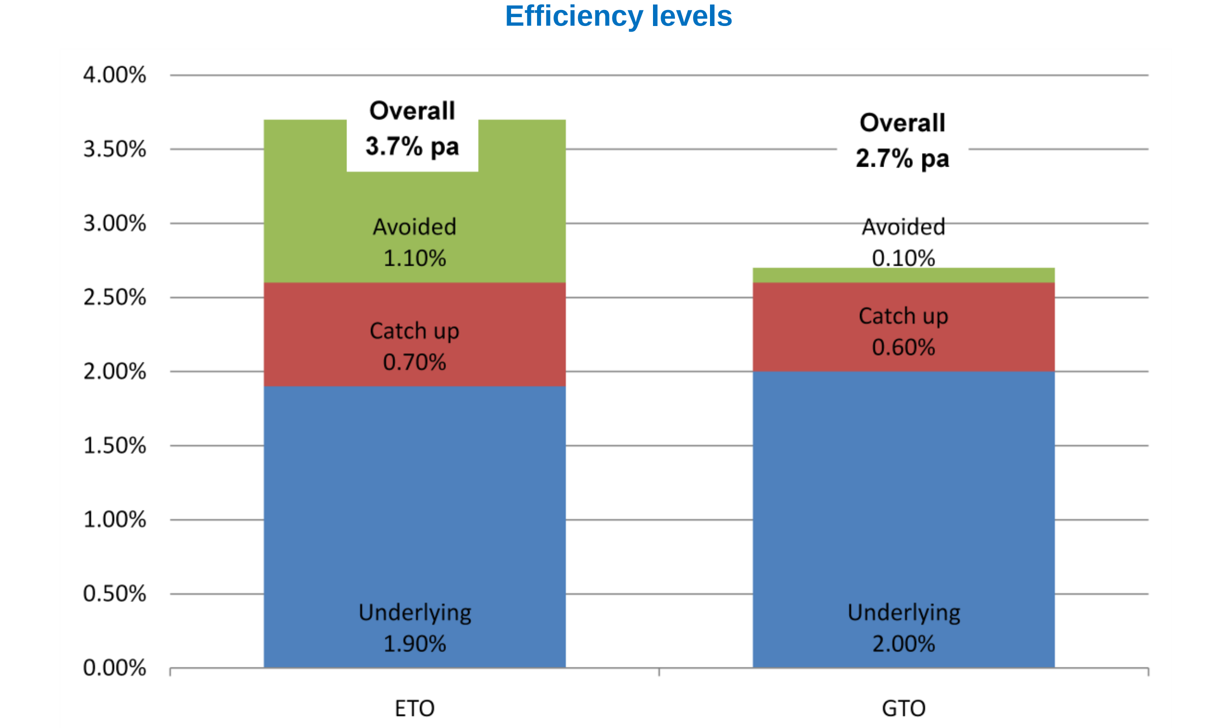
[3] See the 'TPCR4 review' annex of our RIIO-T1 submission for more detail on the changes that have occurred since the allowances were set

- **Avoided cost efficiency:** We had 'grossed up' both cost and related efficiency in presenting the trace of opex costs between 2009/10 and 2012/13. This meant that some of the upward cost pressures were linked to avoided cost efficiencies of £7.5m for ETO and £0.3m for GTO. Incorporating all of the efficiencies and not funding the related upward cost pressures they offset means that the allowances currently remove £4.2m of cost that does not exist from ETO and £0.2m from GTO. This related cost should either be funded or the equivalent figure removed from the efficiencies embedded to increase the allowances.

- **Underlying efficiency**: Outside of the catch up efficiency and avoided cost efficiency the underlying levels within ETO and GTO are 2.0% and 1.9% per annum respectively. This is higher than regulatory and historical precedent which indicates levels of 1-1.5% should be delivered by frontier companies. The evidence for this is explained further in the 'Innovation, efficiency and value for money' annex of our RIIO-T1 narrative but the graph below summarises evidence from four different sources being EU Capital (K), Labour (L), Energy (E), Materials (M) and Services (S) (EU KLEMS) productivity data, the Office of National Statistics (ONS) productivity data, the outcome for the last Electricity Distribution Price Control Review (DPCR5) and from the Competition Commission (CC) review of Bristol Water:



The graph and table below summarises the level and type of efficiency we embedded within our rollover submission. There is more detail on the avoided cost efficiencies, including which upward pressures they link to, in the form of control sections below.



Efficiency type	ETO £m	GTO £m
Avoided cost	7.5	0.3
Catch up	4.7	1.3
Underlying	11.9	3.9
Total	**24.0**	**5.5**

The overall approach to the initial proposals for opex means that the proposed allowance for controllable opex is lower in real terms than the level we spent in 2009/10. With opex workloads increasing as we approach the RIIO-T1 period – not least due to the training and recruitment burdens in support of decarbonisation and network renewal – this would have an impact on delivery of stakeholder requirements and outputs in both 2012/13 and into the RIIO-T1 period.

Non-operational capex

The initial proposals for non-operational capex question whether some of the projects we forecast will actually be delivered in 2012/13. In the detailed by project response below we explain that the three main projects disallowed - our condition monitoring work in Strategic Asset Management (SAM), the High Pressure Monitoring Information System in NGG and asset health work on the Transmission Front Office (TFO) – are already sanctioned and we are already spending money delivering the projects. Deferring these projects from 2012/13 would not only be inefficient (because we would have to stop on-going development giving rise to increased cost in the longer term) it would also impact on reliability and safety of the network. This is explained further in the sections below.

The initial proposals state that non-operational capex for 2012/13 should be kept at levels closer to historical averages. This suggests that non-operational capex is being considered as opex, rather than – as it is – capex in nature. Costs may be funded like opex but the 2012/13 projects are based on both asset refresh of existing IT assets and new capabilities that will help deliver and minimise the capital requirements of the future. For example RAMM

/ SAM investments (total investment of £4.1m in 2012/13) build upon initial tactical SAM investments. These have already avoided costs in 2011/12 through risk mitigation and avoided asset (transformer and GIS) failures that would otherwise have impacted on safety and reliability. Expenditure in 2012/13 helps us to extend SAM capabilities across more of our assets allowing us to maintain reliability and safety outputs and deliver enhanced performance, with attributable benefits of ~ £13m over the RIIO-T1 period.

ETO controllable opex

This section gives more evidence and justification for the upward cost drivers for controllable opex between 2009/10 and 2012/13 in the ETO form of control. In addition we explain the linkages between:

- Avoided cost efficiencies and upward cost drivers
- Non-operational capex and efficiencies

It has been nearly a year since our rollover submission in October 2010, so more information is now available and 2012/13 is closer enabling us to have a clearer view about forecast opex levels. In addition our RIIO-T1 submission provides more detail than was included in the Rollover submission in many of the areas due to our proportionate approach to the Rollover. Where this is the case we point back to where the relevant evidence is included in our narrative. Given the time since Rollover submission there have been some changes to our opex forecasts for 2012/13. This has occurred in two main areas: real pay, workforce renewal and growth. Other changes have also occurred to volume and mix movements (increased due to excluded service costs). These changes were incorporated into our RIIO-T1 submission.

In the case of real pay we agreed a three year pay deal with the trade unions in May 2011 after 11 months of negotiations. The challenges of this agreement and previous pay deal discussions are discussed further in the 'Innovation, efficiency and value for money' annex of our RIIO-T1 submission. This deal means that pay levels are now forecast to be in line with RPI between 2009/10 and 2012/13. The related cost increase was therefore not included in our RIIO-T1 submission and we agree with the initial proposals' view that there will be no above RPI increase in this area. We therefore do not cover the RPE cost increases any further in this document because the allowances include funding for the other areas of RPE.

Having undertaken a comprehensive recruitment programme in 2010/11 (which attracted the resources we targeted in the year) we learnt some lessons which we incorporated into our resourcing strategies. These lessons included changing our replacement strategies in the area of our commissioning engineer roles. We have struggled to recruit experienced commissioning engineers due to low availability so we have changed approach. We are now adopting a strategy to 'upskill' craftspeople (staff level 4 to 5) into technicians, and then subsequently technicians into commissioning engineer roles. This requires back filling the craftsperson roles from increasing our apprenticeship intakes where there is more availability of resource. As this is a longer term approach it requires more recruitment earlier on. In addition we have more information on how the increasing capital plan impacts on our resource requirements. We have therefore increased the recruitment targets in 2011/12 in the RIIO-T1 submission. We recognise that we will not be funded for the £4m extra opex cost of this in 2012/13 but given it is necessary for delivering stakeholder requirements in the RIIO-T1 period we are pressing on with it anyway.

The table below reconciles between the rollover submission and RIIO-T1 submission and compares figures against the initial proposals. Note that the RIIO-T1 figure is the equivalent controllable cost figure to the Rollover figure rather than the figure on table 1.3 in the RIIO-T1 business plan data tables. Controllable costs are defined differently in RIIO with items such as CNI and pension costs being within the definition of controllable cost under the RIIO definitions but not within rollover. As requested by Ofgem a full reconciliation between the two opex submissions will be sent in due course.

	Rollover submission £m	RIIO-T1 submission £m	Difference £m	Initial proposals £m
2009/10 opex	198.5	198.5	-	198.5
Less one-off costs	(5.5)	(5.5)	-	(5.5)
Recurring opex	**193.0**	**193.0**	**-**	**193.0**
Efficiency savings	(24.0)	(24.0)	-	(24.0)
Additional catch up	-	-	-	(4.0)
Total efficiency	**(24.0)**	**(24.0)**	**-**	**(28.0)**
Workforce growth	7.4	9.3	(1.9)	3.5
Recruitment and training	11.0	13.0	(2.0)	5.5
Asset growth and diversity	10.0	10.0	-	4.5
IT running costs	4.0	4.0	-	-
Real price effects	10.0	4.5	5.5	4.0
Volume, mix and other	6.2	9.8	(3.6)	2.3
Total workload	**48.6**	**50.6**	**(2.0)**	**19.8**
Forecast / allowance	**217.6**	**219.6**	**(2.0)**	**184.8**

As can be seen from this table the opex allowances in the initial proposals at £184.8m are £8.2m less than the recurring opex from 2009/10 of £193m. With opex workloads increasing as we approach the RIIO-T1 period – not least due to the training and recruitment burdens in support of decarbonisation – this low funding would have a material impact on delivery of stakeholder requirements and outputs in both 2012/13 and into the RIIO-T1 period.

Efficiency levels

As stated in the summary section above the efficiencies we embedded into our Rollover submission – which have in turn been included in the initial proposals allowances – include £4.7m of catch up efficiency and £7.5m of avoided cost efficiency with the overall split being as per the table below:

Efficiency type	ETO £m
Avoided cost	7.5
Catch up	4.7
Underlying	11.9
Total	**24.0**

The avoided cost efficiencies are linked to upward cost drivers which were included in our trace. Incorporating all of the efficiencies in the initial proposals' allowances but not funding the related upward cost pressures they offset means that the proposed allowances currently remove over £4m of cost that does not exist.

The avoided cost efficiencies and the upward cost pressures they relate to are included in the table below. The 'related workload area' column shows which category the related cost is included within (consistent with the table presentation above) and the 'gap' column shows how much of the related cost is not included within the initial proposals' allowances[4]:

Description	Related workload area	Cost £m	Gap £m
Minimising upward cost pressures - resources	Workforce growth	2.3	1.2
Anticipated organisational savings	Workforce growth	1.5	0.8
Absorbing IT business resource requirements	Workforce growth	0.4	0.2
Sub-total		***4.2***	***2.2***
Tower painting	Asset growth and diversity	0.6	0.3
Substation and cable maintenance savings	Asset growth and diversity	1.7	1.7
PDSA contract savings	Asset growth and diversity	1.0	-
Sub-total		***3.3***	***2.0***
Total		**7.5**	**4.2**

To remedy this inconsistency between the incorporation of all the avoided cost efficiencies but not the related upward pressure the erroneously calculated 'efficiency' should be removed or resultant opex allowances should be increased by £4.2m to cover the costs in the 'gap' column above.

As we have already included catch up efficiency, the extra £4m of efficiency embedded into the proposals is double counted. This element of efficiency was included because we are overspending the ETO allowances in the TPCR4 period. The allowances, however, should not be used as a proxy for the efficient level of expenditure during the TPCR4 period due to the changes that have occurred since they were set. Instead results of benchmarking and market testing should be used to determine whether our costs are efficient. At the highest level 98% of our cost base is either benchmarked or market testing and, as outlined in the 'Innovation, efficiency and value for money' annex of our RIIO-T1 submission, the results are positive. For example the main opex cost in ETO relates to maintenance of our asset base. This cost accounts for over 50% of our opex in any one year and is benchmarked through the International Transmission Operations and Maintenance Study (ITOMS) where results show our reliability to be one of the best in the study with the related cost efficiency above international averages.

[4] Note that where a workload area has been 50% funded in the initial proposals it is assumed that 50% of the cost relating to the avoided cost efficiency has been funded already

TPCR4 ETO allowances

From an allowance perspective the 'TPCR4 review' annex of our RIIO-T1 submission explains the reasons why we have overspent the allowances. In summary the overspend (including the forecast figure for 2011/12) is expected to be ~£150m which has been predominantly driven by the following items:

Reason	Overspend £m	Comments
Workforce renewal and growth	34	Acting to offset growing attrition and retirements rates to maintain and grow the workforce in advance of the RIIO-T1 period – this was not foreseen at the time of TPCR4 submission
Business support transformation costs	39	One-off costs to transform our shared services, procurement and IT departments to deliver future savings in light of changing requirements and market testing / benchmarking that showed we could improve
Asset growth	6	Driven by higher load related capex than expected at the time of TPCR4 submission
Ageing assets / change in asset management strategies	22	Impact of more condition monitoring and unplanned maintenance due managing a growing population of ageing assets and the introduction of risk and criticality asset replacement
Electricity prices	6	Impact of real price growth on our electricity own use requirement - TPCR4 allowances contained no RPE for electricity prices
Other	43	Includes the cost of risks identified at the time of the TPCR4 submission such as the impacts of one-off construction opex costs, tower painting price increases and oil price rises. In addition includes overspend on non-operational capex which has been driven by delivering projects for future benefit such as RAMM / SAM
	150	

The majority of these items are either one-off in nature or have been driven by changes since the TPCR4 allowances were agreed therefore using the level of allowances as a proxy for the efficient level of expenditure is not the right approach for 2012/13.

Workforce growth

	Rollover £m	RIIO-T1 £m	Initial proposals £m
Gross increase	7.4	9.3	3.5
Less avoided cost	(4.2)	(4.2)	(4.2)
Net increase	3.2	5.1	(0.7)

Over the next three years and into the RIIO-T1 period there are growing workloads that our stakeholders expect us to deliver. In order to have fully competent resources to deliver these workloads we are acting to grow the workforce. The main drivers for this are:

- *Delivering an increasing capital plan*: whilst our alliance model gives us access to wider pools of specialist resources some internal resource growth is required in order to retain project management and control around the capital programme

- *Responding to increasing connections requests:* we are experiencing a marked increase in the number and complexity of connection requests. We are growing the workforce to appropriately respond to these through system modelling, customer interaction and determining the investments required to maintain reliability within the security standards in the future transmission network

- *Planning reform*: changes to planning legislation mean that more work is required up-front of an investment to develop several alternative feasible routes and engage with stakeholders so they can influence the design. We are growing the system design team, our level of consents officers and construction workforce to respond to this

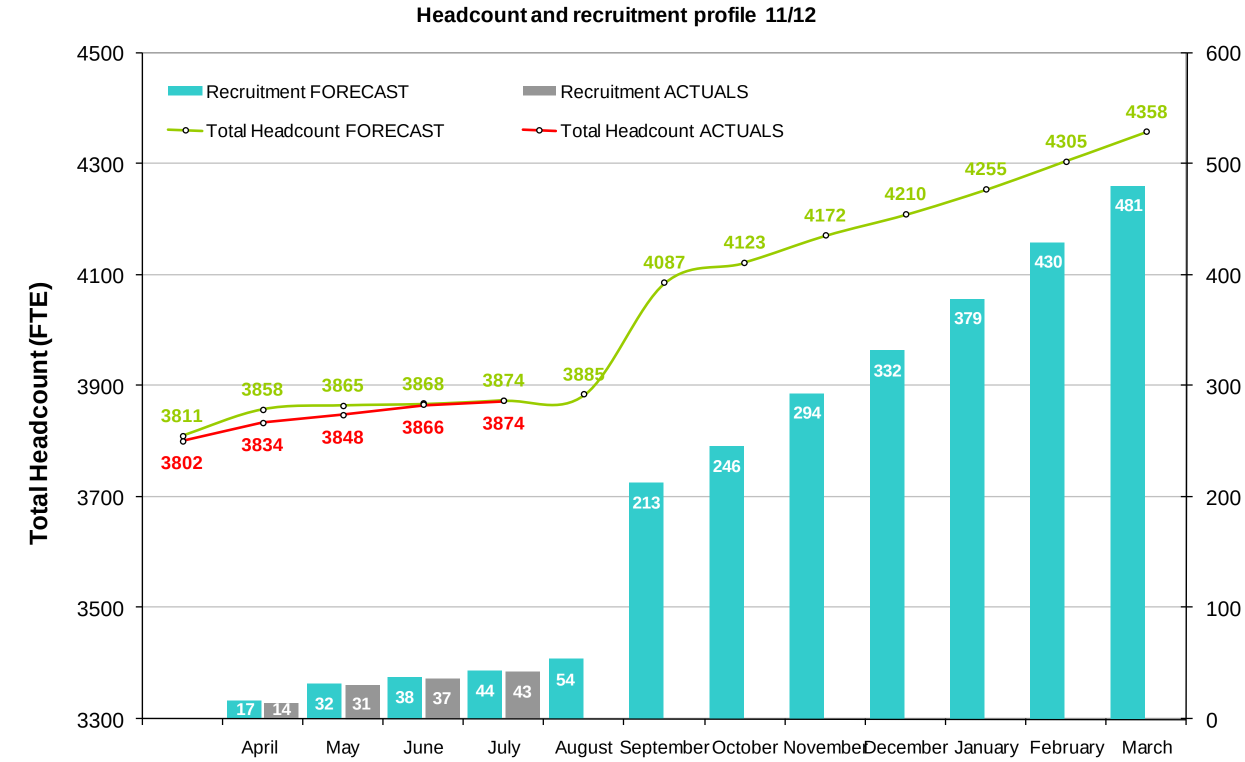
- *Managing a growing and ageing asset base* – load related investment is increasing the asset base we need to maintain and our risk and criticality asset replacement approach means that more of the asset base is ageing. We are growing our workforce to cover this increasing workload

The workforce growth in relation to delivering the capital plan will be capitalised but the other main drivers are opex in nature.[5] Delaying the recruitment in relation to this workforce growth would impact on the efficient delivery of network outputs that our stakeholders expect us to deliver over the next three years.

The recruitment in relation to workforce growth adds to that for workforce renewal (covered in the next section) to give a total forecast between 2009/10 and 2012/13 of 802 for ETO at the time of the Rollover submission. Having undertaken an update to our workforce planning since the Rollover submission this figure has now increased to reflect emerging requirements and a change in some recruitment strategies to increase development scheme intakes (more longer term in nature so require recruitment further in advance) rather than use external recruitment due to low availability in the market for these skills.

Overall in Transmission – and specifically in ETO - we are on course to deliver the recruitment requirements. We have already recruited nearly 300 FTEs in 2010/11 (making us only 25 FTEs short of our end of year headcount target across Transmission) and are on track to recruit nearly 500 more in 2011/12. By the end of September 2011 we will have 213 recruitments in place as these are already on offer. This and the projected recruitment for the remainder of the year is shown by the graph below:

[5] There are further areas which were included in the opex trace tables for rollover and are included more detail in the workforce growth and renewal summary



At the time of Rollover submission we were forecasting 256 recruitments in 2011/12[6] so we are already at 83% of this level with six months of the year to go. This demonstrates we can both deliver the recruitment outlined in our rollover submission and are already undertaking some of the expenditure proposed for 2012/13 at our shareholders' expense due to the necessary nature of the expenditure.

Recognising that we can give more evidence to prove the need for workforce growth and renewal costs we have produced a summary of the requirements and evidence in this area. This summary covers detail for all four forms of control within Transmission (ETO, GTO, ESO and GSO) and is sent separately to this document. Within this document we explain each of the drivers for the workload growth and we outline case studies on the key field force roles in ETO of commissioning engineer, field technician/engineer and craftsperson which cover the majority of the growth and renewal requirements. Amongst other items these case studies outline how we have translated workload levels into resource requirements to give more evidence for the need for workforce growth.

As outlined above £4.2m of the cost increase in this area is forecast to be avoided by delivering efficiencies embedded within the plan. This enables us to minimise the workforce growth and hence the cost. The initial proposals only fund half of the cost increase in this area so only half of the avoided cost is funded. To remedy this inconsistency the allowances should be increased by £2m either by removing the efficiency or funding the related cost.

[6] We are now targeting nearly 500 recruits in 2011/12 as outlined in our RIIO-T1 submission versus the 256 at rollover submission time due to the output from the latest update to workforce planning

Recruitment and training

	Rollover £m	RIIO-T1 £m	Initial proposals £m
Gross increase	11.0	13.0	5.5

The cost increase in this area includes costs of recruitment and training to offset forecast attrition and retirements between 2009/10 to 2012/13 and over the longer term through use of our development schemes. Over the TPCR4 period the issues in this area including low availability of skilled resources and high levels of demand have become more apparent with attrition levels increasing as industry companies compete for specialist skills.

Our modelling illustrates that between 2009/10 and 2012/13 we need to recruit 280 people across ETO just to stay at the same level of resources. When the recruitment to fill our development schemes is included (to offset post 2012/13 projected attrition and retirements) workforce renewal recruitment accounts for 63% of the total recruitment forecast between 2009/10 and 2012/13:

Recruitment driver	Recruitment	% of recruitment
Workforce growth	296	37%
Workforce renewal	506	63%
Total	**802**	**100%**

This means that the current proposals of only allowing half of the expenditure for workforce growth and renewal in 2012/13 would not enable us to remain at the level of employees we have in place today.

Within this modelling we have assumed that:

- Attrition levels remain at the levels we have experienced historically of under 3% per annum
- Retirements occur at the age levels outlined in the relevant pension schemes which has been the practice historically - this equates to approximately 2% per annum

This totals less than 5% leavers per annum which is below Chartered Institute of Professional Development (CIPD) benchmarks of over 10% average in the UK. It is also at a similar level to assumptions used in the Electricity Distribution modelling for DPCR5. The retirement assumption equates to an average retirement age of 62.5 which is higher or in line with other industry modelling. Both of these items mean that the level of attrition assumed in the model is lower than other similar models would use. Given the high demand for resources – not least due to the incorporation of Offshore TOs who will require similar skills to those we require and are willing to pay premiums to our pay levels for them[7] - this could prove to be low. Such an increase in attrition is not factored into our forecasts and would increase recruitment above levels in our rollover or RIIO-T1 submissions.

In order to respond to the challenges in this area we comprehensively reviewed our resourcing strategies and have increased intakes to our development schemes in order to take a long-term, sustainable approach to the problem. We are working with school children to encourage more intake into the engineering profession as a whole and are taking a wider industry role to raise the skills issue and formulate solutions. As part of this review we have worked hard to minimise the training times for people to become competent without diminishing the level of the training that they undertake.

[7] See the 'Innovation, efficiency and value for money' annex of our RIIO-T1 submission which includes evidence from HayGroup that shows the renewable sector is paying 14% premiums to our average salaries

Our strategies in the area of workforce planning have been supported by industry organisations such as the Energy and Utility Skills Sector (EU Skills) and the Royal Academy of Engineering.[8] Recently we initiated cross Transmission workforce modelling with the help of EU Skills and are hoping to collaborate with the Scottish TOs to understand the macro UK challenges in this area further. Output from this work is not ready in time to include in this response but data should be available in the next few months.

As with workload growth more evidence surrounding this cost driver is included within the workforce growth and renewal summary we are sending separately to this document. In order to illustrate the renewal challenge and enable Ofgem to calculate sensitivities around the attrition and retirement assumptions we have included a workforce renewal model within the document.

Asset growth and diversity

The table below summarises the upward cost pressure from our rollover submission in this area compared to the RIIO-T1 submission and initial proposals. The level of avoided cost is also shown on the table showing the link back to the efficiency analysis:

	Rollover £m	RIIO-T1 £m	Initial proposals £m
Gross increase	10.0	10.0	4.5
Less avoided cost	(3.3)	(3.3)	(3.3)
Net increase	6.7	6.7	1.2

As outlined in our submission this category is made up of several items including a growth in Post Delivery Support Agreements (PDSAs), asset painting and direct maintenance. The proposals currently do not fund the increases for direct maintenance of £2.5m and half of the asset painting equating to £3m. We therefore concentrate this response in these two areas offering more information in each area.

Direct maintenance

The section above on efficiencies shows that £1.7m of the £2.5m increase in this area is forecast to be avoided by gaining economies of scale in our maintenance approach and moving further towards a risk and criticality approach to maintenance.[9] This benefit is also linked to our proposed investments in Strategic Asset Management capabilities (SAM) (see non-operational capex section below). This means that we are only forecasting a net increase in cost between 2009/10 and 2012/13 of £0.8m. The underlying increase of £2.5m splits into two areas:

- **Unplanned (non-policy driven) substation maintenance (£2m)**: Under a risk and criticality asset replacement methodology ageing assets (which are less critical) are left on the network for longer. This gives rise to lower capex but has an impact on maintenance levels. More instances of unplanned maintenance requirements arise (i.e. work that needs to be performed outside of policy maintenance visits). This work is required to maintain reliability and safety of the assets which minimises system outages. We are assuming a 1% per annum increase in unplanned work across our substation assets. This is below the latest asset defect figures which suggest increases of 5% per annum and the TPCR4 assumed levels of 3%. We are assuming that we will be able to avoid the majority of this cost through the use of SAM and

[8] As evidenced by letters of support sent independently to Ofgem
[9] As explained further in the 'Detailed plan' annex of our RIIO-T1 submission

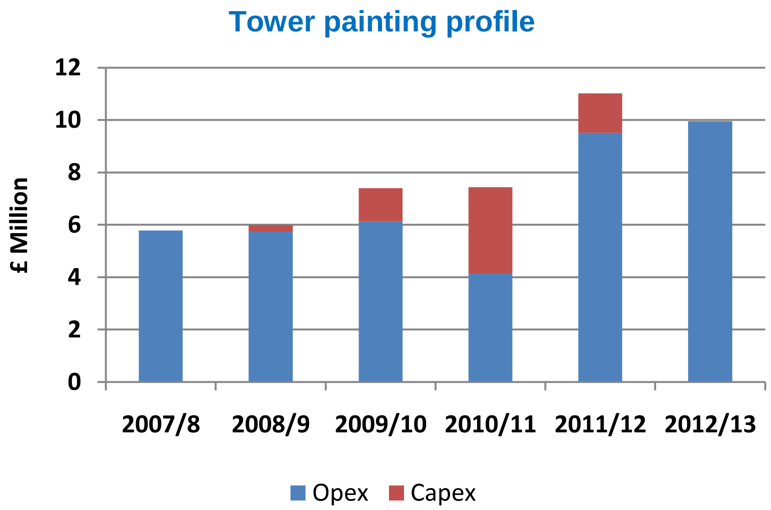
making improvements to our maintenance policies (as discussed in the 'Detailed plan' of our RIIO submission) but a small increase is forecast to remain.

- **Overhead line defect repair and condition assessment work (£0.5m)**: with the delay of some non-load related overhead line work to align with load related investments required (i.e. so we do not replace the assets twice in short succession) and to couple with our improved condition assessment programme we are forecasting an increase in overhead line defect repair work. The drivers for this are discussed further in the 'Detailed plan' of our RIIO-T1 submission but in summary this work will enable us to maintain reliability of the overhead lines, re-introduce live-line working to minimise system access (hence avoiding disruption to the Network construction programme and ensuring maintenance of reliability) and deliver future savings in our tower painting programme. As with the unplanned substation work we are forecasting to be able to offset most of this cost with efficiencies but a small increase is forecast to remain.

Asset painting

The £6.2m forecast increase in asset painting from 2009/10 (which already includes an efficiency) can be broken down into a £4.7m increase in tower painting and a £1.5m increase in plant painting. Half of this value has been allowed in the initial proposals. More detailed justifications have been provided in our response to rollover questions F15 and this has been further updated in our RIIO-T1 submissions for expenditure requirements through to 2021 (see the 'Detailed plan' annex of our submission). Rather than repeat these items in detail here we give a high level summary of the new information we included and the current status of delivery for 11/12 and 12/13 which gives us confidence regarding the deliverability of the opex increase.

From a plant painting perspective we started the programme from a near zero base in 2009/10. This work covers painting of our substation assets (such as our switchgear) to help achieve their technical asset lives. This is a new activity for the next three years as there was no previous maintenance policy. Previous painting had only been carried out in response to specific defects. This is an area where we have been innovative to develop the programme and minimise totex costs because we can delay asset replacement - without this expenditure it is likely that the assets would need asset replacement earlier than in our plan and RIIO-T1 asset replacement figures would be higher requiring more system access and potentially impacting on delivery of customer driven work. The chart below shows the delivery of actual tower painting to 2010/11 and that in delivery in 11/12 and forecast in 12/13:



We have been constrained in delivery during the early part of the TPCR4 period due to supplier issues and the impact of price rises which had not been factored into our opex allowances.[10] With the supplier issues impacting on delivery we took the decision to minimise allowance overspend in this area by taking the time to encourage more suppliers into the market and developing cost saving initiatives such as one-coat painting and improving our condition assessment techniques. These are discussed in detail in the 'Detailed plan' annex of our RIIO-T1 submission. This approach has enabled us to establish the delivery capability as well as mitigate the full cost impact of delivering the tower painting programme without creating a backlog, however a backlog would start to occur if we do not now undertake the levels we are forecasting in the next two years. Such an occurrence would result in costly early asset replacement to maintain reliability.

In the most recent tender exercise we have awarded contracts to three suppliers, increasing the supplier base from the two previous incumbents. This increase is vital not only in enhancing competition but to deliver the increased ramp up of tower painting that we need to undertake to optimise asset lives. The planned increase currently in delivery in 11/12 will incur £9.3m in opex and £1.6m in capex a total of £10.9m overall. The plan is established and the outages being confirmed that will deliver the required volumes in 12/13. We are therefore confident of delivery.

In addition as outlined in the RIIO-T1 submission we now have a more holistic programme than previously considering condition assessment and the links to overhead line defect work. We are an active participant in the International Transmission Operations and Maintenance Study, (ITOMS) benchmarking group. Through a specific working group focussing on tower painting we have had the opportunity to learn and share best practice with other TOs. Other leading companies within ITOMS adopt a similar maintenance policy to ourselves and look to maximise the life of assets through painting individual towers every 15 to 20 years. One of the main learning points however from this exercise was the importance of comprehensive condition assessment. This is required to help determine the timing and prioritisation of the painting programme. The recognition of this is part of the reason why we intend to increase the amount of condition monitoring of overhead line assets going forward (see direct maintenance above). With better condition data and a deeper understanding of the condition of the network, we can be more targeted in our approach to tower painting. From a cost perspective the ITOMS study indicated that our costs per square meter painted are in line with the study average.

IT Running Costs

The table below summarises the upward cost pressure from our rollover submission in this area compared to the RIIO-T1 submission and initial proposals:

	Rollover £m	RIIO-T1 £m	Initial proposals £m
Cost increase	4.0	4.0	0.0

As outlined in the opex trace for rollover the costs forecast in this area related to a number of IT project related items. With nearly a year since submission our forecasts have changed in this area with ~£1m of forecast running cost increases from projects no longer required because the related capex work has changed but this value being replaced in the forecast by a £1m increase due to changed allocations:

[10] We raised this risk during the TPCR4 process (see above)

	RIIO-T1 £m
Optel site access charges	1.7
Opex project increase	0.3
Running costs of new / enhanced IT systems	0.6
Allocation changes	1.4
	4.0

It is important to note that overall IT opex costs are forecast to stay at a similar level between 2009/10 and 2012/13. The extra costs in this area are offset by IT transformation savings included in the efficiencies section of our opex trace. Greater details of this can be found within the detailed plan annex of our RIIO-T1 submission.

Optel site access charges (£1.7m)

Under the new managed services Operational Telecoms contract signed in 2009 there is a £1.7m pa charge in relation to gaining access to operational sites for maintenance. This charge was not required under the previous contract but following a procurement process which identified Cable and Wireless as the winner of the tender this charge is now part of the contract. This cost is more than offset by the savings delivered by the renegotiated contract which appear in the efficiencies section of our forecast. This means that the overall costs of optel reduced in 2010/11 – the upward pressure shows in this section because we had shown the net movements in our submission.

Allocation changes (£1.4m)

During our transformation programme we have reviewed the cost allocation for a number of our telecoms routes and servers which were previously allocated equally across the UK companies. We identified that several were specifically used by one area of the business and hence have changed the allocation for the RIIO-T1 plan. This allocation is more cost reflective but increases ETO costs by £1.4m between 2009/10 and 2012/13 in our RIIO-T1 submission.

Running costs of new / enhanced IT systems (£0.6m)

Changes to business capabilities and process and their enablement by providing or replacing IT systems or services normally result in a change to the opex costs of maintaining and supporting the systems. These changes include changes to network connectivity, communication routes, server and data storage capacity as well as the need for support arrangements with suppliers and developers and software licensing costs, particularly in business critical and operational areas.

Investment in new capabilities lead to an increase in support costs due to a number of factors including:

- Enhanced requirements for security and resilience
- New (additional) equipment to be operated and maintained
- New software licences
- Increased complexity following enhancement to an existing system
- Replacement of existing systems with enhanced non-functional requirements (e.g. disaster recovery)
- Increased volumes (of users or points or frequency of processing)
- Step changes as systems move from an ‘out of support’ position to being

supportable

There are circumstances when investment can reduce support costs, these include:

- Completely like for like replacement onto new technology
- The consolidation of two or more systems into a single system
- Integrating systems into modern architectures

Such reductions are included within the efficiencies section of our opex trace.

For planning purposes we make some high level assumptions about the change in support costs associated with each investment, these are then refined as detailed designs are completed and systems are delivered. This is explained further in the 'Detailed plan' annex of our RIIO-T1 submission. Below we have provided the projects which drive an increase in opex:

RAMM / SAM (£0.5m) – The RAMM programme will deploy new routers and switch units to electricity substations. At the majority of these sites, this is new equipment which will then occur an additional support cost. In addition, there will be server support costs associated with collating the data centrally.

The SAM programme has recently been sanctioned. Over the coming months we will be carrying out a procurement exercise to determine the most appropriate vendor package(s) to deliver the required capabilities. At this stage we do not know exactly what we will implement, but as this will be a new system for which the infrastructure does not currently exist, we will incur additional support costs for the maintenance of new servers and data storage along with licence fees for new software.

Integrating the Alliances (£0.1m) – Greater costs arise from a sustained increase in system footprint and capability. The system will increase from supporting 20 users to around 250 users and will contain additional functionality. Opex costs will therefore come from increases in software licence support costs and hardware system support costs coupled with the creation of a disaster recovery capability.

Opex project increase (£0.3m)

The number of IT opex projects that we plan to undertake are increasing in the rollover year. Opex projects relate to costs incurred on development of IT systems which do not meet capitalisation rules either because the project does not result in a tangible asset (e.g. research), the nature of the costs or because the value is below the £100k threshold for capitalisation of software enhancements.

Within ETO IT opex costs have increased by £0.1m due to strategic research and development. As the UK energy market enters a period of unprecedented change we need to develop new capabilities and the IT systems to support them whilst simultaneously making best use of new technologies. Within IT this expenditure will be focussed on;

- Understanding how new and emerging technology can help us meet the challenges ahead
- Understanding how other organisations have responded to similar challenges
- Understanding best practice in developing IT systems as used by other organisations and how this can be applied to National Grid

The remaining £0.2m increase in IT opex is due to enhanced security spend. Our exposure to security threats is increasing as advised by governmental bodies. In response we have carried out external benchmarking with Deloitte and Gartner which has provided key inputs to the development of our digital risk and security strategy. From this we have developed a prioritised programme of works including tactical and strategic initiatives. The tactical initiatives are generally opex investments due to their short term nature.

Volume, mix and other

	Rollover £m	RIIO-T1 £m	Initial proposals £m
Cost increase	6.2	9.8	2.3

For illustrative purposes for our upward cost pressures we combined a number of smaller items together into this category. These totalled £6.6m and can be further broken down into the following activities. Discussions surrounding our work in relation to the London Olympics have progressed since the Rollover submission and are being considered elsewhere therefore we are not going to cover this cost increase here. With full funding for the increased regulatory workload we do not discuss this further either. Below we take the other forecasted increases in turn to give new information and further justification:

Driver	Forecast £m	Initial proposals £m
Environmental liabilities	2.0	-
Increased regulatory workload	1.1	1.1
Olympics	0.7	-
Insurance increases	0.6	-
Other	1.8	1.2

Environmental provisions (£2.0m)

Many of our operational sites including substations and cable sealing end buildings, have been built on brown field sites that had previous uses such as landfills, power stations and gas works. Many of these sites were transferred to us on vesting and we now carry considerable environmental liabilities.

These liabilities arise mainly from two pieces of legislation:

- Part IIA of the Environmental protection act (1990) and
- Water Resources Act (1991): Pollution of controlled waters

As discussed in the rollover submission to fulfil these obligations we have made a £66.2m provision in 2010/11 to cover the costs for the next 50 years. In adhering to these legislations we have forecast utilising £2m of this provision within the rollover year, without which we would be adversely impacting on the environment surrounding our sites and liable to fines under the above legislation. In addition we are undertaking work in 2011/12 on this programme of monitoring and clear up spending £3m in the year. Undertaking a one-year break in the work schedule would increase the cost in 2013/14 (by at least £1m) because we would have to re-establish monitoring at each site.

Insurance increases (£0.6m)

Insurance cover for both our NGET and NGG businesses is provided for by our own group captive companies. A captive insurance company is an insurance company which insures risks of the business, which are related to it through common ownership.

In our rollover response, ETO insurance costs are approximately £0.6m higher due to changes to our cost drivers. These increases are predominately driven by changes in our risk profile against a backdrop of asset investment and growth, volume mix and the current political and financial climate.

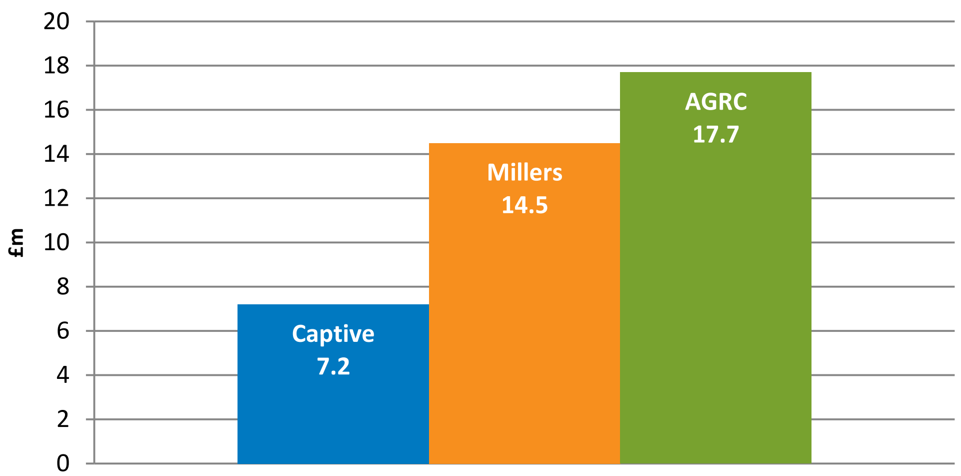
In order to ensure that our captive costs are assessed and challenged for efficiency we compare them against the premiums that would otherwise be charged by commercial insurance companies/market. In addition to allowing demonstration of financial efficiency these reviews also allow us to deliver the key benefits of operating a captive insurance company.

Within the insurance market there is no definitive benchmarking or index linked comparative study – as levels of cover, premiums, appetite for risk and niche coverage constraints will differ from one provider to the next, therefore market testing represents the best proxy to assess the relative efficiency of the premiums charged by the group captive companies.

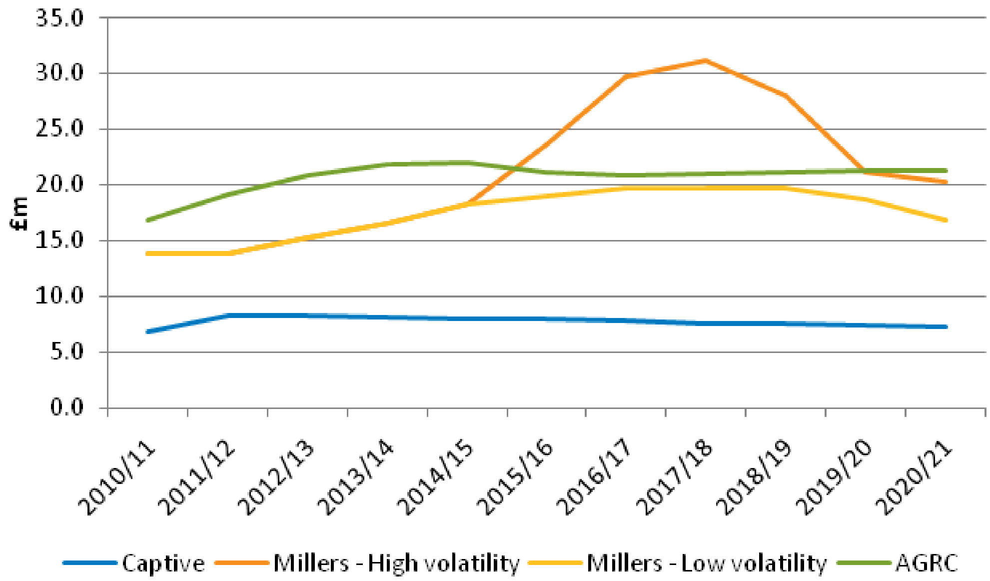
In order to conduct comprehensive market testing we appointed both Aon Global Risk Consulting (AGRC) and Millers Insurance Services Ltd (Millers). The scope of their work was to replicate our insurance cover as of March 2011 against external brokers, whilst estimating premiums with no captive element and provide future projections of costs.

The graph below compares our captive and consultant costs for 2010/11.

2010/11 insurance cover forecasts



This graph shows that our premiums charged by the captive for 2010/11 are below those commercial markets are able to offer. In addition, the captive is able to provide a broader range of cover than the commercial markets have been able to provide. In addition the graph below shows that our future forecasts are below those forecast by Millers and AGRC:



This shows that our insurance costs and forecasts are efficient. Increases to our asset base and external risks that are out with our control are driving up premiums.

Other (£1.8m)

The single largest driver of increased opex costs in this area arises from our Construction directorate. At the peak of our capital programme we will be investing more than twice our current annual spend in expanding and replacing the existing system. In order to manage this process and deliver the capex efficiencies that we have embedded within our Rollover and RIIO-T1 submissions there will be an increase in opex to manage this increase in workload. This focuses around the enhancement of the business planning and compliance teams within the construction directorate which will help optimise the efficiency of our construction activities and maximise best practice between the alliances. With a growth in capex it is important that we maintain compliance with safety legislation and regulatory guidance – an inherently opex activity which grows with the capital plan. Further opex arises from the increase in regulatory burden within the directorate in preparation of our rollover and RIIO submissions which temporarily increase opex costs up to 2012/13.

GTO controllable opex

This section gives more evidence and justification for the upward cost drivers for controllable opex between 2009/10 and 2012/13 in the GTO form of control. As with ETO the year since our rollover submission in October 2010 offers more information available to us now allowing us to give more justification for the cost increases. In addition our RIIO-T1 submission provides more detail than was included in the Rollover submission in many of the areas due to our proportionate approach to the Rollover. Where this is the case we point back to where the relevant evidence is included in our narrative.

Given the time since Rollover submission there have been some changes to our opex forecasts for 2012/13. This has occurred in two main areas: real pay and workforce renewal and growth. These changes were incorporated into our RIIO-T1 submission. As discussed in the ETO section following agreement of a three year pay deal with the trade unions pay levels are now forecast to be in line with RPI between 2009/10 and 2012/13. The related cost increase which was included in our rollover submission was therefore not included in our RIIO-T1 submission and we agree with the initial proposals' view that there will be no above

RPI increase in this area. We therefore do not cover the RPE cost increases any further in this document because the Ofgem's allowances include funding for the other areas of RPE. In relation to workforce renewal and growth the updated workforce planning work has identified that some workforce growth is now required up to 2012/13. We have therefore increased the recruitment targets in 2011/12 in the RIIO-T1 submission. We recognise that we will not be funded for the £2m extra opex cost of this in 2012/13 but given it is necessary for delivering stakeholder requirements in the RIIO-T1 period we will continue to invest in our workforce at this level.

	Rollover submission £m	RIIO-T1 submission £m	Difference £m		Initial proposals £m
2009/10 opex	61.0	61.0	-		61.0
Less one-off costs	(2.0)	(2.0)	-		(2.0)
Recurring opex	**59.0**	**59.0**	**-**		**59.0**
Efficiency savings	(5.0)	(5.0)	-		(5.0)
Workforce renewal and growth	3.0	5.0	2.0		1.5
Asset growth and diversity	1.4	1.4	-		0.6
Real price effects	5.0	2.9	(2.1)		2.9
Volume and mix and IT	3.0	2.0	(1.0)		-
Gas Technical Drawings	4.0	4.0	-		-
Supply and demand volatility	1.0	1.0	-		-
Other	-	-	-		(0.6)
Total workload	**17.4**	**16.5****	**(1.1)**		**4.4**
Forecast / allowance	**71.4**	**70.5**	**(1.1)**		**58.4**

****** The apparent discrepancy between the summation of the upward cost pressures and £16.5m in our RIIO submission are due to rounding differences

Efficiency levels

As stated in the summary section above the efficiencies we embedded into our Rollover submission – which have in turn been included in the initial proposals allowances – total 2.7% per annum and include £1.3m of catch up efficiency and £0.3m of avoided cost efficiency with the overall split being as per the table below:

Efficiency type	GTO £m
Avoided cost	0.3
Catch up	1.3
Underlying	3.9
Total	**5.5**

The avoided cost efficiencies of £0.3m are linked to upward cost drivers which were included in our trace and relate to anticipated organisational savings and therefore offset some of the cost within the workforce renewal and growth category of upward pressure. Only half of our forecast in this area has been allowed so we assume only half of the avoided cost has been allowed too meaning that £0.2m of cost that does not exist has been removed. For accuracy this value should be added to our allowances.

Workforce renewal and growth

	Rollover £m	RIIO-T1 £m	Initial proposals £m
Gross increase	3.0	5.0	1.5
Less avoided cost	(0.3)	(0.3)	(0.3)
Net increase	2.7	4.7	1.2

Unlike ETO our forecasts for GTO in relation to workforce renewal do not contain any workforce growth related items. All the cost relates to workforce renewal. Subsequent to the rollover submission we have identified a need to increase our GTO workforce in relation to increased requirement for network modelling and this has been factored into our RIIO-T1 submission. This is the reason for the extra cost forecast between rollover and RIIO-T1 above.

The recruitment for workforce renewal for GTO is forecast to be 86 between 2009/10 and 2012/13 just to stay at the same level of resources. This includes increasing intakes to our development schemes by 22 over the period. As outlined above in the ETO section we are on course to deliver the recruitment requirements. The assumptions behind these figures – for attrition and retirement – and the related evidence are the same as those in ETO so are not repeated.

As discussed in the ETO section recognising that we can give more evidence to prove the need for workforce growth and renewal costs we have produced a summary of the requirements and evidence in this area. Within the document we outline a case study on the field force technician role. Amongst other items this case study outlines how we have translated the forecast workload levels into resources requirement.

As outlined above £0.3m of the cost increase in this area is forecast to be avoided by delivering efficiencies embedded within the plan. The initial proposals include all the efficiency but not the related cost. To remedy this inconsistency the allowances should be increased either by removing the efficiency or funding the related cost.

Asset growth and diversity

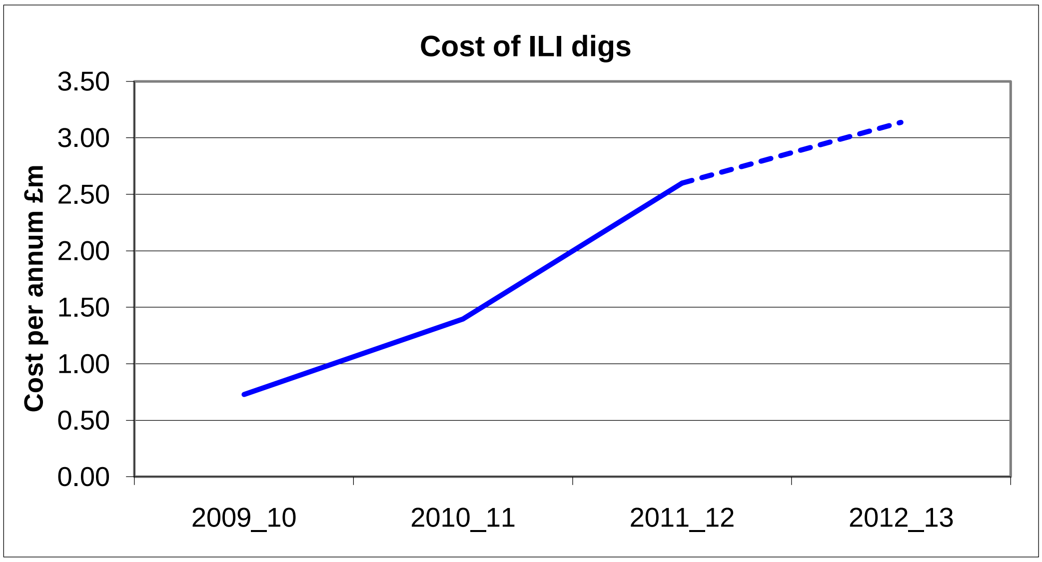
	Rollover £m	RIIO-T1 £m	Initial proposals £m
Cost increase	1.4	1.4	0.6

The increase in costs in this area relates to:

- Contractor costs (£0.8m)
- Maintaining a growing asset base (£0.7m)

Contractor costs (£0.8m)

Contractor costs represent £0.8m of the increase from 09/10 actuals in our Rollover submission, which is predominantly driven by the requirement to complete more physical digs to maintain the condition of our pipelines following identification of corrosion defects by inline inspections (ILIs) – as our assets age, corrosion will inevitably become more prevalent. Latest information strongly suggests an increasing trend of defects (as can be seen from the graph below) above our original Rollover assumptions. At an average cost of £90k per dig, this represents an increase of £2.4m by 2012/13 from 2009/12 levels.



Asset growth (£0.7m)

Increasing volumes of assets place upward pressure on costs and between 2009/10 and 2012/13 the increases are forecast to relate to:

- Additional resources required to maintain new electric variable speed drive (VSD) compressor units. By 2012/13 we will require additional resource at operational VSD sites (£0.4m p.a.)
- Small consumable costs (Other Materials Goods and Services (OMGS)) attributable to Felindre, Wormington, Churchover, St Fergus and Kirriemuir operational sites (£0.2m p.a)
- Post Delivery Support Agreements (PDSAs) which are based upon awarded contract costs for Wormington and Churchover for the new VSDs (£0.1m p.a.)
- Maintenance costs associated with new enhanced gas quality metering equipment at nine sites (£0.1m p.a.)
- The growth of our asset register will attract an increase in insurance premiums (£0.1m)

Cost increases in this area are based on the average costs for similar assets and are gross of efficiencies we are making in the maintenance cost area. The costs we are using for these increases are in line with the costs that benchmark as the top in Europe within the Juran Gas Transmission Benchmarking Initiative (GTBI) study.

Volume, Mix and IT costs

	Rollover £m	RIIO-T1 £m	Initial proposals £m
Gross increase	3.0	2.0	-

The table below gives the detail by driver for the costs in this area. Note that since the rollover forecast IT costs have reduced following changes to the IT project programme reflected in the RIIO-T1 submission:

Cost driver	RIIO-T1 £m
IT projects	0.9
Regulatory workload	0.3
EU impacts	0.4
Insurance	0.2
Property costs	0.2
Total	**2.0**

In response to Ofgem's request for more justification for each of these items the sections below give more evidence for the driver and need for the opex increases in each area:

IT projects (£0.9m)

As described above for ETO IT costs, we are incurring incremental IT opex costs for enhancing the security of our systems. Within GTO this accounts for a £0.1m increase in costs. The plan also includes a further £0.2m increase for the Data model opex project.

Gas transmission assets are currently managed at a 'system' level (e.g. compressor station) in the asset and work management systems. This limits the potential to apply advanced asset management techniques at an asset level. This project will increase the granularity of the data from system to asset level in preparation for the Strategic Asset Management (SAM) programme.

Running costs of new / enhanced IT systems

The single largest increase in running costs of IT systems is from the continuing implementation of our RAMM / SAM capability.

RAMM & SAM (£0.2m) – The RAMM programme will deploy new routers and switch units to compressor sites and above ground installations (AGIs). This deployment is currently ongoing and therefore we are able to provide a detailed breakdown of the future support costs. At the majority of these sites, this is new equipment which will then incur an additional support cost. In addition, there will be server support costs associated with collating the data centrally.

The SAM programme has recently been sanctioned. Over the coming months we will be carrying out a procurement exercise to determine the most appropriate vendor package(s) to deliver the required capabilities. At this stage we do not know exactly what we will implement, but as this will be a new system for which the infrastructure does not currently exist, we will incur additional support costs for the maintenance of new servers and data storage along with licence fees for new software.

Regulatory workload (£0.3m)

Rollover and RIIO-T1 submissions have required an increase in our workload in GTO, similar to those already funded by the initial proposals in ETO. This cost covers the people required to write and complete the submissions. These people are already in place and we are already incurring this cost.

EU impacts (£0.4m)

Within this category we have included cost increases associated with enhanced European involvement. Over the next ten years there will be a radical change in the European gas market, which will have a long term impact on the UK. We are facing increasing challenges from Europe, including compliance with new EU legislation, the resourcing of European organisations and the commitment to provide accurate up to date information. Much of this activity is driven by the European Third Energy Package, which has led to the creation of the European Network of Transmission System Operators for Gas (ENTSOG).

The specific cost increases in this area relate to the GTO allocation of membership fees for ENTSOG and resource required to support this forum. ENTSOG was set up in 2010/11 and the UK's fees for this (charged to ourselves) are £0.4m. Half of this relates to GTO activity and we are already incurring these costs. To enable this forum to run efficiently it requires input from each of the European TSOs. As this is a new activity this means more resource is required to attend meetings and help develop future European codes which will harmonise European energy policy. We are forecasting an extra £0.2m of opex to resource this level of activity – resource that is already in place in our Commercial department.

The European Third Package[11] states that 'costs related to the activities of ENTSOG….shall be borne by the transmission system operators and shall be taken into account in the calculation of tariffs.' We therefore expect recovery of all efficiently incurred costs associated with this work and its consequential impacts.

Insurance (£0.2m)

Insurance increases for GTO are driven by the insurance market forecasts which are detailed in the ETO section above. The ETO section illustrates how our insurance costs are already lower than third party benchmarks and our forecast increases are lower than independent market projections. Whilst this is an increase in opex it is lower than it would be if we used third party providers and enables us to remain at the same risk level.

Property costs (£0.2m)

This increase relates to the growing costs of running our property sites. In spite of forecast delivery of savings from our workplace sharing project (see non-operational capex) repairs and maintenance contract costs are increasing. As outlined in the 'Innovation, efficiency and value for money' annex of our RIIO-T1 submission property costs – despite this increase – are below benchmarks within the Total Office Cost Survey.

Gas drawings

	Rollover £m	RIIO-T1 £m	Initial proposals £m
Gross increase	4.0	4.0	-

[11] In Article 11 of the Gas Regulation EU 715/2009

This investment, in the rollover period, will complete the final phase of an existing programme of work which started in 2009, aimed at enhancing our gas drawings reference base, thus ensuring we remain vigilant in our approach to process safety.

This investment addresses the challenges we have faced in recovery of drawings from previous capital schemes. The schemes did create the majority of drawings, but at closure, some remained outstanding due to various technical challenges in producing these types of records. If we had extended scheme timelines to complete these deliverables, we would have increased original scheme costs. We recognise the need to ensure that all drawings are compliant with policy and to have a complete set of records consistent with our obligations. We therefore need to continue to recover remaining drawings, but accounting rules require us to classify this as Opex. In effect, the avoided increase in previous capital capex costs in previous years is now being spent as Opex, i.e. the total spend is equivalent. This activity will help safeguard against unsolicited incidents, directly supporting our drive for safe and reliable operations.

There will be no future planned spend on major drawings enhancements after 2013/14, except in normal response to new capital schemes, maintenance activity or change in requirements (e.g. as a result of legislation, change in standards etc).

If funds were not available in the rollover period, we would be unable to complete the programme and leave some drawings outstanding. We adopted a phased, risk based approach centred on drawings type (not site type). Partial completion of the programme will create inconsistency within suites of records for individual sites, and introduce a level of additional risk with no planned mitigation.

Additional benefits of this programme include
a) mitigation of risk associated with any potential missing or inaccurate drawings and
b) alignment of drawings with maturing drawings requirements e.g. updated safety integrity level (SIL) and hazardous area classifications, and
c) direct support for our drive to improve our process safety capability

Supply and Demand Volatility

	Rollover £m	RIIO-T1 £m	Initial proposals £m
Gross increase	1.0	1.0	-

Connection activity is increasing on the NTS, as evidenced by the number of enquiries we have today; based upon our market intelligence we expect an increase in the number of new Combined Cycle Gas Turbine (CCGT) and storage enquiries as decarbonisation (specifically wind penetration) of the electricity market increases in line with Government policy. This increased activity drives increased cost for pre-feasibility works.

A direct effect of the increase in both connections and the current (and expected future) supply and demand diversity, is an increase in the complexity of modelling the network. A greater number of nodes[12] on the network increase the interactions between nodes; greater supply and demand diversity increases the number of scenarios which need to be analysed. This is further exacerbated by the introduction of the Planning Act (2008) which requires significantly more in-depth analysis on a greater number of project options than has previously been necessary. Whilst we are actively seeking efficiencies through improved analysis tools, this increase in complexity is leading to a requirement for a greater volume of analysis for the majority of projects.

[12] In this instance the term 'node' is used to describe discrete entry and exit points on the network

Whilst some of these connection enquiries will result in a capitalised asset, it is true that many will not. It is not possible to predict in advance specific projects that will fall into this category however, examples of current or recent projects where this may be the case include:

- South East quadrant – we have received a number of CCGT and storage connection enquiries for this area of the network, all of which interact with each other. Whilst we are developing plans for different combinations of these projects, we do not believe that all will progress. Those that do not lead to a capitalised asset will lead to some costs being expensed.

- GDN flexibility – a large amount of analyst effort was required to assess necessary investments to satisfy the increasing flexibility needs of GDNs as they evolve their gas holder strategies. It is unlikely this work could be capitalised, therefore will contribute to opex.

- Development and progression of alternative options to provision of Operating Margins and Constrained LNG at Avonmouth – following the decline of commercial interest in storage services at the Avonmouth LNG plant, we are considering alternative options to sustaining the site. For those options not chosen, the costs involved will be expensed.

Coupled with the above, the revised planning timescales introduced by the Planning Act strongly incentivises us to progress ahead of a formal customer signal for incremental capacity to minimise the risk of not providing the required capacity in line with our obligated lead times set out in the Licence. This requires us to incur operational spend regardless of whether a bilateral agreement is in place. Where this occurs and the customer does not progress the enquiry to completion, the costs incurred for any work undertaken cannot be capitalised and therefore contribute to opex. Whilst we only undertake these works where our commercial intelligence indicates an increased likelihood of these projects proceeding, inevitably we will not always be successful in this assessment, if for no other reason than customer's own assessment and prioritisation of their projects change over time in response to prevailing market conditions. In our submission £0.7m is attributable to the additional preliminary works and early pre-application consultation activities which we would need to treat as opex in this manner.

We are progressing a potential change to the connection and capacity process which would reduce the risk of such expensed costs, however this will not be in place for 2012/13.

The initial proposals suggest that this cost is linked to the Network flexibility investment and costs in this area have been disallowed on this basis. This is a mistaken belief. Whilst this cost relates to network modelling it does not link to the investments forecast for Network flexibility, rather the level of connections we are experiencing.

Non operational capex

The initial proposals reduce our non-operational capex forecasts focusing on:

- **Main schemes:** Concerns regarding whether expenditure on three projects – RAMM / SAM, Front office replacement and HPMIS – will actually be incurred in 2012/13
- **Deliverability:** Questions regarding deliverability of the increase in expenditure we are forecasting
- **Historical levels:** Requirement for more justification for the increase from historical levels in non-operational capex

We therefore focus our response on these three areas offering more evidence for the justification and deliverability of the projects and the programme overall. Since the rollover submission more of our projects have been taken through formal sanction and in the case of our condition monitoring work in RAMM / SAM we included more justification for the benefits of the projects within our RIIO-T1 submission. We will refer to these items within the text below.

Main schemes

Since the rollover submission the three main projects that have been disallowed (RAMM / SAM, Transmission Front Office replacement (TFO) and HPMIS) have progressed through the formal sanctioning process. Each of the overall programmes are sanctioned and we have already started spending money on their delivery. In continuing these programmes we will therefore incur expenditure in 2012/13 which is currently not funded. Any deferral of work from 2012/13 would mean we would have to stop the project in its progress and restart again post 2012/13 – an inefficient delivery approach which would increase costs for the projects overall. In the case of TFO this would leave us without an effective mobile working solution for ~ 1500 gas and electricity field workers, as our existing solution cannot be sustained beyond March 2014.

The table below gives a summary of the three schemes showing what the benefits of the schemes are and what impact deferring the project from 2012/13 would have. Further on in this response we give more detail for each scheme.

Project	Explanation	Benefits	Impact of deferral
RAMM / SAM	Programme will enhance our remote asset condition monitoring ability and give secure comms links to reduce cyber security risk	We can identify failing assets before they cause safety or reliability issues. This reduces safety risk, avoids costly clear up and unplanned outage impacts.	Project is in flight so additional costs to stop and restart. Project is reliant on access to operational sites and deliverability has been planned outside of capital work increase. Re-planning this would add time / costs to the project and have a potential impact on wider capital work
TFO	Asset health investment to maintain our front office systems which coordinate work management, scheduling and field force support	Sustaining long running efficiency benefits of ~£7m pa. Refresh of systems that are over five years old	Project is in flight so additional costs to stop and restart. OiTH (main investment in 2012/13) needs replacing by 2014 as support will be removed and deferral would not give time for this to occur. Any service failure leading to non-availability of the OiTH system is estimated to result in additional costs of £550k per month and will lead to an increased risk of reliability and safety related incidents.
HPMIS	Asset health investment of system which meters gas flows for transportation charges and supports gas quality compliance	Hardware refresh of system that is exhibiting signs of failure and whose hardware will become unsupportable by 2013	Project is in flight - there will be additional costs to stop and then re-start. Needs to align with Gas Distribution investment plan so impact would be further than just Transmission. Leads to higher support costs.

More detail on the constituent items within these overall programmes is in the attached excel file:

[FILE DELETED]

Supplementing this table we will send a summary of all the forecast schemes in 2012/13, reconciling each scheme between Rollover and RIIO-T1 submission in accordance with the request from Ofgem. At the same time we will attach the sanction papers for these projects.

Deliverability

There are three main areas of non-operational capex which are:

- IT investments
- Property
- Fleet

Each of these areas are mutually exclusive from a deliverability perspective because different resources are required to deliver each efficiently. In many cases the resources required are external to National Grid meaning we can gain access to wider resource levels which gives us confidence we can deliver the workloads.

From an IT perspective we included several pieces of evidence for deliverability within our response to PPA Energy's report in June 2011. These included how our IT organisation allows us to draw on IBM and Wipro resource to deliver projects and how our governance process challenges project managers to ensure deliverability. These items are not repeated here but can be found in more detail in the report. Whilst the response related to SO capex the points are equally valid in non-operational capex because our IT department and governance covers both areas of expenditure. In addition internal resource is required for user specification of the IT systems. These resources are factored into our workforce renewal and growth forecasts covered elsewhere in this document.

For a number of specific categories of expenditure within our non operational capex forecasts a 25% reduction has been made to cover potential achievable efficiencies and deliverability concerns. The above – and more detail by project below – aims to prove that we can deliver the projects we are forecasting. From an efficiency perspective it is worth noting that the 25% reduction is on top of the 10% efficiency for IT transformation we have already embedded into our forecasts and is within the allowances. This would require a 35% reduction in costs – a seemingly unreasonable level of savings to be made.

Historical levels

The initial proposals infer that non-operational capex for 2012/13 should be kept at levels closer to historical averages. This suggests that non-operational capex is being considered as opex, rather than – as it is – capex in nature. Costs may be funded like opex but the 2012/13 projects are based on both asset refresh of existing IT assets and new capabilities that will help deliver and minimise the capital requirements of the future. This means that assessment of the expenditure should be made on a specific project by project basis.

There is a cyclical nature to this expenditure which means that it will not be a similar value each year. For example having invested in our Transmission Front Office (TFO) systems between 2003 and 2005 we embedded ~£7m per annum savings from our Staying Ahead and Ways of Working reorganisations. To ensure that these costs are not required again we need to maintain the Front Office capability. This is the single largest system in our portfolio but we will not need to spend money every year to maintain the capability. Instead the hardware requires refreshing approximately every five years (with the project taking typically two to three years) meaning that increases in investment requirements occur when these refreshes take place. This drives a cyclical profile for the investment and with the refresh of Office in the Hand (OiTH – part of our TFO systems) required in 2012/13 the year is one with cyclically high expenditure not in line with historical forecasts:

The following provides further details and justification for the major areas of expenditure for both ETO and GTO. As several of the major IT applications that are used are common across the two forms of control to best harness synergies, these are discussed together in the ETO section with the GTO section referring back where appropriate.

ETO

	Rollover submission £m	Initial proposals £m
Property	5.9	4.4
Integrating the alliances	2.0	1.5
RAMM / SAM	2.4	0.2
Front Office Replacement	2.6	0.0
Other	10.0	7.5
Forecast / allowance	**22.9**	**13.6**

Property (£5.9m)

This category of spend is increasing principally due to the increasing size of our workforce. As the number of staff increases we need to maximise the value of our existing properties and provide suitable facilities to train our staff in. This gives rise to investment in:

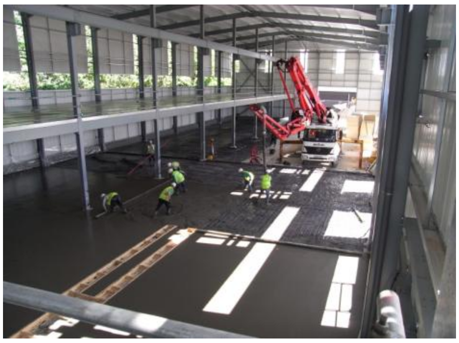
- Our Eakring training facility to increase accommodation to enable more throughput of trainees (linked to the workforce growth and renewal items discussed above)
- Workplace sharing which increases the capacity of our buildings and delivers future savings through not requiring to extend our property footprint and reducing the number of properties instead

Reduction in this investment would increase opex in 2012/13 and future years either through reducing future efficiencies these investments enable or requiring us to use external accommodation for our trainees. The savings (or avoided costs) from these investments total ~£3m per annum which are embedded into our opex forecasts for rollover and the RIIO-T1 period.

Eakring (£5m)

At Eakring, we are in the final stages of expanding the site with the construction of a new training workshop and indoor switchgear bay. This will open in September 2011 in preparation for use by the next intake of apprentices and foundation engineers. We are investing in this at our shareholder's expense.

Whilst this enhances our training capacity we also need to increase the accommodation capacity at Eakring. As a consequence a scheme was sanctioned in March 2011 to construct further onsite accommodation. Construction is expected to begin in April 2012 and when completed will add a further 48 rooms. As we are already performing the improvements on the workshop there is no question regarding delivering this scheme – the picture below shows the progress we made in just a couple of months on the workshop:



In evaluating the options for constructing further onsite accommodation at Eakring the projected increase in training demand has been calculated. This is shown below.

Eakring Training Centre – Delivered Hours	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Eakring Trainee hrs Delivered/Forecast	365,717	356,972	363,148	359,005	356,755	355,931	356,049	344,446	279,111
Assume 80% Residential*	292,574	285,578	290,518	287,204	285,404	284,745	284,839	275,557	223,289
Total "bed-nights" required assuming 8 hour days and 4 nights per week	29,257	28,558	29,052	28,720	28,540	28,474	28,484	27,556	22,329
Total "bed-nights" currently available	10,560	10,560	10,560	10,560	10,560	10,560	10,560	10,560	10,560
Total "bed-nights" shortfall	18,697	17,998	18,492	18,160	17,980	17,914	17,924	16,996	11,769
Total bedrooms required to meet 100% of demand	166	162	165	163	162	162	162	157	127
Proposed total room numbers	60	60	108	108	108	108	108	108	108

In the six months between April 2010 and the end of September, we had to provide 2,751 bed nights of accommodation off site. The incremental cost to training in having to do this was £0.3m. As detailed in the workforce renewal and growth section of opex the level of trainees is growing over the next few years. If we did not undertake the extension to accommodation, with the increase in training requirements we would have to spend £2.2m per annum extra opex on offsite accommodation. This investment therefore pays back in less than three years.

Deferral of the investment would increase opex in 2012/13 by the £2.2m extra costs of external accommodation.

Workplace sharing (£1m)

As the size of our workforce increases to meet the challenges of the next decade we aim to maximise the usage of our existing office space and rationalise where possible. To this end we ran a successful innovative pilot scheme in our Warwick office for our smart work scheme. This provides a new, modern and flexible work environment that supports collaboration and helps teams share knowledge. Space is divided into quiet work areas and formal and informal meeting areas and with the use of 'hot desks' we can reduce the amount of space needed per person. Through this project we will be able to increase the amount of capacity to base staff out of Warwick from 1825 to 2433 people.

The smart work place also provides a number of environmental benefits. We have reduced energy demand by 16% in the pilot floor compared to our more traditional work areas and we have reused or recycled 94% of materials generated by the latest refurbishment. We have achieved Ska accreditation for the latest roll out of the smart work space concept which is an environmental labelling method designed to rate and compare the environmental performance of fit out projects for office buildings in the UK.

Following from the success of the pilot scheme we have fully sanctioned the rolling out of this concept to the whole of Warwick allowing us to increase the intensity of our property floor space. To continue this transformation we will invest £1m for NGET which will deliver £1m per annum property savings. Deferring or reducing the investment would reduce the related efficiency.

RAMM / SAM (£2.4m)

Strategic Asset Management (SAM) is a core component of our SMARTer approach to the management of network assets to meet the challenges of; changes to energy sourcing and demand patterns, ageing assets, and increasing investment volumes. These deliverables benefit both NGET and NGG – for detail on NGG's benefits from Remote Asset Monitoring and Management (RAMM)/SAM, please see GTO section below. The condition assessment and monitoring delivered by the SAM programme is essential to the delivery of our RIIO-T1 investment strategy and supports our move towards risk and criticality. These capabilities are required by 2013 to shape our investment profile and manage the resultant risk and reliability benefits for our customers.

The SAM programme is now fully sanctioned and we are incurring expenditure on this project now in order to achieve benefits as soon as possible.

The SAM implementation will provide an integrated platform that will support future growth in Transmission activities, facilitating faster deployment and avoiding bespoke development of IT systems. Whilst investment in SAM is primarily policy driven, attributable benefits of ~ £13m over the RIIO-T1 period have been identified.

RAMM provides a secure and reliable communication network to electricity and gas operational sites for use by National Grid and third party service providers, enabling real-time access to remote asset data for condition and performance monitoring and fault diagnosis and remediation. RAMM is a fundamental enabler for wider SAM deliverables.

Investment in 2012/13 is forecast to:

- Continue the phased deployment of RAMM secure communications to substation sites
- Develop analytics, decision support, visualisation and reporting capabilities and migrate legacy systems onto the SAM platform
- Integrate remote monitoring data sets with existing core systems

The effective and timely deployment and use of IT systems is essential to maintaining existing capabilities and performance across the TO and is a key enabler for future capabilities required to meet the challenges of the RIIO-T1 period. The innovative SAM solution will enable higher reliability, environmental and safety outputs than would otherwise be the case through:

- Real-time, interactive management of our assets: the move towards risk and criticality for asset replacement means we need a far greater knowledge of asset condition and capability. This needs to be achieved while not exposing the systems to malicious or inadvertent cyber security attacks. This requires us to utilise technology in new assets and be innovative in ways of being able to retro-fit systems to existing assets where economically viable. An example is the recent retro-fitting of sensors to 40-year old transformers. This has enabled us to apply modern thermal modelling and determine how much enhanced capability is available.

- Dynamic network monitoring and control: to meet UK climate change targets, increasingly electricity load will need to be controlled to optimise that taken from renewable energy sources. In so doing the network is moving away from the predictable generation patterns we have been familiar with over the last 40 years. This will require more continuous automated control to manage the complex and continuous adjustments needed to manage the interactions between generation and demand.

- Leveraging greater benefit from existing processes and systems: benefits have already been achieved through adaptation of asset replacement and maintenance regimes. The move to more condition-based regimes will require optimised use of our experts by removing the time spent manually sourcing and manipulating data from a vast number of sources. SAM will integrate and automate processes allowing engineers and operators to make informed decisions without this additional work. The SAM process also provides a platform that manages data overload by presenting information in a various formats that are tailored to the end user.

- Utilising new and sophisticated condition monitoring equipment: sensors and monitoring systems have been shown to provide more information than ever before. These systems have proven their ability to detect developing faults before failure. This enables the move from qualitative to quantitative data, increases knowledge of failure modes and provides enhanced prediction and auditable evidence for replacement. New monitoring techniques and processes are being developed to manage the safety of personnel when working in the vicinity of poor condition assets with known safety-related failure mechanisms, enabling replacement works to take place at that site or the carrying out of routine duties.

SAM will also deliver customer benefits through:

- Minimising constraint costs: Near real time data will allow the exploitation of enhanced ratings with greater knowledge of thermal ratings of large assets

- Avoiding or deferring expenditure: Early detection of defects through continuous on line monitoring allows the timely removal of assets from service potentially allowing them to be refurbished or repaired rather than replaced

- Reduced environmental leaks: Provides earlier detection and dynamic prioritisation in the event of the detection of SF_6 or oil leakages. Condition monitoring also provides earlier detection and dynamic prioritisation in the event of a change in leak rate which is an important indicator of a minor leak becoming major

- Improved cyber security: By providing secure remote access and centralising data our exposure to malicious interference is constrained to relatively manageable levels whilst still providing easy access to important data

The delivery of SAM and RAMM capabilities will be done in a phased programme to ensure timely and effective implementation and early realisation of benefits. Delaying this expenditure will reduce the embedded benefits that have been identified within our RIIO submission from the implementation of these systems, and in particular will compromise our ability to effectively shape our asset replacement programme to deliver a more realistic and efficient investment profile.

Above and beyond the identified future benefits we are already experiencing the advantages of enhancing our remote condition monitoring capabilities. For example in May 2011 we took one of our quad boosters out of service at Legacy following high 'gas in oil' alarms being detected. Initial investigation of the on-line gas trend data showed a rapid rise in gas levels which developed very quickly, going from normal to being switched out of service in less than four hours.

Taking the quad booster offline before failure has delivered several benefits:

- There were no clean up costs from a failure
- Knowledge can be gained to look at failure modes for the family of assets as the quad booster remained undamaged
- Asset is currently being tested to see if it can be repaired, offering potential savings from the avoidance of civils and asset costs associated with the replacement

The deterioration of the asset was detected through our pilot Tactical Strategic Asset Management (TSAM) platform. Our investments in the rollover year on RAMM / SAM capabilities will allow the expansion of our remote condition monitoring capability to a greater proportion of our assets helping deliver further benefits.

International experience, gained through our involvement in benchmarking activities has demonstrated that the use of remote asset monitoring techniques is an integral strategic and tactical part of being one of the leading transmission performers from a cost perspective. We continue to learn from our benchmarking activities and will incorporate any learning into the design and rollout of our capabilities.

Transmission Front Office Replacement (£2.6m)

The core transmission front office (TFO) systems provide a centralised asset register, and support all work delivery and asset management processes across electricity and gas transmission. This includes enabling the safe and efficient delivery of planned and unplanned maintenance work and supporting the delivery of our capital investments.

The core TFO systems comprise of the following :

- Ellipse Enterprise Asset Management (EAM) application: which covers capital and maintenance work planning as well as acting as a central asset register
- ClickSchedule and Field Force Enablement scheduling and mobile applications, which are collectively known as Office in the Hand (OiTH)
- TMAP Geo-spatial Information System (GIS) which holds mapping data for above and below ground assets, used for construction, operations and emergency response
- ECM LiveLink drawing and document management system which provides a secure repository for critical construction and operational drawings and documentation

The total investment in 2012/13 of £2.6m covers expenditure on some of the main TFO system components:

- Initiation of the replacement of the OiTH suite of systems (ClickSchedule and FFE). This is necessary due to equipment obsolescence and termination of support by our current supplier in April 2014.

- Completion of the migration and enhancements to the ECM LiveLink drawing and document management system, as part of a phased programme initiated in 2010/11

- Electricity Asset Management system integration (Note that this is has now been subsumed and sanctioned as part of the SAM programme)

[TEXT REMOVED]

Whilst the scope of OiTH was extended in 2009 to encompass circa 500 gas transmission field users, it is now evident that OiTH will struggle to meet the projected growth of use across transmission activities, and will not provide the level of integration or device flexibility required to meet future field force requirements.

Previous experience confirms that a project of the scale and complexity of OiTH replacement will require at least 18 months to complete allowing enough lead time for a requirement and design phase, procurement process and then the deliverance and testing of the application. Implementation of the OiTH replacement is required by December 2013, to enable 'bedding in' before the main construction and maintenance period commencing again, in March 2014.

The investment in these systems is essential to address asset health and support issues in order to maintain existing business capabilities. In recognition of the importance of these systems as part of our replacement process we have engaged external support to help us assess best practice and technology options in order to refine our planned investment in TFO capabilities.

These TFO systems underpin the continued delivery of long-standing opex efficiencies introduced by the 'Staying Ahead' and 'Ways of Working' business change programmes in 2003 and 2005 respectively. They remain essential to sustaining efficiency benefits of the order of £7m per annum over the long-term in NGET and NGG. Any service failure leading to non-availability of the OiTH systems is estimated to result in additional costs of £550k per month and will lead to an increased risk of reliability and safety related incidents.

Other (£10m)

The other category contains a number of smaller IT refresh projects and investments in our vehicle fleet. Proposed total IT investment in 2012/13 is £12.7m. Once the £7m costs of the three main projects (RAMM / SAM, TFO and Integrating the alliances) which do not have an historical equivalent is removed from this the total reduces to ~£6m. This is less than historical levels of ~£7m leaving the only area of other that is increasing in 2012/13 in relation to fleet.

Fleet (£4.3m)

We intend spending £4.3m on vehicles in the rollover year which is an increase of £1m on historical levels. This is driven by the increasing workforce and the requirement to equip them with safe and reliable vehicles but also the replacement of existing vehicles in line with our policy[13], which optimises the replacement frequency to minimise total ownership expenditure. The breakdown of the number of vehicles procured is shown below.

Type of vehicle	New	Replacement
Light commercial vehicle	63	145
Heavy goods vehicle	3	-
Total	**66**	**145**

Through bulk purchasing we achieve economies of scale, procuring our vehicles in an efficient manner. With expenditure being fully sanctioned we do not have any deliverability concerns.

GTO

	Rollover submission £m	Initial proposals £m
HPMIS	4.7	0.0
RAMM / SAM	1.7	0.1
Front Office Replacement	1.4	0.0
Property	1.5	1.1
Other IT	1.9	1.4
Other	2.3	1.7
Forecast / allowance	**13.5**	**4.4**

High Pressure Metering Information System replacement (HPMIS) (£4.7m)

HPMIS is a business critical system providing the primary source of data for the Flow Weighted Average Calorific Value and Billing Calorific Value processes. FWACV is a strictly regulated calculation process carried out on a daily basis in iGMS using validated CV and high pressure metering values from HPMIS. We have a legal obligation to publish this data under the Gas Calculation of Thermal Energy Regulations and HPMIS data is also used for

13 The criterion for vehicle replacement is age and usage based. It is currently set at 6 years or 80,000 miles for light commercial vehicles and 8-10 years for heavy goods vehicles.

the daily CV Audit process, which is incorporated in the monthly Component Report to Ofgem.

HPMIS also supports the GS(M)R Compliance process, providing historical gas composition data critical for the analysis and reporting of excursions. In addition, the system's scope has extended to include a number of additional regulated (DEFRA emissions data) and business critical processes, providing services and information to the Distribution Networks and wider gas industry, including provision of data for the Unaccounted for Gas and Reconciliation by Differences processes, enabling detection and reconciliation of meter errors in a range of £5m to £20m.

HPMIS was originally implemented in 1997 with an interim refresh in 2005, and is an essential component in the suite of systems that support the safe and efficient operation of the UK gas market. Loss of HPMIS will:

(i) seriously impact the operation of the gas market, including calculation of customer charges as HPMIS provides the basis for the calculation of the commodity component of the gas transportation charge

(ii) reduce our ability to minimise shrinkage

(iii) prevent us from carrying out meter error reconciliations. This equated to £12.0m over a five year period. The exposure to Distribution Networks may be as high as £70.0m for one single meter error based on the current metering error that is currently being investigated within an independent network.

Our Rollover submission forecast £4.7m for a 'like for like' replacement of HPMIS. During the subsequent cost visit we indicated that we were pursuing the most appropriate and economic solution to upgrade/replace HPMIS. Analysis undertaken in early 2011 has developed an approach which requires some immediate tactical investment to address performance and supportability issues, which are currently impacting our and other stakeholders' ability to use the system. Further strategic investment is required to rationalise and upgrade the HPMIS infrastructure, application and operating system to address asset health issues.

Investment of £2.5m, of which £0.5m is in 2011/12 and £2.0m is in 2012/13 is required to deliver this programme of work. This investment is aligned with investment of £1.0m in National Grid Gas Distribution.

Immediate tactical investment is required to:

(i) resolve data upload problems which are preventing us and external stakeholders from automatically uploading essential data, resulting in delayed information flow, disruption to business activities and a requirement to manually upload data

(ii) address reporting tool deficiencies, which force users to directly extract data from the database; this takes up to two hours per site and has potential data corruption and security implications

External stakeholders including the Northern Gas Networks, Wales & West Utilities, Scotia Gas Networks and Ofgem have indicated their support for investment to address the above issues.

HPMIS is experiencing performance issues due to the aged infrastructure, with some 87 incidents (excluding data load issues) reported over the past 18 months. In addition, the vendor who supports HPMIS is also experiencing problems applying software releases to support the application, and is recommending a full upgrade of hardware and software application architecture, as they cannot guarantee to support the existing implementation.

HPMIS data volumes are forecast to grow by 30% over the next two years, and use of the system is required to extend to provide live Uncertainty Calculations and to support NTS environmental incentives and Unaccounted for Gas initiatives from 2012/13. The current HPMIS implementation will not be able to support these developments with an acceptable level of performance.

This investment is aligned with National Grid Gas Distribution plans to ensure timely and efficient delivery of the HPMIS replacement. The sanction status for HPMIS Replacement programme is:

HPMIS	Sanction Date	Sanction Value	11/12 Forecast	12/13 Forecast	Comments
HPMIS Requirements Analysis	Apr -11	£0.4m	£0.3m		
HPMIS Implementation Programme	Aug -11	£2.1m	£0.2m	£2.0m	Additional £1.0m from Gas Distribution in12/13
		£2.5m	**£0.5m**	**£2.0m**	

HPMIS is now considered to be at a high risk of failure and requires essential investment to maintain service beyond 2012. Failure of HPMIS will adversely impact the efficient operation of the UK gas market and associated commercial processes. In addition, any failure would result in us breaching requirements under the Gas Calculation of Thermal Energy Regulations and the Gas Safety Management Regulations GS(M)R, with potential fines in the region of £2m.

RAMM/SAM (£1.7m)

Assets are managed on the NTS to ensure an acceptable and sustainable balance is achieved between performance, cost and risk given that transmission assets:

(i) have high potential safety and environmental consequences on failure
(ii) are critical to secure bulk energy transfer to customers
(iii) have long repair and/or replacement times

To help plan the maintenance of NTS assets, we use the Reliability Centred Maintenance (RCM) methodology, which promotes the use of functional maintenance tasks to predict the optimum time to take action on an asset. The RCM methodology requires the capture of asset performance data to supplement other sources of information (for example, inspection records); greater levels of information relating to the condition and performance of an asset allow for more accurate predictions of the optimum time to maintain or overhaul assets.

Building on the initial work that we have undertaken in improving connectivity and remote asset management by the deployment of RAMM (Remote Access Management & Monitoring), we plan to develop Strategic Asset Management (SAM) tools which will allow performance and functional test data to be captured in a timely manner and be manipulated to enhance our maintenance scheduling. This is increasingly important as:

(i) many parts of the NTS were built 40 or more years ago and 'features' are far more likely on pipelines and other secondary assets of this age
(ii) more volatile and unpredictable gas flows on the transmission system make scheduling of maintenance windows far more challenging –

especially if they are required at short notice to enable emergency repairs to a failed asset

(iii) heightened load related construction activities compete for access to the NTS

We currently operate a small number of strategic asset management systems which provide real time data on the condition and performance of secondary assets. One example of such a system is the combination of the Abriox and Uptime systems, which provide regular measurement of the condition and effectiveness of cathodic protection from over 1,500 test posts on the NTS. This information is central to the assessment of the overall condition of the CP system and pipeline protection, and allows analysis to be performed to focus investment and maintenance activities in the high risk areas.

Other secondary asset groups would benefit from implementation of similar tools (or enhancements to existing tools), including Gas Quality systems, Gas Generators, flow and pressure control equipment and remotely operable valves. We plan to implement other tools and systems to support asset management decisions and improve the targeting of maintenance and investment activities as the benefits of the RAMM programme are delivered.

An example of the type of benefit we expect to create from this capability is a reduction in emissions from venting natural gas. Through better asset information, valve maintenance can be planned for when it is required, rather than on a periodic basis. This will reduce the number of intrusive maintenance activities and the associated venting of gas.

TFO (£1.4m)

Recognising the benefits of utilising common IT systems across our transmission businesses we use the same core systems for both our gas and electricity networks as described in greater detail in the ETO section above. Combined these systems ensure the safe and reliable operation of our network.

The investment in 2012/13 of £1.4m covers expenditure required for initiation of OiTH replacement and expenditure on other major TFO systems such as the click upgrade and Gas Asset management system integration project.

Property (£1.5m)

Our forecast for property capex consists of:

- £0.5m for workplace sharing – which is explained above within the equivalent ETO section
- £0.3m for Eakring training centre – which is explained above within the equivalent ETO section. Note there are less GTO trainees hence the lower cost than ETO.
- £0.7m for regular work on maintaining our operational and non-operational property sites such as replacing leaking roofs which is in line with levels of previous expenditure

Question 2: We invite stakeholders to comment on our proposed capital expenditure allowances for the transmission companies.

Gas Capex:

Non-load related – Asset health

Humber Estuary crossing – Feeder 9

In response to the increased erosion of sediment in the Humber Estuary and exposures observed on our Feeder 9 pipeline, we are currently completing remedial activities to safeguard the structural integrity of this crossing. Given these remedial measures do not currently provide confidence that they shall form a permanent solution, there remains a requirement for us to progress a long term alternative to secure capacity in the Easington area. Our long term network analysis and market intelligence indicates that moving gas into and out of the area will be required into the future to meet commercial and physical obligations. A number of options are therefore being considered both onshore and offshore, together with a direct replacement crossing of the Humber.

The work to be completed on Feeder 9 is an asset health investment to maintain current levels of capacity and should not be confused with any work to deliver incremental capacity.

We commissioned an independent assessment by AECOM of the Paull to Goxhill Pipeline Environmental Statement (March 2008) which was originally prepared by AMEC to better understand whether a replacement pipeline would be likely to have a significant effect on the environment. In February 2011, AECOM provided their summary report which concluded that the Feeder 9 project would be classed as a Nationally Significant Infrastructure Project (NSIP) and would therefore require determination by the Infrastructure Planning Commission (IPC) or its successor, the Major Infrastructure Planning Unit (MIPU) given it was considered to have a significant environmental impact.

It is now highly probable that all of the potential alternative solutions identified, including the tunnelled option, would be classified as NSIP's under the Planning Act and a Development Consent Order would therefore be required.

As set out in our response to F234, there is no credible scenario where we would not incur any spend in relation to this project in 2012/13. The conclusion to deduct all spend relating to this project in 2012/13 on the grounds that we would not gain planning permission to proceed in 2012/13 is not therefore appropriate, as we must now deliver key activities in preparation of an anticipated submission of a Development Consent Order request to the IPC/MIPU under the Planning Act.

At the January 2011 cost visit we highlighted that our spend profile (detailed in F207, including the [TEXT REMOVED] in 2012/13) was based on the following assumptions:-

- The long term solution being a tunnelled crossing of the Humber with a single replacement 1220mm pipeline;
- The tunnel not being classified as a NSIP and therefore outside the requirements set out in the Planning Act 2008.

Since AECOMs report findings our understanding of the Planning Act requirement has grown allowing us to identify the extent of the activities we must undertake, together with their subsequent timings. We anticipate completion of the following key activities in 2012/13, totalling [TEXT REMOVED]:

- [TEXT REMOVED] Front End Engineering Design (FEED) Study - conceptual design to demonstrate the technical viability of the project. The output will then form the basis of our second round of public consultation.

- [TEXT REMOVED] Overwater boreholes – to ascertain the geology to inform the FEED to enable the design to be progressed.

- [TEXT REMOVED] Environmental Support – environmental surveys will be refreshed to bring the environmental report up to date. Environmental support will also be required to during the public consultation process.

- [TEXT REMOVED] UKT staff and consultancy costs - Construction staff will procure and manage both design and environmental consultants to undertake the above activities, Land and Development staff will progress land access and consent issues, and Consultancy costs are associated with the overall management and delivery of the project activities.

- [TEXT REMOVED] Legal fees and communications (Public relations campaign and support during stakeholder consultations)

Given the evolving nature of the situation with mitigation measures being deployed and the fact that this is the first pipeline project we have progressed in accordance with the Planning Act, we have applied more rigorous sanction controls to help manage the direction and appropriateness of the project activities to be delivered. We have already sanctioned the first set of activities required to submit a Development Consent Order in accordance with the Planning Act and expect to sanction the remaining activities as required. The anticipated spend has been re-profiled to ensure we complete the key tasks and receive the required planning consents to proceed with the long term replacement of the current underwater pipeline.

Electricity TO Capex

Load-related

The proposed allowances adopt the submitted baseline capex forecast in line with the proposed extension of the revenue driver mechanism. We support this approach and the extension of the Work In Progress (WIP) mechanism for expenditure in 2012/13. Further detail on the extension of the revenue driver mechanism is provided in our response to Question 10 and the timelines for remuneration of the revenue driver mechanism are discussed in our response to Question 11.

Non-load related

The proposed reductions in allowances (as compared to the submitted baseline capex) within the various non-load related categories are primarily based on three areas:

1. *Reductions to align expenditure with historical average*

In the 'Switchgear', 'Protection and Control' and 'Other TO' categories, a proportion of the proposed reduction in allowances is justified by comparison to historical expenditure. We believe that there are sound engineering reasons for the forecast increases in expenditure, and that simple extrapolation of history is therefore not appropriate. Further detail on this is included within our confidential annex, but examples of new areas of expenditure (which would not therefore be included in an historical average) are listed below:

- The switchgear expenditure in 2012/13 includes replacement of wider infrastructure not driven by the replacement of the circuit breaker (which is considered to be the lead asset). Within the forecast of £97.5m for 2012/13, KEMA specifically identified the 'substation infrastructure' cost as circa £20m greater than the TPCR4 average annual expenditure and reduced the proposed allowance by £18m to align with the 2011/12 forecast. Of this increase, £10.7m is associated with critical safety-related expenditure following the recent disruptive failures of specific current transformer types. These failures are in addition to our historical average spend; adequate provision for this safety critical work needs to be made.

- The 'Other TO' category forecast expenditure in 2012/13 of £64.0m includes expenditure associated with flood prevention (£8.0m). This has only recently been identified through discussions with DEFRA, DECC, Ofgem and the Environment Agency. The increase in spend towards the end of 2011/12 and into 2012/13 is necessary to ensure electricity transmission assets are protected in accordance with the latest technical recommendations, as accepted by the Energy Emergencies Executive Committee. Reducing the 'Other TO' category to align with the TPCR4 historical average does not reflect these new costs.

2. Certain unit costs being higher than GB average and KEMA estimates

In the 'Switchgear', 'Overhead lines' and 'Protection and Control' categories, the fact that unit costs are apparently above the GB average or KEMA estimate is used to justify a reduction in the proposed allowances. Further detail on this aspect is included within the confidential annex.

- Switchgear: It is challenging for us to respond to a reduction based on unit costs when it is unclear whether the benchmarks are comparable in terms of scope and technology. In fact, as evidenced by subsequent discussions with Ofgem, their RIIO consultants and the three TOs, the specific assets that comprise a unit were not aligned until they were better defined as part of the preparatory work for the RIIO-T1 submission. We maintain that the overall cost of schemes specifically reviewed by KEMA were comparable, hence supporting our costing methodology.
- Overhead Lines: In this case, the GB data is so disparate that KEMA acknowledge that costs have not been submitted on the same basis. Reductions are therefore made based solely on KEMA's estimate; we have not received any information regarding the scope of KEMA's unit and again it is difficult for us to comment on valid differences in scope. There is the potential for significant differences because the scope of our schemes has developed and been refined over the years:
    - NGET fittings only schemes replace full insulator strings (including hardware), phase fittings, earthwire fittings, spacers and vibration dampers. Compression joints have their resistance recorded as a minimum (and are replaced or bypassed if the value is not acceptable), while anchor clamps and jumper palms are split and cleaned. This extensive overhaul is carried out to give an overhead line route another 10-15 years of reliable service and protect the conductor (which often has a longer life than the fittings). In addition, based on route-specific condition, steelwork, tower bolts, step bolts, tower paint, anti-climbing guards, muffs and tower plates may be partially or wholly replaced.

- NGET full refurbishment schemes basically cover the same scope of fittings only schemes except that the phase conductors and earthwire (including jumpers) are also replaced. Muffs are broken off and replaced on all towers to check the integrity of each tower's interface with its foundations (rather than just on condition). Steelwork replacement may be more extensive because we are seeking to ensure that the tower, with satisfactory maintenance painting, remains in good condition for an additional 40 years; tower painting is normally required.

- Protection and Control: The analysis completed by KEMA on protection and control was limited, considering the unit cost for a feeder protection bay which comprises only around a quarter of the expected expenditure in 2012/13. Expenditure on other elements (such as control and operational tripping) has not been considered even though we have provided additional information. Finally, as for the other plant types, the definition used for a standard unit for protection was not clear enough to support robust comparison.

3. Risk and contingency costs apparently being high

Ofgem's concerns about the size of overheads as applied to switchgear, overhead lines, underground cables and cable tunnel schemes seem all to stem from KEMA's analysis of a single, unique cable tunnel scheme. As a result, a widespread reduction in allowances has been proposed due to perceived high on-costs covering risk and contingency on just one project. As was acknowledged within the KEMA report, they are not correctly interpreting our use of risk and contingency. This area of concern is discussed further in our confidential annex.

Question 3: We invite stakeholders to comment on our proposed operating cost allowances for the gas and electricity system operator.

Summary

As with the TO opex proposals SO opex funding for the rollover year needs to strike the right balance between a proportionate approach which defers discussion of some issues into the RIIO-T1 process so long as it does not impact on stakeholder outputs either in 2012/13 or into the RIIO-T1 period. The aim for the rollover is to get to a position of adequate allowances to deliver stakeholder requirements and to move incrementally where volumes and cost of service provisions are rising into the future in order to smooth the transition and make the step change more deliverable.

The signals given by Ofgem in the initial proposals indicate a desire to defer investments which may impact on the efficient delivery of network reliability and safety in the future. For example funding of half of the workforce growth and renewal costs would not allow us to keep to the same resource levels we have in place currently as, of the costs to be incurred in 2012/13, two thirds will be incurred to offset expected attrition and retirements. Not being able to respond to this would impact on the efficient delivery of future outputs.

We recognise that there are some specific areas where our proportionate approach to the rollover submission has meant that Ofgem have not got all the evidence they require in certain areas. We welcome the opportunity to provide new and improved information which enables a more detailed assessment of the opex costs.

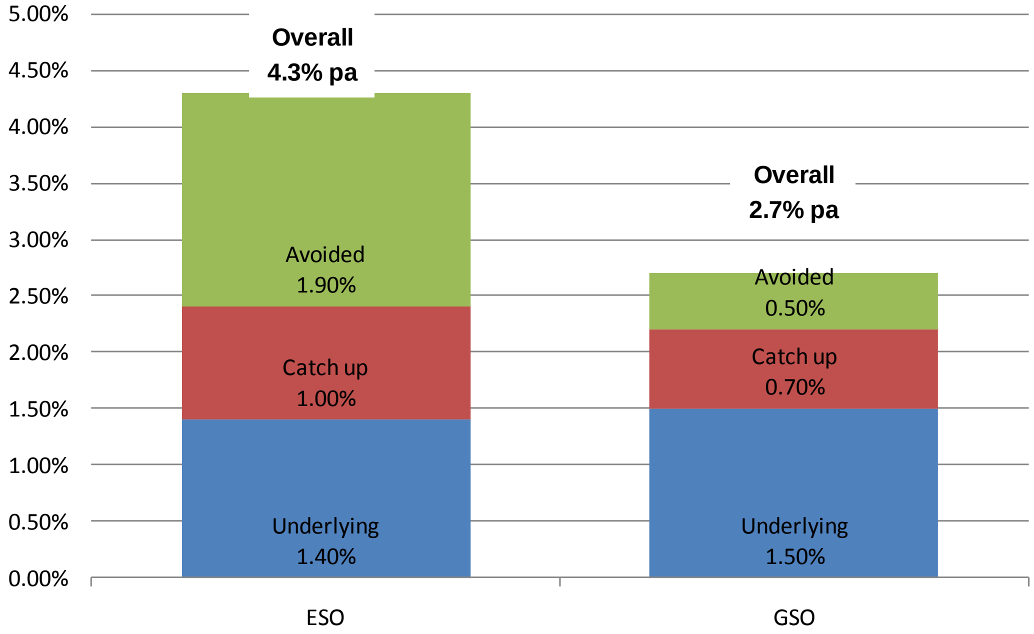
We are strengthening the justification for each of the areas of upward cost increases between 2009/10 and 2012/13, providing more detail in the sections below and highlighting areas where our information may have been misinterpreted. For example we give new information on the efficiencies we have embedded into our plan which shows that the Initial Proposals include avoided cost efficiencies without allowing the related cost increases they offset.

The initial proposals embed an efficiency target into the proposed allowances which is stated as being 1.5% per annum for on-going efficiency. In reality for ESO and GSO the efficiency level applied has been based on top of the efficiency levels we included in our submission. These already totalled 4.3% per annum for ESO and 2.7% per annum for GSO.

We agree that we should be delivering 1.5% efficiency per annum based on regulatory and historical precedent – that is why we have already embedded over this value in our submission. The efficiency levels we embedded into our plan incorporated catch up efficiency, avoided cost efficiency (linked to specific upward cost pressures) and underlying efficiency equivalent to the levels any network should strive to deliver (sometimes called frontier shift).

We had ‘grossed up’ both cost and related efficiency in presenting the trace of opex costs between 2009/10 and 2012/13. This meant that some of the upward cost pressures were linked to avoided cost efficiencies of £4.2m for ESO and £2.1m for GSO. Incorporating all of the efficiencies and not funding the related upward cost pressures they offset means that the allowances currently remove cost that does not exist. This related cost should either be funded or the equivalent figure removed from the efficiencies embedded to increase the allowances.

Outside of the catch up efficiency and avoided cost efficiency the underlying levels within ESO and GSO are 1.4% and 1.5% per annum respectively. This is in line with regulatory and historical precedent which indicates levels of 1-1.5% should be delivered by frontier companies as discussed in the TO section of this response above. The graphs below show the split of efficiencies by form of control:



ESO

To continue the safe and secure operation of the NETSO transmission system we forecast spending £65.1m, which is £9.9m higher than the initial proposals. For each of the upward cost pressures we have given further evidence for the requirement for funding each of these specific items. Where necessary we have split the upward cost drivers into the underlying constituent parts recognising that this level of detail has yet to be shared with Ofgem.

As with TO opex it has been nearly a year since our rollover submission in October 2010, so more information is now available and 2012/13 is closer enabling us to have a clearer view about forecast opex levels. In addition our RIIO-T1 submission provides more detail than was included in the Rollover submission in many of the areas due to our proportionate approach to the Rollover. Where this is the case we point back to where the relevant evidence is included in our narrative.

Given the time since Rollover submission there have been some changes to our opex forecasts for 2012/13. This has occurred in two main areas: real pay, workforce renewal and growth; the reasons for which are explained within the TO opex sections. Other changes have also occurred to increase the IT running costs due to changes in the SO capex forecasts. These changes were incorporated into our RIIO-T1 submission.

	Rollover submission £m	RIIO-T1 submission £m	Difference £m	Initial proposals £m
2009/10 opex	58.6	58.6	-	58.6
Less one-off costs	(2.6)	(2.6)	-	(2.6)
Recurring opex	**56.0**	**56.0**	**-**	**56.0**
Efficiency savings	(8.0)	(8.0)	-	(8.0)
Additional catch up	-	-	-	-
Total efficiency	**(8.0)**	**(8.0)**	**-**	**(8.0)**
IT running costs	1.0	2.9	(1.9)	0.5
Real price effects	3.0	0.4	2.6	0.4
Volume and mix	3.0	3.0	-	1.3
Workforce growth	4.0	6.0	(2.0)	2.0
Recruitment and training	6.1	7.5	(1.4)	3.0
Total workload	**17.1**	**19.8**	**2.7**	**7.2**
Forecast / allowance	**65.1**	**67.8**	**2.7**	**55.2**

Efficiencies

The avoided cost efficiencies are linked to upward cost drivers which were included in our trace. Incorporating all of the efficiencies in the initial proposals' allowances but not funding the related upward cost pressures they offset means that the proposed allowances currently remove ~£2m of cost that does not exist.

The avoided cost efficiencies and the upward cost pressures they relate to are included in the table below. The 'related workload area' column shows which category the related cost is included within (consistent with the table presentation above) and the 'gap' column shows how much of the related cost is not included within the initial proposals' allowances[14]:

Description	Related workload area	Cost £m	Gap £m
Avoided cost due to implementing IT systems	Recruitment and training	3.1	1.5
Anticipated organisational savings	Workforce growth	0.4	0.2
Absorbing market change requirements	Workforce growth	0.3	0.2
Total		**3.8**	**1.9**

To remedy this inconsistency between the incorporation of all the avoided cost efficiencies but not the related upward pressure the erroneously calculated 'efficiency' should be removed or resultant opex allowances should be increased by £1.9m to cover the costs in the 'gap' column above.

[14] Note that where a workload area has been 50% funded in the initial proposals it is assumed that 50% of the cost relating to the avoided cost efficiency has been funded already

IT Running Costs

	Rollover £m	RIIO-T1 £m	Initial proposals £m
Gross increase	1.0	2.9	0.5

As outlined in the opex trace for rollover the costs forecast in this area related to a number of IT project related items. With nearly a year since submission our forecasts have changed in this area with ~£0.5m of forecast running cost increases added because the related capex work has changed and a £1.4m increase due to changed allocations:

	RIIO-T1 £m
Allocation changes	1.4
Opex project increase	0.7
Running costs of new / enhanced IT systems	0.8
	2.9

Allocation changes (£1.4m)
As with ETO during our transformation programme we have reviewed the cost allocation for a number of our telecoms routes and servers which were previously allocated equally across the UK companies. We identified that several were specifically used by one area of the business and hence have changed the allocation for the RIIO-T1 plan. This allocation is more cost reflective but increases ESO costs by £1.4m between 2009/10 and 2012/13 in our RIIO-T1 submission.

Opex project increase (£0.7m)
As described in our Rollover Submission and in more detail for RIIO-T1, the UK energy market is entering a period of change. To respond to these changes we need to develop new capabilities and the IT systems to support them. Our IT costs in this area are just part of our overall approach to innovation as described in our Innovation, Efficiency and Value for Money Annex of our RIIO submission. Within IT we are forecasting £0.5m of research expenditure in ESO which will be focussed on:

- Understanding how new and emerging technology can help us meet the challenges ahead;
- Understanding how other organisations have responded to similar challenges
- Understanding best practice in developing IT systems as used other organisations and how that could apply to National Grid Transmission.

In addition we are forecasting £0.2m of security expenditure. As explained elsewhere, our exposure to security threats is increasing, and greater opportunities to exploit vulnerabilities are available. Advice from external governmental bodies is that the security threat of a malicious attack on us is real, and that we should consider ourselves a viable target.

We have carried out external benchmarking with Deloitte and Gartner which has provided key inputs to the development of our digital risk and security strategy. From this we have developed a prioritised programme of works including tactical and strategic initiatives. The tactical initiatives are generally opex investments due to their short term nature.

Running costs of new / enhanced IT systems (£0.8m)

As outlined within the ETO opex section we are undertaking our IT transformation project to optimise the way that we procure, build and operate our strategic IT systems to support both our TO and SO operations. Whilst this is helping reduce the overall totex cost of providing IT capabilities to the business and delivering opex efficiencies elsewhere, IT running costs are increasing for ESO. Within the rollover year we are continuing to increase the number and complexity of our IT systems leading to additional requirements for software licences and hardware support. The increase in opex costs between what was forecast in the rollover and the RIIO submission is due to an increased focus on enhancing our strategic research into optimal long term solutions.

For planning purposes we make some high level assumptions about the change in support costs associated with each investment, these are then refined as detailed designs are completed and systems are delivered. More detail on this process is contained within the 'Detailed plan' annex of our RIIO-T1 submission. The below projects are driving up the cost of IT support:

Energy Balancing System (£0.6m): We have purchased the new Energy Balancing System (EBS) from ABB. Our contract includes full support costs for the five years after implementation (with an option to extend for a further five years).

The overall running costs for the Balancing Mechanism service will rise during 2012/13 and 2013/14 because of the need to support both the existing and the new systems during the testing and parallel run phases of the project. Without this we would be taking a risk with a new system and no opportunity to cut back to the old system, giving rise to more risk of unreliability. From 2014/15 the running costs will reduce to current levels.

BSIS Market Simulator – (£0.2m): This is a new system which was implemented during 2010/11 to enable better forecasting of BSIS costs. The majority of the increase in support costs for this project are associated with an annual licence fee of £150k. In addition there are costs associated with support for new servers and for database licences.

Volume and Mix

This category of spend is made up of several smaller upward cost pressures. We have expanded on several of these areas where we felt it would help Ofgem understand the upward cost pressures that we face.

	Rollover £m	RIIO-T1 £m	Initial proposals £m
Gross increase	3.0	3.0	1.3

The table below splits the £3m cost into its constituent parts:

	RIIO-T1 £m
Regulatory team	0.3
Insurance	0.2
Network operations	1.3
Property repairs	0.2
Other	1.0
	3.0

The categories below take each driver and explain the reason for the cost increase. The initial proposals already fund the regulatory team and the other category so these are not discussed further below:

Insurance (£0.2m)

Insurance increases for ESO are driven by the insurance market forecasts which are detailed in the ETO section above. The ETO section illustrates how our insurance costs are already lower than third party benchmarks and our forecast increases are lower than independent market projections. Whilst this is an increase in opex it is lower than it would be if we used third party providers and enables us to remain at the same risk level.

Network Operations (£1.3m)

The changing generation mix combined with increasing European interactions is the dominant driver of other non workforce related increases in spending within Network Operations. In combination the following costs amount to a £1.3m increase.

- Additional weather forecasting services focussing on the enhancement of wind forecasting. This is helping reduce wind forecast error allowing greater optimisation of our balancing actions

- Membership of Coreso allows us to share operational information between members helping manage flows between mainland Europe and the UK and enhancing security of supply. The cost of membership is rising across the period

- Professional service fees are increasing, in line with greater research into the effects of decarbonisation on our system and fees for increased recruitment consultancy costs associated with workforce growth

- Enhancing our marketing and raising awareness of balancing opportunities for demand side providers

Property repairs (£0.2m)

This increase relates to the growing costs of running our property sites. In spite of forecast delivery of savings from our workplace sharing project (see non-operational capex) repairs and maintenance contract costs are increasing. As outlined in the 'Innovation, efficiency and value for money' annex of our RIIO-T1 submission property costs – despite this increase – are below benchmarks within the Total Office Cost Survey.

Workforce growth

	Rollover £m	RIIO-T1 £m	Initial proposals £m
Gross increase	4.0	6.0	2.0
Less avoided cost	(0.7)	(0.7)	(0.7)
Net increase	3.3	5.3	1.3

Over the next three years and into the RIIO-T1 period there are growing workloads that our stakeholders expect us to deliver. In order to have fully competent resources to deliver these workloads we are acting to grow the workforce. The main drivers for this are the decarbonisation of electricity production which requires more resources to manage the increases in data and deliver necessary IT projects and European impacts.

The recruitment for ESO is forecast to be 182 between 2009/10 and 2012/13. This includes increasing intakes to our development schemes by 43 over the period. As outlined above in the ETO section we are on course to deliver the recruitment requirements. The assumptions behind these figures – for attrition and retirement – and the related evidence are the same as those in ETO so are not repeated.

As discussed in the ETO section recognising that we can give more evidence to prove the need for workforce growth and renewal costs we have produced a summary of the requirements and evidence in this area. Within the document we outline a case study on the power system engineer and power system manager roles. Amongst other items this case study outlines how we have translated the forecast workload levels into resources requirement.

As outlined above £0.7m of the cost increase in this area is forecast to be avoided by delivering efficiencies embedded within the plan. The initial proposals only fund half of the cost increase in this area so only half of the avoided cost is funded. To remedy this inconsistency the allowances should be increased either by removing the efficiency or funding the related cost.

Recruitment and training

	Rollover £m	RIIO-T1 £m	Initial proposals £m
Gross increase	6.1	7.5	3.0
Avoided cost	(3.1)	(3.1)	(3.1)
Net increase	3.0	4.4	(0.1)

The cost increase in this area includes costs of recruitment and training to offset forecast attrition and retirements between 2009/10 to 2012/13 and over the longer term through use of our development schemes. Over the TPCR4 period the issues in this area including low availability of skilled resources and high levels of demand have become more apparent with attrition levels increasing as industry companies compete for specialist skills.

Our modelling illustrates that between 2009/10 and 2012/13 we need to recruit 56 people across ESO just to stay at the same level of resources. When the recruitment to fill our development schemes is included (to offset post 2012/13 projected attrition and retirements) workforce renewal recruitment accounts for 54% of the total recruitment forecast between 2009/10 and 2012/13. This means that the current proposals of only allowing half of the expenditure for workforce growth and renewal in 2012/13 would not enable us to remain at the level of employees we have in place today.

The assumptions we have made in this area and our response are discussed further in the ETO section. As with workload growth more evidence surrounding this cost driver is included within the workforce growth and renewal summary we are sending separately to this document. In order to illustrate the renewal challenge and enable Ofgem to calculate sensitivities around the attrition and retirement assumptions we have included a workforce renewal model within the document.

GSO

To continue the safe and secure operation of the GB gas transmission system we forecast spending £34.1m, which is £5.8m higher than Ofgem's initial allowance. For each of the upward cost pressures we have given further evidence for the requirement for funding each of these specific items. Where necessary we have split the upward cost drivers into the underlying constituent parts recognising that this level of detail has yet to be shared with Ofgem.

As with other opex areas it has been nearly a year since our rollover submission in October 2010, so more information is now available and 2012/13 is closer enabling us to have a clearer view about forecast opex levels. In addition our RIIO-T1 submission provides more detail than was included in the Rollover submission in many of the areas due to our proportionate approach to the Rollover. Where this is the case we point back to where the relevant evidence is included in our narrative.

Given the time since Rollover submission there have been some changes to our opex forecasts for 2012/13. This has occurred in two main areas: real pay and workforce renewal and growth; the reasons for which are explained within the TO opex sections. Other changes have also occurred to reduce the IT running costs due to changes in the SO capex forecasts and the addition of costs for one-off compensation. These changes were incorporated into our RIIO-T1 submission.

	Rollover submission £m	RIIO-T1 submission £m	Difference £m	Initial proposals £m
2009/10 opex	28.7	28.7	-	28.7
Less one-off costs	(1.7)	(1.7)	-	(1.7)
Recurring opex	**27.0**	**27.0**	**-**	**27.0**
Efficiency savings	(2.5)	(2.5)	-	(3.0)
Additional catch up	-	-	-	-
Total efficiency	**(2.5)**	**(2.5)**	**-**	**(3.0)**
IT running costs (Volume and mix)	4.0	4.6	0.6	2.0
Real price effects	1.0	0.3	(0.7)	0.3
Supply and demand volatility	1.4	1.4	-	-
Workforce renewal and growth	2.0	4.6	2.6	1.0
Other	1.2	1.0	(0.2)	1.0
Total workload	**9.6**	**12.1****	**3.0**	**4.3**
Forecast / allowance	**34.1**	**36.6**	**3.0**	**28.3**

** The apparent discrepancy between the summation of the upward cost pressures and £12.1m in our RIIO submission are due to rounding differences

Efficiencies

The avoided cost efficiencies are linked to upward cost drivers which were included in our trace. Incorporating all of the efficiencies in the initial proposals' allowances but not funding the related upward cost pressures they offset means that the proposed allowances currently remove ~£0.3m of cost that does not exist.

The avoided cost efficiencies and the upward cost pressures they relate to are included in the table below. The 'related workload area' column shows which category the related cost is included within (consistent with the table presentation above) and the 'gap' column shows how much of the related cost is not included within the initial proposals' allowances[15]:

Description	Related workload area	Cost £m	Gap £m
Deferred GNCC resource recruitment	Workforce growth	0.4	0.2
Anticipated	Workforce growth	0.1	0.1

[15] Note that where a workload area has been 50% funded in the initial proposals it is assumed that 50% of the cost relating to the avoided cost efficiency has been funded already

organisational savings			
Total		**0.5**	**0.3**

To remedy this inconsistency between the incorporation of all the avoided cost efficiencies but not the related upward pressure the erroneously calculated 'efficiency' should be removed or resultant opex allowances should be increased by £0.3m to cover the costs in the 'gap' column above.

IT Running costs (Volume and mix)

	Rollover £m	RIIO-T1 £m	Initial proposals £m
Gross increase	4.0	4.6	2.0

The table below shows the constituent parts of the Rollover forecast:

	Rollover £m
IT running costs	3.1
Insurance costs	0.3
Regulatory workload	0.6
	4.0

IT running costs

As highlighted within the ETO opex section, IT costs remain flat between 2009/10 and 2012/13 but we have grossed up the transformation savings (in efficiencies) and the running costs of systems which are increasing. These cost increases are due to the continuation of an increase in the number and complexity of our IT systems and the higher standards and reliability that our core systems need to deliver. Without the savings associated with our IT transformation programme these costs would be greater. The continued investment in our IT capabilities allows us to deliver opex efficiencies in other parts of the business.

It is worth noting that the forecast cost increase in this area is now expected to be £2m, not the £3.1m in the rollover submission largely as a result of the deferral of the implementation of the Gemini Replatforming Project.

Similar to the other forms of control, there is an increase in IT opex projects. For GSO this amounts to an extra £0.2m of expenditure which is focussed on strategic research and development and enhancing security arrangements. There are a number of system changes, each contributing a small increase in opex to support and maintain them, which aggregate to a total £2m increase.

For planning purposes we make some high level assumptions about the change in support costs associated with each investment, these are then refined as detailed designs are completed and systems are delivered. To illustrate this increase, we provide below two example projects that are driving up the cost of IT support:

GNCC Control Telephony – (£0.1m) Since the telephony system used by GNCC was commissioned six years ago various environmental and business changes have progressively highlighted issues with the system. These include:

- More calls from Shippers due to the growing complexity of the commercial regime
- More calls from engineers on site visits resulting from a greater number of network assets, requiring maintenance and inspection
- More Control Centres to liaise with following Network sales
- Longer call duration due to Safe Control of Operations requiring communication of more complex instructions to field engineers.

These changes have led to a requirement for an updated telephony system which will have an associated increase in IT support costs. This is because the existing shared solution will need to remain to support the Network Operations Centre and the Distribution National Control Centre, who at present have no plans to change from the existing solution.

Netsip – (£0.2m) The NetSip project is extending an existing system used to plan the National Transmission System (NTS) for use in the Gas National Control Centre (GNCC) as an operational tool. The increased scope leads to increased support costs due to the requirement for 24/7 support and an increased number of licenses.

Insurance costs

Insurance costs are been driven up from the increasing asset base and the external drivers that are affecting premiums. Greater details are again given in our ETO opex response above.

Regulatory workload

We have assumed that funding for increases in regulatory workload is fully funded as is the case for ETO so do not discuss in greater detail.

Supply and demand volatility

	Rollover £m	RIIO-T1 £m	Initial proposals £m
Gross increase	1.4	1.4	-

The linkage made in Ofgem's Initial Proposals between the SO Supply and Demand Volatility expenditure and Network Flexibility investment is erroneous. Logically, if the ability of the NTS to respond to changing needs is not physically enhanced (as the Network Flexibility investments are targeted to do), the need for the System Operator to develop its capabilities is further accelerated as we will have to attempt to manage the new gas flows within the constraints of the existing network. It is not the case that this SO cost will only be incurred if the Network Flexibility investments are made.

The full £1.4m cost increase relates to necessary increases in headcount to develop and operate enhanced and new capabilities, from running enhanced processes to developing and using new IT systems. Without these additional resources, the SO will not be able to produce sufficiently accurate forecasts to ensure optimum configuration of the network, leading to sub-optimum use of compressors and restrictions to capacity made available.

The enhanced capabilities required by the SO to manage the future and continue to operate the NTS safely and efficiently will be required almost irrespective of the level of NTS investment that dynamic behaviour and the requirement for increased physical system flexibility may drive. The SO needs to ensure it can continue to meet its obligations and commitments to operate the network in an optimal manner to mitigate physical and commercial risks to customers and ourselves. This is to some extent independent of what the system build entails, unless it is reinforced to such an extent as to remove all balancing and constraint risks, which is unlikely to be the most efficient option.

Enhancements to forecasting abilities, twinned with simulation and superior decision support capabilities are essential tools the SO will need in the near future in response to more dynamic, less predictable gas flows. Both our TPCR4 Rollover and RIIO-T1 submissions explain in detail the effects declining UKCS supplies is having on supply volatility and profiling, and the impact increasing wind generation on the electricity network will have on the demand profiles and needs of CCGTs. The requirements of the NTS are evolving as our customers' behaviour changes, and it is therefore inevitable that our capabilities to manage the network must also develop.

Workforce renewal and growth

	Rollover £m	RIIO-T1 £m	Initial proposals £m
Gross increase	2.0	4.6	1.0
Avoided cost	(0.5)	(0.5)	(0.5)
Net increase	1.5	4.1	0.5

Over the next three years and into the RIIO-T1 period there are growing workloads that our stakeholders expect us to deliver. In order to have fully competent resources to deliver these workloads we are acting to grow the workforce. The main drivers for this are the decarbonisation of electricity production which requires more resources to manage the increases in data and deliver necessary IT projects and European impacts.

The recruitment for GSO is forecast to be 71 between 2009/10 and 2012/13. This includes increasing intakes to our development schemes by 14 over the period. As outlined above in the ETO section we are on course to deliver the recruitment requirements. The assumptions behind these figures – for attrition and retirement – and the related evidence are the same as those in ETO so are not repeated.

As discussed in the ETO section recognising that we can give more evidence to prove the need for workforce growth and renewal costs we have produced a summary of the requirements and evidence in this area. Within the document we outline a case study on the power system engineer and power system manager roles. Amongst other items this case studies outline how we have translated the forecast workload levels into resources requirement.

As outlined above £0.5m of the cost increase in this area is forecast to be avoided by delivering efficiencies embedded within the plan. The initial proposals only fund half of the cost increase in this area so only half of the avoided cost is funded. To remedy this inconsistency the allowances should be increased either by removing the efficiency or funding the related cost.

Our modelling illustrates that between 2009/10 and 2012/13 we need to recruit 28 people across GSO just to stay at the same level of resources. When the recruitment to fill our development schemes is included (to offset post 2012/13 projected attrition and retirements) workforce renewal recruitment accounts for 61% of the total recruitment forecast between 2009/10 and 2012/13. This means that the current proposals of only allowing half of the expenditure for workforce growth and renewal in 2012/13 would not enable us to remain at the level of employees we have in place today.

The assumptions we have made in this area and our response are discussed further in the ETO section. As with workload growth more evidence surrounding this cost driver is included within the workforce growth and renewal summary we are sending separately to this document. In order to illustrate the renewal challenge and enable Ofgem to calculate sensitivities around the attrition and retirement assumptions we have included a workforce renewal model within the document.

Question 4: We invite stakeholders to comment on our proposed capital expenditure allowances for the gas and electricity system operator.

Introduction

The response to this question focuses on the key questions that PPA still have remaining about the macro issues affecting our proposed SO capital expenditure including:

- Business processes driving our investment decisions
- Deliverability
- The effects of Electricity Market Reform interactions
- Maximising synergies between our gas and electricity SO roles.

The second part of this response focuses on the justification of the timing and needs case for the expenditure on individual schemes that have not been funded in the initial proposals. We have focussed our response on the three main ESO projects and the main GSO areas of investment, giving further detail of the needs case for these investments. Since the rollover submission we have gained more knowledge on the forecast projects and our forecast has therefore been updated for the RIIO-T1 submission. The majority of projects remain in place in 2012/13 with these projects representing the main impacts if they were deferred from 2012/13.

Further details about the requirement to upgrade our data centres are contained within the GSO section of this response. Servers hosting ESO applications, utilise the same data centres so the needs case and strategy for increased funding also applies to the ESO business.

Business processes

In developing our investment plans we have fully considered the external drivers that are shaping the way we operate our systems. We have been developing the underlying business process changes that give rise to the IT systems proposed for the last three years. This has been discussed during the RRP process. The updated processes are more fully detailed within our RIIO-T1 submission in the 'Detailed plan' annex which identifies the requirement to both maintain and enhance our IT capabilities to meet future challenges. We recognise that we did not discuss these process changes as part of the rollover process but we focused in the rollover more on the resulting IT systems because these required funding in 2012/13 whereas we had funded the business process changes in the TPCR4 period.

Our focus is on the IT system developments because they can minimise future costs for consumers. Whilst undertaking our IT asset refresh programme, we will take every opportunity to use the latest standard solutions offered by suppliers to contribute towards the enhanced capabilities that we will require. Our proposals take a holistic view of the enhancement and refresh requirements to ensure the overall programme is efficient, timely and deliverable. The successful and timely delivery of the rollover programme is the foundation of our RIIO-T1 plans and the benefits they are expected to deliver.

Our business processes are continually assessed to meet our requirements and are heavily influenced through engagement with stakeholders. For example we have published our 'Operating the System in 2020' consultation and continue to hold operating forums to discuss the tools, processes and balancing services we require to manage the system in a safe, efficient and reliable manner. We have also considered the experience of other utilities internationally through visits and formal benchmarking to ensure we are aware of developments taking place elsewhere. In addition our plans are driven by the need to develop innovative solutions to some of the new challenges we are facing and we are working collaboratively with suppliers, academia and other utilities to achieve this.

We have sought to strike the most effective balance between new systems and additional resources where these options exist. In general, where an increased volume of activity could not be met by a commensurate increase in resource levels, the main benefit to consumers is delivered by IT systems that enable actions to be automated or taken more quickly and comprehensively helping enhance reliability and reduce constraint costs. Examples of this are Automatic Post fault actions, and elements of the EBS (Electricity Balancing System) programme.

We have considered the introduction of Automatic Generation Control (AGC) – as suggested by PPA in their report – and the EBS programme will deliver this functionality in 2014. This will not be able to solve all the issues associated with decarbonisation though because, although this is extensively used in continental Europe, in its current form it will not provide the optimal solution within the GB market.

In response to the comparisons made by PPA on the management of wind:

(i) It is notable that most European TSOs (for example in Portugal, Spain and Germany) who have a high load factor met by wind generation are connected to their neighbouring systems by AC connections. They therefore benefit from being connected to the wider European power grid. The GB power network is an 'island system' that is only connected to the wider European power grid by DC Interconnectors. The DC Interconnectors in effect decouple the GB system from the larger system and therefore the way in which the system is planned and operated differs to that from our European neighbours.

(ii) The electricity network in Ireland has similar 'island' characteristics to that of the GB system, and has already a high load factor that is met through wind generation. Like us the Eirgrid network operations function is engaged in developing its capabilities to manage the intermittency issues. There are however different market rules and the Irish system is small in comparison to the GB.

(iii) Although there are notable differences in the systems, the findings from our comparisons to each of these countries have been useful. We have developed aspects of these findings to meet our system specific conditions (such as AGC and visualisation techniques in the ENCC) and they have been incorporated into our plans.

Since our initial submission and following the PPA report we acknowledge that parts of our plan could have been better articulated. In further developing our submission, we have continued to reassess the way that we deliver the solutions we require to the challenges we face and have taken a more holistic approach to the programme of work. To illustrate this we have bundled individually linked projects into holistic programmes of work. Examples of this include our Transmission Analysis roadmap (TARmap) and our iEMS programme, both of which are discussed in greater detail below.

Deliverability

We continue to believe that the scale of the investments put forward for capex investments for both our gas and electricity SO roles are deliverable and that we are not increasing system risk by aiming to deliver this amount of work in a single year. Whilst we recognise that there is a risk in refreshing the hardware and software in real time system operator platforms, the risk in continuing to rely on ageing infrastructure for our critical operating systems is greater. This was evidenced by the level of P1 and P2 incidents that occurred due to ageing infrastructure early in the TPCR4 period which impacted on the operation of the system. In addition we are taking steps to minimise the risk at cut-over to the new systems. For example see the ESO opex section which discusses how we will parallel run the Balancing Mechanism system and its replacement EBS for a year to ensure continuity is maintained.

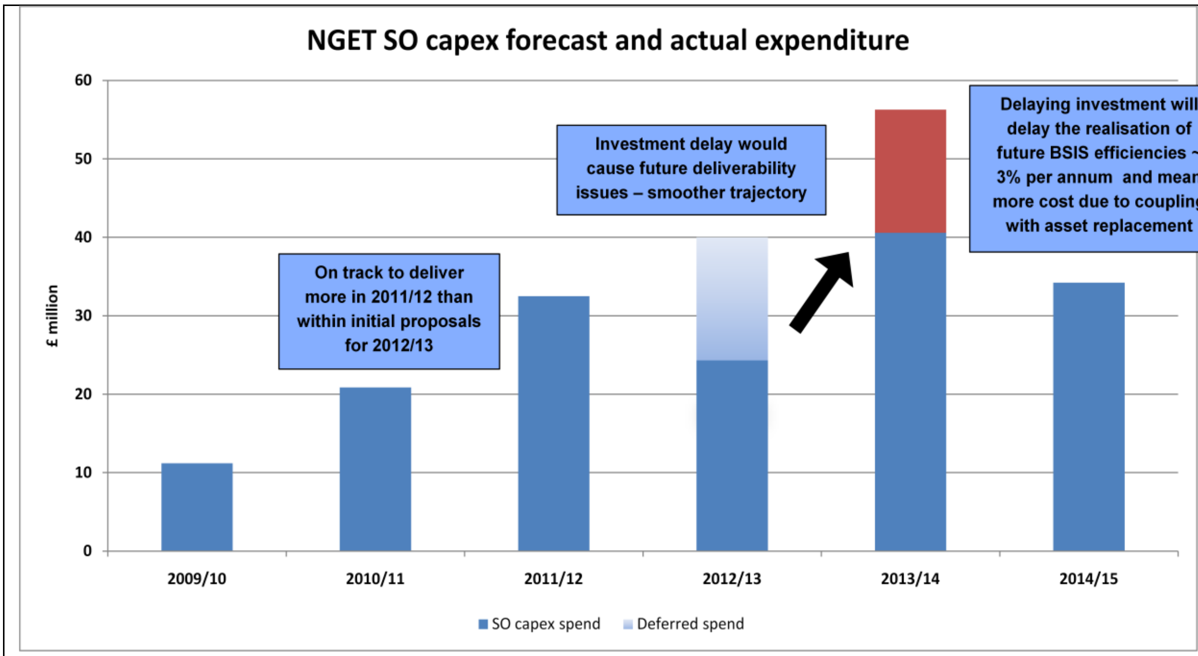
As discussed in greater depth (in the separate workforce renewal and growth paper) we have incorporated into our rollover submission 21 extra business resources to back fill key individuals that will support the delivery of the required applications. To support our delivery we have put in place contracts with Wipro and IBM for application development to complement the existing arrangements we have with other large providers TCS and Zensar. These companies offer the support and scale we require to deliver our capex plans.

Our IT transformation programme has also strengthened our ability to define strategically aligned programmes, such as TARmap, that provide benefits in reducing delivery risk and providing a more efficient delivery of a suite of interlinked applications. Furthermore, supporting our delivery, we have robust governance structures in place to challenge and review the needs case and the progress in implementing our IT requirements making sure that a holistic view is achieved in efficiently maintaining existing systems and delivering the required future capabilities.

Within our initial PPA response we outlined our internal governance processes for the sanctioning of IT projects. We can now confirm that the pilot governance process put in place for NGG in managing the technical interactions between multiple projects has now been mirrored for NGET. This complements the existing governance routes we have in place making sure that costs and system outages are minimised in delivering the IT capabilities that our System operator roles require.

Using ESO capex as a case study[16] we are currently on track to continue to deliver increasing amounts of investment in 2011/12. If the total amount of disallowed expenditure is deducted from our 2012/13 investment proposals then the graph shows that we will actually deliver more in 2011/12. As we build our delivery capabilities we will have the capacity to deliver our proposed investments. Delaying these investments would cause potential delivery issues in future years and would delay the realisation of benefits from these investments. The graph below illustrates this trend.

[16] We have excluded data centre expenditure within this analysis



Electricity market reform

DECC published their Electricity Market Reform (EMR) white paper in July setting out changes to the UK's electricity system to ensure that future electricity supply is secure, from low-carbon sources and affordable. The key elements of the reform package include:

(i) A carbon price floor (CPF) to reduce investor uncertainty, as announced in the 2011 budget

(ii) Introduction of new long-term contracts Feed in tariffs with contracts for difference (FiT CfD)

(iii) An emissions performance standard (EPS) set as an annual limit equivalent to 450g CO2/Kwh

(iv) The introduction of a capacity mechanism (CM) to ensure future security of supply

Policy will be finalised by the end of 2011 with the bill being introduced in May 2012 with the aim of legislation reaching the statute book by Spring 2013. Whilst the exact details of the final outcome of EMR are still unknown, with regards to IT impacts, we believe that this would only really necessitate the potential for a new charging system and potentially incremental links into our EBS system[17]. Our rollover submission does not contain any specific schemes to cover this. With the focus of investments in 2012/13 around IT systems to help manage wind intermittency and control of the system EMR will not have an impact on the scope of the IT projects we will be implementing in the rollover year.

SO synergies

In PPA's final report, it was suggested that there would be "more initiatives to save costs through the sharing of costs and support arrangements" between ESO and GSO. We did not emphasise this in our submission for TPCR4 rollover, however all of our Critical National Infrastructure (CNI) systems are supported by a single team which is constantly seeking efficiencies in how support is provided. Our business systems and the associated infrastructure are all managed and supported on a shared basis with costs allocated to the

[17] As stated in the assumptions for our RIIO-T1 submission, we have not put any specific funds in our plan for such changes to our systems

appropriate area of National Grid. The achievement of economies of scale through this approach is demonstrated through our IT transformation programme. However, further opportunities to directly share costs and support for GSO and ESO operational systems are limited by the fundamental differences in the physicality of balancing requirements and timescales between gas and electricity market operations, leading to different IT systems to manage the respective networks and consequently a requirement for different skill sets to support those systems.

The TO sides of the business do use many of the same IT systems, including maintenance scheduling and field force systems; these shared systems are then supported by specialist applications specific to the asset type. As we progress our Transmission Front Office (TFO) programme we expect to achieve further synergies between gas and electricity in asset management.

ESO capex

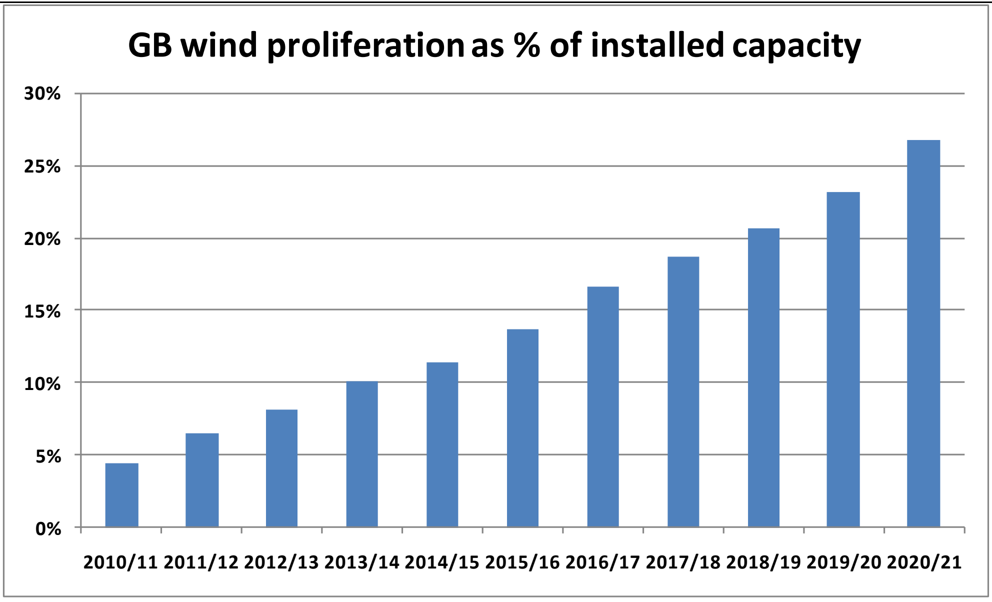
Within our rollover submission we included ESO capex investments totalling £42m in 2012/13. The initial proposed allowances of £25.3m is £16.7m short of our initial request. To help explain the needs case for the requested investments the following section focuses on the three projects that make up the majority of the funding gap. These are highlighted within the table below.

	Rollover submission £m	Initial proposals £m
Stability Control	4.0	0.0
iEMS Programme	7.6	5.9
TARmap	5.1	0.2

We recognise that the forecast for several projects have changed since we submitted our response in October 2010. To address this we will reconcile the movements on an individual scheme basis for SO capex projects and will provide Ofgem with this information in our response to the separate question that was posed.

Stability Control system

There are a number of factors that influence the stability of a power system. In particular system stability is determined by the inertia of generation, the inertia of demand, the distance and strength of the connections between generation and demand centres and the size and location of any events that can disturb system stability. Increasing amounts of installed intermittent generation such as wind, located predominantly at the periphery of the system, will have increasing effects on the stability of the GB transmission system. The graph below illustrates the forecast build up of wind capacity on the system.



This in combination with the need to actively control the setting of new SMART assets on the transmission network creates a more challenging environment for the management of system stability. Whilst our present capability is appropriate for the current environment it will not be sufficient in the future and we will have to apply conservative operating margins in order to be confident of maintaining system stability. This would likely have consequential effects on Balancing Services Incentive Scheme (BSIS) costs and the maximum utilisation of wind output.

In response to this we are working up what our precise future requirements will be to manage this area of system operation. We continue to look to learn from the experience of other system operators on how they manage increasing system stability issues. Currently there is only limited international experience on which to draw upon. However, we have spent time in understanding how the Irish system operator(s) are managing their current system stability.

Like ourselves, stability issues are more prevalent on their system than on more heavily interconnected systems such as those found on the continent, due to it being an island system. Currently, 18% of Irish installed generation capacity is wind. Whilst we are unlikely to reach similar levels of wind until 2016/17, the complexity of our future system with the installation of HVDC links, quad boosters and series compensation will require these control systems at lower levels of wind penetration. Like the Irish we intend to install a stability control system but need to refine our precise future requirements. In order to do so we have commissioned DIgSILENT, a leading industry expert, to analyse this area further.

In line with this we have reduced our forecast expenditure in 2012/13 to £2m which will be spent on research and the initial design phase. The system will ultimately enable fast control actions to be taken to ensure that stability is maintained at an efficient cost and system security is maintained following system events.

iEMS replacement / iEMS programme

The Integrated Electricity Management System (iEMS) is the fundamental control system used on the electricity network. Failure of the iEMS will result in the Electricity National Control Centre (ENCC) losing visibility and control of the electricity transmission system, substantially increasing the risk of a total loss of all electricity supplies in England, Wales and Scotland. It is therefore paramount that appropriate investments are made in this fundamental control system, to maintain the reliability and resilience of the iEMS systems and associated business processes.

The initial proposals allow expenditure on the main IEMS refresh in 2012/13 but not for related investment in the wider, linked programme. We have reviewed our complete portfolio of projects and the inherent linkages between the timing and delivery of key projects. Accordingly the iEMS programme and replacement scheme should be viewed as a complete programme of works, with the most efficient delivery of each component reliant on the delivery of the programme as a whole. Whilst we are undertaking the replacement of the main iEMS system hardware, we plan to undertake work on the other programme areas as this is the most economic approach. For example, we have forecast that to undertake the other items separately would add more than £1m to the overall cost. This means that deferring the expenditure on the programme would nearly double the related expenditure. Simultaneously we aim to minimise risk by undertaking the programme of iEMS work as a whole rather than having to undertake multiple outages to the iEMS system.

We recognise that within our original submission we did not fully articulate what the individual components that made up the iEMS programme are, so have provided further details below:

iEMS network refresh - £0.6m (part of iEMS programme)

Alignment with the iEMS hardware refresh is the most efficient method of deployment of this investment as both can be completed as a single programme. If the network refresh were to be delayed and carried out as a separate programme, this would introduce the potential for reduced reliability and an increased cost of circa £1m to complete. This extra cost would relate to the increased cost of additional hardware for parallel running, increased testing and project management overheads.

PTE emulator refresh - £0.3m (part of iEMS programme)

The emulator is required to ensure that the iEMS database and the substation database(s) are aligned via end to end testing in an offline environment. This replacement is required to ensure that the accuracy of the alarms received and the controls sent form the ENCC are 100% accurate, ensuring the integrity of our site assets and safety of our personnel. Not refreshing this hardware (which is already seven years old) would raise reliability and safety risk.

GI74 replacement - £0.1m (part of iEMS Programme but was formerly included within other critical ops)

This scheme looks to foster the replacement of bespoke legacy GI74 protocol with the industry standard IEC870 protocol. Initially work will be undertaken at the ENCC and at four substations to upgrade communications between the iEMS and the substation control systems (of differing manufacture) as pilot projects. This will help identify application and implementation issues, process impacts, risks and benefits and finalise the requirements.

The replacement of our bespoke system with a modern industrial standard, will remove obsolescence issues and enable communications with a greater diversity of equipment / substations connected to the network.

Videowalls refresh - £0.4m (part of iEMS programme)

The current videowalls were installed as part of the BETTA programme in 2004 and although the operating software has been regularly updated, the current hardware will not support the enhanced requirements to facilitate improved situational awareness in the Control Rooms. These requirements are incorporated into the refresh programme.

Automatic post fault actions - £0.2m (part of iEMS Programme but was formerly included within other critical ops)

This capability is required to create sequences of control actions that automatically operate following a fault on the power system, with minimal control engineer input. The complexity in the number of post fault actions and the requirement for shorter implementation timescales than currently possible is required, as the impact of intermittent renewable generation increases. These predefined actions facilitate running the system in a less risk averse manner and therefore more efficiently without reducing safety and system security.

Transmission Analysis Roadmap (TARmap) programme

Transmission Analysis is carried out from seven years ahead right through to real time and post event. It is used to help design and run the network as securely and economically as possible. Existing processes are manually intensive and systems have limited capabilities for optimising or modelling dynamic equipment or demand side services. This means both systems and processes have limited capacity to adequately model the more volatile operating environment that is emerging as a result of the increasing intermittent generation as outlined in the “Gone Green” scenario.

We have identified an investment programme up to 2020 to deliver the required improvements to Transmission analysis capabilities and to maintain the IT systems assets health.

The investments will affect a common set of business resource across the business, and are focussed on specific systems and processes. The same systems and processes cut across multiple timescales. Therefore a programme approach has been developed to ensure the dependencies are managed effectively and maximise the benefits across investments by aligning and optimising business processes, systems data and new capabilities.

The programme stage will run until the end of the rollover period, setting the foundations for improvements to transmission analysis. The definition phase will optimise the delivery of the overall investment optimising the enhancement of existing business design and core requirements already established. As a programme of work this will allow OLTA platform to respond to the challenges of decarbonisation and changes to technologies deployed on the transmission system, which is likely to include the following functionality:

- Enhance current analysis capabilities from 1-2 periods a day up to 48 periods per day
- Facilitate the creation of multiple scenarios for multiple time periods e.g. high wind, low wind, high interconnector imports / exports
- Facilities to share working models between multiple users
- Facilities to provide advice on automatic corrective actions
- Facilities to optimise control variables eg voltage and Quad Booster tap positions
- Automation of manual repetitive tasks and workarounds

The foundation to the successful delivery of the TARmap programme is the replacement of the current hardware, as none of the other developments in the transmission analysis suite can take place without refreshing these assets, some of which have already been sanctioned and the rollover allowances granted. The most efficient delivery is to combine the asset refresh and capability enhancements ensuring that the performance of the hardware can meet the requirements of the software enhancements. Separation of these core elements will result in the inefficient delivery of component parts resulting in separate projects, increasing the hardware requirements for testing, and the testing and resource requirements for delivery. It is estimated that should individual elements be carried out separately this will add an additional cost to the programme of circa £1.5m. The alignment of individual software enhancements detailed above allows for the capability developments to be carried out optimally by the provider ensuring that the correct solutions are delivered, and reduces operational risk of the piecemeal introduction of new software.

The overall delivery is aligned with the introduction of SMART transmission assets and increased renewable connections. The deferral of these elements would result in us not having the capability to efficiently plan, operate and manage the system. We would therefore have to adopt a risk averse approach to operating practices to ensure system security is maintained, increasing constraints and operating costs, resulting in the benefits of the investments by the TOs not being fully realised.

Detailed below are specific areas of the sanctioned TARmap programme that we plan to undertake within the rollover year:

OLTA Hardware - £2.5m (other asset health)

The current hardware was purchased in 2006, seven years before we are forecasting hardware refresh. This investment is required to maintain reliability of the system – required to perform operational planning for the ENCC – and provide the increased capability to enable OLTA (Off-line transmission analysis tool) to facilitate the increase in scenario planning to up to 48 studies per day. The hardware refresh is necessary to provide the platform for the transient and dynamic stability tool and Super OLTA deployment. OLTA is a memory and processor intensive application which will benefit significantly from being able to take advantage of hardware improvements allowing studies to be undertaken faster, freeing up resources to optimise the system.

Improved Modelling - £1.3m (Super OLTA)

Our existing business processes are already being stretched by the decarbonisation of the generation mix, in order to facilitate the increase in scenario planning. The improved modelling capability is delivered by the software update to OLTA; this will also provide the enhanced capability needed to provide a more efficient use of the OLTA tool enabling automation of current manual actions. This software update cannot be deployed on the current hardware due to incompatibility issues.

Flow Management Tools - £0.8m

The proposed investment in flow management tools is to provide predicative advice of the position of SMART transmission devices (Quad Boosters, Series Compensation and HVDC control) to provide optimal operating plan, and maximise the benefits of the investments by the TOs in these SMART assets. The investment will help control engineers optimise for a full range of contingencies and scenarios ensuring that thermal limits are managed to provide maximum utilisation while avoiding potential system overloads.

Probabilistic System Security (other critical ops breakdown) £0.5m

The development of this project will allow a move from operation based on rigid Security and Quality of Supply Standards (SQSS) to more of a probabilistic risk based approach. The tool will provide optimal operating advice dependent on current system risk versus cost, helping reduce system operation costs whilst still maintaining suitable security standards to maintain reliability.

GSO capex

Within our rollover submission we included GSO capex investments totalling £45.1m in 2012/13. The initial proposed allowances of £28.3m is £16.8m short of our initial request. To help explain the needs case for the requested investments the following section focuses on the projects that make up the majority of the funding gap.

We recognise that the forecast for several projects have changed since we submitted our response in October 2010. To address this we will reconcile the movements on an individual scheme basis for SO capex projects and will provide Ofgem with this information in our response to the separate question that was posed.

Integrated Gas Management System (iGMS)

iGMS is the key operational system for system operations and has been categorised by DECC as Critical National Infrastructure (CNI). It is made up of three main integrated functional components (Network Manager, Business Applications and Management Information System). Each of these components is an integrated suite of functional applications which supports business capabilities and processes in different ways.
The critical nature of iGMS demands appropriate levels of resilience and reliability, achieved through robust design and support arrangements underpinned by current vendor support for all components of the system.

In our TPCR4 Rollover submission we outlined the approach we were taking to replace this system, the infrastructure and applications for which were procured in 2002 to support the original development project to replace a number of legacy systems. The approach was based on a number of drivers, with aspects of the approach and the criticality of timescales primarily driven by the removal of vendor support by Hewlett Packard (HP) for the hardware from 2012.

We sought independent recommendations from HP and Oracle in considering the options and drivers for replacement of the iGMS application software to ensure the most economic, efficient and deliverable route to eventual upgrade or replacement of iGMS before vendor support was withdrawn, whilst also maintaining supportability in the short term.

Replacement of the full suite of iGMS hardware, infrastructure and software was acknowledged as complex. Internal and external experts considered options for replacement of iGMS, short listing three key options:

(i) Upgrade of the HP servers with no software upgrade and a parallel project to deliver iGMS application replacement (a ‘big bang’ approach).

(ii) Full upgrade of hardware and software to refresh the existing infrastructure, followed by separate investments to replace the iGMS applications (phased approach).

(iii) Hardware replacement with more flexible commodity servers and upgrade of software incorporating flexible architecture, to be followed by separate investments to replace the iGMS applications (phased approach).

Options (i) and (ii) were rejected on economic, timescale and strategic alignment grounds. Option (iii) was recommended as the most efficient strategic option as it mitigated the hardware risks by 2012 whilst contributing to the functional replacement of the iGMS components by 2018. The key underpinning feature of this recommendation was that whilst none of the options provided the opportunity to replace the iGMS within the period of guaranteed hardware vendor support, this option did allow the hardware to be replaced in time, and also provided a platform for the subsequent application replacement.

During 2010, further information became available relating to the potential to support and operate the current iGMS system beyond 2012. Factors contributing to this included:

(i) the vendor (HP) cessation date for support of the iGMS hardware had been extended to December 2014 from 2012

(ii) significant improvement in system reliability and performance as a result of changes to support arrangements and tactical asset health deliverables

(iii) the successful implementation of ancillary hardware upgrades to alleviate capacity constraints

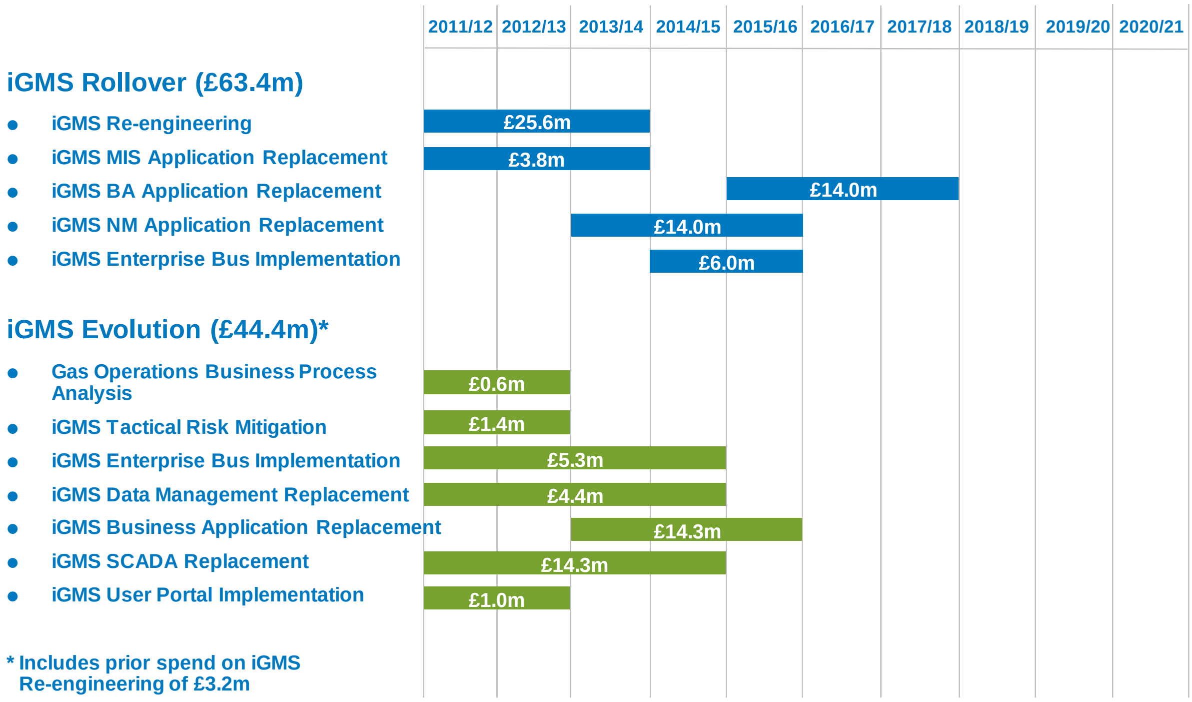
Following identification of risks affecting cost and delivery of the project, and improved system reliability, the project was modified to undertake a new two part review of:

(i) the strategy for iGMS to deliver its replacement

(ii) the current and forecast health and capacity of the systems in light of the changes identified above

The review completed in December 2010 and confirmed that the system was supportable and operable to the end of 2014. The extended supportability of the current system created the opportunity for an alternative approach to the replacement of iGMS hardware, software and applications without the need to refresh or re-engineer the infrastructure first.

Our July 2011 RIIO-T1 submission details much of this evolution of strategy, and the diagram below (taken from our RIIO-T1 submission) presents both the TPCR4 Rollover and RIIO-T1 submissions. Note the £1.5m referred to in the Ofgem Initial Proposals for iGMS Replacement relates to the iGMS Network Manager application replacement (total cost £14.0m, £1.5m of which is in 2012/13).



This revised approach delivers full replacement more cost effectively and quicker than the previous strategy. The total cost of £44.4m (£10.1m in 2012/13) for the revised approach is £19.0m less than the previous strategy (£9.4m as reported in TPCR4 Rollover[18]) and the total length of time to replace the system reduced by approximately two years (note the original re-engineering project would replace the hardware by 2012 and would be followed by phased application replacement). The figure above compares the original and new replacement strategies for iGMS.

This more efficient approach, whilst costing more in 2012/13 than our original TPCR4 Rollover submission, will deliver benefit in the longer term. It is designed as an integrated programme and Ofgem's suggested reduction of £1.5m funding for 2012/13 will extend the timescales for delivery and will risk increasing costs for the programme as a whole, and therefore we believe it is not justified on an overall efficiency basis.

[18] £7.9m iGMS Re-engineering to replace hardware and £1.5m to start the programme to replace applications

[TEXT REMOVED]

Business capability (£1.4m reduction)

A number of investments were identified in the rollover plan to reflect the need to develop and modify our operational capabilities in the face of a changing operational environment. This requirement was further reviewed in our RIIO-T1 submission, which identified and reduced requirements for this in 2012/13 to £0.2m and therefore the originally proposed investments around demand forecast and NTS interfaces have been moved out of 2012/13. We intend to continue development of the requirements and modelling in this area and the total of £0.1m propose allowance is inadequate for this work.

Asset health investments (£1.1m reduction)

There are a number of asset health investments (Lotus Notes, Information Provision, Business Information Systems, etc) in the rollover submission for work to ensure the ongoing reliability of a range of systems that support critical control room operations. All of these have been deferred by PPA in their proposals for further review in the RIIO-T1 review. Asset health investments are planned against a defined refresh schedule set to optimise service and deliverability risk, coupled with specific analysis on the requirements around the specific system. Deferral of this schedule increases the risks we carry as a business around failure of operational systems and the consequential operational and commercial impacts.

GNCC Capex (£0.7m reduction)

The Gas National Control Centre (GNCC) is responsible for the 24 hour operation of the NTS in Great Britain and for facilitation and residual balancing of the GB gas market. This role is physically carried out from the Gas National Control Centre (GNCC) itself in Warwick and two associated Emergency Control Rooms (ECRs) which are not manned but held in warm standby should the GNCC itself not be capable of carrying out the role due to evacuation of the site or significant systems failure. The GNCC, as well as housing the control room, also contains the planning office which provides planning and operational support to the control function, and the incident control room which is used for the management of situations such as National Gas Supply Emergencies. The control room is designed to accommodate 7 shift roles, and the support office has been progressively modified over the last 3 years to increase capacity from 18 to 32 desks (and has now reached capacity).

The GNCC was commissioned in 2003/04, was effectively a direct copy of the previous control room in Hinckley, and has to date remained substantially unchanged. There are now a number of drivers for change that will require us to develop the control room environment, and to ensure these are implemented efficiently and safely will need to be taken forward in a coordinated manner:

- asset health – much of the equipment is approaching 10 years old and needs replacement and refurbishment. Carrying this out whilst ensuring full operational control at all times provides a significant logistical challenge and our programme of work is designed to ensure this is completed effectively
- changing operational environment – as stated elsewhere in our submissions, the changing operational environment in the UK is driving increased workload into the planning and operational functions for which we expect to need increased headcount in a number of areas, including control room (increasing by 1 shift position in 2012/13 and a further position in 2015/16) and additional staff in planning and support functions, increasing planning office manning from 35 to 42. In a control environment this does not just involve the introduction of extra desks, it requires a full review of the control room layout to ensure optimum performance and maximised communications between staff to mitigate risk of error, as well as changes to systems and support services
- human factors – since the development of the GNCC, there have been significant advancements in the understanding of human factor impacts in control room environments. This work impacts a number of areas of control room operation that aim to maximise the performance of staff who are working shift patterns, and also to safeguard the health of these staff by developing their working environments, the shift working arrangements and also the human machine interfaces. We are taking advice from the HSE and other appropriate bodies to ensure that best practice is followed in the development of the new designs
- IT system developments – over the next 5 years the iGMS system is going through a major replacement programme (iGMS evolution) which has been discussed elsewhere in more detail, and the introduction of this new system will in itself create a new operating dynamic in the control room requiring revised desk layouts and role definitions, as well as a significant disruption to normal operations during its implementation

These changes are all interacting in the near future and the plan we have put in place which involves engaging architects, designers and relevant equipment manufactures during 2012/13 for delivery and implementation in 2013/14 ensures that the layout is resolved in time to accommodate the systems and staffing implementations and also to mitigate the asset health and human factors issues we are also dealing with at the moment. Delays to this programme will have potentially serious implications on our change programme and may lead to inefficient deliveries as changes have to be made in multiple stages rather than as part of a single programme.

Xoserve (£3.8m reduction)

Wholly owned by National Grid and the independent Distribution Networks (Wales & West Utilities, Northern Gas Networks and Scotland & Southern Gas Networks), Xoserve delivers transportation transactional services on behalf of all the major gas network transportation companies, providing one consistent service point for the gas shipper companies, thereby meeting transporters' obligations for efficient, contestable, and transparent service provision to the gas industry.

Acting as the Gas Transporters' (GTs') agent, Xoserve's operational services are defined and detailed in the contract governing its deliverables, the Agency Service Agreement (ASA). Xoserve is also responsible for providing process and system solutions to GT obligations introduced and developed as part of the Uniform Network Code (UNC) Modification process. This includes operation, maintenance and development of the UKLink suite of systems, which includes Gemini.

Gemini

The Gemini system supports Gas Capacity Management, Energy Balancing and associated invoicing processes on behalf of gas transporters and the shipper community. It is closely integrated with both iGMS (with which it shares a common physical infrastructure) and other UKLink systems. Gemini is owned by NGG Transmission and managed under contract by Xoserve on our behalf, whereas the other UKLink systems are owned by all transporters through Xoserve.

Following stability issues in late 2007, Xoserve appointed Capgemini to conduct a health check of the Gemini system and inform the timing and focus of a re-platforming exercise given the age of the system infrastructure. Following this, Xoserve reviewed the planned infrastructure re-platforming and engaged with us to develop a combined view on the timing and nature of this investment.

Forecast spend on the Gemini Re-platforming Project (GRP) was £17.0m in our TPCR4 rollover submission, including £7.2m in 2012/13. Since then, Xoserve have reported upward pressures taking the 2012/13 forecast above £9m. Whilst we are actively working with Xoserve to manage these costs down, Ofgem's proposed 5% (£0.4m) reduction in the cost of this evolving project is not appropriate given these external upward cost pressures.

There is also an expectation of significant regulatory driven change over the next few years which will drive a number of systems developments. As Gemini is the core commercial system for the UK market, we can be confident that any rule changes that are implemented via the UK or EU regulatory processes will have an impact on the operation or design of the system (it is also likely that other systems such as IGMS may be affected). Examples of the types of change we are expecting to be statutory, regulatory or EU driven include:

(i) changes resulting from the development of European Network Codes under the 3rd Package (such as changing of the start of the gas day from 06:00 to 05:00, to align with European requirements, or changes to the Capacity Allocation Methodology which will drive material changes in the Gemini system)

(ii) likely modifications to the Exit arrangements following implementation of Exit Reform in October 2012

(iii) changes required as a result of the review of SO incentives for 2012/13

Ofgem's proposal to reduce funding for Gemini releases by 75% (£3.4m) is exacerbated by the proposed removal of any option to log up costs related to this type of development[19]. Any

[19] It is our expectation that, should the logging up mechanism be removed for 2012/13, recovery of existing logged up costs will not be affected.

requirement imposed on us by the EU, Ofgem or wider industry will cause us to incur costs in excess of this proposed allowance without any mitigation for the risk we face.

Since our Rollover submission in October 2010, we have seen continued development of the new European codes and have a better understanding of the timescales (and therefore potential costs in 2012/13) than before. We are likely to see the first of the codes (Capacity Allocation Methodology) completing its process through to the end of comitology during 2012. It is likely that we will need to start specifying process and system changes ahead of this to maximise the likelihood of delivering the required change within the required timescales following comitology. We will also be developing the impact assessment for the next set of codes which will be delivered soon after. Ofgem, through the effective removal of funding to develop the necessary changes to support the European processes, risk delaying the implementation of the new European network codes in the UK.

Our best view of the costs we will incur in 2012/13 is circa £2.0m:

- £1.5m for Gemini development (for example to meet the requirement to split ASEPs at interconnectors)

- £0.5m associated with the development of other changes, which may include output from the Security of Supply (SoS) review currently ongoing with Ofgem (e.g. post-emergency cashout arrangements, development of a commercial demand-side interruption mechanism and increased management information production to show Shipper and Network performance against obligations)

In addition, it is likely such changes will impact National Grid systems such as iGMS and MIPI. We expect to incur at least £0.5m specifically associated with design work to support the implementation of the European codes (such as changes to the gas day and Market Information Provision changes in the MIPI system), and the development of impact assessments of future European code requirements

Given the increased clarity over timing and likely impact, we propose that an ex ante allowance should be provided for these costs.

The above assumes the role of Xoserve remains unchanged and the current ownership and management arrangements between us and Xoserve for the Gemini system continue across the RIIO-T1 period. Any change to these assumptions may require a fundamental review of the Gemini management strategy.

Question 5: We invite stakeholders to comment on our proposal our proposal to disallow expenditure relating to network flexibility on the gas transmission network.

Executive Summary

There has historically been no recognition in the commercial framework of the evolution of needs of existing NTS users, with a zero base allowance for network developments explicitly indicating that the needs of existing network users will remain static. This assumption is no longer valid, with supplies dramatically changing now and into the future and demand patterns changing over the next decade.

In addition, the NTS has been designed to manage peak demand days however many of the expected issues will arise away from peak. This brings into question the validity of the existing design standards. We have already started engagement with industry on the appropriateness of using the 1 in 20 winter peak as a design standard, and will be furthering this debate at our next stakeholder event in November 2011.

Given these changing assumptions, the majority of the capabilities necessary to manage the future gas flows were not, and could not have been reasonably considered when setting existing revenue drivers and have therefore not been funded before.

It is imperative that, given the lack of credible alternatives to a physical solution in Scotland, some of these investments are progressed at the earliest opportunity to ensure we can continue to meet our 1 in 20 obligations and therefore maintain security of supply. Whilst the initial proposals do not support these investment requirements, to mitigate disruption to existing and future consumers we are now progressing investment options related to moving gas north into Scotland as we do not believe it appropriate to allow Scottish demand to bear the increasing risk. Delaying the start of this work by 18 months through lack of funding next year will further increase risks to Scottish demand when St Fergus supplies are low.

Enhanced capabilities in the heart of the NTS are also necessary to manage evolving east to west and west to east gas flows and to meet the forecast needs of our customers. These capabilities minimise future commercial risk and failure to do this in the period extends the risk of material system management costs to both ourselves and the end consumer.

Introduction

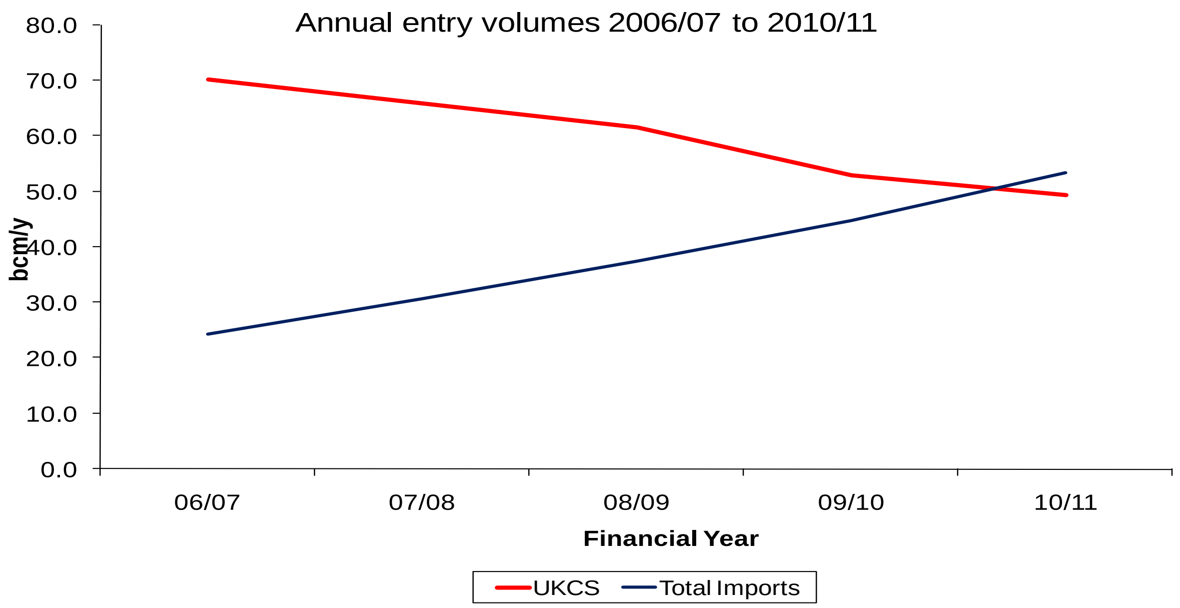
Our understanding of the implications posed by changing user behaviour on the network and the need for increased flexibility on the NTS has evolved since our submission in October 2010. We have hosted engagement workshops to seek stakeholder views and to provide detail of the current and future challenges resulting from customers' evolving needs. Further workshops are planned for early November 2011 to continue this debate. Where investments to manage the long term needs of our stakeholders remain a priority, we are committing to spend to ensure their successful timely completion.

There has historically been no recognition in the commercial framework of the evolution of needs of existing NTS users, with a zero base allowance for network developments explicitly indicating that the needs of existing network users will remain static. This is in contrast to electricity transmission, where there is explicit recognition that the network is required to evolve over time to meet changing customer needs, with a base allowance to develop the network and a mechanism to adjust this allowance to match the rate of change of user needs. Such investment is required to optimise and manage the level of constraints on the electricity transmission system, and can be assessed for efficiency against the historical trend of constraint costs.

As evidenced by the limited constraints on the gas network over recent years the approach to gas transmission system evolution has been appropriate in the past, with network developments triggered by signals for incremental capacity. More recently, however, the needs of existing users of the NTS have been changing and will continue to do so into the future as gas supplies and demand patterns change.

The closure of coal, oil and nuclear generation plant is likely to increase dependency on gas fired generation plant and the increasing penetration of wind generation will drive different (and increasingly volatile) demand profiles. These combined effects will drive very different needs from the NTS to support the decarbonisation of electricity generation in the UK.

It is clear that UK gas supplies have been changing over the past five years, with the introduction of significant LNG importation capability, Norwegian gas landing at Easington, developments in gas storage and increases in European interactions through the interconnectors. As can be seen in the graph below the UK is now dependent on imported gas, and since 2010 has received more gas supplies from imported sources than the UK Continental Shelf (UKCS), bringing different physical plant and commercial characteristics into different geographical locations around the UK:



One of the main consequential impacts of this evolution is the fact that we are increasingly experiencing issues off peak (as evidenced in the Scotland example below). Previously the NTS was designed for peak demand conditions under a range of credible supply scenarios, with an assumption that a network sized for peak demand will be capable of managing all other flow conditions. This was appropriate for steady state, predictable flow conditions however it is not appropriate for dynamic, less predictable conditions. Many of the network studies identify Network Flexibility investment requirements at demand levels far below peak and within supply ranges now seen on the network (an instance of this is explained in the Scotland example below).

Part of the difficulty in understanding the need case and efficiency of Network Flexibility investment in gas is the lack of historical trend of constraint costs. We are entering a period where constraints on the NTS will become a material issue leading to physical issues and significant commercial costs for the UK, and we need to act to mitigate them by enhancing the capability of the network in a timely manner. Considering the lead time to plan, develop, build and commission transmission assets, waiting until the full effect of these issues is seen will lead to a multiple year period before effective and efficient solutions can be put in place.

Funding

Our network developments have historically been funded through incremental revenue drivers in response to incremental capacity signals from the market. These revenue drivers are agreed between Ofgem and ourselves and set using an agreed methodology to model and analyse the NTS, determining potential investments which would be required to meet the incremental requirements within the parameters of the agreed supply and demand scenario.

This process identifies network capabilities required to support the incremental capacity based on the use of robust and reasonable assumptions of supply and demand levels[20]. This additional capacity may be delivered through a combination of investment, commercial arrangements or acceptance of operational risk. Where reality proves to be outside the range of assumptions used in this modelling there may be a requirement for additional network capabilities which could not reasonably have been identified at the time. This is the case for the drivers of the Network Flexibility investments.

The matrix below shows, for each of the Network Flexibility investments, the drivers for the investment and whether this was (or could have been) identified at the time previous revenue drivers were set:

Driver	Investments	Inclusion in previous revenue driver?

[20] These agreed supply & demand patterns are constructed to reflect information received from the industry during the Transporting Britain's Energy process.

Insufficient St Fergus entry flows to support Scottish demand	Moffat 8MW Compressor – north facing compression Aberdeen FCV (Flow control valve) Aberdeen Re-wheel (1 unit) Avonbridge Re-wheel (2 units) Bishop Auckland Re-wheel (1 unit) Asselby Compressor (2 × 8MW)	None of the investments related to this driver have been included in previous revenue drivers. In the Incremental Entry Capacity Revenue Driver analysis completed in August 2006 prior to TPCR4, the analysis methodology, as agreed with Ofgem, stated that a "Free Increment" should be calculated for each aggregate system entry point (ASEP) to represent its maximum entry flow capability, given a national demand level of approx 580mcm/d, fixed supplies at neighbouring ASEPs and current system infrastructure at that time. Incremental levels of entry flow were then considered on top of this Free Increment level and, only then were appropriate system reinforcement projects identified. A Free Increment and levels of reinforcement were calculated for each ASEP under the three supply scenarios that were considered during TPCR4 (Auctions+, Transit UK and Global LNG). The most likely revenue driver which may have triggered these investments is that used for the Milford Haven LNG importation projects. The NTS infrastructure used in the analysis included the pipeline and compressor projects which were identified following the signal for 87.7mcm/d (950GWh/d) of Entry Capacity at Milford Haven. As a result, the Free Increment calculated for Milford Haven ASEP ranged between 80.17mcm/d (868GWh/d) and 86.9mcm/d (940GWh/d) depending on the supply scenario being considered. (These levels were lower than the 87.7mcm/d (950GWh/d) capacity signal due to high levels of interaction with some ASEPs. For example, entry flows at Bacton were forecast to be 190mcm/d in the Global LNG and Transit UK scenarios where the free increment at Milford Haven was lower. The level of Bacton flow was significantly lower when the analysis to determine the Milford Haven reinforcement projects was first completed.) When calculating the Free Increment, a terminal of minimal interaction was used to act as a supply balancing point and in the case of the Milford Haven analysis, St Fergus was used. The forecast peak flow at St Fergus ranged between 98mcm/d and 118mcm/d depending on the supply scenario being considered and following the calculation of the Milford Haven Free Increments for each scenario, the St Fergus flows had reduced to a range of 74mcm/d and 96mcm/d. Off-peak, we are now frequently seeing supplies below 30mcm/d today. These levels of St Fergus flow (at which no system reinforcement was required) are far in excess of the current forecast levels of St Fergus peak supplies which are expected to reduce to approximately 50 mcm/d by 2020. When additional Incremental levels of entry flow were then considered at Milford Haven, and St Fergus supplies further reduced accordingly, reinforcement projects which are comparable to some of the Network Flexibility projects were identified. For example, for a 46.16mcm/d (500GWh/d) increment at Milford Haven (total level of Milford Haven supply of 129.5 mcm/d) on the Transit UK scenario, the St Fergus supply was reduced to 28.6mcm/d and the following reinforcement was identified as part of a wider suite of projects: • Bishop Auckland Reverse • Wooler Reverse (comparable to Moffat Compressor Project) • 10MW compressors at Pannal, Ganstead & Asselby (comparable to Asselby Compressor Project) As no signals have been received for further incremental capacity at Milford Haven, no funding has been received via the existing Milford Haven revenue driver to progress these projects.
Central Corridor E-W/W-E flows	Peterborough Compressor (2 × 8MW units)	This investment has not been included in previous revenue drivers. We are increasingly seeing a wider range of flows through Peterborough Compressor station in response to varying supply levels on the east and west side of the system. The range of flows seen extends to the limits of, and on occasion beyond, the operating envelope of existing compression. These two new compressors are to replace the existing units and provide increased flexibility to operate Peterborough throughout this wider range of flows. This does not necessarily mean an increase in total power at the station or increased levels of flow through the units. This investment has not therefore been identified through any previous revenue driver analysis as only projects which are beyond current plant capability would be included, rather than works that are required to improve the overall efficiency of the station.
	Kings Lynn Compressor (8MW)	We have received partial funding for this investment through the Isle of Grain phase 3 revenue driver. Extra Power at Kings Lynn was identified in each increment tranche of the Transit UK scenario revenue driver analysis upon which the Isle Of Grain Revenue Driver was based. As we received an incremental signal at Isle of Grain in October 2007 for 246GWh/d (23mcm/d) the triggered revenue driver has provided 5 years worth of incentive revenue. We believe that an adjustment would be appropriate to account for the level of revenue already received. It was not efficient to progress this investment at the time of the incremental signal in 2007 as the forecast levels of supply at Bacton had fallen significantly from the 190mcm/d that was forecast in the Transit UK scenario in 2005.

	Peterborough Flow Control Valve	This investment has not been included in previous revenue drivers. The Peterborough FCV is required to manage levels of flow towards Bacton to aid with levels of IUK export. This type of flow pattern was not considered as part any entry capacity revenue driver analysis as this analysis was conducted on a steady state basis. It is worth noting this project is also required to support potential offshore storage at Bacton, and therefore forms part of the current discussions with Ofgem regarding future revenue drivers.
	Peterborough Re-wheel (1 unit*) (to operate in a central range of flows – not specific to higher or lower flows)*	This investment has not been included in previous revenue drivers. Re-wheels for higher flows through the site have been identified as part of the Isle of Grain revenue driver analysis through which we have received incentive revenue (following the incremental signal at Isle of Grain in September 2007) however there has been no funding for a re-wheel to accommodate more efficient operation in the current range of site flows.
	Kings Lynn Compressor re-wheel ***(for high flows)***	This investment has not been included in previous revenue drivers. Extra Power at Kings Lynn was identified in the Isle of Grain revenue driver analysis (even at the smallest increments) however re-wheels for high flows were not included. This investment is required to manage the within day flows on the NTS relating to profiling of the interconnectors and interactions with the Isle of Grain.
	Kings Lynn Compressor multi-junction	This investment has not been included in previous revenue drivers. This project is required to help manage the transition between export and import of interconnectors and the management of linepack in the Bacton area. These dynamic within-day changes were not considered in the agreed revenue driver analysis, which was undertaken through steady state analysis.
	Panel & Nether Kellet Flow Control Valve	This investment has not been included in previous revenue drivers. This project, as agreed with KEMA, is required to help manage the transition between supply patterns and the management of linepack between the East and West of the NTS. These dynamic within-day changes were not considered in the agreed revenue driver analysis, which was undertaken through steady state analysis.
	Churchover FCV	This investment has not been included in previous revenue drivers. This project, as agreed with KEMA, is required for the management of linepack in the South West of the NTS as a result of high Milford Haven flows and changing supply levels at other ASEPs. These dynamic within day changes were not considered in the agreed revenue driver analysis, which was undertaken through steady state analysis.
	Alrewas Flow Control Valve	This investment has not been included in previous revenue drivers. This project is required for the management of linepack between the East and West of the NTS. These dynamic within-day changes were not considered in the agreed revenue driver analysis, which was undertaken through steady state analysis.
Efficiency under Central Corridor and SW Demand scenarios	Huntingdon Re-Wheel (1 unit) ***(for efficiency purposes)***	This investment has not been included in previous revenue drivers. Huntingdon plays a key role in supporting pressures in the south of the NTS. The network configurations required to manage variable central corridor flows (across a range of off-peak demand levels) pull gas away from the South of the network. This leads for a requirement to run Huntingdon across a wide range of flow levels to meet southern assured pressures. This re-wheel will provide higher efficiency and increased flexibility to run across the required range of flows. This investment has therefore not been identified through any previous revenue driver analysis as only projects which are beyond current plant capability will have been included rather than works that are required to improve the overall efficiency of the station.
Changing SW flow patterns due to a combination of load growth and changes in supply distribution and behaviour	Lockerley Compressor (8MW)	Lockerley was originally built as a single unit site with standby to support the connection of Seabank power station signalled in 1995. We have not received funding for this site as part of any revenue driver since this original investment was made. Changing flow patterns are requiring parallel running of the main and standby units, effectively removing the standby capability at the site. A third unit (salvaged from the recently decommissioned Peterstow compressor site) is therefore required. Extra Power at Lockerley was identified when calculating the Portland (Mappowder) entry revenue driver, however as no incremental signal has been received at this storage site for either entry or exit capacity, we have not received any funding to progress this project.
Updating ageing infrastructure to operate in response to significant changes in supply behaviour	Bacton Rationalisation	This investment has not been included in previous revenue drivers. The investment is required to meet the challenges as set out in our Rollover submission, which relate to the transient nature of flow patterns. Changes to the composition of offshore supplies, along with interactions with the interconnectors and Isle of Grain are driving a need for enhanced control capability at the site which this investment will deliver. These dynamic within-day changes were not considered in the agreed revenue driver analysis, which was undertaken through steady state analysis.

As can be seen, in the majority of cases no funding has been received for these investments as it was not reasonable to foresee the requirement based on information available at the time, and they were not therefore explicitly included in any revenue driver. For those investments where incentive revenue has been received, we believe an adjustment is appropriate to account for the level of revenue already received.

For gas transmission, unlike electricity transmission, there has up to now been no concept of reducing entry flows at points driving changes to necessary network capability and a reduction in existing capacity obligations. This is because the UK has not previously faced material reductions in gas supplies at particular points which impact upon the operation of the network. Under the current capacity regime it is also not clear what the potential indicator for such decremental signals may be. Capacity currently provides users with the option to flow gas up to that level on the system, but does not oblige them to do so. Additionally, given the incremental capacity regime, users cannot directly signal reductions in their capacity requirements (and obligations) going forwards.

The revenue drivers provide remuneration related to the incremental capacity which by design, incentivise us to deliver the necessary capacity in the most efficient manner, providing us with incentive revenues for the duration of the incentive scheme (five years for TPCR4) to manage any additional risk we choose to accept. We then manage the risk posed by incremental capacity requirements through contracting for services (such as turn up contracts), accepting increased operational risk (i.e. accepting exposure to operational costs to manage any issues on any given day) or investing in enhanced network capability.

For situations where investment is made to support incremental capacity in the incentive period, there is clarity over the treatment of these capital costs and the associated funding. There is less clarity, however, over the future treatment of the opex costs associated with commercial solutions, or for situations where investment is required after the incentive period to provide enhanced network capability to manage flows which were not reasonable to foresee or were only forecast to occur outside the incentive period. We welcome the opportunity the RIIO-T1 process presents to discuss this with Ofgem for resolution from 2013/14 onwards.

It is important to note that, where investment has not yet been made for those projects which were foreseeable when the revenue drivers were set, the incentive revenues do not provide full funding for the likely cost to reinforce the network to a point where operational risk is not impacted by the incremental capacity. The current five year incentive scheme funds up to 38%[21] of the total investment cost (applicable at that point in time) and where we consider an alternative to a build solution is the most efficient answer, these revenue streams cease at the end of the incentive[22] period.

Investments which could not have reasonably been foreseen, either by the agreed modelling methodology for setting revenue drivers or by our supply and demand forecasts (as informed by industry through our annual Transporting Britain's Energy (TBE) process), have not been funded.

[21] 38% is calculated as the comparison of 45 year revenues received between scenarios of where:

- zero investment is made against the revenue driver
- investment is made perfectly in line with the parameters of the revenue driver, assuming a rate of return of 6.25%.

[22] Once the incentive scheme finishes, revenues are amended to only remunerate actual expenditure deemed economic and efficient by Ofgem. If no investment has been made by this point, there is no future funding.

SO incentives on gas shrinkage and natural gas venting

KEMA has suggested that the investments relating to the facilitation of more efficient operation of the network identified above should be funded through the SO incentives. This is in direct conflict with the position set out in Ofgem's "Strategy for the next transmission price control – RIIO-T1 Outputs and incentives" document published on 31st March 2011 which states in paragraph 4.48:

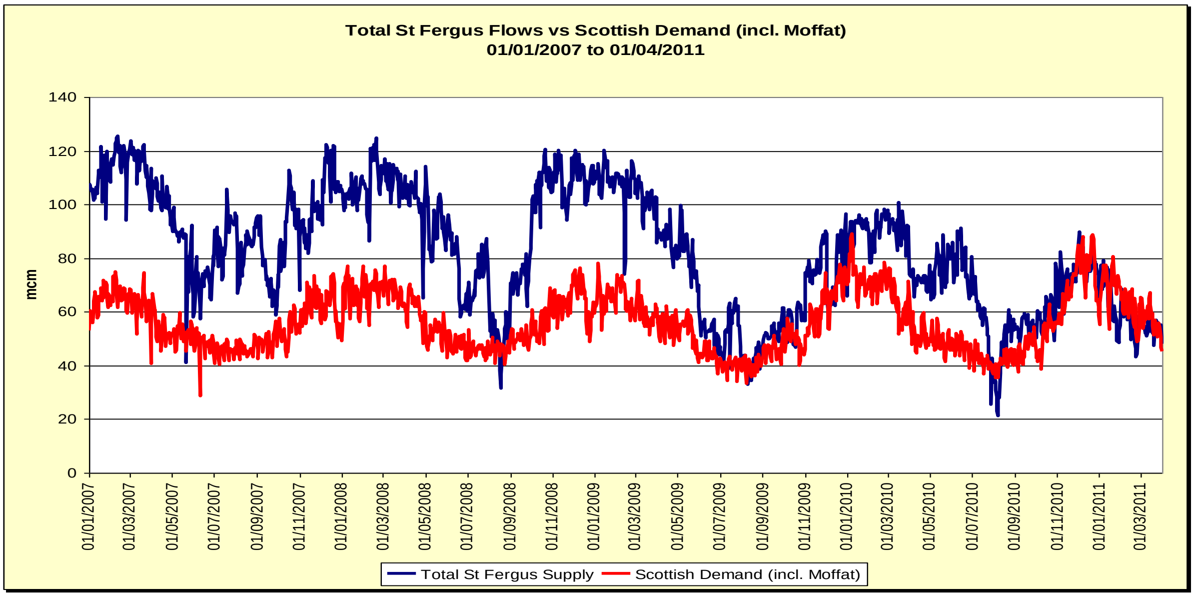
"The current SO incentives are relatively short term. As a result NGG does not have an economic incentive as either SO or TO to consider the longer-term costs and benefits of potential options for reducing shrinkage and venting. This means that consumers could miss out on investments that have higher upfront costs but might result in lower total system costs of managing these outputs over the longer term."

Therefore there is currently no funding mechanism available to us during the 2012/13 rollover period to remunerate investments which improve the efficiency of our compressor fleet in terms of fuel or emissions and it would not be reasonable to assume otherwise. We therefore maintain that this funding should be allowed to ensure consumers do not miss out on enhanced outputs which would result from these investments.

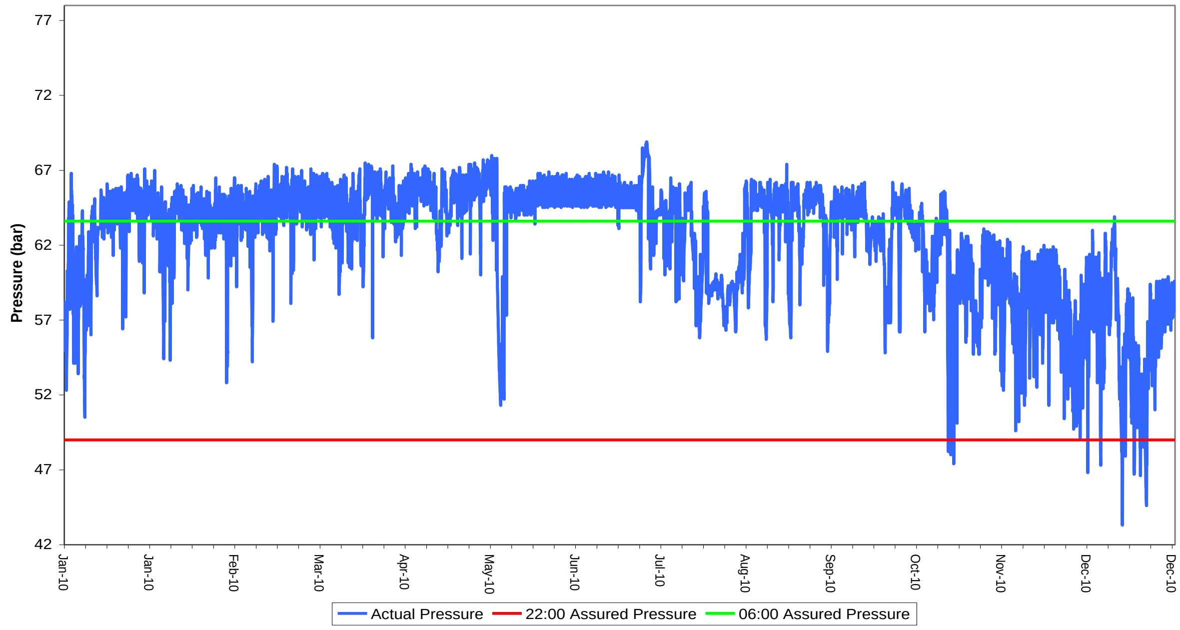
Scotland

One of the main scenarios which drives investment in this category is declining UKCS supplies into Scotland, which threatens security of supply in Scotland. We presented and debated this scenario with our stakeholders earlier this year.

With the continuing decline in UKCS supplies, the volume of gas entering the UK via Scotland and flowing south is reducing. We are already experiencing demands, both off peak and near to peak, which are exceeding supplies at St Fergus and we are struggling to maintain pressures to support these demands, as can be seen from the graphs below. The first graph presents St Fergus supplies plotted against Scottish demand (including the Irish interconnector at Moffat) and shows a converging pattern with periods where demand exceeds supply. This causes a depletion in local linepack, a reduction in pressures and other operational issues as the NTS currently has no ability to compress gas North into Scotland.



The graph below shows the Assured Offtake Pressure[23] at a representative offtake in Scotland[24]. The inability to compress gas north into Scotland creates an increased risk of curtailing firm (including domestic) demand.



The Gas Distribution Networks (GDNs) in Scotland and northern England recognise the challenge this situation presents, and have already agreed in principle to a reduction in Assured Offtake Pressures (contractually agreed pressures at key points during the day the GDNs require to ensure they can manage their networks under 1 in 20 conditions). The process is still ongoing, however full agreement to the reductions in Assured Offtake Pressures would lead to the avoidance of some planned investments. Without the remaining investments to enhance the capability of the NTS, even these reduced Assured Offtake Pressures will be unattainable under a number of scenarios, hence investment is still required albeit at a reduced level.

Beyond the reduction in Assured Offtake Pressures with the GDNs, potential options to meet our wider obligations (ensuring security of supply through the satisfaction of 1 in 20 peak day demand conditions, providing flex capacity and maintaining pressure commitments) include:

- Constrain Scottish demand – there is little ability for Scottish demand to respond in this way, as evidenced by both the OM tenders in this region and the level of available DN interruption post Mod 090 (Revised DN interruption arrangements), therefore we do not believe this is a credible option
- Constrain the SNIP interconnector to Ireland – this is not a credible option as the Irish have no alternative sources of gas
- Buy gas on at St Fergus:
    - UKCS – uncertainty exists over the continued level of availability of UKCS supplies at St Fergus in the future to ensure supplies will be present when needed to meet our 1 in 20 demand obligations
    - Norwegian gas –uncertainty exists over the availability of Norwegian gas at St Fergus to the UK due to the Norwegian's long term supply commitments with Europe to ensure supplies will be present when needed to meet our 1 in 20

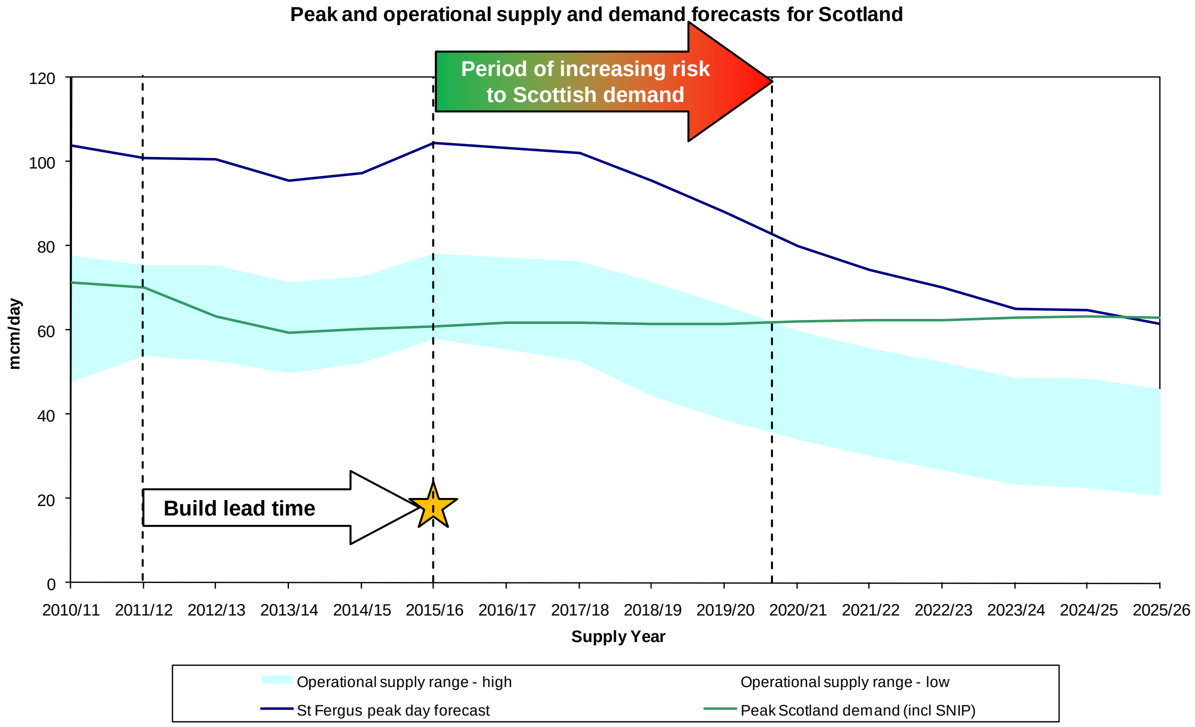
[23] For each day in any gas year, the "Assured Offtake Pressures" are the 06:00 and 22:00 pressures specified for that gas year in the Offtake Pressure Statement.

[24] Note the Agreed Pressure process under the Uniform Network Code is used where Assured Offtake Pressures cannot be met.

demand obligations. The 'time of flight' for additional supplies to arrive from Norwegian production facilities also needs to be considered in the event the gas supply is needed to respond to a supply loss affecting Scotland.

- Build material volumes of storage in Scotland to support demand in the absence of St Fergus flows – our experience of planning requirements for storage projects suggest this would be a slow and expensive option, and we cannot be certain that storage stock levels could be maintained unless there were sufficient gas supplies at St Fergus
- Build reverse flow capability to take gas north into Scotland – given the alternative options considered above, this is the most economical and effective solution

The following graph shows an extrapolation of actual supplies from last winter in line with TBE forecasts. The 'operational range' in the graph is estimated from the actual supplies seen during winter 2010/11 for high demand days. The graph shows that peak Scottish demand, which we are obligated to secure, is currently within the range of actual flows seen on high demand days and that there are a number of days where St Fergus entry flows in the winter are insufficient to meet peak demand levels, placing Scottish demand at risk. The slight upturn in St Fergus flows around 2015 relates to new gas coming on (e.g. West of Shetland) however this is insufficient to curb the downward trend resulting from the decline of UKCS supplies. By 2019, peak demand exceeds the credible range of forecast supplies.



Given likely design, planning and build lead times, the earliest we can build a physical solution is 2015, which is clearly part way through this increasing risk period. Whilst the Initial Proposals do not support the investment requirement, to mitigate disruption to existing and future consumers, we are now progressing investment options related to moving gas north into Scotland as we do not believe it appropriate to allow Scottish demand to bear the increasing risk. This entails developing the physical options in parallel to investigating any commercial options, ensuring we are keeping all reasonable options open until final investment decisions are required. Delaying the start of this work by 18 months through lack of funding next year will further increase risks to Scottish demand when St Fergus supplies are low.

Through our stakeholder engagement events, we have debated the situation and consequences with the wider industry. Many of our stakeholders recognised this situation is inevitable and that something has to be done to mitigate the impact.

The reduction in St Fergus flows has happened much more quickly and sharply than any reasonable expectations, including those of the Shippers at St Fergus who are bringing in the gas. Our annual Transporting TBE processes are heavily informed by the wider gas industry, which before last year did not show gas supplies at St Fergus falling below 70mcm/d at any time in the foreseeable future. For the first time however, the 2010 TBE process showed a steady decline until 2014. New supplies are then anticipated helping to alleviate the decline temporarily, eventually falling to 50mcm/d by 2019. In reality, however, we are frequently seeing supplies below 30mcm/d today.

Central corridor (East → West / West → East)

This scenario results from the within-day volatility and interactions of the large LNG importation terminals on either side of the country and the interconnectors to mainland Europe. The central corridor scenario was also presented and debated with our stakeholders earlier this year.

The drivers for the issues in the central part of the NTS are different to those in Scotland. The flow patterns we are experiencing from the LNG importation terminals, twinned with the increasingly erratic behaviour of the interconnectors to Europe, are creating control issues at the heart of the network. Originally designed to move gas steadily from North to South, the NTS does not have the inherent capability to reconfigure quickly to respond to the very fast increases and decreases in flow rates between the East and the West, caused by LNG plant and the interconnectors. The ability of our compressor fleet to quickly reverse the direction of flow, or for the system operator to control the flow path of gas around the country, is now felt to be insufficient to manage the future flow patterns. Indeed we are already seeing examples of this, such as at Kings Lynn compressor site where flow reversal has taken too long to support reversal of flow on an interconnector.

Unlike Scotland, commercial alternatives are possible in the central corridor, however due to the number of parties required and the frequency of commercial action necessary to mitigate the impact of this seemingly enduring requirement, our analysis suggests that the enduring costs of such a strategy will far outweigh the cost of investment to enhance the network to allow it to manage the flows.

We presented a view of the potential actions and costs involved if we did not invest to mitigate the impact of these effects at our stakeholder engagement events. Some of the feedback we received, as published in the independent reports on the events at www.talkingnetworkstx.com, suggested that the actions we would need to take would not be welcomed by the industry (for example, gas fired power station operators believe that holding them to notice periods on the NTS would prevent them participating in the electricity Balancing Mechanism) and that we should progress with enhancing the physical capabilities of the NTS as they compared favourably with the costs of not investing. Others did not believe they could support the proposed investments without further information. We plan to continue this debate at the next stakeholder event planned for early November 2011.

Alternatively we could delay investment, or avoid it altogether, and manage the ensuing consequences through system management tools available to us. We do not believe this would represent the most economic and efficient way forward as this risks material costs being incurred in line with those presented at our stakeholder events and could represent an uncapped exposure to both ourselves and industry participants until future investment could be made to mitigate the risk. Should this eventuality emerge, we would need to develop a more appropriate mechanism for dealing with such constraint costs.

Chapter: 3

Question 6: We invite stakeholders to comment on our initial proposals for the structure of the incentives and uncertainty mechanisms for the rollover year for the electricity and gas transmission licensees.

We support the proposed mechanisms for logging-up the Critical National Infrastructure costs, the continuation of pass-through costs and maintaining the existing reliability incentives for the rollover year. The extension of the efficiency incentives is appropriate to a proportionate treatment for 2012/13.

Section 3 of the consultation considers incentive and uncertainty mechanisms, and paragraph 3.3 documents the proposed approach for the rollover year. One new mechanism which will apply to revenues during the rollover has recently been confirmed by Ofgem but is omitted from this section: this is the RPI indexation mechanism that was described in Ofgem's decision letter of 1 July 2011. As explained at page 2 of that letter:

> "*This decision affects the treatment of all revenues (including incentive revenues) that are currently under review and indexed by RPI within the licence:*
>
> - *RIIO-T1 and RIIO-GD1 revenues from 2013-14*
> - *TPCR4 rollover revenue for 2012-13*
> - *Transmission Investment for Renewable Generation (TIRG) and Transmission Investment Incentives (TII) revenues from 2012-13*."

We assume that the absence of any comment on this matter in the Initial Proposals represents an oversight and does not, in any way, signal a reversal of the decision taken on 1st July to amend the mechanism for indexing revenues by RPI for the rollover revenues. We agree with the decision announced on 1st July and expect it to apply to the rollover.

Electricity

The extension of the revenue driver mechanism is discussed in Question 10 and the environmental target (SF_6) in Question 8.

Gas

Permits

Permits are an SO incentive scheme relating to the timing of the release of incremental obligated capacity.

The Permits scheme was originally designed to incentivise us to release incremental capacity ahead of the obligated lead times, as set out in the Licence, for entry (42 months) and exit (38 months). As it was implemented before the Planning Act (2008) came into force, it was never intended for this scheme to be used as mitigation for the impact of the changes to the planning regime.

The scale of potential applications for incremental capacity in 2012/13 is large, both on exit (potential and probable applications from CCGTs) and entry (potential applications from large scale storage and LNG importation). Many of the developers of these projects already have planning consent (from applications submitted before Planning Act came into force), however any subsequent NTS reinforcements will require planning consent under the Planning Act. This misaligns the timescales required for delivery of the third party projects and delivery of the network reinforcements to support them by a number of years.

We are working to develop a process which will, in future, help align our timescales to those of the developers of new projects, thereby minimising this issue. Until this point, however, there remains the risk of developers with planning consent already granted wishing to connect to the NTS ahead of when it is possible to reinforce the network under the new planning regime. System management tools will be required in the RIIO-T1 period to help manage these situations and we expect to develop these through the RIIO-T1 process.

Ofgem's proposal to pro-rate the TPCR4 Permits scheme for 2012/13 is a reasonable one. We agree that the value of the scheme should be pro-rated, however are concerned about the volume of probable and possible incremental capacity signals in 2012/13. We therefore propose that the price of each permit is pro-rated (i.e. is reduced to one fifth of the TPCR4 level) and the volume of permits is maintained at TPCR4 levels.

Question 7:	We invite stakeholders to comment on our initial proposals for the structure of the incentives and uncertainty mechanisms for the rollover year applicable to National Grid's internal costs incurred in balancing the electricity and gas transmission systems.

NG response:

We are happy with the proposals surrounding the internal cost incentives and uncertainty mechanisms

Question 8:	We invite stakeholders to comment on our proposed revised SF6 leakage targets for the rollover year.

The proposed SF_6 leakage target is challenging based on the age and specification of existing SF_6 insulated equipment and our investment plans for 2012/13. We would still prefer to see a 'stepped' incentive as proposed in our submission as this would provide a series of smaller incentives for incremental improvements, rather than Ofgem's proposed 'all or nothing' scheme. Even small reductions in SF_6 leakage benefit the environment.

Question 9:	We invite stakeholders to comment on our proposal to apply the capex incentive adjustment over a number of years to protect users of the transmission system from fluctuating charges.

The reason given by Ofgem for spreading the capex incentive adjustment is to avoid fluctuating transmission charges. It is not clear to us that charges would fluctuate if the adjustment was paid in full in 2012/13. The largest adjustment is in NGET. Our RIIO business plan submissions included full recovery of this incentive adjustment in 2012/13 but still projected higher income in 2013/14 than 2012/13. The plans did not demonstrate a spike in revenues in 2012/13. We therefore question whether spreading the adjustment would smooth revenues at all.

The TPCR4 Final Proposals specified that the capex incentive revenue adjustment would be made in the year 2012/13: Paragraph 7.12 of the TPCR Final Proposals states "The 25 per cent incentive will be applied through a one-off revenue adjustment on 1 April 2012". This one-off adjustment in the 2012/13 year was then codified in the relevant licences (e.g. Special Condition D9 of the NGET licence, and Special Condition C8B of the NTS Licence).

The proposal to re-profile the revenue adjustment over five years represents a reversal of a previous regulatory commitment (agreed in the settlement and documented in the licence). As such, it would set an unfortunate precedent against which any proposal to use after-the-event adjustment in RIIO would need to be carefully considered.

Our RIIO submission in July highlighted a need to attract finance to fund the significant investment required in the networks and explained why regulatory risk is so important to investors. The proposal, if implemented, would significantly confirm the relevance of investor concerns about regulatory risk. If investors cannot have faith in the current regulatory contract (licence) how can they expect that all the new arrangements in RIIO (uncertainty mechanisms, mid-point reviews, new incentive exposures) will be properly enacted and result in an ability for them to earn the returns they expect on any finance they provide. For consumers, an increase in regulatory risk will increase the cost of capital.

In part, Ofgem's proposal seems to be based on the materiality of the adjustment for NGET in particular. In this regard it is worth noting that, unlike SHETL and SPTL, the revenue driver uncertainty mechanism for NGET provided no incremental revenues during the 2007/08 to 2011/12 period. In part, the materiality of the adjustment is a consequence of not providing additional revenues sooner, i.e. during the TPCR4 period. The incentive adjustment relates to past performance with respect to already incurred costs and already represents deferred recoveries. A further delay to the recovery of these revenues, even if undertaken in a manner consistent with the cost of capital underlying the parameters defined in the TPCR4 capex incentive mechanism, would represent a further imposition on our finances. Such delays would also mean that costs giving TPCR4 benefits are imposed on future customers.

With regard to the values of the capex incentive adjustment we believe the correct amounts to be £211.7m for NGET and £11.2m for NGG (both in 2009/10 prices). The NGG value is significantly lower than the £47.5m included in the Initial Proposals. Calculations to support these values will be submitted separately and are not included in this response.

For all these reasons, we do not support the spreading of the capex incentive adjustment over a number of years and believe the adjustment should be made in full in 2012/13 on a provisional basis.

Question 10: We invite stakeholders to comment on our approach to maintain the existing revenue drivers for the electricity transmission licensees into the rollover year.

NG response:

Maintaining the existing revenue driver mechanism is consistent with the proportionate approach to the rollover year. In order for the revenue-driven allowances to be calculated at the end of the rollover year, it is necessary to define a baseline scenario to allow the revenue driver adjustments to be calculated. To maintain consistency with the TPCR4 baseline allowances and the intended extension of the mechanism without associated changes to the Unit Cost Allowances, it is assumed that baseline from the TPCR4 final proposals document is to be used. This equates to the baseline scenario values (in MW) shown below for each of the relevant terms and zones.

		Base Scenario
Zone	**BGC**	2012/13
a	South & South West	2100
b	Thames Estuary	1840
c	London	0
d	South Wales	0
e	East of England & Home counties	0
f1	West Midlands	250
f2	East Midlands	0
g	North West & North Wales	844
h	Yorkshire & Lincolnshire	540
i	North East	0

		Base Scenario
Zone	**BZS**	2012/13
a	South & South West	-2939
b	Thames Estuary	6713
c	London	-7527
d	South Wales	1604
e	East of England & Home counties	-1530
f1	West Midlands	-3416
f2	East Midlands	4699
g	North West & North Wales	2193
h	Yorkshire & Lincolnshire	6263
i	North East	531

		Base Scenario
Zone	**BZD**	2012/13
a	South & South West	2939
b	Thames Estuary	-6713
c	London	7527
d	South Wales	-1604
e	East of England & Home counties	1530
f1	West Midlands	3416
f2	East Midlands	-4699
g	North West & North Wales	-2193
h	Yorkshire & Lincolnshire	-6263
i	North East	-531

	Base Scenario
	2012/13
BST	3,200

Question 11: We invite stakeholders to comment on our proposed timeline for the application of the rollover capex incentive and reconciliation of the provisional TPCR4 capex incentive.

NG response:

As explained in our response to Question 9, we do not agree with the proposal to spread the recovery of the capex incentive adjustment due in 2012/13 over a number of years. We believe that adjustment should be made in full in 2012/13.

Although not stated explicitly, we assume that the provisional revenue driver capex allowance will be included within the revenue allowances for 2012/13. If this is not the case, we would seek to have an adjustment to revenues in 2013/14 for the provisional capex incentive adjustment.

We understand the rationale behind the proposal to true-up the base revenue allowed in 2012/13 through an ex post adjustment to revenues for the rollover capex incentive in 2014/15 and agree with this timeline. We note that it is also consistent with the RIIO proposals to calculate ex post revenue adjustments with a two year lag.

Chapter: 4

Question 12: Do you think the proposed allowed return is appropriate to a one year rollover?

NG response:

For reasons previously explained we do not think that the cost of capital should be reviewed for the rollover. In the interests of brevity the reasons previously identified are not repeated here, and we instead refer Ofgem to our previous responses including the covering letter to our response of 13 May 2011.

However, we wish to clarify the asymmetric risk that we consider is created by the decision to review the cost of capital in the roll-over, without all other aspects of the price control being reviewed. This asymmetric risk is not simply that Ofgem failed to raise rates in the TPCR3 roll-over as suggested in the TPCR4 Rollover Initial Proposals at Paragraphs 4.25 to 4.30, but stems from the unusually large discretion which Ofgem has over the approach that they choose to adopt in a rollover and an apparent willingness to change the approach adopted with minimal justification, creating a regulatory risk whereby investors perceive undue bias.

This regulatory / asymmetric risk is not merely hypothetical, but was demonstrated in the last NGET roll-over for the financial year 2006/07. Ofgem seek to address this in the Rollover Initial Proposals at Paragraphs 4.25 to 4.30 but only consider the position in the TPCR3 rollover Initial and Final Proposals. Our concern stems from the changes in Ofgem's approach during that rollover so it is necessary to look further back in the review to fully appreciate the nature of the risk:

- Early in the process Ofgem indicated (in May 2004) the approach that would be adopted to set the cost of capital for 2006/07 should the cost of capital be reviewed in that rollover. This approach was either (i) to adopt the DPCR4 cost of capital, or (ii) to base the allowed return on that from DPCR4, but to subtract the 0.25% differential between the allowed return in the previous transmission and distribution price controls (with the differential acknowledging the potential for risk to differ between transmission and distribution). Clearly, at that stage Ofgem considered this a reasonable and proportionate approach if the cost of capital was to be reviewed.

- This approach appeared to be confirmed in July 2005, when Ofgem wrote "*Ofgem considers that the approach to setting the cost of capital used in the electricity distribution price control is broadly applicable for the purposes of extending the NGC price control, given the similarities between the electricity distribution and transmission businesses and the timing of the review*." The main issues were then said to be "*the extent to which any difference of approach would be applicable to NGC*" e.g. in relation to tax and gearing, and then 2 options were identified: "*Option 1 adopts the underlying outcome of the recent distribution price control review with a simple conversion for tax allowances for the interim period*", and Option 2 was to "*derive a value for the cost of capital based on the common components of the DPCR conclusion, but taking a view of specific risks and tax liabilities pertaining to NGC*." Neither of these involved looking at the underlying parameter values used in DPCR4 nor re-assessing market data.

- These approaches would have given an increase in the cost of capital for the 2006/07 NGET roll-over from 6.25% to either 6.9% or 6.65%. However, in the September 2005 Initial Proposals, once the outcome from these stated options had become clear, Ofgem chose to ignore this result and instead adopted a different approach to leave the cost of capital unchanged at 6.25%. Whilst noting the DPCR4 approach remained applicable to the TPCR3 rollover, Ofgem continued "*However, this does not mean that the cost of capital determined for the extension of NGET's TO price control should be the same as* *that concluded at the recent distribution price control review, as market parameters will change between reviews and as there may be differences between the risk profiles of NGET and the electricity distribution companies. Accordingly, Ofgem has examined current market data in formulating its initial proposals for the price control extension*."

- By the time of Final Proposals, the approach was summarised as "*Ofgem has considered high level market evidence specific to NGET, which suggests that maintaining the current cost of capital allowances would be reasonable*."

Regulatory commitment is recognised as important for investors and needs to be maintained if unnecessary increases in networks' cost of capital are to be avoided. Changing the approach to setting an important parameter such as cost of debt midway through a review, after the results of different approaches have become clear, runs a serious risk of undermining the perception of regulatory commitment. It is therefore most concerning that in this new rollover Ofgem again appear to be deviating from the approach they have said, and continue to say, they will follow. Ofgem have been clear that for the TPCR4 rollover the approach to setting allowed return will follow the approach used in TPCR4, but in relation to the cost of debt element this is not the approach that is now being adopted. The TPCR4 Final Proposals document is explicit that the cost of debt was based on long-term values, but as explained in our previous response and more fully below the approach actually being adopted deviates from this.

At Rollover Initial Proposals Paragraph 4.10, Ofgem respond to the argument that allowed return, or individual elements of the allowed return, should not be reconsidered for the rollover "*as the TPCR4 proposals were accepted in the round*", suggesting this has no merit because the network companies will be able to consider whether to accept the rollover proposals "*in the round*". Whilst it is true (as in any price control) that network companies can refer final proposals in aggregate to the Competition Commission, this does not in any way lessen the requirement for Ofgem to justify its proposals.

Notwithstanding the arguments above, if the cost of capital is to be reviewed for the TPCR4 rollover:

- We agree with Ofgem's proposed decision to keep the cost of equity (7%) and gearing (60%) unchanged from the considered assessment in TPCR4.
- We disagree with the proposed reduction to the cost of debt from 3.75% to 3.25%.

The rest of this answer considers further the proposed reduction to the cost of debt.

Cost of Debt

Ofgem has not addressed important points raised in our response of 13th May 2011, which undermine the proposed change to the cost of debt:

- the cost of debt used in TPCR4 was explicitly stated to be based on long term values of risk-free rate and debt spreads, and Ofgem has not presented evidence to justify a reduction in these long-term values.
- the Rollover Initial Proposals again asserts (Paragraph 4.16) that Smithers presented a range for the risk free rate from 2.0% to 2.5%, to support and help justify the use of 2.0% for the roll-over, but as we previously pointed out, Smithers' range for the long-term risk free rate (i.e. the parameter used in TPCR4 Final Proposals) was from 2.5% to 3.25%.

We develop these points more fully below. Our earlier response also presented data and evidence (including future nominal gilt rates, and long-term average index-linked gilt yields) which showed that the 2.5% long-term risk free rate used in TPCR4 should not be reduced, but in the interests of brevity we do not repeat this information here and instead refer Ofgem to our May 2011 response document.

The value of the cost of debt that was derived in TPCR4 was based on:

- a value of 2.5% for the risk free rate, this being the conclusion in the Smithers report that this is "*the best **long term** estimate of the risk-free rate*" (Final Proposals Paragraph 8.10);
- that it may be necessary "*to apply a term premium [which Smithers' estimated may be up to 0.75%] to estimate the risk free yield accurately, although the evidence to support this is less clear*." (Final Proposals Paragraph 8.10)
- a debt premium (seemingly considered representative of A and BBB rated debt) of 1.0 to 1.5 per cent based on "*analysis of **long term** average spreads*" (Final Proposals Paragraph 8.11)
- combining these, the Final Proposals concluded that the pre-tax real cost of debt was 3.5% to 4.0% (Paragraph 8.12) with a point value used in deriving the cost of capital for the control (taking the various factors and wider approach described at Paragraph 2.22 into account) at the centre of this range, i.e. 3.75%.

Thus, the TPCR4 methodology was to use estimates of risk free rate (2.5%) and debt premium (1.0% to 1.5%), where both of these were expressly stated to be **long-term** values rather than current or short-term rates. The use of long-term values seems apt, given the long-term nature of the assets that need to be financed, and remains so for the rollover. It follows that it is not appropriate to update either of these values for the TPCR4 roll-over in response to **short-term** signals indicated by current market values.

In the new roll-over Initial Proposals:

- The proposed reduction in the cost of debt assumption from 3.75% to 3.25% for the rollover is said to "*reflect a reduction in the risk-free rate from 2.5% to 2.0%*" (see TPCR4 Rollover Initial Proposals Paragraph 4.3).
- This reduction in risk-free rate is (again) justified on the basis that there is "*sufficient evidence to use the lower end of the Smithers risk-free range (2.0%) rather than the top end of the range (2.5%) that was used in TPCR4*." (see TPCR4 Rollover Initial Proposals Paragraph 4.5).
- As acknowledged in the Initial Proposals at paragraph 4.18, the average of 10yr trailing average spreads for A and BBB bonds has risen (by c.10 bps), though Ofgem suggest this is "*not material*" in the context of a one-year rollover.

In the Rollover Initial Proposals, at Paragraph 4.12, Ofgem have confirmed that their approach "*to setting the allowed return for the rollover would follow the approach used in TPCR4, which in turn was largely based on the Smithers Report*". We agree with and support this approach, but the proposed reduction to the risk-free rate is incompatible with it, because:

- as shown above, TPCR4 used a long-term risk-free rate: the data considered in the new Initial Proposals (Paragraph 4.16 and Figures 2 and 3) does not inform this long-term rate;
- as explained in our previous response, Smithers estimate of the "*Real Long-term Risk-Free Yield*" was not 2.0% to 2.5% but was from 2.5% to 3.25%, as shown by the following table which is reproduced from the summary section of the Smithers (2006) report:

	See section of report	Estimate
Real Risk-free Rate	8	2.5%
Term Premium	8	0 to 0.75%
Real Long-term Risk-Free Yield	**8**	**2.5% to 3.25%**
Default Premium on A-Rated Debt	5,6	1% to 1.5%
Real Yield on Long-Term A-Rated debt	5,6,7,8	3.5% to 4.75%

Thus, as we pointed out in our response of 13 May 2011, the TPCR4 Final Proposals did not in fact use "*the top end*" of a risk-free range from 2.0% to 2.5% from Smithers, because the Smithers report did not give such a range. Rather, Smithers concluded that "*We have not altered our estimate of the real market return on equities (6.5% to 7.5%) or our estimate of the risk-free rate (2.5%)*." If any range for the long-term risk-free rate was to be taken from Smithers, it would be the range from 2.5% to 3.25% shown in the above table.

The Rollover Initial Proposals ignores the above table in the Smithers report and these points from our previous response. Instead, at Paragraph 4.13 and 4.14, the Initial Proposals seeks to assert that the "*key*" paragraph from Smithers is the following: *"…the best current market-based estimate of the forward-looking real interest rate is the nominal yield on medium-dated bonds, less the Bank of England's inflation target of 2%: thus a figure of around 2 to 2.5%, remarkably close to that in the benchmark "Taylor Rule"*."

This extract is being used out of context, but in any case it does not advocate or justify using the nominal yield on medium-term bonds to update Smithers' estimate of the long-term risk free rate. In the original report the paragraph begins "*If the term premium is indeed close to zero the best current market based estimate of the forward-looking real interest rate*….", and from this it follows that the approach now being adopted by Ofgem is explicitly said to be a method for estimating a **current rate** rather than the **long-term** average as used in TPCR4. In any case, Smithers did in fact consider it appropriate to include a term premium in their estimates (see the table reproduced above), so if weight is to be given to this paragraph it merely reinforces that focus should be on the actual range for the long-term risk-free rate in the Smithers report, from 2.5% to 3.25%.

Moreover, Smithers did not consider the risk-free rate at any length in the 2006 report but instead based their point estimate of 2.5% (before term premium) on the previous Smithers (2003) report. In the Smithers (2006) report the paragraph which Ofgem now claim to be "*key*" does not even relate primarily to the risk-free rate at all, but to a section of the report concerned with the term premium and not the risk free-rate (whether long-term or current). Thus, whilst the truncated paragraph at Paragraph 4.14 was taken from the summary to the Smithers (2006) report, this was merely a slightly shortened version of the full paragraph later in the Smithers 2006 report (Page 44). We previously set this out in full, and in its proper context, in our 13th May 2011 response, and the relevant paragraph from our response is itself reproduced in full below:

> "The Smithers (2006) report, in a section on "Term Premium", does contain text (see page 44/45, summarised also on pages 4 and 27) that refers to a range for the current (but not long-term average) risk free rate as follows, "*In the absence of any evidence of a significant term premium, probably the best current market-based estimate of the forward-looking real interest rate is the nominal yield on medium-dated bonds, less the Bank of England's inflation target of 2%: thus a figure of around 2 to 2 ½%, based on the most recent figures shown in Chart 8.1. This is remarkably close to that in the benchmark "Taylor Rule", and to the estimate in Mason, Miles and Wright (2003)*." The

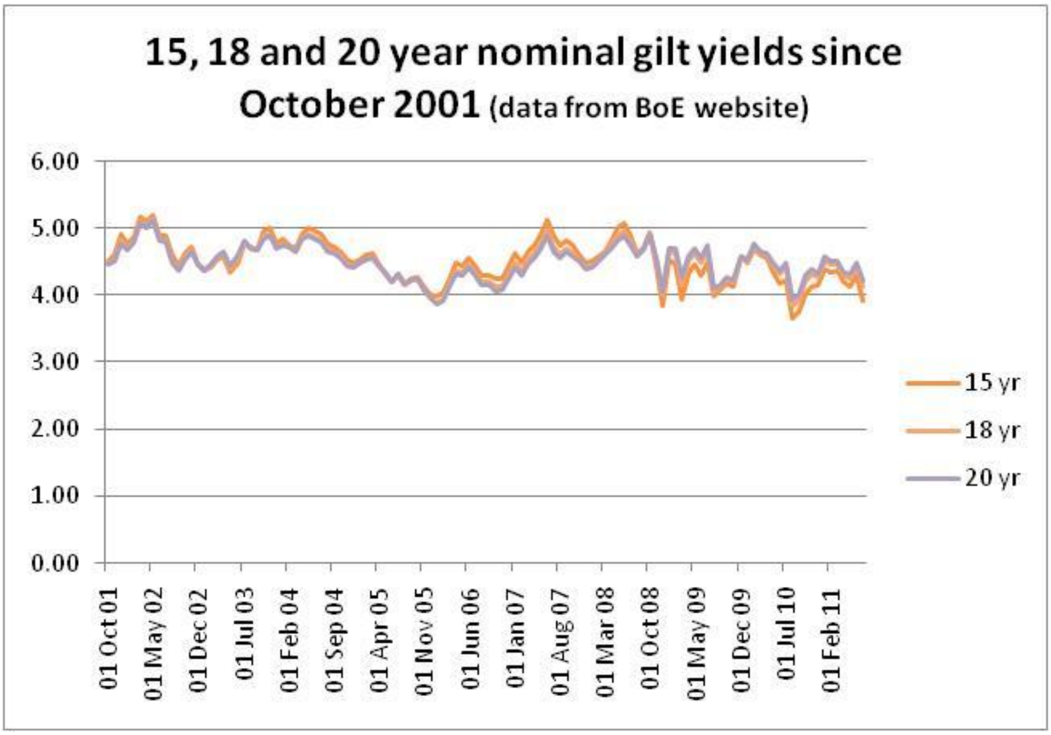
following paragraph then speculates about the term premium and possible future trends for RFR before concluding "*Given this risk, which is probably greater on the upside than on the downside, a more conservative approach might be to assume a term premium close to the average over the twentieth century, ie, a figure of around ¾%."* Thus, Smithers (2006) final position was that the real long-term risk-free rate is 2½% to 3¼%, as shown in the table above, rather than 2% to 2½% as claimed at Paragraph 5.7 of the new [April 2011] rollover document."

Finally, the paragraph reproduced in the Rollover Initial Proposals at Paragraph 4.14 cannot be claimed to be "*key*". Other paragraphs in the summary section of the report are equally or more important, e.g. "***We have not altered** our estimate of the real market return on equities (6.5% to 7.5%) or **our estimate of the risk-free rate (2½%)***", and "*A very important caveat is that, while short-term rates and long-term yields are likely to move together in the future, their average level is quite uncertain. Both could in principle be pulled upwards towards the historically much more stable equity return. In the heyday of the stock market boom in the 1980s and 1990s real interest rates were significantly higher*", and most importantly Smithers' overall view of long-term risk free rates (2.5% to 3.25%), which drew all their analysis together (including the paragraph claimed by Ofgem to be "key"), was given in, and should be taken from, the table at the end of the summary section to the Smithers (2006) report, which is reproduced above.

There is, in fact, no basis on which to claim that the paragraph highlighted above is a "*key*" paragraph in relation to the long-term risk free rate as used in TPCR4. Referring back to the value in the earlier Smithers (2003) report, which the 2006 report chose not to update, the distinction between long-term and current rates was fully recognised. For example, the 2003 report notes that "*If assumptions are to be made about the safe rate over reasonably long horizons, it is not sufficient simply to take a snapshot of whatever the current short rate happens to be*." When seen in this light, it becomes even clearer that the extract from Smithers reproduced in the Rollover Initial Proposals at paragraph 4.14 does not give a basis on which to update the previous estimate of the long-term risk free rate that was used in TPCR4.

It is telling that in referring to the Europe Economics (EE) report, the Initial Proposals says at Paragraph 4.5 that the proposed reduction in risk-free rate and thus cost of debt for the rollover "*was based on EE's update of the Smithers report*" where "*EE found a notable decline in the risk-free rate in the period since 2006*". Clearly, information since 2006 is insufficient to support a change to the long-term risk free rate used in TPCR4, particularly when this period has seen unprecedented financial instability and so should not be used to update the TPCR4 value of long-term average rates.

The only data that is presented in the Initial Proposals is the yield on short and medium term nominal gilts presented in Figures 2 and 3. Once it is recognised that the relevant risk-free rate for the rollover, consistent with the figure used in TPCR4, is a long-run value, Figure 3 (which only covers the period since late 2006) ceases to be relevant, and Figure 2 merely confirms that current rates are not representative of long-term averages. Moreover, as explained in our previous submission, these charts are heavily distorted by including data for shorter tenor gilts (especially those <10 years), where use of short-term gilts in assessing risk-free rate is recognised to be inappropriate, both conceptually given the long-term nature of network investments, but also for specific reasons that are well-understood and widely recognised (including, in recent years, the market distortions caused by quantitative easing and the current anomalies in base rates and inflation). Focussing only on longer term instruments would reduce the scale of any changes suggested by the data, albeit resulting estimates of risk-free rates may still be too low because of distortions associated, for example, with quantitative easing. Ofgem has recently shown (Figure 3.5 of the December 2010 RIIO–T1 and GD1 Financial Issues Consultation) that bonds from energy network companies have an average tenor of 18.6 years (20 years for Transmission networks): using data for 15, 18 and 20 year gilts from the Bank of England (monthly data up to the end of July 2011) shows that for gilts of relevant tenor there is virtually no difference between the typical nominal gilt yields in the years leading up to the Smithers report in 2006 and the years since that report:



The average yield both in the (almost) 5 years since the Smithers (October 2006) report and in the 5 years leading up to the Smithers report is close to 4½%, and so subtracting the Bank of England inflation target of 2% (in the same way as Smithers) would still give the same risk free rate of around 2½ % as derived in 2006.

5 year trailing averages for:	to Sept 2006	to July 2011
15 yr gilts	4.59%	4.44%
18 yr gilts	4.59%	4.46%
20yr gilts	4.58%	4.47%

Smithers earlier (2003) report which, unlike the 2006 report, did consider risk free rate, noted that "*Problems in assessing historic mean values of the safe rate imply that estimates of the <u>future</u> risk free rate …should probably be derived in a forward-looking way from current rates.* ***However, in so doing, account should be taken of forecast future movements of short-term rates derived both from market data and published forecasts***." Ofgem are therefore wrong to suggest at Initial Proposals Paragraph 4.15 that Smithers "*does not advocate the use of forward rates to estimate the future cost of debt*." Thus, if Ofgem wishes to use Smithers to justify using recent information on nominal gilt rates to estimate the future long-term risk free rate, the correct approach requires consideration of future rates as implied in the yield curve. This approach was adopted in producing the charts in National Grid's May 2011 response at page 17 and Scottish Power's May 2011 response at page 10, and in each case the responses show that even recent market data, when fully considered in the way proposed by Smithers, would not support a reduction in the long-term risk free rate.

In conclusion, there is no basis for reducing the assumed cost of debt for the roll-over, given:

- Confirmation that the approach "*to setting the allowed return for the rollover would follow the approach used in TPCR4*", which used long term rates
- That insufficient evidence has been presented that the long-term risk free rate used in TPCR4 has changed, (the information that is presented (at paragraphs 4.16 and Figures 2 and 3) being insufficient for this purpose (based on Smithers) without considering also future rates as implied from the yield curve, and where these future rates do not support a reduction in risk-free rate), but
- There is evidence (which Ofgem acknowledge) that debt spreads have increased since TPCR4.

If, after considering the arguments in this response, Ofgem chose to change the approach to setting the allowed return for the rollover to move away from a consideration of long term rates and the Smithers report, such a change would demonstrate a breach of regulatory commitment which would further increase investor perceptions of regulatory risk, discourage investment in the energy sector, and increase the cost of capital.

Question 13: Do you agree with the adoption of the new pensions methodology for the rollover?

NG response:

The proposed treatment of pension costs for the rollover year, as set out in recent documents including the 31 March RIIO-T1 Financial Issues Decision Document, appears in most respects to be a pragmatic way of moving towards the new pensions methodology for a rollover, although we have a number of specific comments in relation to the separate elements of the proposed pensions allowances as explained below.

In addition, at the time of the Rollover Business Plan submission last October/November, the March 2010 triennial valuations for both of National Grid's DB pension schemes were still ongoing. It was, therefore, recognised that the pension cost information and forecasts provided last year would need to be updated to reflect the final, agreed outcome of the actuarial valuations. This can now be done and the July 2011 RIIO-T1 business plans have been prepared in line with those completed March 2010 valuations.

Moreover, Ofgem's proposed approach is to set allowances for certain elements of pension costs (in particular TPCR4 true-up and deficit costs) on a consistent basis for the rollover year and for the 8 years of RIIO-T1, and this also implies that the updated July RIIO-T1 business plan information should be used as the basis of the rollover allowances. For example, underfunding during TPCR4 is to be spread across 9 years, i.e. the rollover year plus the 8 years of RIIO-T1, whilst deficit allowances are to be spread over 15 years starting with the rollover year.

Then, considering each element of the proposed allowances in turn:

- Deficit costs – National Grid supports the proposed approach to base deficit allowances on the latest triennial valuations (in the rollover year the valuation to 31st March 2010), since this best reflects the likely actual deficit costs that will be incurred. For the same reason and to ensure consistency with the rollover year, the deficit allowances in the main control should also be based on the latest formal triennial valuations.
- Regulatory Fraction – The regulatory fractions for NGET and NGG for the rollover year relate to the proportion of the March 2010 triennial valuations that should be funded by consumers and as such should be calculated based on that March 2010 valuation. These revised fractions have been provided in the July 2011 RIIO Business Plans. It would be inappropriate to use outdated regulated fractions from the 2006 or 2007 valuation and apply them to deficit contributions which are funding a different valuation. Using the latest updated regulatory fractions for NGET and NGG would also ensure greater consistency with the treatment proposed for SHETL and SPTL in Paragraph 4.51[25]; to apply the most recently calculated regulatory fraction as agreed for DPCR5.
- PPF Levy costs – the Pensions Regulator is in the process of revising the basis on which PPF levy costs are set, and at the time of the October/November 2010 rollover submission there was significant uncertainty over the likely level of future levy costs. National Grid has been able to provide updated estimates of these costs for the rollover year in its July RIIO business plan, and whilst some uncertainty remains it would seem reasonable and

[25] This reference relates to the paragraph 4.51 which comes between 4.53 and 4.54 on page 42 of the Initial Proposals

proportionate to update the PPF allowances from the figures in the Initial Proposals to match the July 2011 submission. In line with Ofgem's defined methodology under both TPCR4 and RIIO, mismatches between the allowances and actual costs in the rollover year are, in any case, subject to future true-up, and so there seems no rational reason not to use the most recent estimates of future costs in setting allowances.

- Admin costs – Ofgem has excluded certain elements of National Grid's forecast admin costs relating to Corporate Centre Costs from the proposed allowances for the rollover, pending further explanation and justification of these costs. Additional explanation of these costs was provided in the July 2011 RIIO business plans, together with updated (and slightly reduced) forecasts. Given that under Ofgem's methodology (in TPCR4, the rollover and in RIIO) admin costs, like PPF levy costs, are subject to future true-up, it would be in all parties' interests for the most recent estimates of these costs to be used in setting allowances.
- Ongoing cost allowances (DB and DC ongoing contributions) – Consistent with the other elements of pensions cost discussed above, and to reduce the magnitude of future over/underfunding adjustments, the ongoing cost/contributions should also be updated to take advantage of the more recent information submitted as part of the July 2011 RIIO-T1 business plans.
- Under-funding during TPCR4 – Table 18 in the Initial Proposals sets out true-up adjustments for over and under-funding during TPCR4, part of which is to be added to the RAV at the start of the rollover year with the rest being spread over 9 years (i.e. rollover plus RIIO-T1). As explained above, since these values will also be used for RIIO-T1, they should be based on the more recent information contained in the July RIIO-T1 Business Plans. In addition, we have previously provided Ofgem with detailed comments on the calculation of the proposed true-up amounts for NGET and NGG, together with a revised version of the spreadsheet used by Ofgem to calculate the true-up values.
- NGET SO under funding adjustment – The Initial Proposals capitalise a proportion of the true up adjustment for NGET, both in the TO and SO forms of control. It is clear from the licence, and financial model that supports the Final Proposals, that no such capitalisation should take place for the NGET SO form of control so all of the adjustment should be made through an annual adjustment to income for the nine years beginning with 2012/13. The updated values based on the July RIIO-T1 Business Plan in the tables below have been amended for NGET SO to reflect this observation.
- Tax allowance impact of pensions - It should be noted that the under-funding true-up adjustments referred to above have been calculated to be post-tax values and, as such, represent the net monies due to the licensees after the deduction of tax. Unfortunately the financial model understates the tax allowance by mistakenly including a cost (which does not exist) to offset the revenue adjustments. By doing so, the tax allowance is not impacted by the true up adjustments which means that revenues only include the post tax value. As there is no further cost to pay relating to these adjustments, the company will have a taxable profit on which tax will be paid. With a tax rate of 25%, this means that, after tax, the company will only get 75% of the true up adjustment actually required. The financial model should be adjusted to correct for this error.

The effect of updating the pensions allowances for 2012/13 proposed in the rollover Initial Proposals for the points above and for the more recent costs presented in the July 2011 RIIO-T1 business plan are shown in the following Table:

	Deficit Recovery	Ongoing Pension Costs	Admin Costs	PPF Levy	True-up	Total
From Rollover Initial Proposals for 2012/3 (in 2009/10 prices), £M						
NGET TO	29.8	18.6	0.9	1.0	1.1	51.3
NGG TO	29.8	7.2	1.6	2.9	12.9	54.5
NGET SO	9.1	6.2	0.4	0.3	0.7	16.7
NGG SO	0.2	4.0	0.9	0.0	(1.3)	3.8
Updated values based on July RIIO-T1 Business Plan & NGET SO amendment (in 2009/10 prices, £M)						
NGET TO	24.6	19.6	1.2	0.7	1.7	47.8
NGG TO	32.8	6.7	3.0	2.9	15.2	60.6
NGET SO	7.5	6.7	0.4	0.3	1.1	16.0
NGG SO	0.2	4.3	1.5	1.5	(0.2)	7.3

Similarly, the updated cash adjustment and amounts to be included in the RAV in respect of the true-up for under/over-funding during TPCR4 are as follows, where it should be noted that the values in this table are "post-tax", as explained above.

	Total Adjustment for TPCR4 Period (excluding RAV additions)	**Annual Adjustment commencing in 2012/3** (excl. effect of RAV additions)	**Additions to RAV**
From Rollover Initial Proposals for 2012/3 (in 2009/10 prices), £M			
NGET TO	8.4	1.1	2.2
NGG TO	95.2	12.9	0.0
NGET SO	5.3	0.7	1.1
NGG SO	(9.8)	(1.3)	0.0
Updated values based on July RIIO-T1 Business Plan & NGET SO amendment (in 2009/10 prices, £M)			
NGET TO	12.6	1.7	3.5
NGG TO	112.3	15.2	0.0
NGET SO	7.9	1.1	0.0
NGG SO	(1.4)	(0.2)	0.0