Consultation on strategy for the next transmission and gas distribution price controls - RIIO-T1 Outputs and incentives

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Target audience: Consumers and their representatives, transmission companies, generators and gas producers/importers, suppliers, shippers, debt/equity investors, environmental organisations, other network companies, government policy makers and other interested parties

Overview:

The next transmission price controls, RIIO-T1 will be the first (along with RIIO-GD1) to reflect the new RIIO model. RIIO is designed to drive real benefits for consumers; providing network companies with strong incentives to step up and meet the challenges of delivering a low carbon, sustainable energy sector at a lower cost than would have been the case under our previous approach. RIIO puts sustainability alongside consumers at the heart of what network companies do. It also provides a transparent and predictable framework, with appropriate rewards for delivery.

We are now consulting on the strategy for the two price control reviews. This supplementary annex to the main consultation document sets out our proposed approach to setting RIIO-T1 outputs and associated incentives. This document is aimed at those who want an in-depth understanding of our proposals. Stakeholders wanting a more accessible overview should refer to the main consultation document.

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Associated documents

Main consultation paper

- Consultation on strategy for the next transmission price control - RIIO-T1 Overview paper (159/10)
  http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/RIIOT1%20overview.pdf

Links to supplementary annexes

- Consultation on strategy for the next transmission price control - RIIO-T1 Tools for cost assessment
  http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1%20Cost%20assessment.pdf
- Consultation on strategy for the next transmission and gas distribution price controls - RIIO-T1 and GD1 Business plans, innovation and efficiency incentives
  http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1%20and%20GD1%20BP%20prop.pdf
- Consultation on strategy for the next transmission and gas distribution price controls - RIIO-T1 and GD1 Financial issues
  http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1%20and%20GD1%20finance.pdf
- Consultation on strategy for the next transmission and gas distribution price controls - RIIO-T1 and GD1 Uncertainty mechanisms
  http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1%20and%20GD1%20uncert.pdf
- Consultation on strategy for the next transmission and gas distribution price controls - RIIO-T1 and GD1 Impact Assessment
  http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1%20and%20GD1%20IA.pdf

Links to other associated documents

- Consultation on strategy for the next gas distribution price control - RIIO-GD1 Overview paper (160/10)
  http://www.ofgem.gov.uk/Networks/GasDistr/RIIO-GD1/ConRes/Documents1/RIIOGD1%20overview.pdf

A glossary of terms for all the RIIO-T1 and GD1 documents is on our website:
http://www.ofgem.gov.uk/Networks/GasDistr/RIIO-GD1/ConRes/Documents1/Glossary.pdf

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1. Introduction and context

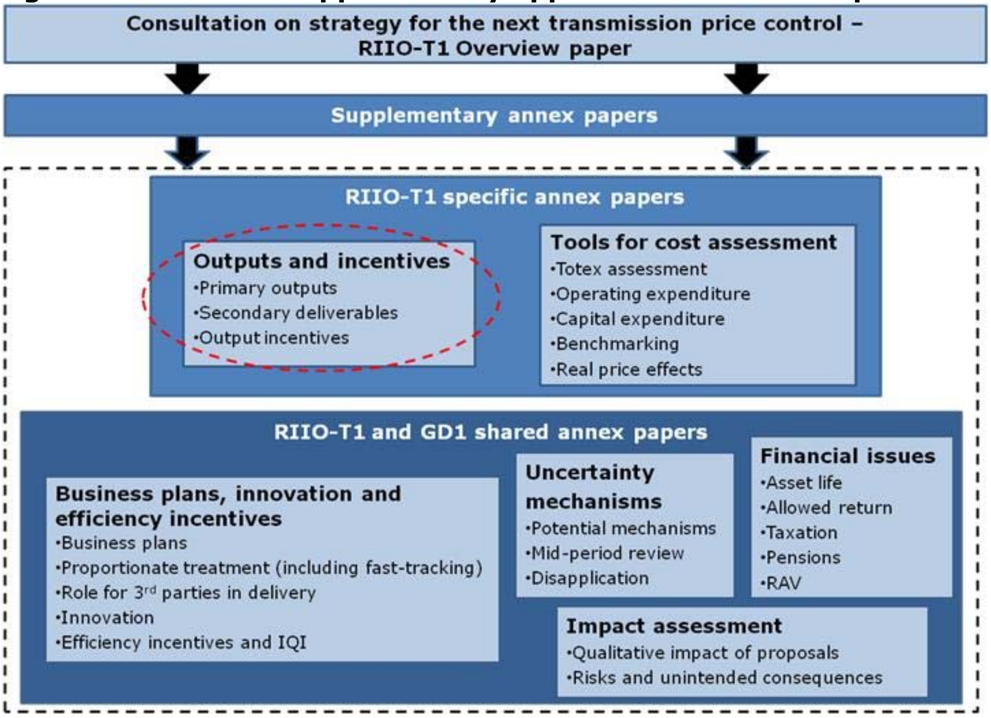
Chapter summary

This chapter summarises our overall approach to identifying the outputs that the TOs will need to deliver during RIIO-T1, as well as our approach to the development of associated incentive mechanisms. We also discuss our proposed approach to regulatory reporting requirements which will support the outputs-based framework. In addition, this chapter sets out the structure of the remaining document.

Question 1: Do you have views on the approach we have undertaken in developing the outputs framework?
Question 2: Do any of our proposed output measures present potential difficulties in ensuring the submission of accurate and comparable data?
Question 3: Are there any aspects of our proposed outputs framework where the reporting requirements are likely to lead to disproportionate regulatory costs?
Question 4: Do you have any views on whether, in principle, it is appropriate to consider requiring the companies to do more to verify their regulatory reports?
Question 5: Should we introduce an independent examiner for the TOs to improve regulatory reporting?
Question 6: Do you have any views on our proposed approach to revising outputs?

1.1. The next transmission and gas distribution price controls, RIIO-T1 and RIIO-GD1 respectively, will be the first to reflect the new RIIO model. We are now consulting on the strategy for the two price control reviews. This supplementary annex to the main RIIO-T1 consultation document sets out our proposals for the outputs that network companies will need to deliver over the price control period, and the associated incentive mechanisms. This document is aimed at those who want an in-depth understanding of our proposals. Stakeholders wanting a more accessible overview should refer to the 'RIIO-T1 Overview paper'. Figure 1.1 below provides a map of the RIIO-T1 documents published as part of this consultation.

Figure 1.1 RIIO-T1 Supplementary appendix document map*



*Document links can be found in the 'Associated documents' section of this paper.

Development of outputs framework

1.2. Outputs are at the heart of the RIIO regulatory framework. The outputs developed need to be consistent with the objectives of the framework and, in particular, need to be set to encourage TOs to play a full role in delivery of a sustainable energy sector. The RIIO framework identifies a number of areas in which network companies need to ensure delivery to facilitate the transition to a sustainable energy sector. These are included within the RIIO framework as output categories. The output categories include:

- customer satisfaction
- reliability and availability
- safe network services
- connection terms
- environmental impact
- social obligations.

1.3. These categories reflect the broad role that energy network companies need to play in delivering the objectives of the RIIO model. They will be included in the TOs licence at the start of the price control. Where network companies deliver against these output categories this will provide transparency to consumers with respect to what they are paying for. The TOs will face clear incentives to deliver in light of this transparency and the strong incentives that we intend to put in place to encourage efficient delivery.

1.4. We have worked with stakeholder working groups and through other fora to test whether these output categories are appropriate for RIIO-T1. We confirm in this consultation our view that these do form a comprehensive set of output categories.

1.5. We are grateful to all those stakeholders involved in proposing, discussing and reviewing options discussed in this document.

1.6. Table 1.1 below summarises the key elements of the proposed RIIO-T1 outputs, highlighting the ways they come together to encourage TOs to play a full role in delivering a sustainable energy sector. The level of performance will need to be justified in the companies' business plans with the aim of ensuring long-term efficient delivery of these outputs. The detail of each output category follows in the later chapters, but Table 1.1. below illustrates that it is the combination of the output categories that will ultimately deliver a sustainable energy sector.

Table 1.1: Summary of RIIO-T1 outputs framework

What's being delivered?	How it will be secured through outputs framework?
TOs facilitate the energy sector meeting its contribution to the decarbonisation and renewables targets	**Primary outputs** on contribution to broad environmental targets, timeliness of connections, customer relations and reliable networks. **Secondary deliverables** to encourage efficient and timely delivery of wider works to facilitate sustainable delivery against these objectives. Monitoring the percentage of low carbon/renewables connected as proportion of low carbon/renewables seeking connection.
Secure supply for its customers	**Primary outputs** on energy not supplied, timely connections and customer relations. **Secondary deliverables** on asset health, risk, wider works.
Wider reinforcement works when necessary throughout the control period and in timely and efficient way (electricity only)	Specific **secondary deliverables** around boundary capacity and/or specific project milestones. Supported by **primary outputs** on customer satisfaction and timely connections.
Future network development (gas only)	Series of specific indicators. Supported by **primary outputs** on customer satisfaction.
A safe network	**Primary outputs** on safety obligations reflecting legislative requirements. Supported by **secondary deliverables** on asset health and risk indices.

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Output measures

1.7. We established working groups[1] in July to identify outputs and incentive mechanisms for each of the six output categories. The working groups included the TOs, as well as other stakeholders, including environmental, social, and customer

[1] Further information on the RIIO-T1 working groups can be found on Ofgem's website at: http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/WorkingGroups/Pages/WG.aspx

representative groups and the Health and Safety Executive (HSE). Our recommendations reflect the working group discussions as well as views expressed at other stakeholder forums.

1.8. The outputs framework comprises both primary outputs and secondary deliverables. Primary outputs concern aspects of the services that network companies provide directly to customers. Secondary deliverables are indicators of performance which may be used in support of the companies' required primary outputs. For example, the reliability of the networks directly impact consumers whereas asset health is a factor impacting reliability.

1.9. In identifying primary outputs, we have drawn on the principles set out in the RIIO handbook[2]. This includes ensuring that they are: controllable by the network companies, measurable, auditable, and comparable. Where we have concerns about controllability, we will consider carefully the applicability of financial rewards or penalties.

1.10. If a TO is only focused on delivery of primary outputs in the forthcoming price control period, there is a risk that it will miss opportunities to take action that could improve its delivery of primary outputs in future periods. We expect network companies to include in their business plans the costs required to deliver primary outputs in future price control periods. To ensure consumers do not pay unnecessarily high prices, companies will be expected to set out the rationale for expenditure in the context of a long-term strategy for delivery.

Setting baselines

1.11. Our work has focussed on how the outputs for each category are defined and measured, to ensure there is clarity for customers about the output that will be delivered, and to enable us to hold companies to account.

1.12. For most output measures, we do not propose to set the level of each output (or baseline) to be delivered. Instead, companies will need to set out their proposed level of output delivery in their business plans, justifying the proposed level in terms of the costs and benefits to network users. Their views in this respect should be informed by their stakeholder engagement. The exceptions to this include health and safety related output measures – where network owners need to comply with HSE specified outputs.

1.13. The proposed outputs framework also has implications for regulatory reporting as we will need to be able to monitor and evaluate companies' performance against the output measures. We discuss our proposals for regulatory reporting in the section below.

[2] See page 35 of the handbook:
http://www.ofgem.gov.uk/Networks/rpix20/ConsultDocs/Documents1/RIIO%20handbook.pdf

Incentive mechanisms

1.14. For each output category, we have considered a range of incentive mechanisms to encourage TOs to deliver the primary outputs and secondary deliverables at value for money to current and future consumers. These incentives include financial rewards/penalties and 'reputational' incentives.

1.15. The structure of the incentive mechanism, for example whether is it symmetric/asymmetric, and the basis for setting the reward/penalty will depend on the output measure. Where network companies under deliver against their outputs, a penalty for under delivery could be enforced based on a measure of the value of work avoided through under delivery. However, we might also set out an additional penalty as a deterrent to under delivery, as we did in DPCR5. As an alternative, we could require companies to deliver the shortfall in outputs during the subsequent price control period without providing additional funding for this.

1.16. Where we cannot set out a mechanistic reward/penalty, we set out rules for how we will determine the size of the reward/penalty in the light of a company's performance. For example, in some instances we propose to set a penalty for under delivery of outputs based on a measure of the value of work avoided through under delivery, with the possibility of an additional penalty to deter under delivery. We do not expect to provide any additional revenues associated with the over delivery of outputs where this is not valued by consumers. However, in other cases, where the company can demonstrate the incremental output that was delivered was desired by network users, we will recognise the efficient costs associated with this output in setting allowed revenues.

1.17. We have not proposed financial incentive mechanisms for all output measures. For example, we have not proposed any financial incentives for the set of safety related outputs. For these outputs, the network owners need to comply with legal obligations, and are subject to HSE enforcement action in the event of non-compliance. For other output measures where the network companies have a low level of control over performance, such as the proportion of renewable energy transported, we propose to require the TOs to report on their performance in order to provide a reputational incentive, but do not propose a financial incentive.

Monitoring delivery and reporting

1.18. The RIIO model proposes a balanced scorecard approach to assessing company performance in output delivery. The purpose of the scorecard is to provide a clear and simple way to convey information about network company performance and to facilitate a meaningful comparison of performance over time.

1.19. The development of the scorecard is relevant to the delivery of other parts of the RIIO framework including facilitating discussion during enhanced engagement; supporting our approach to proportionate assessment; and providing scope to attach financial incentives to overall performance.

1.20. We propose that the scorecard focuses on the delivery of primary outputs with secondary deliverables used only where they are particularly useful in illustrating network company performance. The primary outputs will be weighted with, for example, greater weight given to areas identified by stakeholders as priorities during enhanced engagement.

1.21. In line with the RIIO recommendations, we propose that the scorecard take the form of a 'traffic light' system with company performance judged on whether their delivery is low (red), medium (amber) or high (green).

Reporting requirements

1.22. We will need to introduce new reporting requirements on companies to enable us to monitor and evaluate their performance against the proposed set of outputs.

1.23. We have two main reporting processes to enable us to monitor TO performance for the current price control. We require TOs to submit to us on an annual basis regulatory reporting packs (RRPs) which provide a common framework for the collection and assessment of accurate cost information. We also require TOs to submit data as set out in our Regulatory Instructions and Guidance (RIGs), which provides a common framework for TOs to report relevant outputs and standards of performance data.

1.24. For RIIO-T1, we will need to revise and expand the current RIGs to enable us to monitor TOs performance against the output measures. We propose to start work early on the development of RIGs for RIIO-T1 and to issue draft revised RIGs in advance of our final proposals in December 2012. We will work with the industry in developing common reporting templates which will form part of the RIGs.

1.25. We would welcome respondents' views on whether any of our proposed output and performance measures present potential difficulties in terms of ensuring accurate and comparable data submissions. We would also welcome respondents' views on whether there are any aspects of our proposed outputs framework where the data requirements are likely to result in a disproportionate regulatory burden.

1.26. We are considering whether we should require the companies to take measures, such as appointing an independent reporter to verify their returns, to provide us assurance as to the accuracy of their regulatory reports. Under the current licence conditions, we can request an independent examiner to assess companies' systems, processes and procedures and the specified information, to ensure the company is in compliance with the RIGs. However, this is not a standardised process. We note that reporter arrangements are used in the regulation of the rail and water sectors and a variant of these may be appropriate as we move to an outputs approach. We invite respondents' views on whether, in principle, it would be appropriate to consider requiring the companies to do more to verify their regulatory reports. We also seek views on whether the use of reporters or other approaches would be appropriate.

Changes to outputs

1.27. There are circumstances where it might be appropriate to change the outputs set at the time of the price control review. For example the mid-period review of outputs (discussed in Chapter 7 of the 'Supplementary Annex – RIIO-T1 Uncertainty mechanisms') provides a mechanism to make changes to outputs where:

- material changes to existing outputs can be justified by clear changes in Government policy, for example if Government policy on climate change changes, a higher or lower level of delivery or performance may be needed
- introducing new outputs may be needed to meet the needs of consumers and other network users.

1.28. There are two other areas where we also consider that it might be appropriate to make changes to the outputs. These changes would be separate from the mid-period review and are set out below:

- **Administrative errors:** If we identify errors by Ofgem in the target/baseline or the incentive rate associated with an output then we would look to correct these errors without delay.
- **Unfit measurement/reporting arrangements:** If we identify that the measurement/reporting of an output does not meet the intended purpose (eg there is scope for gaming on reporting of the figures) then we would look to refine the reporting arrangements to ensure the intended purpose is met. As part of this revision it may be necessary to adjust the target/baseline to maintain consistency with the policy intention at the price control review. This might be an area where we would consider using reporters to make an independent assessment of any required changes.

1.29. We would not look to use the approaches above to change outputs for other reasons. For example, we would not look to make any changes if, with hindsight, any output target/baselines was too onerous or not sufficiently demanding for the network companies. We would also not change the incentive rate associated with outputs if new information were to arise unless the change qualified for the mid-period review of output requirements. We do not propose any changes in these instances as we want to provide regulatory certainty that we would not retrospectively change the 'deal' made at the price control.

1.30. We welcome views on the proposed approach to revising outputs set out above.

Context

SO incentives

1.31. In both electricity and gas the system operator (SO) role is separate from the TO role. We currently incentivise the SO separately from the price control (though the SO internal costs, for example control room capital costs, are met through the price control). In electricity, NGET is the SO, while it also acts as TO in England and Wales. SHETL and SPTL act as TO in Northern and Southern Scotland, respectively, and work with the SO consistent with the SO-TO code (the STC). In gas, NGG is SO and TO, both owning and operating the national transmission system (NTS).

1.32. As per our July open letter consultation, we are considering options for aligning the SO incentives with the price control. This work is ongoing but where there are links to the work that we have been taking forward in developing outputs we have highlighted the current situation and potential options that might improve the way we incentivise the SO and the TOs in their roles to the overall benefit of consumers.

Project TransmiT

1.33. Our work on Project TransmiT has potential and actual linkages with RIIO-T1. Project TransmiT is our independent and open review of transmission charging and associated connection arrangements. We received and have reviewed the responses to our call for evidence. In some areas relevant to RIIO-T1 we have sought further information.

1.34. Project TransmiT is closely related to the price control work to develop connection outputs and the joint work on this is described in the section below that considers that output category. However, the charging issues may also affect the TOs as they produce their business plans in the first half of 2011. We expect a well-justified business plan to take account of the developments on Project TransmiT.

Review of Security and Quality of Supply Standards (SQSS)

1.35. We are currently undertaking a fundamental review of the SQSS. In undertaking the next phase of this review, the industry review group recognised the importance of the transmission price control in influencing their work. They recognised that RIIO-T1 stakeholder engagement would among other things inform:

- the value that different stakeholders place on reliability, and the role that the SQSS plays in ensuring this reliability
- the appropriate level of detail required to describe the processes used to develop an economic and efficient system
- the nature, and level, of customer choice
- the role of the SQSS in co-ordinating the transmission owners
- the right balance of risk and benefit that should be made when developing the transmission system

- the potential for provision of further demand services.

1.36. The design of the primary outputs and secondary deliverables discussed in this paper will inform the work on the SQSS review which is being developed in parallel. For example, work on the value customers place on reliability will inform decisions about whether to retain or change the level of system security requirements.

Other context

1.37. We will also need to be mindful of other contextual issues. One aspect is EU developments including, amongst other developments, the Third Package.

Structure of document

1.38. The remainder of this document sets out our proposed output measures and incentive mechanisms for the six output categories. These are:

- chapter 2: Safety
- chapter 3: Reliability and availability - electricity
- chapter 4: Reliability and availability - gas
- chapter 5: Environment
- chapter 6: Customer satisfaction
- chapter 7: Conditions for connections
- chapter 8: Secondary deliverables for electricity transmission wider works.

2. Safety outputs and incentives

Chapter summary

This chapter sets out our proposed safety outputs, associated secondary deliverables and incentives.

Question 1: Do you have any views on the primary output and secondary deliverables for electricity and gas transmission safety?
Question 2: Are these appropriate areas to focus on and are there any other areas that should be included?
Question 3: Do you agree with the proposed approach to setting safety incentives?

2.1. TOs are required to design and operate their networks to ensure the safety of the public and employees. The HSE monitors and enforces performance in this area as determined by legislation.

2.2. We tasked the reliability and safety working group with developing a set of outputs recognising the importance of safety within the regulatory framework whilst being mindful of the HSE's role as the principal safety regulator. The TOs and the HSE participated in this working group.

2.3. We propose that the primary output for safety should be for the TOs to comply with their legal safety requirements. We will ensure the long-term delivery of this primary output through secondary deliverables relating to asset risk (asset health, criticality and replacement priorities). These secondary deliverables are set out as part of the reliability work (see chapters 2 and 3).

2.4. We do not intend to attach financial incentives to the primary safety outputs as other agencies and mechanisms (the HSE and legal obligations) incentivise the companies to deliver.

2.5. In this chapter we provide background and context to setting safety outputs. We present our proposed primary output and secondary deliverables and the reasons for these. Finally, we discuss the incentive framework for delivering these outputs.

Background and context to setting safety outputs

2.6. The TOs are subject to a range of legal safety obligations. In the case of electricity transmission, TOs must comply with:

- The Electricity Safety Quality and Continuity Regulations (ESQCR) 2002 that specifies the standards that TOs (and their contractors) must adhere to on their networks. It also specifies events which must be reported to the Secretary of

State (for example deaths and injuries occurring to members of the public caused by the network).
- The Health and Safety at Work Etc. Act 1974, which makes provision for securing the health, safety and welfare of persons at work and for protecting others against risks to health or safety in connection with the activities of persons at work.[3]
- The Electricity at Work Regulations (EAWR) 1989, which also ensures health, safety and welfare of persons at work specifically in relation to electricity.

2.7. The HSE regulates TO compliance with these requirements. In the event of non-compliance, the HSE has a number of sanctions available to them to secure compliance with the law and to ensure a proportionate response to criminal offences. Inspectors may offer duty holders information and advice, both face to face and in writing. This may include warning a duty holder that, in the opinion of the inspector, they are failing to comply with the law. Where appropriate, the HSE may also serve improvement and prohibition notices, withdraw approvals, vary licence conditions or exemptions, issue simple cautions (England and Wales only), and they may prosecute (or report to the Procurator Fiscal with a view to prosecution in Scotland).[4]

2.8. In the case of gas transmission, NGG must comply with:

- The Gas Safety (Management) Regulations (GS(M)R) 1996 which stipulate that the TO must produce a safety case which describes how they will manage the gas network and how they will deal with emergencies. This safety case is subject to acceptance and routine inspection by the HSE.[5]
- The HSWA as set out above.
- The TO must also provide the HSE, the Scottish Environment Protection Agency (SEPA) and the Environment Agency (EA) with a risk assessment in accordance with the GS(M)R 1996, the Control of Major Accident Hazard (COMAH) Regulations 1999, and the Pipeline Safety Regulations 1996.[6]

Primary outputs and secondary deliverables

2.9. We propose that the appropriate output for safety is compliance with the safety requirements which are set out in legislation and monitored by the HSE. The RIIO principles suggest that primary outputs should be material, controllable, measurable, comparable, applicable and legally compliant. In the case of safety outputs, we consider that legal compliance is the most important of these principles and propose this as our primary output. This output is measurable (a TO is either legally compliant or it is not) and comparable (all TOs must abide by the same legislation).

[3] See ‘Introductory text’ of the ‘Health and Safety at Work Etc. Act 1974’
[4] HSE, 'Enforcement Policy Statement',
http://www.hse.gov.uk/pubns/hse41.pdf
[5] Further detail provided in the Gas Safety (Management) Regulations 1996 ‘Safety Case Assessment Manual’
http://www.hse.gov.uk/gas/supply/gasscham/gsmrscham.pdf
[6] Frontier Economics, RPI-X@20: Output measures in the future regulatory framework,
http://www.ofgem.gov.uk/Networks/rpix20/ConsultReports/Documents1/rpt-outputs.pdf

The HSE is the principal safety regulator and our primary output supports, rather than duplicates, their functions.

2.10. It is our view that the primary output should not stipulate an exhaustive list of legislative requirements but include examples of legal obligations such as ESQCR, HSWA and the GS(M)R. This will ensure that the primary output remains relevant should any further legislative requirements be imposed on the businesses during the price control period.

2.11. We propose that the secondary deliverables for both electricity and gas transmission safety should be the asset health, criticality and replacement priorities. These secondary deliverables are the same as those developed for reliability and provide a framework for managing network risks including safety implications. A full description of this framework is contained in chapters 3 and 4.

2.12. Our initial view is that asset health, criticality and replacement priorities provide a useful means of ensuring that the ability of TOs being legally compliant in the future is not put at risk by decisions made in the current control period. Asset condition (measured through an asset health index) and criticality are currently reported under Standard Licence Condition B17 Network Output Measures (NOMs) of the electricity transmission licence and Special Condition C13: Network Output Measures of the gas transporter licence. We are considering whether these measures need further development as part of this price control review and have set out further details of our proposed changes in appendix 3.

2.13. The asset health and criticality reports are to be modified as part of the reliability secondary deliverables work, which will see the development of replacement priority reporting.

2.14. During the reliability and safety working group, participants proposed that safety outputs should be based upon three core drivers: public safety, staff safety and asset condition. We consider that these drivers are sufficiently captured within our primary outputs and secondary deliverables whilst avoiding duplication of the HSE's regulatory function.

2.15. In addition, Frontier Economics[7] suggested the use of Emergency Testing as a primary output for gas transmission to show the TO has measures in place to cope in the case of an emergency. We consider that this forms part of the gas safety case and is not required as a separate primary output.

Incentives

2.16. As noted above, we do not propose to attach financial incentives to the primary safety outputs as the businesses are incentivised by other agencies and mechanisms.

[7] Frontier Economics, RPI-X@20: *Output measures in the future regulatory framework*, May 2010

2.17. The HSE is the principal safety regulator and our primary output supports, rather than duplicates, their functions. We envisage our strong bilateral engagement, developed through the RIIO-T1 process, will be ongoing so that:

- the HSE can continue to assist Ofgem to understand the safety obligations that the businesses have
- Ofgem can assist the HSE in quantifying the efficient cost of its current and proposed safety requirements

2.18. At the Price Control Review Forum (PCRF), the Consumer Challenge Group (CCG) suggested that additional financial penalties beyond those imposed by other agencies and mechanisms could be applied. These additional penalties would largely replicate the reputational damage that a firm in a competitive sector may suffer from not meeting its legal safety requirements.

2.19. Our initial view is that it is not appropriate for us to apply further specific penalties on the primary output. In deciding on a penalty to impose on any business, the relevant agency (be that the HSE or a court) will take into account several factors including the impact on the public as well as the degree to which the penalty should act as a disincentive for future poor performance. A court would have regard to the degree of reputational damage suffered by the business. We are also concerned that, in cases where a penalty has not yet been imposed on the business (for example in the case of criminal sanctions), it could also place Ofgem in a position of pre-empting the decision of the relevant agency.

2.20. We note that our customer satisfaction outputs, which look at survey evidence, complaints handling and stakeholder engagement, will include elements of the reputational damage that TOs may suffer due to poor performance in several areas including safety. Further detail of this measure is provided in Chapter 6.

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

2.22. In summary, we will undertake a performance assessment at the end of the period to determine whether the TO has performed satisfactorily and delivered the level of asset health related network risk it agreed to deliver over the course of RIIO-T1. Financial consequences may apply in cases where there is clear and material under or over-delivery. TOs will also be required to provide ratings of the asset health, criticality and replacement priorities at annual intervals throughout the price control.

3. Reliability and availability – electricity transmission

Chapter summary

This chapter sets out our proposed primary outputs and secondary deliverables for reliability and availability for electricity transmission during RIIO-T1. We also set out our proposals on how incentives should be applied to these.

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

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

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

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

3.1. The differences in the nature of the gas and electricity markets require a different set of reliability outputs for electricity and gas transmission. This chapter sets out our proposals for electricity transmission. The following chapter sets out our proposal for gas transmission.

3.2. The reliability and safety working group was tasked with developing a set of primary outputs and secondary deliverables to provide clarity to TOs and other stakeholders on the way that performance will be assessed and used to incentivise delivery of outcomes for RIIO-T1. The working group has examined outputs proposed by Frontier Economics[8] as well as those included in current incentive schemes.

3.3. For electricity transmission, we propose that the primary reliability output for all TOs should be energy not supplied (ENS).

3.4. We propose that the TOs are provided with a marginal reward/penalty for over/under-performing against target levels of the primary output, ENS. We propose that the incentive be symmetrical.

3.5. TOs are responsible for network planning, stewardship of their assets and operational decisions over time, to ensure any risk to delivery of primary outputs is managed and that they deliver long-term value for money for existing and future customers. If price controls focused only on the delivery of primary outputs, TOs could deliver these at the lowest cost during the eight-year price control period, potentially at the expense of delivery of primary outputs over the longer term. To protect against this, we are proposing that several secondary deliverables be introduced.

3.6. We propose to use a suite of secondary deliverables in four areas to ensure any risk to delivery of the primary output is managed and that they deliver long-term value for money for existing and future customers. These are:

- asset health, criticality and replacement priorities
- system unavailability and average circuit unreliability (ACU)
- faults
- failures.

3.7. We propose an incentive framework for secondary deliverables that will require the TOs to demonstrate how their expenditure is linked to managing network risk both at the beginning and end of the price control period. We will undertake a performance assessment at the end of the period to determine whether the TO has performed satisfactorily and delivered what it was paid to do over the course of RIIO-T1. This does not oblige the companies to deliver exactly the mix of secondary deliverables that was set at the price control. In fact, we would expect companies to respond to new information that becomes available such as type faults or improved means of assessing asset deterioration. However, the TOs must be able to demonstrate that they have achieved an equivalent level of risk reduction and that the programme that has been delivered is of equal or greater benefit to customers.

3.8. Financial penalties or rewards may apply in cases where there is clear and material under or over-delivery, taking into account the cost of the additional work/shortfall in what has been delivered.

[8] Frontier Economics, *RPI-X@20: Output measures in the future regulatory framework*, May 2010.

3.9. We also consider it important to include an incentive to optimise constraint costs from electricity TO activities. In England and Wales, NGET is both the TO and the SO, and so sees the constraint cost sharing factor for constraints caused by its actions as TO. However, in the case of the Scottish TOs (SHETL and SPTL) there is no link between actions they may take which impact constraint costs and costs under the SO sharing factor.

3.10. The following section provides an overview of the background and context for setting reliability and availability outputs for electricity transmission. We then describe our proposed primary outputs, secondary deliverables and their associated incentives.

Background and context

3.11. Under TPCR4, electricity TOs are currently subject to the Network Reliability Incentive Scheme (NRIS). This provides them with rewards/penalties for over/under-performing against target levels of unsupplied energy (NGET) or the number of loss of supply events (SPTL and SHETL).

3.12. The NRIS was implemented in 2005-06 following two transmission failures in London and Birmingham. Whilst the current scheme has provided a starting point for developing a primary output, we considered it appropriate to re-examine several of the assumptions underpinning the scheme (including the definitions of several exclusions) and have progressed this work as part of the safety and reliability workshops.

3.13. The working group also explored similarities between the Distribution Network Operators (DNOs) Interruptions Incentive Scheme (IIS) (which is based on customer interruptions (CI) and customer minutes lost (CML)) and the NRIS based on ENS. We feel that it is important to align the treatment of particular loss of supply events between the schemes, where possible.

3.14. We have also examined the Network Output Measures (NOMs) in relation to asset health and criticality taking into account similar work that was carried out as part of DPCR5. The NOMs provide a useful starting point for secondary deliverables for RIIO-T1.

Primary output

3.15. The RIIO model states that primary outputs should be material, controllable, measurable, comparable, applicable and legally compliant. On this basis, we propose that the primary output for electricity transmission reliability ENS.

3.16. ENS is readily measurable, is controllable over the long term, can be consistently measured and compared, and is the most applicable metric as it incorporates both the frequency and duration of interruptions, providing a measure that reflects the ultimate output delivered to customers.

3.17. NGET is currently incentivised on the basis of ENS under the NRIS. SPTL and SHETL are not currently incentivised on ENS but instead are incentivised on the basis of the number of interruptions.

3.18. We consider it important for all TOs, including SPTL and SHETL, to be incentivised on a consistent basis and on a basis that incorporates both the number of outages and the volume of load that is interrupted. An output based only on the number of interruptions does not provide any financial incentive for the TOs to restore supplies as quickly as possible, or to provide contingencies to allow rapid restoration.

3.19. Unlike NGET, SPTL and SHETL do not perform an SO function. We note that the duration of loss of supply events is affected by both the assets and actions of the TO as well as the actions of the SO and are therefore proposing an output for the Scottish TOs that takes account of this split. For SPTL and SHETL, we propose that the duration of events used for calculating ENS should end when they advise the SO that the network elements necessary for restoration are available.

3.20. For NGET, we propose that the duration of events should be consistent with the current scheme and thus incorporate its role as both TO and SO. However, to provide greater transparency between the TO and SO functions, we propose that NGET report on a basis consistent with the Scottish TOs – that is, reporting the time taken to make the necessary network elements available for restoration, and separately reporting the time taken for the SO to restore supply.

3.21. Whilst the working group reached agreement on a primary output of ENS, there has been debate on how this should be defined, or more specifically, the types of loss of supply events that should be included. The TOs developed an ENS strawman that builds on the exclusions in the current scheme. Our approach has been to look at the ENS output from first principles but using the current scheme as a starting point. We are proposing several changes to the current scheme for RIIO-T1. The following sections describe:

- exclusions from the current scheme that we propose maintaining
- loss of events lasting three minutes or less
- events relating to three or more directly connected customers
- events relating emergency de-energisation, third party damage, extreme weather and exceptional events
- events relating to planned outages
- events on adjacent systems

Exclusions under current NRIS that we propose maintaining

3.22. We propose that the following exclusions in the current NRIS be maintained:

- any unsupplied energy resulting from a shortage of available generation
- any unsupplied energy resulting from a user's request for disconnection in accordance with the Grid Code
- any unsupplied energy resulting from a de-energisation or disconnection of a user's equipment necessary to ensure compliance with an instruction by the SO to the licensee pursuant to the STC

3.23. These events are all currently excluded from the NRIS. These events are largely outside the control of the TO and hence we consider it appropriate for them to continue to be excluded from the primary output of ENS.

Unsupplied energy from events lasting three minutes or less

3.24. We propose that the definition of a relevant loss of supply event should exclude events lasting three minutes or less. The TOs have argued that excluding events of less than three minutes duration would allow for the correct operation of delayed auto-reclose (DAR)[9] which could be assumed to cover events for which the cause is weather. This proposed exclusion is also consistent with the DNO IIS.

3.25. As part of the CCG we received feedback that interruptions of three minutes or less can be painful for customers. However, we note the limited control that the TOs have over short duration interruptions. We also note that events lasting for fewer minutes tend to make a small contribution to the total level of ENS. Tables 3.1 and 3.2 show the number of incidents and ENS for events shorter than and longer than three minutes for the period 2006-07 to 2008-09. Events less than three minutes generally account for less than 1 per cent of the total ENS.[10]

3.26. We would welcome views from stakeholders on this proposed exclusion.

[9] DAR refers to the automatic re-energisation of overhead lines after transient flashover events such as lighting strike or conductor clashing after a short delay to allow the event to pass.
[10] It should be noted that this is based on ENS as defined by the current NRIS.

Table 3.1 Number of incidents less than three minutes 2006-07 to 2008-09

	2006-07		2007-08		2008-09	
	≤3 mins	>3 mins	≤3 mins	>3 mins	≤3 mins	>3 mins
NGET	3	2	4	9	5	3
SPTL	0	3	3	15	2	10
SHETL	9	8	13	4	7	7
Total	12	13	20	28	13	20

Source: TO submission to Safety and Reliability Working Group

Table 3.2 ENS less than three minutes 2006-07 to 2008-09 (MWh)

	2006-07		2007-08		2008-09	
	≤3 mins	>3 mins	≤3 mins	>3 mins	≤3 mins	>3 mins
NGET	3	310	2	1512	2	334
SPTL	0	21	1	96	1	334
SHETL	2	174.5	1	63	1	178
Total	5	506	4	1671	3	845

Source: TO submission to Safety and Reliability Working Group

Unsupplied energy that causes electricity not to be supplied to three or fewer directly connected parties

3.27. We propose that the exclusion relating to unsupplied energy to three or fewer directly connected parties should be amended to reflect only those customers that have requested lower standards of connection.

3.28. The TOs have argued that the exclusion in the current NRIS for interruptions involving three or less directly connected parties should be maintained. It was originally included as a proxy measure of events involving a lower standard of connection and the TOs have argued this eases the reporting burden of maintaining a list of lower standard connections.

3.29. We are not convinced by these arguments. The TOs have a small number of lower standard connections on their system (NGET 10, SPTL 1 and SHETL 1) and hence we believe that the reporting burden of maintaining this list should not be great. In this case, we consider it more appropriate to use the actual lower standard connections as the relevant exclusion, rather than the proxy used in the current scheme.

3.30. We note that changing this definition will have implications for the historical levels of incentivised ENS. We are requesting historical information from the TOs that takes account of our proposed definition of ENS and the relevant exclusions.

Unsupplied energy resulting from actions to ensure public safety[11], third-party damage, severe weather and other exceptional events

3.31. We propose that unsupplied energy from emergency de-energisation to comply with ESQCR or to otherwise ensure public safety, third party damage, severe weather and other exceptional events should not automatically be excluded from the primary output. We propose using a framework consistent with the DNO IIS whereby the TOs would need to demonstrate that they have met specified exceptionality requirements for an adjustment to be made to the incentivised level of ENS. For example, in the case of third party damage, the TO would need to demonstrate that the event was not attributable to any error on their part and that they had taken all reasonable preventative and mitigating actions.

3.32. As part of the working group, the TOs proposed that events relating to third party damage and public safety should continue to be excluded from the definition of a relevant loss of supply event. Examples of these events could include a member of the public climbing a transmission tower notwithstanding the presence of anti-climbing guards, or there was a fire adjacent to a site where emergency de-energisation was required. TOs estimate that there are approximately two to three events of this nature each year.

3.33. We acknowledge that events of this nature can often be outside the control of the TO and would not want to create a framework that discourages the TOs from taking decisions to ensure the public safety. However, we consider it appropriate that the TOs be provided with some incentive to manage these risks. For example, TOs should be encouraged to learn from these events both on their networks and elsewhere and to ensure that they take reasonable steps to prevent them in the future. An automatic exclusion for these events provides no incentive for the TOs to do this.

3.34. Our view is that a framework that is consistent with their treatment under the DNO IIS is more appropriate. For all exceptional events other than severe weather, the TOs would be required to demonstrate that they have met exceptionality requirements that include:

- that the event was a consequence of an external cause
- that they had taken all reasonable steps preventative and mitigating actions both to limit the number of customers interrupted and to restore supplies quickly and efficiently having due regard to safety and other legal obligations. This should include having taken appropriate risk assessment for key sites.

3.35. We note that the Authority has recently indicated concerns with the application of the DNO licence condition reflecting these requirements.[12] We have indicated that

[11] Emergency de-energisation or disconnection of a user's equipment necessary to ensure compliance with the Electricity Safety, Quality and Continuity Regulations 2002 or to otherwise ensure public safety (exclusion under current scheme)

we will be undertaking an in-depth review of all of the relevant licence conditions in order to ensure that proportionate requirements are on all DNOs to assess and, where appropriate, to take steps to address risk. We would expect the outcomes of this review to be reflected in the transmission scheme for RIIO-T1.

3.36. Extreme weather events are defined in the current scheme based on the number of faults caused by weather in a 24 hour period (50 faults in 24 hours for NGET, seven faults in 24 hours for SPTL and SHETL). Given that the threshold for these limits has been in place since the commencement of the scheme, we consider it timely to assess whether they remain appropriate and are seeking views from stakeholders in this area.

Planned outages (exclusion under current scheme)

3.37. We are seeking further comment from stakeholders on whether the current exclusion relating to planned outages should be maintained in the primary output for RIIO-T1. Our initial proposal is that, in principle, interruptions that impact on customers' load should be incentivised to reflect the impact they have on these customers.

3.38. The current NRIS excludes events resulting from planned outages as defined in the Grid Code whilst the DNO IIS does not exclude these events. DNOs are currently incentivised on a 50 per cent weighting for CI and CML. This DNO scheme balances the need for DNOs to be incentivised to minimise the length of planned outages and their requirement to reinforce the network and the reduced impact on customers where they are given advance notice of interruptions. As noted above, it is our view that we should seek to align the treatment of particular loss of supply events between the DNO IIS and our primary output of ENS.

3.39. The TOs have argued that planned outages should not be included in our primary output ENS because:

- including planned outages could create an incentive for the TOs not to reinforce the network
- an incentive mechanism for minimising the impact of planned outages currently rests with the SO
- historical baselines for ENS calculated in accordance with the current scheme would be zero because planned outages are always agreed with customers in advance
- it is difficult to set a baseline level of future performance given difficulties associated with forecasting ENS for planned outages.

3.40. We consider that these arguments do not sufficiently justify automatically excluding all planned outages from our primary output of ENS. However, we

[12] Explanation of Authority's reasons for the direction issued under special condition C2 pursuant to special condition CRC8 – EDF Energy Networks (LPN), plc
http://www.ofgem.gov.uk/Networks/ElecDist/QualofServ/Documents1/EDFE%20LPN%20Reasons.pdf

acknowledge that a scheme that mirrors the treatment of planned outages in the DNO IIS may not necessarily be suitable for transmission.

3.41. Our initial thinking is that we do not agree that including planned outages necessarily creates an incentive for the TOs not to reinforce the network. Rather, a scheme that includes planned outages needs to balance an incentive on the TOs to minimise the length of outages that affect customers and their requirement to reinforce the network in the same way that DNOs are required to. Furthermore, we are proposing a marginal incentive for ENS around a forecast baseline level of performance. The baseline levels of performance need to be developed based on historical performance as well as forecast build programmes. We would expect the TOs to put forward options on a level of performance that seeks to balance network reinforcement with customer needs.

3.42. The SO incentive will motivate the SO to optimise the financial impact of planned transmission outages, but for reasons other than reliability of supply to customers. However, there is currently no incentive either on the SO or the TO to minimise the duration or frequency of planned interruptions to customers.

3.43. We note that the SO has overall responsibility for outage management and seeks to minimise constraint costs associated with this. Outages are agreed between customers, the TOs and the SO in accordance with STC and Grid Code obligations. However, our view is that it is also important to create an incentive on the TOs to minimise the frequency and length of time required for planned outages that impact on customers (including any overrun).

3.44. We note the arguments put forward by the TOs that not all planned outages result in a reduction of the load required by customers and that in these cases, ENS would be equal to zero. TOs have also noted that all outages are agreed with customers in advance. We are seeking further information from the TOs on the nature, frequency and magnitude of planned outages in previous price control periods to understand the differences between the load that customers would otherwise have been placing on the network in the absence of work being done by the TO. We also consider it important to understand the 'willingness' of customer agreement to planned outages. We also note that in setting any incentive on planned outages we would consider the impact that pre-notification has on the disruptive impact of the outage.

3.45. Although customers agree to outages beforehand, this may not always have been done willingly, (for example, they may only have input into when in a particular period the outage should take place, but not whether it would take place). Because of this, and because customers do experience the effects of outages (whether planned or not), our initial view is that the primary output and baselines should at least take account of the difference between the planned outage load and load customers would otherwise have been placing on the network.

3.46. We note TO arguments about difficulty forecasting levels of performance for planned ENS. Forecasting these levels requires an understanding of the future work programme, the physical state of the network and supply and demand balance. However, we are not convinced that these issues differ substantially between forecasting planned and unplanned levels of performance.

3.47. We are seeking comments from stakeholders on these issues.

Events triggered on an adjacent system

3.48. We propose that there be no exclusion for unsupplied energy resulting from events triggered on another system. We see no difference to the value that customers would place on these events, and therefore feel that the rationale for incentivising these events continues to apply. We propose that a framework should be developed to enable the TOs to equitably share the total incentivised ENS across all of the networks that contributed to the energy not supplied. In the case of events on the Scottish TOs' systems, this share should also reflect the role of the SO in restoring supply.

3.49. As part of the safety and reliability working group, the TOs proposed exclusion for any unsupplied energy resulting from events triggered on an adjacent system. They suggested that including loss of supply events caused by outages on another TO network might lead to double-counting.

3.50. There have been only two events of this nature in the last 20 years. The TOs provided an example of one such incident that occurred at Windyhill in March 2009. In this incidence, a catastrophic failure of a piece of equipment at Windyhill 275kV substation caused the loss of supplies to customers at seven Grid Supply Points (GSPs) in the Windyhill group and multiple locations on the SHETL network. Table 3.3 shows the impact on both the SPTL and SHETL networks.

Table 3.3 – Impact of Windyhill Incident on SPTL and SHETL

Network	**Estimated unsupplied energy (MWh)**
SPTL	292
SHETL	144.76

- Source: TO submission to Safety and Reliability Working Group

3.51. We consider that an incentive should be placed on either one or both of the TOs to ensure that they are exposed to the loss of supply to customers on both networks. Our view is that allowing exclusions for events triggered on an adjacent TO system would mean that the TOs are not exposed to the value that customers place on lost load.

3.52. We propose that a framework be developed with the objective of sharing the total 'pool' of unsupplied energy between the relevant TOs. Given the small number of events that have occurred historically, this should not create a significant burden on TOs whilst still ensuring that there is an incentive to minimise unsupplied energy to customers regardless of whether the fault occurs on their transmission network or that of an adjacent operator. It will also avoid double-counting of ENS.

3.53. We propose that the sharing mechanism be based on the following principles and will further develop the framework over the course of the price control review:

- In the first instance, the TO whose customers are interrupted would be subject to the incentive.
- Where the TO can demonstrate that the interruption was caused by, or substantially contributed to by, events occurring on the adjacent TO's network then it would be entitled to apply to allocate an agreed proportion (up to 100 per cent) of the unsupplied energy from the event to the adjacent TO, with arbitration by a third-party in the event that agreement cannot be reached. The arbitrator would determine the proportion of the ENS incentive to be allocated to each party based on the degree of control that each party had over the events that led to the interruption and the duration of the interruption. The total amount allocated between the TOs and the SO would always equal 100 per cent of ENS.
- In the case of events on the Scottish TOs' systems, the share should also reflect the role of the SO in restoring supply.
- Alternatively, the Authority could maintain discretion to make a decision on the proportion of energy that should be allocated. In this case, the Authority would be likely to use an external examiner to make a recommendation on how to apportion the incentive.

Secondary deliverables

3.54. As part of this working group it was agreed that in the long term, the TOs should pursue a system-wide risk assessment for justifying investment in assets that impact on the reliability and safety of the network or on environmental impacts. However, the TOs argued that they do not make investment decisions based upon an overall measure of network risk and take into account a range of factors when prioritising investment programs. We recognise that the TOs make asset management decisions trading off resource impacts and risk on a daily basis. However, we consider it important that they have a more consistent framework for articulating this.

3.55. As a first step in the shorter term, we propose a framework that requires the TOs to articulate how they use other risk management processes in conjunction with our proposed secondary deliverables when making asset management decisions. This framework should:

- be objective
- include how TOs make their case for spending a marginal pound across different asset categories (for example, describe how risk trade-offs are made between different assets)

- show how trade-offs are made between areas of expenditure (load, non-load capex, opex)
- potentially allow for an assessment of over delivery as well as under delivery.

3.56. This should build towards the development of a broader risk metric in the medium to longer term.

3.57. We propose secondary deliverables in four areas. These are:

- asset risk (asset health, criticality and replacement priorities/risk)
- system unavailability and average circuit unreliability (ACU)
- faults
- failures.

3.58. These secondary deliverables are the same as those used for safety and provide a framework for managing network risk including safety, reliability and environmental implications.

3.59. The TOs currently report on each of our proposed secondary deliverables under Standard Licence Condition B17 Network Output Measures (NOMs). We do not propose significant changes to the way in which criticality, system unavailability, Average Circuit Unreliability (ACU), faults and failures are reported. However, we are proposing amendments in relation to the way asset health and replacement priorities are reported and used in addressing whether the TOs provide long-term value to customers. The following sections provide an overview of these secondary deliverables. Appendix 3 contains further information on our proposed amendments.

Asset risk (asset health, criticality and replacement priorities/risk)

3.60. An HI provides a framework for collating information on the health (or condition) of network assets and tracking changes in network health over time. We consider it a useful indicator of potential future reliability and safety issues. Asset health, criticality and replacement priorities should be used by the TOs to identify capital programs for the forthcoming price control.

3.61. Criticality provides a measure of the consequence of failure an asset. By considering both the health and criticality of assets, replacement priorities are then derived as a tool for describing how TOs prioritise asset replacement decisions.

3.62. The replacement priority indicates how TOs prioritise asset replacement decisions. It is a function of the asset health and the criticality of the substation or circuit where the asset is located.

Average circuit unreliability (ACU) and system unavailability

3.63. ACU provides data to show the impact of asset unreliability on the network which could be an indicator of the decline of overall asset health.

3.64. System unavailability is a measure of the percentage amount of time for which circuits are unavailable. We consider it a useful secondary deliverable as it shows the impact on the network from all types of outages.

Faults and failures

3.65. A fault is an event which causes plant to be disconnected automatically from the high voltage system.

3.66. A failure usually indicates where an asset needs replacing, but does not necessarily result in the automatic disconnection of a network element. Failures are defined specifically for each asset type (for further information see appendix 3).

Proposed incentives

Primary outputs

3.67. We propose that the TOs be provided with a marginal reward/penalty for over/under performing against target levels of the primary output, ENS. We propose that the incentive be symmetrical (ie the same reward/penalty for over/under delivery). This arrangement will seek to provide the TOs with a reasonable balance of risk and reward, while protecting consumers' interests by setting incentives that encourage the TOs to improve their performance in the future and penalise it for deterioration in performance relative to a baseline level.

3.68. The financial incentive should take the form of an automatic annual adjustment during the price control period.[13] We consider that a within period adjustment is appropriate given the clarity on the output that is to be achieved, its relative importance to customers and the level of confidence in the data that will be used to measure performance.

3.69. The following sections outline our proposed approach to both:

- setting a baseline level of performance
- setting key incentive characteristics such as the use of revenue neutral dead-bands, aligning incentive rates between the TOs and the use of caps and collars

[13] Given the lag associated with reporting on historical data and the investigation of any one-off events, this annual adjustment is likely to take place with a two year time-lag.

3.70. During the price control review we will set a baseline level of performance for each of the TOs. The companies will propose baselines as part of their well justified business plans. We will consider whether these are appropriate and, if necessary, set an alternative.

3.71. As part of their well justified business plans, the companies should provide background and context to how they have developed proposed future levels of performance and other relevant factors such as the impact of the TOs forecast work programme on planned outages.

3.72. We do not propose a dead band around the target level of performance. The current NRIS uses a dead band (237-263 MWh for NGET, 10-12 events for SHETL and eight to ten events for SPTL). The NRIS was introduced mid-way through TPCR3 and this dead band meant that the TOs were not penalised or rewarded for short-term fluctuations in performance. The TOs have also argued that these dead bands are appropriate in situations where it is difficult to forecast the value of the primary output. We note these concerns but consider that under an eight-year price control, the businesses will be better equipped to deal with short-term fluctuations in performance and hence we propose that we remove this dead band.

3.73. There is a natural cap on the reward that a TO can achieve for over-performance (ie the best performance that a TO can achieve is 0 MWh of unsupplied energy).

3.74. We are consulting on the maximum penalty that the TOs face for underperformance. It is our view that we should remove the current limit on the maximum penalty that is included in the NRIS. Removing the collar would strengthen the incentive by exposing the businesses to the full value that customers place on unsupplied energy.

3.75. We note that our decision on whether this collar should be removed will also take account the suite of output measures and their associated incentives and potential impact on the overall return on regulated equity (RoRE). Were the collar to be maintained, we would consider whether a further additional penalty (imposed through a licence condition) should apply if the TOs' levels of performance did deteriorate beyond the collar.

3.76. We have considered whether the incentive rate should be symmetric. We also considered this issue when developing the DPCR5 IIS. In general, evidence on willingness to pay from improvements versus willingness to accept deteriorations suggests that customers place greater value on deteriorations than they value improvements. However, we note that an asymmetric scheme is more complex and results in volatility becoming more of an issue. On balance, we consider that a symmetric approach is more appropriate but will consider stakeholder comments in this area when making our decision.

3.77. We propose that the strength of the incentive should be aligned as far as possible between the TOs. We will take into account information and submissions on consumer willingness to pay for a desired level of ENS. Our preliminary view is that the current incentive strength of approximately £33,000 per MWh is above the value that customers place on being without supply. Whilst we recognise that it is not possible to come to an exact view, we propose moving the strength of the incentive towards a value that better reflects the value customers place on electricity when they are without supply. A value in the order of half this strength would still be above value of lost load (VoLL) in other jurisdictions.

Secondary deliverable incentives

3.78. We propose an incentive framework for secondary deliverables that will require the TOs to demonstrate how their expenditure is linked to managing network risk both at the beginning and end of the price control period. We will undertake a performance assessment at the end of the period to determine whether the TO has performed satisfactorily and delivered the level of asset health related network risk it agreed to deliver over the course of RIIO-T1.

3.79. This framework will ensure that the delivery of primary outputs in future periods is not put at risk by a failure to deliver a suitable level of asset health at the end of the current price control period.

3.80. The secondary deliverables we propose will encourage the TOs to improve the way that they plan and operate their networks. For example, a TO may undertake the minimum work required to maintain an asset to allow it to deliver a reliable network service in line with its primary output of ENS. However, in the event that the asset is nearing the end of its useful life, it may need to be replaced. A delay to the replacement of this asset could result in increased short term costs and network interruptions in future periods, which will compromise the ability of the TO to meet its primary output. Inefficient deferral may also result in an increase in replacement expenditure in future periods, or increased costs associated with replacement on failure. In this example, it would have been more efficient for the TO to replace the asset in the current period before it began to fail. Although this will require the TO to incur higher costs in the current period, it will likely mean that the total costs and risks passed on to customers will be minimised. In the absence of an incentive framework on these secondary deliverables, TOs will not be encouraged to replace assets at the appropriate time.

3.81. We propose that the framework for secondary deliverables should build on that implemented for network output measures as part of DPCR5. As part of this framework we will ask TOs to set out their views on asset health, criticality and replacement priorities at:

- the start of RIIO-T1, effectively reflecting the TO’s view on the current condition, risk and replacement priorities of the network
- the end of RIIO-T1 with no intervention, effectively reflecting the TOs view on asset degradation over the period
- at the end of RIIO-T1 with investment as proposed in their well-justified business plan.

3.82. We propose conducting an outputs assessment at the end of RIIO-T1 and will consult on the outcome as part of the RIIO-T2 process. The purpose of the performance assessment will be to determine whether or not a TO has satisfactorily delivered a package of secondary deliverables consistent with the change in the level of risk agreed through the RIIO-T1 settlement.

3.83. For example, we will ask the TOs to describe the asset management decisions made during RIIO-T1 and provide evidence of the impact on these secondary deliverables. The onus will be on the TOs to justify that they have delivered a package of outputs consistent with the agreed change in the level of network risk.

3.84. Financial consequences may apply in cases where there is clear and material under or over-delivery. We are considering two options for how these consequences should be applied. We welcome stakeholders' comments on these options.

3.85. The first option would involve us making a revenue adjustment at the end of RIIO-T1 (potentially in a similar way to that used for DPCR5). If we determine that a TO has under-delivered, TOs would be subject to a financial penalty at the end of RIIO-T1. Depending on the level of the penalty, this option can be used to tilt the incentive in favour of delivery.

3.86. The second option would involve us beginning the next price control on the assumption that the TOs have achieved agreed levels for the deliverables. This would automatically penalise or reward the TOs during RIIO-T2. For example, where a TO has under-delivered during RIIO-T1, the TO would fund the shortfall between their forecast and what they actually delivered. This is consistent with the principles we outlined in the RIIO Handbook.

3.87. Under each of these options, we are considering whether the framework should allow for over-delivery as well as under-delivery. The TOs would need to clearly demonstrate that any material over-delivery was in customers' best interests. Where we were satisfied that this is the case, there is the potential for the TO to be rewarded.

3.88. TOs will also be required to provide ratings of the asset health, criticality and replacement priorities at annual intervals throughout the price control.

3.89. As part of the annual submission, TOs will be required to provide commentary on all material changes that have occurred during the year. The TOs will be required to track and articulate the reasons for changes in asset health, criticality and replacement priorities during RIIO-T1 relative to the agreed levels. We expect that there will be a substantive discussion between us and the TOs following the annual submission, during which Ofgem will set out its opinion at that time on the progress being made against the forecast deliverables for the end of RIIO-T1.

Incentives to optimise constraint costs arising from electricity TO activities

3.90. We are seeking comment from stakeholders on whether the TOs should be incentivised to optimise constraint costs that result from planned line or substation outages for maintenance or construction works. Our initial proposal is that, in principle, constraint costs attributable to TO's actions should be incentivised in order to minimise total costs to customers.

Background

3.91. Constraints arise when there is insufficient capacity on the transmission system to transmit electricity from where it is being generated to where it is being consumed.

3.92. When constraints arise, NGET as the SO will take actions in the market (including in the Balancing Mechanism) to increase and decrease the amount of electricity at different locations on the network. For example NGET may purchase additional generation (or reduce demand) in one location and reduce generation (or increase demand) in another location. The amount NGET has to pay for additional electricity generally exceeds the amount they receive from the reduction in generation. Whilst there is some additional complexity around the calculation, in general terms the difference is referred to as a 'constraint cost'.

3.93. It is not always efficient to spend significant sums augmenting the network where constraints arise or are forecast to arise. Rather, the aim should be to minimise the long-term cost of investment plus constraints as this ultimately minimises costs to customers. Long term investment in network augmentations is dealt with in Chapter 8.

3.94. Constraints can also be significantly impacted by real time TO activities, such as taking equipment out of service for maintenance or refurbishment. In many cases constraint costs could be reduced if the duration of these works was shortened or if works were undertaken at times of favourable energy flows (eg when a specific power station that would be behind a constraint was also on maintenance).

Existing Arrangements

3.95. The SO is currently incentivised to optimise constraint costs through a sharing factor which forms part of the SO Incentive scheme. The current scheme sets a target for a bundle of costs including constraint costs. The SO will receive no payment when outturn costs are within the dead band. When outturn costs are below (above) the dead band then NGET will receive (pay) 15 per cent of the difference, subject to a maximum of £15m[14].

3.96. In England and Wales, NGET is both the SO and the TO. Through its common ownership NGET has an incentive (through the sharing factor) to reduce constraint costs even where these costs are caused by its behaviour as a TO rather than as a SO.

3.97. In Scotland the TOs have no incentive to consider constraint costs. However, NGET (as the SO) sees the impact of constraints through the sharing factor regardless of how they arise.

3.98. Under the current arrangements in the STC the SO coordinates the development of the transmission outage plans in collaboration with TOs and generators.[15] A Final Outage Plan (FOP) is agreed in week 49 of the current year for the next financial year.

3.99. For the networks in Scotland, there are arrangements in place through the STC to allow NGET to request changes to the agreed FOP. Any changes to the FOP requested by the SO allow the TOs to recover reasonably incurred costs from the SO at cost reflective rates. An allowance of £1m[16] is currently available to the SO to make outage change payments to the TOs although in the past few years the outage change costs paid have been significantly lower than the £1m allowance[17].

3.100. However, the current arrangements provide for a relatively small fund (£1 million per annum – only a small portion of which is spent), and only allow the SO to compensate the Scottish TOs for costs. This provides no incentive for the Scottish TOs to explore possible constraint mitigating options, such as implementing higher dynamic ratings (which may result in earlier asset replacement) for parallel circuits, training of additional contractors or staff to allow work to proceed on a 24 hour basis, or putting circuits back in to service in peak times.

3.101. The SO recovers these costs via the Balancing Services Use of System (BSUoS) charges.[18] For England and Wales, there is no allowance for recovery of

[14] For further discussion see Ofgem's "National Grid Electricity Transmission System Operator Incentives from 1 April 2010 – Final Proposals Consultation" (Reference number: 33/10) and related documents at http://www.ofgem.gov.uk/Markets/WhlMkts/EffSystemOps/SystOpIncent/Pages/SystOptIncent.aspx.
[15] The process is outlined in the STC for the SO and TOs and in the Grid Code for generators
[16] In 2004/05 prices
[17] P.28 of Ofgem's 2010/11 Electricity System Operator Review – Preliminary Conclusions following Phase 1 at http://www.ofgem.gov.uk/Markets/WhlMkts/EffSystemOps/SystOpIncent/Documents1/Phase%201%20recomendations%20doc%204.pdf.
[18] If the actual costs differ from £1m allowance by more that £300k, it must notify the Authority of this "outage cost adjusting event . This notification triggers the process for the full cost pass through and removes any financial risk/benefit to NGET if the outage change costs are in excess of £1.3m or less than £0.7m. If the actual costs are within the range £0.7m-£1.3m, NGET recovers the £1m allowance regardless of the actual level of costs incurred within this range. The discontinuity in the incentive potentially may create perverse incentives. Ibid, page 27.

outage change costs, as it is assumed that NGET's benefits can be derived through the Balancing Services Incentive Scheme (BSIS) to outweigh the costs.

3.102. Outage change costs incurred prior to the development of the FOP are not currently compensated.

Relationship to system operator review

3.103. Constraint costs related to the Scottish TOs are material. In 2009/10 constraint costs were in the order of £139 million, with around £86 million related to the Cheviot boundary and £16 million related to constraints within Scotland. TO activity significantly impacts these constraint costs. For example, NGET's operational update in October 2010 noted that "Outages in Scotland extended increasing costs some £12m (ie as a result of the delay in the return of a circuit in Scotland following an outage NGET incurred an estimated additional £12m in constraint costs)."[19]

3.104. Our System Operator Review published in July this year noted that:

"Currently, the TOs have incentives only to minimise their respective OPEX and CAPEX costs, and thus do not take into account potential constraints costs when planning outages. Therefore, we are looking at NGET to consider ways in which outage planning can be improved under the auspices of the STC (System Operator – Transmission Owner Code). It should be noted that through our RPI-X@20 project we are considering changes to the transmission regulatory framework to encourage TOs to act in this way. For example, as discussed in our Emerging Thinking consultation and in work recently commissioned from Frontier Economics, we are looking at how to include in an output led regime an output on TOs that links to constraint management."

Proposed approach

3.105. We appreciate the work being undertaken on outage planning under the STC, including STC Amendment Proposal CA039 which proposes extending the current outage proposal submission timescales from one year to two years[20].

3.106. In our view, placing an incentive on the Scottish TOs to optimise the constraint costs that they cause could complement the existing arrangements. Whilst common ownership means that the existing SO incentive is passed through to the TO in England and Wales, we believe that, given the materiality of the constraint costs, there is a case for passing a portion of the SO incentive on to the TOs in Scotland, based on the proportionate level of impact that the TO's activities have on constraint costs. Such a mechanism could, we believe, provide a stronger incentive to ensure all constraint mitigating options (proportionate to the expected constraint costs) are adequately explored.

[19] Page 15, http://www.nationalgrid.com/NR/rdonlyres/A963C6DC-FB93-4C43-9B91-6AD4C543C84F/43603/01_OperationalUpdate.pdf.
[20] http://www.nationalgrid.com/uk/Electricity/Codes/sotocode/Amendments/

3.107. We believe that a linkage to actual constraint costs rather than a more general measure such as circuit availability is important as this will encourage the TOs to incur costs in compressing or changing the timing of circuit outages or increasing real time equipment ratings for parallel circuits only where there is a net benefit in doing so.

3.108. We recognise that there may be a number of options for developing the pass through mechanism alongside the incentive structure, including:

- placing a licence condition on the TOs and SO to develop an appropriate arrangement
- proposing a fixed sharing factor as part of the price control
- developing a mechanism where the TOs and SO enter bilateral negotiations such that the SO incentivised the TO to the extent necessary to deliver the requested behaviour
- a combination of the above

3.109. There are advantages and disadvantages to each approach. For example, the monopoly position of the TOs as sole providers or the position of the SO may be an issue for some options. We would therefore welcome stakeholder feedback on advantages and issues with the proposed approaches.

3.110. We note also that pass through of a portion of the sharing factor would necessarily require the Scottish TOs to have access to actual or forecast constraint costs in order to make informed decisions. Schedule three of the STC sets out the information and data permitted to be disclosed by a party to a TO, and modifications may be required in order to allow the Scottish TOs to access the data that they require.

3.111. It has been suggested that such disclosure may be an issue for some stakeholders by, for example, revealing expected user bids for balancing services, and we would welcome feedback on whether such concerns exist, if so, what the undesirable impacts would be, mechanisms by which any undesirable impacts from information disclosure could be mitigated, and whether the residual concerns would outweigh the benefits of passing through a portion of the SO sharing factor.

3.112. We would also welcome stakeholder views as to whether there would be merit in extending the above principles to constraints that could occur as a result of unplanned circuit interruptions on intact networks. Chapter 8 also discusses the potential for using constraint costs as an incentive for timely delivery of additional boundary transfer capacity.

Cancellations

3.113. The SO can cancel outages organised and agreed with the TO subject to payments set out in the TO Outage Change Costing Procedure (STCP11-3) contained under the STC. Under the proposed arrangements the cost allocations set out in this procedure will need to be reviewed to reflect the costs attributable to each party where outages are moved in order to avoid constraint costs.

3.114. Some stakeholders have also suggested that the costs and consequences to the TO of the SO cancelling an outage are not fully captured in the existing arrangements. If this is the case, then the benefits of cancellation will not be considered alongside the full costs and consequences of cancellation, leading to inefficient decisions. The price control proposal could require the review of the procedure to incorporate the full cost of cancellation to the TOs and/or consideration of other consequences, and we would welcome stakeholder views on whether such a requirement is warranted.

England and Wales

3.115. The fact that NGET owns both the TO and SO in England and Wales means that the sharing factor should be appropriately taken into account in both TO and SO decisions. However, there is currently a lack of transparency around this decision-making process between the TO and SO.

3.116. We believe that there may be merit in incentivising the England and Wales SO and TO roles as if they are separate companies, in a similar way as proposed for Scotland. This would ensure that both the SO and the TO in England and Wales were appropriately incentivised regarding the effects of their actions and would also provide an improved level of transparency on the impact of decisions made on the TO side on constraints costs.

Incentive strength

3.117. For activities that are deemed ‘TO’, NGET currently faces sharing factors of 100 per cent as under TPCR4 a target allowance was set and NGET is fully exposed to opex increases/decreases around this allowance. The presence of different sharing factors with regard to TO opex (100 per cent) and SO opex and balancing costs (15 per cent) may therefore have distorting effects.

3.118. Different incentive strengths may drive sub-optimal decision-making by making a pound spent in one area appear to be more valuable than a pound spent in another area. Our preliminary, in principle, view is that the incentive strength in the TO and SO price controls should be aligned. However, this may result in the SO and, through the mechanisms proposed above, the TOs having significantly increased exposure to constraint cost volatility, and we would welcome stakeholder views on this issue.

4. Reliability and availability – gas transmission

Chapter summary

This chapter sets out our proposed primary outputs and secondary deliverables for reliability for gas transmission during RIIO-T1. We also set out our proposals on how incentives should be applied to these.

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

Question 2: Do you have views on whether additional transparency and separation should be provided between the TO and SO roles?

4.1. The differences in the nature of the gas and electricity markets require a different set of reliability outputs for electricity and gas transmission. This chapter sets out our proposals for gas transmission. The following chapter sets out that the principal outcome that we require from the National Transmission System (NTS) is for it to convey the required volume of gas in a reliable and efficient manner (reflected at both entry and exit). This outcome results from a combination of TO and SO activities and should be pursued through a suite of primary outputs and secondary deliverables.

4.2. The TO is responsible for building and maintaining the gas transmission network ie making the assets available for the SO to operate. Despite this distinction between the roles, we found that there is clearly overlap in the delivery of reliability outcomes and we have found difficulty in separating the SO and TO incentives for reliability under the current arrangements.

4.3. Further, in a manner analogous to constraint costs in electricity, incentives are currently seen by the SO, even where the costs result from a failure of the TO's network.

4.4. There is also an interrelationship between existing incentives relating to reliable gas delivery and other SO incentives – for example, those related to shrinkage, residual balancing and unaccounted for gas.

4.5. We propose that one primary reliability output for gas transmission should be for NGG to comply with its obligations to convey gas volumes as required at system entry and exit points under the Uniform Network Code (UNC), its Gas Transporter Licence (GT Licence) and ultimately, the Gas Act 1986.

4.6. However, we would also welcome comments on whether additional transparency and separation should be provided between the TO and SO roles.

4.7. Subject to Section 9 of the Gas Act, Standard Special Condition A9 of the GT Licence requires NGG to plan and develop its pipeline system to enable it to meet '1 in 20' peak aggregate daily demand.[21] The GT Licence also sets out 'baseline' capacity obligations on NGG in respect of entry and exit capacity which, subject to the provision of other conditions within the licence, NGG NTS is obliged to meet. The commercial regimes applying under the UNC for the allocation of NTS entry and exit capacity also place firm obligations on NGG NTS in respect of meeting the new capacity needs of NTS users[22].

4.8. However, we consider there may be gaps associated with system network flexibility both in the sense of diurnal flows at entry and exit and varying flows across the network. We are requiring NGG to report additional information and develop associated outputs and deliverables as part of justifying any proposed investment in these areas.

4.9. We acknowledge that our primary output is impacted by NGG's role as both TO and SO for the NTS. Given the commercial arrangements that are in place, we consider it difficult to isolate NGG's role as TO in developing our primary output and recognise that any changes to the buy-back schemes that are largely SO incentives do have implications for the delivery of the primary output we propose for RIIO-T1.

4.10. In common with electricity transmission, we propose that the long-term delivery of primary outputs should be ensured through secondary deliverables relating to asset risk (asset health, criticality and replacement priorities).

4.11. We are seeking comment on whether further incentives on the primary output beyond those currently captured in the commercial and operational arrangements stipulated by the UNC and GT Licence are required.

4.12. We propose to use a similar framework as in electricity transmission for incentivising the secondary deliverable of asset risk (asset health, criticality and replacement priorities).

4.13. The following section provides an overview of the background and context for setting reliability and availability outputs for gas transmission. We then describe our proposed primary outputs, secondary deliverables and their associated incentives.

[21] '1 in 20' peak aggregate daily demand is defined as the peak aggregate demand level which, having regard to historical weather data derived from at least the previous 50 years, is likely to be exceeded (whether on one or more days) only in 1 year out of 20 years.
[22] Users include shippers, DNOs and large industrial users.

Background and context

4.14. The reliability and safety working group was tasked with developing a set of primary outputs and secondary deliverables to provide clarity to TOs and other stakeholders on the way that performance will be assessed and used to incentivise delivery of outcomes for RIIO-T1. The working group has examined outputs proposed by Frontier Economics[23] as well as those included in current incentive schemes (for example the operational buy-back incentive scheme).

4.15. As noted above, NGG is the owner and operator of the NTS that transports gas from the entry terminals to gas distribution networks or directly to power stations and other large industrial users. As TO, NGG's role includes the construction and maintenance of the assets that transport gas. As SO, NGG has responsibility for operating the system including system and residual balancing activity on the NTS.

4.16. NGG is currently subject to obligations and incentives at system entry and exit points under the UNC, its GT Licence and ultimately, the Gas Act. These incentives and obligations apply to NGG's role as TO and SO. The working group has considered these obligations and incentives and their interactions in developing outputs for NGG and we indicate below whether they are placed on NGG in its TO or SO capacity.

4.17. We note that the reliability and safety working group included representatives from NGG, the HSE, RenewableUK, DECC and Centrica. We consider it important that our outputs incorporate feedback from as wide a group of stakeholders as possible, including other users of the NTS such as shippers, large industrial users and GDNs. We are therefore seeking detailed comment on several areas of our proposed framework. We also anticipate that NGG will further engage with these stakeholders in developing its well-justified business plan. These areas will be developed further prior to the release of our March 2011 strategy decision document.

4.18. We have also examined the NOMs in relation to asset health and criticality taking into account similar work that was carried out as part of DPCR5. The NOMs provide a useful starting point for secondary deliverables for RIIO-T1.

Primary outputs and secondary deliverables

4.19. We consider that the proposed reliability primary outputs and secondary deliverables for gas transmission should reflect the principal outcomes that are required from NGG as owner and operator of the NTS.

4.20. As noted above, the principle outcome we require from the NTS is for it to convey the required volume of gas in a reliable and efficient manner (reflected at both entry and exit). This is affected by:

[23] Frontier Economics, RPI-X@20: Output measures in the future regulatory framework, May 2010.

- whether the network has adequate capacity to meet the desired levels of demand both now and in the future influenced by NGG in its role as TO and SO (during working groups we have discussed investment for system flexibility within this context)
- whether the network assets perform as required influenced primarily in NGG's role as TO (during the working groups we have referred to this as asset risk which is made up of asset health, criticality and replacement priorities).

4.21. Our initial proposal is that one primary output should be for NGG to comply with its obligations to convey gas volumes in a reliable and efficient manner as required at system entry and exit points under the UNC, its GT Licence and ultimately, the Gas Act.

4.22. There are different obligations and associated incentives at entry and exit points of the NTS. These obligations and incentives have been developed to provide appropriate signals as to how and when capacity is made available to users. These include obligations and incentives to provide entry capacity baselines as well as incremental obligated and non-obligated entry capacity. In developing the primary output, we considered these obligations and incentives and whether in combination, they provide the appropriate incentives for NGG to meet it overall reliability outcomes described above (see Background and context).

4.23. It is our view that these obligations (including capacity baselines and the NTS commercial arrangements) largely fulfil the need for output measures and associated incentives for the NTS in relation to meeting the '1 in 20' peak demand as well as user requirements at entry and exit. However, we consider there may be gaps associated with system network flexibility both in the sense of diurnal flows at entry and exit and varying flows across the network. We are requiring NGG to report additional information and develop associated outputs and deliverables as part of justifying any proposed investment in these areas.

4.24. The following section gives a brief overview of these obligations and incentives in relation meeting the '1 in 20' demand and user requirements at entry and exit (further detail is contained in appendix 2). We then discuss the development of outputs and deliverables associated with system network flexibility.

Meeting '1 in 20' demand and user requirements at entry and exit

Existing obligations at entry

4.25. NGG is required to offer capacity at entry points in four forms:

- firm non-incremental entry capacity as specified in the licence, which is referred to as 'baselines'
- incremental obligated entry capacity refers to additional capacity that can be released via the Quarterly System Entry Capacity (QSEC) auctions when user commitment signals the need for capacity beyond the baseline levels

- non-obligated entry capacity, which is capacity that NGG NTS has elected to make available over and above the baseline
- interruptible entry capacity which can be curtailed when there is an entry capacity shortfall.

4.26. When operating the NTS, NGG may find itself in a position where it cannot meet the capacity obligations that it has sold. In such a situation there are several commercial and operational tools available to NGG. NGG is incentivised via its SO role to adjust its entry capacity obligations via two entry capacity incentive schemes:

- the incremental entry capacity buy-back incentive scheme that relates to incremental obligated entry capacity released as part of the long-term capacity auctions that have occurred since 1 April 2007
- the entry capacity operational buy-back scheme that relates to all other entry capacity excluding interruptible entry capacity.

4.27. NGG has two main options to deliver incremental entry capacity. It can:

- invest to increase NTS capability via its TO role – this results in increased capex costs but reduces the likelihood that NGG will have to buy-back capacity to meet its obligations; or
- accommodate the increased obligations by better utilising the existing network via its SO role – this saves on capex costs but results in a greater risk of having to buy-back capacity.

4.28. Furthermore, if NGG did not make capacity available in accordance with these obligations it would be in breach of its licence conditions.

Existing obligations at exit

4.29. Exit capacity is made up of three elements:

- NTS exit (flat) capacity, which is capacity which a user is treated as utilising in offtaking gas from the NTS at a rate which (for a given daily quantity) is even over the course of a day
- NTS exit (flexibility) capacity, which is capacity which a GDN user is treated as utilising in offtaking gas from the NTS to the extent that (for a given daily quantity), the rate of offtake is not even over the course of the day.
- NTS off-peak exit (flat) capacity which is daily exit flat capacity that is subject to curtailment.

4.30. In the enduring period (from 2012), NGG is subject to the incremental exit capacity buy-back scheme that incentivises NGG to provide incremental enduring exit (flat) capacity allocated under the user commitment framework of the reformed exit regime. The incremental exit capacity buy-back scheme is characterised by the same parameters as the incremental obligated entry capacity buy-back scheme.

4.31. Other than this scheme, NGG is not subject to incentives on NTS exit (flat) capacity beyond the obligations imposed by the GT Licence to use all reasonable endeavours to make capacity available and to meet '1 in 20' peak day capacity demand.[24]

Existing incentives at entry and exit

4.32. The current incentive arrangements include target levels of performance as well as caps and collars on NGG's exposure. Specifically:

- the incremental obligated entry capacity and incremental exit capacity buy-back schemes both have a target cost of zero with 100 per cent exposure to buy-back costs subject to a cap on NGG's exposure of £4 million a month and £36 million a year
- the entry capacity operational buyback incentive has a target cost (net of revenues) of £13.5 million with 50 per cent sharing between NGG and shippers of costs (net of revenues) with an upside cap of £13.5 million and a downside collar of £10 million.

4.33. In addition there is a cap on NGG's total downside risk across all three incentive schemes at £48 million. This cap was imposed as part of TPCR4. Although the probability of NGG incurring maximum losses under all three schemes is low, we considered that this was a risk that we could not reasonably impose on NGG.

Our considerations in developing a primary output for meeting '1 in 20' demand and user requirement at entry and exit

4.34. As outlined above NGG's main reliability outcome is to convey the volume of gas required by users at entry and exit in a reliable and efficient manner. This outcome was developed and consulted on as part of the reliability and safety working group and should be reflected in primary outputs and secondary deliverables.

4.35. The primary output proposed to deliver the above outcome is compliance with the Gas Act, UNC and GT Licence.

4.36. Subject to Section 9 of the Act, Standard Special Condition A9 of the GT Licence requires NGG to plan and develop its pipeline system to enable it to meet '1 in 20' peak aggregate daily demand.[25] The GT Licence also sets out 'baseline' capacity obligations on NGG NTS in respect of entry and exit capacity which, subject to the provision of other conditions within the licence, NGG NTS is obliged to meet.

[24] We also note that GT Licence includes an exit capacity buy-back and interruptions incentive scheme that applies until the start of the enduring period (1 October 2012). In the enduring period, NGG can claim back certain buy-back costs but these relate primarily to user behaviour (as advised by NG as part of the reliability and safety working groups see: NGG, Proposed reliability outputs straw man submitted to reliability and safety working group)

[25] '1 in 20' peak aggregate daily demand is defined as the peak aggregate demand level which, having regard to historical weather data derived from at least the previous 50 years, is likely to be exceeded (whether on one or more days) only in 1 year out of 20 years.

The commercial regimes applying under the UNC for the allocation of NTS entry and exit capacity also place firm obligations on NGG NTS in respect of meeting the new capacity needs of NTS users.

4.37. We consider the proposed primary output captures NGG's reliability outcomes whilst being mindful of the commercial arrangements that have been put in place to encourage the efficient and economic operation of the NTS.

4.38. The commercial and operational arrangements that flow from these requirements provide a framework for incentivising NGG to deliver its primary output.

4.39. We propose to monitor compliance with our primary output by requiring NGG to report on the actions that it has been required to take under the relevant obligations. This includes action taken to ensure that capacity has been made available as required by users. There is currently a requirement on NGG to report on the volumes of exit capacity that were curtailed and the reasons for this curtailment. We propose that NGG should report on these volumes and the causes of curtailment at both entry and exit.

4.40. We note that in the enduring exit regime, NGG's baseline obligations are financially firm. Furthermore, if NGG were unable to deliver its baselines it would be in breach of the GT Licence and face subsequent penalties that result from this. Our initial view is that historically, these incentives appear to have been sufficient in ensuring that NGG makes non-incremental capacity available at exit. However, we are seeking comments from stakeholders as to whether this will continue to be appropriate over the course of the RIIO-T1 price control (see below).

4.41. As noted above, we acknowledge that our primary output is impacted by NGG's role as both TO and SO for the NTS. Given the commercial arrangements that are in place, we consider it difficult to isolate NGG's role as TO in developing our primary output and recognise that any changes to the buy-back schemes that are largely SO incentives do have implications for the delivery of the primary output we propose for RIIO-T1.

4.42. We have also considered how terminal flow advices (TFAs) and maintenance days are treated.

4.43. TFAs are issued to address both gas quality and pressure-related issues:

- **Quality**: NGG manages the quality of gas entering the NTS by issuing TFA communications to the Delivery Facility Operators (DFO). If the gas supplied to the NTS by a DFO has the potential to fall below the standard required by the GS(M)R data, a TFA is issued requesting the DFO to reduce or cease supply.
- **Pressure**: A TFA is issued to connected system operators when actual or notified rates of entry would cause the NTS to breach its Minimum or Maximum Permitted Pipeline Operating Pressure.

4.44. NGG has argued that TFAs issued for gas quality purposes are unrelated to the reliability/capability of the NTS and that TFAs issued for pressure management are either a result of the customer's flow profile being outside the UNC specification (1/24th of daily flow per hour) or the ramp rate contained in the network entry or exit agreement (NEA or NExA), or as a result of asset failure. We understand NGG's arguments that it is not appropriate for it to be penalised for TFAs issued because a user's flow profile is outside specification.

4.45. We note however that TFAs caused by asset failure in some cases could be associated with incentivised commercial actions where this affects their ability to meet sold capacity rights for the day. We are seeking further comment on the likely frequency of TFAs where commercial actions have not been undertaken. In such cases it may be appropriate for an additional incentive to be applied to NGG.

4.46. Maintenance days on exit are defined in the UNC and NGG uses contractual arrangements to ensure that it can meet its system obligations in a safe manner. Maintenance days on entry are not defined in the UNC but where this maintenance impacts on a shipper's ability to flow gas in accordance with its allocated capacity, NGG would be subject to the commercial actions as part of the entry buy-back incentive schemes. We are seeking comment on whether there is a case for providing a mechanism to minimise planned capacity interruptions.

System network flexibility

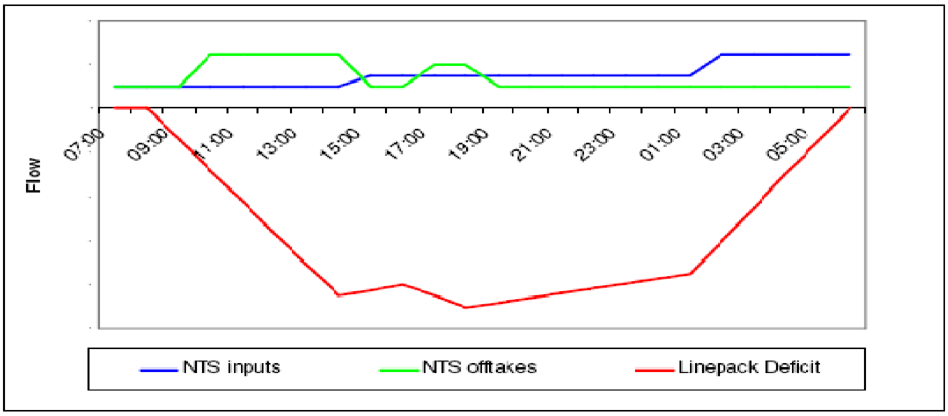
4.47. Significant changes in the use of the NTS are forecast over the coming decade. The proportion of GB gas supplies coming from traditional gas supply sources is anticipated to fall relative to gas imported from Europe or via LNG import terminals. Elsewhere, investment in renewable energy generation has the potential to change the ways in which combined cycle gas turbine (CCGTs) electricity generators take gas from the NTS, potentially moving towards less predictable demand patterns in response to energy intermittency elsewhere in the sector. Change in the use of the NTS has the potential to impact gas flow patterns and gas entry and exit rates and, as a consequence, system capacity needs.

4.48. As system operator NGG uses system flexibility to manage differences between entry capacity and exit capacity rates. Gas Shippers and GDNs operators book NTS entry capacity and NTS exit capacity from NGG in order to bring gas on and to take gas off the NTS. Shippers and GDNs value the ability to vary the rate at which they enter and exit gas relative to the steady hourly rate implied by 1/24 of their capacity bookings for commercial and operational reasons. Changes in the future predictability of entry and exit capacity flows have the potential to increase NTS users flexibility capacity needs.

4.49. NGG NTS describe flexibility capacity as the capacity, inherent in the system, used to manage gas supply and demand mismatches without compromising safety. At a system-wide level mismatches arise as a consequence of aggregate differences between the rates at which gas enters and exits the system. The availability of flexibility capacity within the NTS is not unlimited and is broadly dependent on the level of linepack, diurnal storage and the physical capability of the system, including factors such as pipeline diameter and compressor capability. Linepack is gas kept in the system at all times to maintain pressure and affect the uninterrupted flow of gas to customers at exit points.

4.50. System flexibility on a given day is dependent on the physical capability of the pipeline system, and the location, interaction and coincidence of entry and exit capacity flow profiles. When NTS users concurrently seek to take gas from the NTS at an hourly rate higher than that implied by 1/24th of their total capacity holdings this reduces the aggregate level of flexibility capacity available. If exit and entry flow profiles are not managed capacity constraints can arise. Figure 4.1 provides a simplistic illustration of the relationship between entry and exit profiles and the availability of linepack. It demonstrates how system linepack can drop when demand exceeds supply, and is then replenished when supply picks up.

Figure 4.1 NTS flex system level definition – linepack changes



Outputs and deliverables for system network flexibility

4.51. In its October Forecast Business Plan Questionnaire (FBPQ) response to the fourth Transmission Price Control Review (TPCR4) rollover, NGG has indicated that it has identified a significant need for system flexibility investment in the period 2012-13 to 2017-18.

4.52. NGG has argued that while the NTS was previously primarily planned to meet the requirements on the '1 in 20' peak day based on a stable and predictable set of entry supply scenarios, the potential volatility of future entry flows undermines this assumption. Based on its FBPQ submission, NGG consider that significant new system flexibility investment is required to accommodate an increased probability of bi-directional flows at the Bacton Interconnector and to recalibrate the system to accommodate the reversal of net North to South flows associated with the decline of flows from St. Fergus.

4.53. In our view any investment to provide increased system flexibility under the RIIO framework must be justified by supporting indicators and robust supply and demand modelling assumptions. Furthermore, under the RIIO-T1 framework, business plans must be justified in terms of the network outputs they will deliver and we expect NGG to link any investment proposals to specific output measures.

4.54. To identify and support NGG's future system flexibility investment plans we propose that a system flexibility reporting regime should be developed and implemented by NGG. We consider that this work should build on the flexibility capacity monitoring regime.[26] We consider that it would be appropriate for NGG to seek views on the conclusions which it would be appropriate to draw from the information and the relative importance of the outputs identified and that this data should support and identify NGG's system flexibility investment plans.

4.55. In parallel to this consultation we are consulting on system flexibility issues in our Update Consultation on NTS Flexibility Capacity released in December 2010. Responses to both consultations will inform our March 2011 strategy decision document.

4.56. We also consider that it would be appropriate for NGG and the GDNs to make explicit consideration of optimising investment efficiency across the NTS/GDN interface in formulating their business plans. The current UNC arrangements do not allow GDNs to signal a willingness to pay for additional NTS flexibility capacity. This has the potential to inhibit coordinated investment efficiency across the integrated GB gas pipeline system. In our view it is important that GDNs are able to compare the efficiency of additional NTS flexibility capacity alongside other capacity management options.

4.57. We also note that the commercial arrangements applying to the allocation of NTS entry and exit capacity provide NGG with efficient financially backed signals for NTS users' future flat capacity needs, but under the current arrangements may not fully indicate the type of investment required to meet wider system flexibility needs. As part of thinking about future system flexibility requirements we consider that it is important that NGG considers whether the commercial regime and charging arrangements are providing them with enough information about NTS users' flexibility needs or providing NTS users with appropriate charging signals regarding the efficient use of capacity. If significant costs are demonstrated to be imposed on the system by forecast changes in users' entry or exit flow requirements, it is appropriate that users of the system who benefit from this investment, contribute to funding it.

Secondary deliverables for asset risk

4.58. As noted above, the principal reliability outcome required from the NTS is also affected by asset risk. We consider that a secondary deliverable to address asset risk

[26] The flexibility capacity monitoring regime was initiated by NGG following the implementation of UNC195AV 'Introduction of Enduring NTS Exit capacity Arrangements'.

will ensure any risk to delivery of the primary output is managed and that NGG deliver long-term value for money for existing and future customers.

4.59. As for electricity transmission, it was agreed that in the long term, NGG should pursue a system-wide risk assessment for justifying investment in assets that impact on the reliability and safety of the network or on environmental impacts. However, NGG argued that they do not make investment decisions based upon an overall measure of network risk and take into account a range of factors when prioritising investment programs. We note that the TOs make asset management decisions trading off resource impacts and risk on a daily basis but we consider it important that they have a more consistent framework for articulating this.

4.60. As a first step in the shorter-term we propose to develop a framework consistent with electricity transmission that requires the TOs to articulate how they use other risk management processes in conjunction with our proposed secondary deliverables when making asset management decisions.

4.61. An HI provides a framework for collating information on the health (or condition) of network assets. Criticality provides a measure of the consequence of failure of assets typically measured in terms of system, safety and the environmental implications. By combining asset health and criticality, TOs can develop replacement priorities that determine capital replacement priorities.

4.62. NGG currently reports on measures of asset health and criticality under Licence Condition C13 NOMs. However, we are proposing that these measures be further developed for RIIO-T1 to provide a more consistent framework to that outlined for electricity transmission (and developed as part of DPCR5). Appendix 3 contains further information on our proposed developments for RIIO-T1.

Proposed incentives

4.63. As discussed above, the licence conditions and UNC, and the commercial and operational arrangements that flow from these, provide a framework for incentivising NGG to deliver its primary output. We have the ability to impose financial penalties on NGG for breach of its licence conditions. In addition, NGG is exposed to financial incentive schemes in relation to costs it incurs in meeting the relevant obligations (for example, the costs of operational or incremental buy-back and the costs of developing incremental capacity). We discuss our proposals in relation to these efficiency incentive schemes can be found in our annex paper on RIIO-T1 and RIIO-GD1 Business plans, innovation and efficiency incentives.

4.64. With the exception of the area of network flexibility outlined above, it is our view that NGG's obligations (including capacity baselines and the NTS commercial arrangements) largely fulfil the need for output measures and associated incentives for the NTS.

4.65. We are seeking further comment from stakeholders on whether existing arrangements provide sufficient incentives in situations where there is an inability or failure by NGG to supply gas. We propose a gas transmission incentive framework for asset health, criticality and replacement priorities/risk that is the same as that being proposed for electricity transmission. It will require NGG to demonstrate how its expenditure is linked to managing network risk both at the beginning and end of the price control period. These areas are discussed in further detail below.

Inability or failure to supply gas

4.66. Some working group members have argued that the current incentive arrangements as stipulated by the UNC and GT Licence may not adequately incentivise the reliable supply of gas in all scenarios. During events covered by force majeure, NGG is relieved of the liabilities that arise from any delay or failure in performing any of its obligations.

4.67. Under the UNC, force majeure events/circumstances include:

- war declared or undeclared, threat of war, war declared or undeclared, act of public enemy, terrorist act, blockade, revolution, riot, insurrection, civil commotion, public demonstration, sabotage or act of vandalism
- ‘act of God’
- strike, lockout or other industrial disturbance
- explosion, fault or failure of plant, equipment or other installation which the affected party could not prevent or overcome by the exercise of the degree of skill, diligence, prudence and foresight which would reasonably and ordinarily be expected from a skilled and experienced operator engaged in the same kind of undertaking under the same or similar circumstances
- governmental restraint or the coming into force of any Legal Requirement.[27]

4.68. For example, NGG has claimed relief from its liabilities associated with providing incremental capacity at Milford Haven citing local planning restrictions. It has been suggested that NGG being relieved of its liabilities in an event such as this may not reflect current best commercial practice. We also note that the types of events covered in the last two points above would be treated as exceptional events in calculating the electricity transmission primary output of ENS. Under our proposed incentive in electricity transmission, the TO would be required to demonstrate that it has taken all reasonable steps to prevent the event from affecting supply and to mitigate its effect (both in anticipation and subsequently) while in gas NGG may declare a force majeure event.

4.69. We are seeking further comments from stakeholders on whether the current incentives that apply when NGG is unable or fails to deliver gas are adequate and the situations under which this occurs. We will consider stakeholder concerns in these areas and assess the suitability of current arrangements as part of our March 2011 strategy decision document.

[27] Uniform Network Code – General Terms Section B 3.1.1

4.70. We note that any areas of concern identified through further consultation may not necessarily be best addressed through developing an additional output. It may be more appropriate to address any concerns through changes to the GT Licence or the UNC. We will consider this area further in light of the comments we receive from stakeholders.

4.71. We also note that we will consider any potential changes in terms of their cost implications. Changes to the commercial arrangements will impact on the target level of costs currently included in the incentive arrangements.

Asset health, criticality and replacement priorities

4.72. We propose an incentive framework for asset health, criticality and replacement priorities that is the same as electricity transmission will require the TOs to demonstrate how their expenditure is linked to managing network risk both at the beginning and end of the price control period.

4.73. In summary, we will undertake a performance assessment at the end of the period to determine whether the TO has performed satisfactorily and delivered the level of asset health related network risk it agreed to deliver over the course of RIIO-T1. Financial consequences may apply in cases where there is clear and material under or over-delivery. TOs will also be required to provide ratings of the asset health, criticality and replacement priorities at annual intervals throughout the price control.

4.74. We provide further information on this framework in Chapter 3.

5. Environmental outputs

Chapter summary

This chapter sets out our proposed approach to setting environmental outputs for the transmission companies. We also set out our proposals on how incentives should be applied to these.

Question 1: Do you have any views on the environmental outputs outlined?
Question 2: Are these the appropriate areas to focus on and are there any other areas in which primary outputs and secondary deliverables should be set?
Question 3: Do you agree with the proposed approach to setting environmental incentives?
Question 4: Do you have any views on what the TOs 'full role' in a low carbon economy may involve by the year 2020?
Question 5: What role is there for a primary output in RIIO-T1 on TO's contribution to the UK's environmental and energy objectives and what type of incentive would be most effective to drive TOs delivery in this area?
Question 6: Do you have any additional views on RenewableUK's proposal for a specific low carbon economy output including the form and size of such a reward mechanism?
Question 7: Do you have views on the relative roles of the TO and SO in relation gas shrinkage and venting, and how we might align the incentives between the two parties?
Question 8: What incentives should companies face to manage their carbon footprint?
Question 9: What incentive should be put on TOs in relation to losses?
Question 10: What are the options to avoid any perverse impacts on network development to connect renewable generation?
Question 11: Do you agree with the principle of full internalisation of environmental costs? To what extent should the output for SF6 move towards this objective?

Introduction

5.1. For both gas and electricity transmission we are consulting on a set of primary outputs for TOs to deliver better environmental performance. From our stakeholder engagement to date, we understand that the main environmental impacts stakeholders want RIIO-T1 to focus on are:

- TOs' contribution to environmental and energy targets
- direct network emissions including the companies' business carbon footprint (BCF)
- the adverse impacts of the network on the local environment such as issues of visual amenity

5.2. This chapter sets out the options we are consulting on for primary outputs and incentives. This work has been informed by our enhanced stakeholder engagement including discussions in the RIIO-T1 working group, comprising the TOs, network users, environmental interest groups and consumer organisations.

5.3. In particular, we are consulting on whether we include a broad environmental output measure and highlight a specific proposal put forward by RenewableUK. We also set out proposals for outputs focussing on direct network emissions and on each TO's business carbon footprint.

5.4. We also set out the importance of companies taking account of wider impacts on the environment including the impact on the local landscape, visual amenity and noise levels.

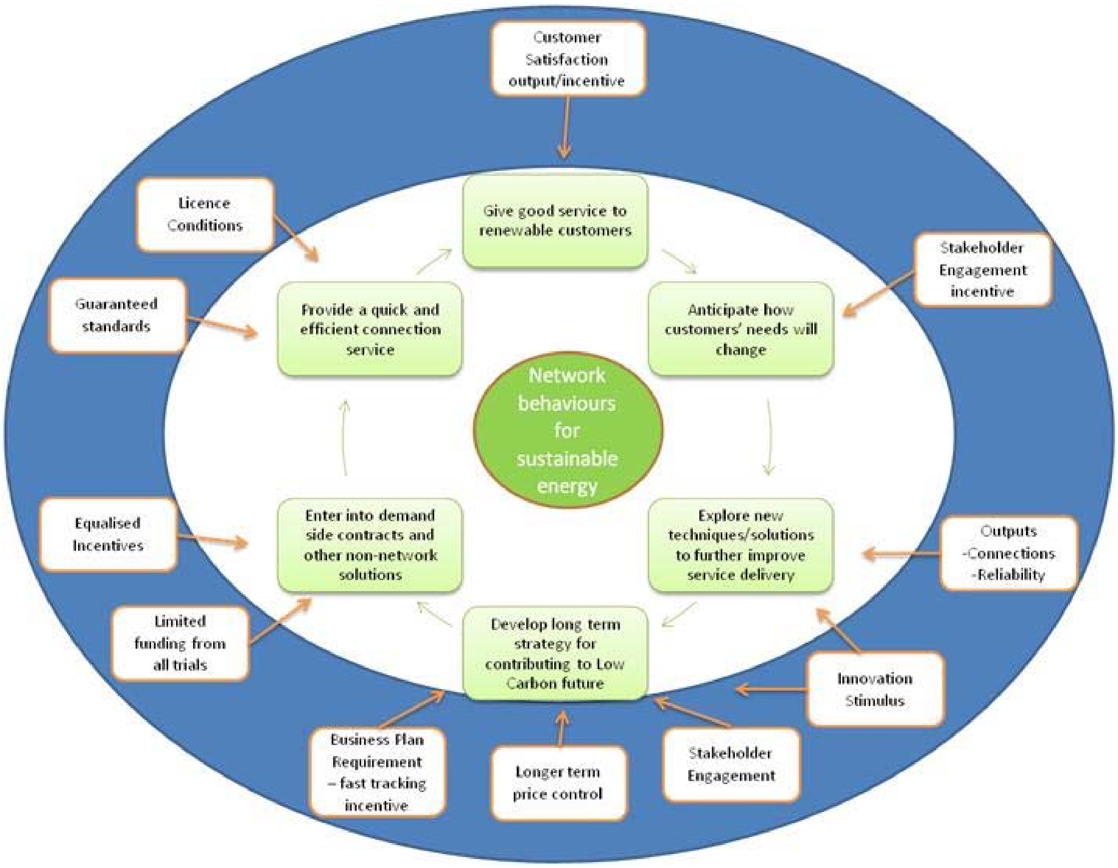
Background

5.5. A high-level objective of the RIIO framework is to ensure the regulated companies deliver the networks needed for a sustainable energy sector. In particular, this will involve the network companies supporting the energy sector to meet the:

- UK’s contribution the EU 2020 renewables target
- UK government’s climate change target for 2050 – an emissions reduction of 80 percent from 1990 levels.

5.6. No single output category will achieve this. Instead, a coherent combination of outputs as well as other parts of the regulatory framework will need to work together. These are outlined in figure 5.1.

Figure 5.1 Interactions of outputs and other aspects of the regulatory framework contributes to wider environmental/energy objectives



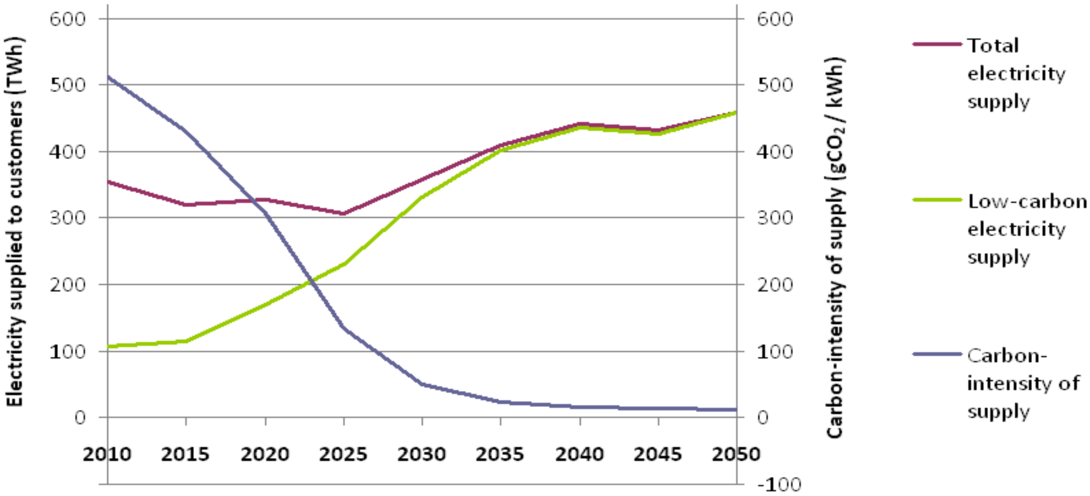
Contribution to UK's environmental and energy targets

Broad environmental objectives

5.7. The UK government is committed to moving to a low carbon economy. This transition will transform the energy sector. Government policies seek a seven-fold increase in renewable energy to meet the UK's contribution to the EU 2020 target and the decarbonisation of electricity and sources of heat towards an 80 percent cut in emissions on 1990 levels by 2050.

5.8. In addition to the scale of change, uncertainty about the rate of change is another major challenge. In its 4th Carbon Budget Report, the Committee on Climate Change recommends the most cost-effective way to meet the UK's 2050 reduction target is the decarbonisation of the power sector by 2030 followed by the electrification of heat and transport. The Committee's analysis in figure 5.2 below shows that over the next two price controls, we could see a step change in the amount of low carbon generation connecting to the system.

Figure 5.2 Step change in low carbon connecting to the system



TOs' role in the UK's broad environmental objectives

5.9. The TOs' contribution to our broad environmental objectives is vital. The things network companies do, and do not do over the next price control period, will have an impact on our ability to meet our energy goals.

5.10. We are committed, through the RIIO framework, to encourage and support TOs to play their 'full role' in achieving the UK's environmental objectives. RIIO, at its heart, is about driving network companies to be proactive in seeking the best way of providing good value, sustainable network services for the long term.

5.11. The TOs' role should involve better performance on traditional activities. But, given the challenges and the scale of interventions to encourage the market delivery, TOs should also seek out new areas and opportunities to facilitate a move towards a low carbon economy. For these reasons we consider it is appropriate to consult with stakeholders on whether we include as part of the price control strategy a broad environmental output measure.

5.12. We welcome views on what the TOs' 'full role' in a low carbon economy should include.

Stakeholders' views on a broad environmental primary output

5.13. Stakeholders at our environment impacts working group have told us they want RIIO-T1 to drive networks to play their full role in securing a sustainable energy sector. The working group also agree that TOs must be given the right incentives to play their part. However, there are a range of views about the combination of primary outputs that will be most effective in driving TOs' contribution.

5.14. Some stakeholders have argued that a specific primary output for contributing to a low carbon economy should be included in RIIO-T1. They have said an output for TOs to reduce the greenhouse gas emissions of generation and inefficient consumption on their networks could bring significantly more material benefits for the UK than reducing the network's own carbon footprint, including losses. For example, in 2009, carbon emissions from electricity transmission losses were 2.6MtCO2, compared with 149MtCO2 from power stations. These benefits could include reduced carbon emissions as well as cost savings for consumers to meet our renewable energy targets and carbon reduction targets.

5.15. They also suggest that a specific primary output will help ensure that companies' plans to achieve other primary outputs are consistent with the over-arching objectives of RIIO. For example, a broad environmental primary output would help ensure an output on timely connections does not create a perverse incentive to avoid making connection offers to renewable generators which can take longer to connect. They also think a broad measure would encourage companies to innovate and seek out new opportunities to contribute which might not otherwise be captured by the other output categories.

5.16. Other stakeholders are less supportive of introducing a specific primary output for contributing to broad environmental objectives. This is because they are not sure it would be an effective way of driving the TOs' contribution or provide good value to existing and future consumers. They argue that future investment in low carbon generation investment and energy efficiency depends on various factors, most of which the TO has little or no control over, eg carbon prices, public acceptability of new development sites. They also think a broad incentive might also duplicate incentives on other primary outputs around connections, reliability and customer satisfaction. Thus this group of stakeholders are concerned that a broad measure might reward companies for market activity they had little impact on and/or doubly reward companies for the delivery of other primary outputs.

5.17. They also think there could be issues about the interaction of a broad environmental output with incentives for other primary outputs as well as networks' licence obligations. For example, depending on the strength of the incentive, it could create perverse incentives for the network to discriminate between users wanting to access the network depending on their carbon intensity.

Principles for setting primary outputs

5.18. The above discussion gives a good sense of how a broad environmental output might rank against the RIIO principles for setting primary outputs. A broad environmental output on TOs is material for delivering a sustainable energy sector – a high level objective of RIIO. However, TOs control over the various factors that influence market delivery is, at best, only partial. There are also practical questions about how easy it would be to measure a company's actual impact and whether this was additional to other output deliverables. There may also be issues around comparability over time and across companies due to changes in government policy or differences in the availability of market opportunities across regions.

5.19. Although a broad environmental output might not rank highly across all the principles set out in the RIIO handbook this does not mean we should not include an output on TOs contribution to a low carbon economy. Instead it might mean that care is needed when designing any incentive. For example, in cases where TOs do not have a sufficient degree of control over performance against the primary outputs we would look closely at the type and strength of incentives attached to the output.

Potential incentives on a broad environmental output

5.20. Under RIIO, companies will have a variety of incentives to deliver primary outputs over the price control. This may, in some cases, include penalties should they fail to deliver. In addition to looking at a primary output on TOs for a broad environmental objective we also need to consider the type of incentive that is appropriate to drive delivery.

5.21. One type of incentive we could use on a broad environmental output is financial. Financial incentives work by adjusting the company's revenue in line with its performance in delivering primary outputs. In the RIIO handbook we said we would use financial incentives when:

- there is clarity on the primary outputs to be delivered
- there is confidence in the data used to measure performance
- we consider delivery of the primary output to be important
- the strength of any incentive should take account of the degree of network company's degree of controllability control over the output
- there are not already incentives in place on the network company through other schemes or obligations.

5.22. Points 1 and 3 give support for a financial incentive on a broad environmental output. This is because it would be very relevant to the high-level RIIO objectives and have a clear aim for TOs to reduce the carbon emissions on their network. However, points 2 and 4 suggest that financial incentives would not be appropriate because of the issues about duplicating incentives on other outputs and the potential difficulty measuring the company's actual contribution.

5.23. Another option would be to use reputational incentives. These are non-financial and work through the value companies place on having a good track record for delivery with their stakeholders. A reputational incentive would measure the company's delivery performance against a broad environmental output which will then be publicised to groups of interested stakeholders.

A low carbon economy output measure

5.24. One specific option that would be a direct way of incentivising the contribution of TOs to the broad environmental objectives has been put forward by RenewableUK through the stakeholder engagement process. They have provided a strawman proposal for this consultation, a low carbon economy output, which explores in more detail some of the considerations for implementing a broad environment output.[28]

5.25. RenewableUK has suggested basing a broad environmental output on one or a combination of the following broad indicators of the UK's progress towards its high level targets:

- percentage of total generation of renewable generation originating from the network (or GB system), or
- carbon intensity of energy flowing on the network (or GB system)

5.26. One advantage of using a high-level measure is that it would not inhibit the type of activity a TO can contribute. RenewableUK consider this would ensure support is available for innovative solutions that would not otherwise be encouraged through specific output measures. Additionally, both output measures would capture changes to the type of generation exporting to the network as well as changes to demand on the network (or GB system).

5.27. RenewableUK also suggest that there should be a one-sided financial reward in the form of a 'good performance bonus'. With this type of incentive companies would be rewarded for improvement in the output measure. A TO's performance against a low carbon output could be measured either by any incremental improvement in the output measure in year n from the initial baseline or meeting a target improvement in year n, where the target is consistent with Government targets, a company's well-justified business plan.

5.28. The performance bonus for a company could be calculated either as:

- a marginal incentive so that the bonus depends on the amount or unit change in the underlying output measure, or
- an agreed bonus as a percentage of total revenues for meeting an agreed target in the low carbon economy output.

5.29. RenewableUK suggest different ways of allocating the performance bonus among the transmission companies. For example, it could be shared among the companies as a team bonus. This approach might also be appropriate if successful delivery of the output was largely dependent on a collaborative approach, including other players such as the system operator, offshore transmission owners and distribution companies. Alternatively, the bonus could be earned as an individual bonus, based on company specific performance. This approach might be more suitable if companies were able to implement and demonstrate success on their own networks. This approach would also limit the opportunities for companies to free-ride on others efforts. Another option might be to reward companies with a weighted combination of a team and individual bonuses that vary over time. For example, a diminishing weight on the team bonus over the course of the price control might

[28] RenewableUK will publish some more information about their proposal for a low carbon output on their website shortly. Interested stakeholders should visit www.bwea.com

encourage companies to be more proactive and to develop data and/or indicators about their specific contribution.

5.30. We welcome views on the proposal put forward by RenewableUK including the merits of a performance bonus and the form and size of any such bonus. We also welcome views on any other proposal for incentivising the contribution of the TOs to the low carbon economy.

Direct network emissions

Gas transmission

Shrinkage

5.31. Shrinkage describes where gas is either consumed within a transporter's system, or is otherwise unaccounted for because of difficulties in settlement reconciliation. Shrinkage can result from gas transmission companies using gas within their transportation systems to fuel gas compressors. To compensate for shrinkage, NGG as SO needs to buy in gas to replace the shrinkage. Currently incentives on NGG for shrinkage are delivered through its SO incentives.

5.32. In practice, decisions made that affect shrinkage are driven by NGG as SO and as TO. For example, as TO it might invest in the assets in its compressors leading to a reduction in the level of shrinkage. As part of the work on alignment of the SO and TO incentives, we want to understand how to drive the best decisions taking both roles into account.

5.33. We propose to include shrinkage as a primary output. We will consider whether the financial incentive remains as an SO incentive, is moved wholly to be set on RIIO-T1 output delivery and outperformance or some hybrid approach. We consider the current SO incentive level to be a useful starting point. However, we are interested in views not just on the presence of a financial incentive in this area but whether the current SO incentive level is appropriate.

Methane venting

5.34. In operating the transmission network in its role as SO, NGG emits natural gas from the transmission network. This has environmental impacts because natural gas is made up largely of methane, a greenhouse gas with a Global Warming Potential (GWP) 21 times stronger than CO_2. NGG estimates that venting of gas compressors accounts for around 81 per cent of these emissions, and this venting is the subject of an existing SO incentive.

5.35. The current green house gas (GHG) emissions incentive for compressor venting expires in March 2011, and a consultation is taking place with a view to establish a new incentive to operate from April 2011 to March 2013. The timing of the new incentive will enable a review of the incentives across the TO and SO in time for the commencement of RIIO-T1.

5.36. We propose to include the venting of natural gas as a primary output. We believe that it is right to work towards an arrangement whereby the costs of environmental emissions are fully internalised; that is, the costs are fully accounted for in NGG's costs. We are keen to progress the work on internalising the costs also in time for the commencement of RIIO-T1. However, we need to consider the appropriate placement of financial incentives. That is, we need to consider the appropriate balance between incentives on NGG as TO and SO, and the interaction between these two parties.

5.37. The extent to which SO actions impact the environment is influenced to a certain degree by TO investment in assets. In the case of venting, GHG emissions associated with gas compressors could be reduced as the result of replacing aging assets and installing additional assets to manage emissions, but these would be dependent upon the TO's decisions on construction and funding. Similarly, the TO is not solely responsible for emissions of natural gas from the transmission network. It can invest in assets that should, in theory, make it possible to reduce the volume that is vented, but the outcome is also affected the operational decisions that the SO makes when operating those assets.

5.38. As part of RIIO-T1 we will be looking at the relative roles and responsibilities of the TO and SO in relation to venting, and, if appropriate, at the need to further define the relationship between these parties. This will allow us to determine upon which party (or parties) the incentive should be placed, and to ensure that there are consistent incentives across the SO and TO roles so that both are incentivised to work together to develop and operate the network to efficiently reduce these emissions.

5.39. There are a number of possible routes for achieving this. For example, we could create incentives under the TO framework regarding emissions, and retain an incentive on the SO in relation to operation of the system. Or we could provide sharper incentives on the SO along with a mechanism by which it can require the TO to invest in particular technologies, and can reward the TO for so doing. We will give further consideration to these and other options as part of the development of proposals for RIIO-T1 and the SO incentive schemes that will apply from April 2013. We welcome views on how to achieve align the incentives for the SO and TO in relation to venting of natural gas.

Electricity transmission

5.40. The three electricity TOs emit several environmentally damaging gases - CO_2 and SF_6 are the most significant and we propose primary outputs for these.

CO_2

5.41. A business carbon footprint comprises CO_2 emissions that result from the company's day-to-day operations and activities. A TO's BCF includes direct emissions of CO_2 from the burning of fossil fuels for energy used in company offices or sites and transportation (eg car and plane). It also includes indirect emissions arising from electrical losses on the network. Our proposed approach on losses is discussed below. The remainder of this section focuses on the TOs' remaining BCF.

Business carbon footprint

5.42. TOs participate in mandatory UK and EU schemes covering some of their CO_2 emissions. These include the EU emissions trading scheme and the Carbon Reduction Commitment (CRC) Energy Efficiency Scheme. Some companies also monitor their carbon footprint as part of corporate social responsibility initiatives. National Grid for instance displays its CO_2 emissions record on its website and discusses ways it could be reduced.

5.43. We do not propose to duplicate the existing regulatory framework but to bring other aspects of the TOs' carbon footprint not otherwise targeted within RIIO-T1. For example, carbon emissions from a TO's transport fleet are not regulated under the CRC Energy Efficiency Scheme.

5.44. We seek views on introducing a primary output for companies to report annually on total CO_2 equivalent emissions (including losses). With this option we are considering using a reputational incentive to encourage companies to monitor and manage their BCF. We propose to mirror the approach taken in DPCR5 and publish an annual league table of companies' emission levels.

5.45. We will develop options for the reporting framework and will seek to build on company's existing efforts in carbon reporting where possible. One area that will need to be developed are the emissions that fall outside the scope of the CRC or EU ETS, ie transport emissions.

5.46. To develop a reporting approach in this area we need to understand the composition and scale of unregulated emissions. We welcome more information from stakeholders on these and how they might change over the eight year price control. This data will be important for understanding the cost effective mitigation opportunities and whether the emissions sit in the traded or non-traded sector. This data would also help us to understand how to set a meaningful and comparable performance measure across companies' carbon footprint.

5.47. With a primary output on their BCF we expect companies would submit as part of their well-justified business plans schemes to reduce their BCF. We would look to fund those schemes that offer broadly efficient carbon abatement when compared to the appropriate carbon values.

Losses

5.48. Some CO_2 emissions result from electrical losses from the system. Electrical losses occur due to the physical resistance of carrying electricity on wires from the point of generation to the point of use. Losses increase with distance between supply and demand but less electricity is lost if it is transported at higher voltages. Total losses across the electricity transmission network represent, on average, some 1.7 per cent of the electricity generated, or 6 tera-watt hours (TWh).

5.49. Electricity losses matter. If losses were lower, then generators would need to produce less electricity to meet any given level of demand. In turn, this would lower carbon emissions associated with electricity generation. In future, losses could be less important in terms of carbon emissions because the carbon intensity of electricity is expected to fall. Nonetheless greater system efficiency will benefit consumers through lower system costs and have a smaller local environmental footprint.

5.50. Losses are caused by a mix of factors. Indeed much of the losses are driven by the energy flows determined by the energy market and SO activities. NGET is currently encouraged to reduce losses in its capacity as SO. Investment in the network can also reduce losses through replacing ageing equipment with low loss alternatives or providing low loss choices for SO actions. An output on losses would encourage the TOs to consider the impacts of different investment decisions and take a rounded decision.

5.51. It is likely that as the proportion of renewables in the energy mix increases, losses will also increase. Some stakeholders at the working group suggest that putting a financial incentive on losses could discourage network growth to connect renewables where increased losses are likely to be a by-product.

5.52. There are a number of options for setting a losses output:

- not set an output on the grounds that losses are not fully controllable
- establish the controllable elements and set an output on the TO against these
- include the carbon emissions from losses on the network in the BCF primary output as a reputational incentive.

5.53. We consider that given TOs actions can impact losses and they can control those actions then the elements that are controllable should be incentivised. We seek views on this option. We also welcome information on how to reflect the respective controllable elements from the different TOs, how this should interact with any remaining incentive on the SO and how the measure should be normalised so as not to discourage network development where this is needed to meet other outputs.

SF_6

5.54. SF_6 is a potent GHG. It has a GWP nearly 24,000 times stronger than CO_2 but it is emitted in much lower quantities. SF_6 has excellent insulating characteristics and is used in high voltage switchgear. Currently there is no equivalent it terms of its properties as an insulating agent.

5.55. TPCR4 introduced an incentive on two of the three TOs. Under the incentive companies could earn 0.2 per cent of allowed revenue for each year of TPCR4 they met the target leakage rate. This incentive has encouraged TOs to reduce leakage rates and improve the accuracy of reporting SF_6 leakage. Since the incentive was introduced in 2008 the participating TOs have received around £7.5 million. The average cost of emission abatement was approximately £200/tCO_2eq under the incentive.

5.56. On 30 June 2010 we published our document setting out the scope of the TPCR4 rollover. It is considering the SF_6 incentive for the additional year of TPCR4 (2012–2013). This work will inform our March 2011 strategy decision document.

5.57. An important principle in setting incentives on greenhouse gas emissions is the long term goal of full internalisation of environmental costs. Another is the consistent treatment of greenhouse gases and the appropriate use of the correct traded and non-traded values of carbon. We are not proposing to change the incentive to fully internalise the environmental costs in RIIO-T1 at this time. However we are seeking stakeholders' views on the extent to which an incentive on SF_6 should be moving towards these objectives.

5.58. For example, one way to improve the incentive could be to change the output measure from a target leakage rate to a target level of SF_6 leaked emissions. And another option might be to change the structure of the incentive from a one-sided reward to a marginal incentive based on the non-traded value of carbon.

5.59. We are interested in stakeholder views on changes that might be made to the form of the SF_6 incentive or the target level of performance.

Wider network impacts

5.60. The transmission network infrastructure can have a significant impact on local landscape, habitat, visual amenity and on noise levels.

Stakeholder views

5.61. The relevant stakeholder working group and PCRF agreed the planning regime is the appropriate forum for managing the local environmental impacts of specific network developments. There was some concern that TOs sometimes use the planning system to test the least-cost project proposal ahead of a full consideration of alternatives. There was also a view that network companies could only justify higher cost proposals to Ofgem after a consent application had been refused. Some stakeholders said that it would be beneficial if Ofgem set out some criteria to help TOs and stakeholders understand when additional investment can be justified to address local environmental impacts or loss of local amenity value.

5.62. Some stakeholders suggested the major ‘regulatory gap’ was around companies’ environmental assessment and stakeholder engagement on their longer-term network development strategy. With significant network expansion needed, some stakeholders think RIIO-T1 should ensure companies improve their performance in this area because:

- traditional methods of increasing system capacity, such as new overhead line routes, are difficult to achieve due to planning constraints and environmental concerns
- difficulties might result in long delays in additional transmission capacity needed to meet UK targets.

5.63. Some stakeholders argue that a new requirement for companies to environmentally assess and consult with stakeholders on their network development strategy would help to:

- highlight where local environment impacts are likely to arise and how these might be addressed
- ensure proper consideration is given to alternative routeing and technologies, especially where additional economic and/or additional environmental benefits can be expected
- justify extra expenditure TOs might need to investigate new or previously unused technologies on the GB transmission system
- reduce the lead time for transmission planning consent applications.

5.64. Some stakeholders thought such a requirement would contribute to the well-justified business plans companies have to prepare for the price control.

Should we review our position?

5.65. At TPCR4 we set out the following approach on undergrounding “that we would deal with the matter on a case by case basis, particularly taking account of the planning issues”.[29]

5.66. We agree that it is important for decisions on investments to take account of a range of factors, including cost, the delivery timescale and the impact on the local landscape, visual amenity and noise levels. We also agree that it is important that the companies’ plans are formulated following active engagement with all interested

[29] Ofgem, *Transmission Price Control: Final Proposals*, Ref 206/06, December 2006.

parties. The planning process will continue to be the main arena where decisions about the acceptability of local impacts are taken.

5.67. However, we recognise that the scale and timing of future network expansion and the implementation of the RIIO framework for network regulation changes the context compared to TPCR4. The TOs should be able to consider broader costs and benefits, including environmental impacts and potential mitigation options, at the earliest possible stage and take this into account in their development plans. This could include, for example, the TOs consulting on the environmental impacts of their network development strategy as part of their well justified business plans, which is consistent with the RIIO principles of wider stakeholder engagement and delivering a sustainable energy sector at long-term value for money.

5.68. We will work with DECC and other stakeholders to consider how further guidance might be provided to help companies and stakeholders consider the broader environmental costs and benefits, potential mitigation options and expenditure on these grounds.

6. Customer satisfaction outputs

Chapter summary

This chapter sets out our proposed customer satisfaction outputs. It also considers how we might apply incentives to encourage delivery. It builds on work in the relevant RIIO-T1 stakeholder working groups and other stakeholder engagement. We are consulting on this proposal and welcome views. This includes ways we might improve our proposal but also alternative approaches. As we need to establish outputs and incentives in March for the network companies to develop their business plans, it would be helpful if respondents could set out in some detail suggested changes or alternatives. These should, as far as possible, cover both reasons for change, practical implications and next steps.

Question 1: Do you have any views on the primary outputs outlined for customer satisfaction?
Question 2: Are these the appropriate areas to focus on and are there any other areas that should be included?
Question 3: Do you have comments on the proposed approach to setting incentives related to the customer satisfaction outputs?
Question 4: Should the incentives apply to National Grid both for good performance as SO as well as in its TO role?

6.1. Under the RIIO model, we intend to develop a primary output to capture satisfaction of a broad range of consumers, including network users. It envisaged that this category would define customers in the widest sense while reflecting the different customer's perspectives. The range of consumers could include both direct and end users of the transmission network. They would also include other stakeholders, for example non-network parties seeking to trail innovative projects under the innovation stimulus package.

6.2. We propose that we inform the primary output primarily by survey performance. We are consulting on also having the possibility of a discretionary reward for outstanding stakeholder engagement. The latter reward is conditional on the presence of competent complaints handling.

6.3. We recognise that it’s important to test the information that will drive this output. In particular, we will work with the industry to develop financial incentives in this area with caution.

Background to setting customer satisfaction outputs

6.4. The wide definition of customers, while necessary, brings a challenge. We need to make sure the performance reflected picks up the different experience of different customers. While weighing these against each other it also needs to ensure that all voices are heard.

6.5. This output category will have a positive relationship with other output categories. This differs from a number of other RIIO output categories where performance improvements in one might be achieved at the expense of a reduction in performance in others (with the network companies needing to understand the trade-offs when evaluating its plan). This positive relationship means that as reliability or timeliness of delivering connections improve, for example, it is likely that the customer satisfaction measures will also improve. We will need to recognise this in the design of the customer satisfaction outputs and the way we incentivise them.

6.6. The output category is not duplicative. Instead, there are a range of things that will only be covered here and we need to make sure that these aspects of customer and stakeholder relations are reflected. For example, this output will reflect stakeholder views on how well the TO interacted with them, for example quality and timeliness of information provided.

6.7. The customer satisfaction output plays an important part in contributing to TOs playing a full role in meeting and facilitating solutions to the major challenges facing different parts of the energy system. For example, the information and support provided by network companies to potential connecting customers considering new energy efficient solutions are central to whether the network companies hinder or help in meeting these targets. A successful connection of new generation is partly dependent on whether the connecting customer receives quality and timely information from the TO. The experience at an initial meeting might be important, for example.

Previous experience

6.8. There is no direct incentive on TOs on customer satisfaction within the current transmission price control. We have useful experience from the most recent price control in electricity distribution (DPCR5), although this is still very recent. In DPCR5, we introduced a customer satisfaction 'broad measure' to apply to electricity distribution network companies. This broad measure involves applying financial incentives to three components:

- survey evidence
- complaints handling
- stakeholder engagement

6.9. Over the last few years, National Grid (NGET and NGG), has developed a company wide customer survey with qualitative and quantitative elements. We think this is a positive step and that we could and should make use of this existing information where possible. We will work with National Grid as they test and develop this further and will consider against the principles identified below for survey evidence.

Proposed approach

Introduction

6.10. The proposed approach we are consulting on follows a similar approach to that developed in electricity distribution in DPCR5 and that envisaged in RIIO-GD1. Like them, it makes use of three components (survey evidence, an assessment of stakeholder engagement and complaints handling). Given the different relationship with customers in transmission, it only uses complaints handling as a reputational measure. We propose that it also influences the potential for any reward for stakeholder engagement more generally.

6.11. We recognise that the relationship with customers and stakeholders in transmission is different from distribution. We have discussed this during stakeholder engagement in this early part of RIIO-T1. We also recognise that there might be differences between different TOs, particularly between NGET given its SO function and the Scottish TOs. We propose to reflect these differences where necessary in the detail of the approach rather than proposing a different approach.

6.12. Differences that we propose to recognise in this way (eg through design of survey questions) include:

- some customers being quite far removed from the activity of TOs (eg most end users)
- some customers being more closely involved with the activity of TOs, for example generators seeking connection
- type of activities differ, for example gas distribution companies have direct involvement in making end users equipment safe in an emergency.

Survey evidence

6.13. A survey score would be the first part of the primary output. Both the change in performance from the previous year and the absolute level of performance in the current year could feed into the incentive. We are interested in views on how absolute levels of performance in the survey and performance changes should be taken into account. As a working proposal we suggest that 50 per cent of the incentive should be based on the absolute score against a baseline target proposed by the TO following stakeholder engagement and agreed by the Authority. We welcome views on whether the survey needs to be standardised to allow comparisons across the TOs or whether we treat each company separately. The other 50 per cent in value terms should be based on the change in score from the previous year. We would hope to have a dummy year for NGET so as to be able to start immediately in 2013-14. We may need a variant on this aspect of the incentive as part of transitional arrangements for the Scottish TOs (SHETL and SPTL). Further details of the incentives are set out in the next section.

6.14. We will continue to work to decide on the principles that any survey would need to be consistent with to be used in this output category. We consult on the following principles:

- survey needs to be clear about TO role and other roles, for example SO
- development/changes over time should be informed by stakeholder views including Ofgem
- some independent review of the survey should have taken place
- needs to take account of geographic differences
- the option should be available to Ofgem to propose a question or suggest a modification to an existing question
- needs to reflect separately the needs of organisations or individuals new to the industry.

6.15. For March, we intend to finalise these principles and set out some example questions that might be used. We do not think that we need the full survey at this point for the TOs to prepare their business plans given that the aim of meeting customer satisfaction is largely dependent on actual performance during the control period rather than their plan. Although if this is to be assessed as well-justified, it should reflect stakeholder engagement, as set out in 'Supplementary Annex – Business plans, innovation and efficiency incentives'.

6.16. We think that National Grid's survey might be at least part of the information used in this output for them and we will discuss further with TOs and other stakeholders what other evidence might be needed.

6.17. We also welcome views on what would be needed to reflect the differences between the TOs. At this stage, we understand that the Scottish TOs do not have experience in customer satisfaction surveys. They also face difficulties in obtaining customer views on performance that properly recognise the separate TO role from NGET's SO role. This is important because in developing a baseline for performance, a number of years experience in understanding the data received is useful.

6.18. We are keen to work with all the TOs to develop surveys that can be used and are consistent with our principles set out above. We consult on a proposal that will require them to develop customer survey questions consistent with these principles as part of RIIO-T1. We think there should be enough time to develop this evidence for the start of the new control period in April 2013.

6.19. In relation to the survey, we consult specifically on:

- how absolute performance and degree of year on year change should be reflected in the output, eg each making up 50 per cent of the output (paragraph 6.13)
- principles that should apply to survey(s) being used to inform the output measure (paragraph 6.14)
- types of questions that should be included
- who should be consulted through the survey

- how the different roles should be explained
- what the TOs should consider when proposing a baseline level of performance
- should the final incentive be based on an approach like that proposed in RIIO-GD1 comparing scores in a league table with distribution network companies

6.20. National Grid's existing survey will reflect comment on its TO and SO performance. The design of the survey could attempt to separate these effects. We welcome views on whether the RIIO-T1 customer satisfaction output on National Grid should extend to its performance as SO as well as TO.

Stakeholder engagement and complaints handling

6.21. We are considering the option of providing a discretionary reward for effective stakeholder engagement. The TOs could apply for this, for example, at the end of each year. We will develop guidance on what is likely to make this application successful and the amounts likely to be available. It will not be about how many meetings with stakeholders were held or how glossy the information provided was. Instead, TOs will need to demonstrate that strong stakeholder engagement directly led to better outcomes.

6.22. Stakeholder engagement should be central to the TO's development of their RIIO-T1 business plans. However, it should also be something that happens all the time. Including this element of the broad measure should encourage TOs to put stakeholder interests at the heart of their business. We want networks to demonstrate that they have identified who their stakeholders are and what are their concerns and needs. They should also be able to demonstrate that they have considered their needs in the way they plan, run and evaluate their businesses.

6.23. We are seeking to design an incentive that rewards those TOs that can demonstrate a genuine commitment to stakeholder engagement and show how this informs the development of business plans and strategies and the resulting outcomes. This is not about simply who carries out what stakeholder engagement activities. We will provide guidance on how we will assess companies' stakeholder engagement strategies, but we will not set a detailed output target associated with the type or level of engagement. We believe networks should be free to tailor these to meet their stakeholder needs.

6.24. We propose that the best companies are rewarded but, as evaluation requires subjective assessment, that there is no penalty attached to this element of the broad measure. As above, the likelihood of receiving a reward will be reduced if complaints handling problems are detected (see below for further clarification).

6.25. TOs will be able to apply for the award on an annual basis. We will establish minimum requirements for networks to demonstrate in making their application. Submissions will be put forward for assessment by an independent panel who will also determine the level of the reward for each company.

6.26. We do not propose to have a penalty for poor complaints handling as in electricity distribution in DPCR5. The more distant relationship between TOs and end users mean that the level of complaints is likely to be less. Instead, poor stakeholder relations are more likely than direct complaints.

6.27. We intend to require competent complaints handling as a pre-requisite for receipt of a discretionary reward for stakeholder engagement.

How to encourage performance in this category

6.28. Table 6.1 summarises the financial incentives proposed. We have limited evidence on which to base this and this is a first indication. The + or – 0.5 per cent of revenue mirrors the arrangements that have been implemented in DPCR5 for electricity distribution.

Table 6.1: Financial incentives

Component	Percentage of allowed revenue subject to incentive	Application of penalty/reward
Customer satisfaction survey	+0.5/-0.5 This mirrors the percentage incentive in electricity distribution Indicative as starting point for consultation	Penalty/reward with 50 per cent based on actual annual score compared with proposed baseline and 50 per cent based on change from previous year. Do you think we should include a dead-band in the incentive around the finally agreed target?
Stakeholder engagement	+0.5	Discretionary reward based on qualitative assessment of companies' by independent panel
Complaints handling	Pre-requisite for stakeholder engagement	

7. Conditions for connection

Chapter summary

This chapter sets out our approach to establish outputs related to connections transmission networks make to their networks and the related incentives. The current arrangements vary between gas transmission and electricity transmission.

In relation to gas there are arrangements in place that incentivise NGG to delivery incremental entry and exit capacity in a timely manner. We are seeking views as to whether these are sufficient and the requirement for additional obligations or incentives.

In relation to electricity transmission, while significant work has been done in RIIO-T1 including through the working groups, this is now joint work with Project TransmiT. This chapter outlines the interactions with Project TransmiT and other relevant work areas.

Question 1: Do you have any comment on the key principles we have identified for the delivery for connections?
Question 2: Do you have any comment on the interactions with the other workstreams, in particular Project TransmiT, for electricity transmission connections?
Question 3: Do you have any views on the existing arrangements for gas transmission?
Question 4: Do you consider any specific obligations and /or incentives are required for gas transmission?

7.1. It is important that a TO delivers new connections to its network in a timely way. This is important, for instance, so that new sources of generation can come online promptly both to meet security of supply and environmental objectives.

7.2. We propose a primary output based on timely delivery of connections both in electricity transmission and in gas transmission. Given the recent introduction of the connect and manage arrangements (see section 7.13 below), our focus on electricity has been to consider whether a financial incentive should be set to encourage better than required performance at the pre connection phase between application and offer. In gas, the focus has been on the delivery of incremental capacity and whether the existing incentives are sufficient to encourage NGG to deliver. Over the past year, there have been productive discussions between shippers and NGG on timelines for connections under the auspices of a UNC working group. We would be interested in views as to whether this work should be integrated with the price control.

7.3. Connection is an issue that cuts across Project TransmiT and we have sought further information for both areas of work through a letter of 14 December 2010.[30]

Background and context

7.4. This chapter is concerned with setting a primary output in relation to connections. The current arrangements vary between gas transmission and electricity transmission.

7.5. In gas transmission there are licence arrangements in place which incentivise NGG to deliver incremental capacity within defined timescales. The connection design and operational agreements are addressed on a bilateral basis between the developer/shipper and NGG. There are no similar arrangements in electricity transmission. There have been a number of recent developments in electricity transmission which impact on setting a primary output in this area for NGET, and the Scottish TOs. There has been progress made in this area but we consider there is still work required to provide a framework that delivers new connections to its network in a timely way.

Existing gas transmission connection arrangements

7.6. In gas transmission there are three processes that need to be completed before gas can flow into or out of NTS:

- the physical connection to the NTS has been completed and the measurement equipment has been validated
- the operational agreement detailing the conditions for gas to flow has been signed by NGG and the shipper
- shippers have obtained sufficient capacity via the relevant entry and exit capacity processes.

7.7. The connecting pipeline to the NTS can be built by developers, or it can be built by NGG. There is also the option of NGG subsequently taking ownership of a line constructed by a third party. Typically, NGG would be involved in feasibility studies with any party requiring capacity ahead of any design process being initiated.

7.8. The operational agreement will be largely determined by the design characteristics of the connection. The connection design and operational agreements are sorted out on a bilateral basis between the developer/shipper and NGG.

7.9. Further detail on the arrangements for the connection of a facility to the NTS are given on NGG's connections website.[31]

[30] Consultation on the issue of timely connection to the electricity transmission network - Ofgem, December 2010
http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/121410%20timely%20connnection%20draft%20letterdoc.pdf

7.10. During the last year, discussions have taken place on the processes around the upgrading of connections to the NTS[32]. We understand that this has led to a standardisation of information that is required by NGG, which should speed up the process. But some shippers have expressed concerns that the timescales around the process can inhibit the development of gas projects. We would welcome views on whether this area should be included in the remit of RIIO-T1, and if so, how it should be addressed.

Electricity transmission – interactions with other policy developments

The Transmission Access Review

7.11. The joint Ofgem/Department for Energy and Climate Change (DECC) Transmission Access Review (TAR)[33] explored the case for change to the transmission access and associated connection arrangements. The review culminated in the TAR final report, published in June 2008, which identified a range of options for enduring access reform. The report noted that it is for industry to take forward and develop appropriate arrangements through the industry processes.

7.12. The TAR process highlighted that there was an enthusiasm from generators to develop a model for timely connection based on requests to connect being met within a defined period of the connection offer being signed or based on another trigger.

Connect and manage arrangements

7.13. In June 2010 DECC set out changes to the arrangements by which generators gain access to the transmission system using the powers available to the Secretary of State under the Energy Act 2008[34]. This provided the basis for an enduring transmission access model. The aim of these reforms is to accelerate the connection dates of new generators, thereby removing a key barrier to the connection of large amounts of renewable and other low carbon generation necessary to meet government climate change and energy targets and ensure security of supply.

7.14. The recently implemented reforms allow generators access rights to use the system irrespective of whether the system can accept the generation in real time. Under this grid access model, a new generator or demand user seeking to connect to and use the electricity transmission system will be able to gain full access to the transmission system once all the ‘enabling’ works are completed. All generation related offers and modification applications being issued after 11 August 2010 will be issued in accordance with the ‘connect and manage’ requirements.

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[31] http://www.nationalgrid.com/uk/Gas/Connections/ntsentry/
[32] UNC273 - Governance of Feasibility Study Requests to Support Changes to Network Exit Agreements
[33] http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/TAR/Pages/Traccrw.aspx
[34] Section 84(1) of the Energy Act 2008.

Project TransmiT

7.15. In September 2010 we launched 'Project TransmiT' - our independent and comprehensive review of transmission charging arrangements and associated connection arrangements. The initial focus of Project TransmiT is to consider charging arrangements and associated connection issues that the Government has explicitly left for Ofgem and the industry to resolve.

7.16. Project TransmiT is due to report in summer 2011. It is closely related to the price control work to develop connection outputs.

RIIO-T1 work to date

7.17. One implication of the fact that the work areas discussed above impact the delivery of connections is that during our enhanced stakeholder engagement it was too early to assess the success of the new arrangements and consequently whether any further developments would be needed.

7.18. As a result of the new arrangements, the discussions during stakeholder engagement focussed on other aspects, particularly the timeframe for electricity transmission connections between a full application being made and the delivery of a firm offer by the TO. Under the existing licence requirements, this has to be done in 90 days. However, there was some discussion in our outputs working group before Project TransmiT was launched as to whether it was worth incentivising faster delivery of more certain delivery within 90 days. For example, we could achieve this by encouraging via financial incentive an average performance a little better than the required 90 days.

7.19. In gas transmission the overall delivery of incremental entry capacity was cited as a timeframe that could have additional incentives, though the current incentives for delivery of this within 42 months was recognised.

7.20. In the working group discussions, we recognised that output(s) in this category could consider both the timing of delivery of the connection as a whole and of phases within the whole process.

Joint work with Project TransmiT

7.21. As an issue that cuts across both Project TransmiT and RIIO-T1, we have recently published a consultation letter on facilitating the timely connection of generation. In the letter we outline options for incentivising TOs to deliver connections in a timeframe that is better aligned with the requirements of generators. We also request data from the TOs on the issues impacting their timeframes for connection. We will consider responses to this letter and the additional information provided by the TOs in setting out a connections output in our March 2011 strategy decision document.

7.22. As part of joint work with Project TransmiT and in the light of the results of its call for evidence, we published a further detailed information request for information that included the value stakeholders placed on the timely delivery of connections as a whole. It also considered the stage between application and offer being made in electricity.

7.23. This information will inform whether we propose that the primary outputs in this area are simply the obligations under the current codes and connect and manage arrangements or whether we think it appropriate to incentivise faster delivery.

Principles for consultation

7.24. The proposed approach in this category is not yet established because of this joint work but the key principles we propose for connection are as follows:

- for both electricity and gas, TOs need to deliver connections to the timescales set out in existing codes and, in the case of electricity, in the context of the ‘connect and manage’ arrangements - we therefore propose this as a primary output
- for electricity, the TOs are on the process of implementing new arrangements which are consistent with the connect and manage regime; it is too early to measure the success of these changes and this is something that we might need to return to, for example, at the mid-period review of outputs or via a specific uncertainty mechanism
- for electricity, we are seeking detailed information to provide evidence of the value of more timely delivery of the 90 day phase of the process and in general terms
- for electricity, we will also need to consider whether there are any implications for general price control performance of any changes made in the commercial arrangements on connections through Project TransmiT
- for gas, we welcome views on whether the current incentives are working sufficiently well; we would also welcome views as to whether any additional obligations and incentives are required and we seek respondents’ views on the form of these obligations and incentives and any supporting evidence we should consider in determining the appropriateness of any additional arrangements

8. Secondary deliverables – electricity transmission wider works

Chapter summary

This chapter sets out our proposed approach to encourage TOs to carry out wider network reinforcement work where this is in the interests of consumers. We make proposals for setting secondary deliverables and discuss options for applying financial incentives to encourage timely delivery. Finally, it identifies a need for uncertainty mechanisms or other arrangements to ensure that there is flexibility, during the price control period, as to what increases in transfer capability companies will deliver.

Question 1: Do you agree that there is a need for secondary deliverables that relate to wider reinforcement work on electricity transmission networks?
Question 2: Do you agree with our proposed approach to the specification of these secondary deliverables?
Question 3: How should we encourage timely delivery and deal with non-delivery?
Question 4: Have we identified appropriate options for bringing flexibility, over the price control period, to the secondary deliverables that TOs should deliver and to the revenues that they receive for this delivery? Which options work best for consumer interest? How would this depend on specific circumstances?
Question 5: Do you agree with our plan not to develop proposals for an asset utilisation incentive scheme (option (d)), and to focus, instead, on the other options?

8.1. To encourage TOs to carry out wider network reinforcement work where this is in the interests of consumers we propose to:

- set secondary deliverables that are specified in terms of agreed increases in transfer capability at electricity transmission network boundaries
- provide financial incentives to encourage timely delivery
- set out options for uncertainty mechanisms or other arrangements to ensure that there is flexibility, during the price control period, as to what increases in transfer capability companies should deliver.

Background and context

8.2. A new generation station must be connected to an electricity network if it is to export its output to electricity consumers. We are currently considering the definitions of different required works. For the purposes of this discussion we use the terms ‘enabling works’ and ‘wider works’.

8.3. ‘Enabling works’ are works to extend or reinforce the existing transmission network as necessary to connect a new generation station. Chapter 7 describes our proposals for encouraging TOs to deliver timely connections. ‘Wider works’ involve increasing capacity, or capability, of electricity transmission networks to accommodate increased flows of electricity, including work to attain compliance with the national electricity transmission system security and quality of supply standards (NETS SQSS).

8.4. Under the connect and manage regime, generators can connect to the transmission network in advance of the completion of any wider works that are considered necessary to accommodate them. In the period between the completion of enabling works and the completion of wider works, TOs can be granted derogations from the NETS SQSS. If the transmission network has insufficient capability to transfer the flows of electricity resulting from generators' scheduled output, wider works can reduce the constraint management costs incurred by the SO which are ultimately borne by consumers.

8.5. We do not think that the reliability and availability primary outputs we have identified for electricity transmission in chapter 3 will be sufficient to encourage TOs to take appropriate decisions about expenditure on wider works that will be needed over the longer term. This is particularly so for investment projects where consumer benefits justify the investment, for example through lower constraint management costs.

8.6. We recognised this issue when developing the RIIO framework. The RIIO handbook identifies that we could use secondary deliverables to encourage companies to take actions that bring long-term benefits to consumers but are not needed to deliver primary outputs efficiently over the upcoming price control period.

Use of secondary deliverables

8.7. We propose to use secondary deliverables for electricity transmission wider works expenditure. We are seeking views on the following arrangements, explained in more detail below.

- We would treat increases in transfer capability, across specified transmission network boundaries, as the output of wider works expenditure. We would recognise that investment in network infrastructure is not necessarily the only way to increase boundary capability.
- As part of their business plans, TOs would need to set out the increases in boundary capability that they intend to deliver over the price control period to meet the needs of consumers. TOs would take account of factors such as potential impacts on future constraint costs and expected construction costs. We would expect TOs to consider different ways of achieving increases in boundary capability and to propose an approach that is in the interests of consumers.
- Drawing on a review of the TOs' business plans, we would include secondary deliverables defined in terms of increases in transfer capability, across specified transmission network boundaries, as part of the price control. We would provide upfront funding for these as part of base revenue.
- We would set realistic timeframes for delivery, together with financial penalties, (and potentially rewards) around the timeliness of delivery. Financial incentives would reflect the constraint costs arising from delays to delivery and would be developed in line with our work on primary outputs relating to network outages.

- We would include arrangements in the price control that would allow additional increases in boundary capability, beyond those agreed at the price control review, to be approved (or triggered) and funded during the price control period.
- We have suggested an approach under which TOs would be given some flexibility as to what increases in boundary capability to deliver, provided that decisions they take are compatible with an agreed network planning policy. Additional delivery would be funded through volume drivers that are set at the price control review. We may also need to develop a process to approve and fund proposals from companies for additional increases in boundary capability during the price control period, in light of the latest available information. This would need to be supported by measures to encourage TOs to maintain a network development plan and come forward with proposals for projects that are in consumers' interests. We are consulting on a number of different mechanisms or arrangements that could be used, potentially in combination. We will look to the TOs to propose and justify their preferred options as part of their business plans.

8.8. The remainder of this section takes the following issues in turn:

- the specification of secondary deliverables
- initial agreement on secondary deliverables at the price control review
- risks of double-counting in base revenue
- arrangement to encourage timely delivery
- provisions for non-delivery or agreed delays
- delivery timescales spanning more than one control period
- uncertainty mechanisms and other arrangements to bring flexibility.

8.9. We have not identified a corresponding need for secondary deliverables linked to capacity or network reinforcement work for the gas transmission network. The commercial and regulatory arrangements are significantly different.

The specification of secondary deliverables

8.10. We consider two main ways in which secondary deliverables could be defined in relation to the contribution of wider works expenditure:

- the achievement of specified increases in transmission boundary capability
- the installation of specified assets or asset upgrades

8.11. Boundary capability is defined by NGET[35] as the lower of two limits that are placed upon a circuit, namely the thermal capability and the voltage capability. These relate to the maximum current and the maximum voltage that the circuit can tolerate without any 'unacceptable events' occurring. These events are: loss of supply capacity, unacceptable overloading transmission components, unacceptable voltage conditions, and unacceptable frequency conditions (system instability). As

[35] Boundary Capabilities and Required Capabilities, GB Seven Year Statement 2009, http://www.nationalgrid.com/uk/sys_09/default.asp?action=mnch8_3.htm&Node=SYS&Snode=8_3&Exp=Y

well as being determined by the physical characteristics of the circuit, the boundary capability can also be limited by other factors. For example, if the output of a generating station adversely affects the system's frequency then the boundary capability will be reduced to below its theoretical value. The Anglo-Scottish interconnector is an example for which various factors have affected the boundary capability.[36]

8.12. As an alternative to secondary deliverables defined by reference to boundary capability, they could be defined in project terms, where the project is intended to achieve increases in boundary capability. Under this approach, secondary deliverables would relate more to the installation of specified network assets or to asset upgrades rather than to the impact of this work on boundary capability. An overall project could be broken down into sections, with deliverables at particular key points or milestones, such as completing detailed design works, obtaining planning permission and completing the construction work.

8.13. Our Transmission Investment Incentives (TII) work provides an example of how deliverables can be defined under this second approach. In each case, the TOs identified anticipated future need for additional boundary capability. This used long-term network planning and the scope and timing of proposed reinforcement options further refined through cost-benefit analysis. Under the TII framework, initial funding provided for pre-construction work enables the TO to develop a range of options in more detail. We make the decision to provide consumer funding for construction or upgrading of specified assets separately, taking into account the justification for proceeding with the proposed investment and the readiness of the TO to take forward the planned work. The TII funding is provided along with associated deliverables. These deliverables include annual milestones consistent with the planned programme and, in the case of construction funding, technical output measures, such as the installation of a particular set of infrastructure. This information is set out in the licence conditions, which include a requirement on the TOs to provide reports on their spending and on their progress towards the milestones.

8.14. We believe that boundary capacity should be used where possible. Specifying secondary deliverables in terms of projects related to specified assets seems unduly restrictive in the case of a longer-term regulatory framework. It may be possible to achieve the same desired increase in boundary capability in different ways, including different approaches to the development and upgrading of transmission network assets.

8.15. We recognise that by the time a secondary deliverable is agreed, a TO may be far down the path in planning network reinforcement projects. This may limit its flexibility to innovate and find alternative approaches to delivery. For instance, planning approval may have been granted and, even if an alternative way of delivering the increase in boundary capability were identified, this could not be achieved without major delay. Nonetheless, we believe that there will be greater

[36] Transmission System Operation Review Group (TSORG) Final Report v1.0, 8/10/7, pp42-43, http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/tar/Documents1/071005%20TSORG%20Final%20Document.pdf

flexibility and scope for innovation if TOs are asked to deliver specified increased in boundary capability rather than a list of asset upgrades and installations.

8.16. Defining secondary deliverables by reference to boundary capability also fits better with the aims of an outputs-based approach. Achieving an increase in boundary capability relates more closely to what the transmission network can do for network users than an agreement to install specific assets, such as 400kV substations.

8.17. There may be practical issues surrounding the use of increases in boundary capability as a secondary deliverable. As highlighted above, boundary capability depends upon various factors and we would need to be sure that it is measured objectively and consistently. Also, an increase in boundary capacity could be achieved by a number of different approaches. An increase could be realised by using operational actions, or by asset investments to address factors that prevent full utilisation of the theoretical capability. Or it could be achieved through the construction of new assets that provide additional capacity over and above the existing boundary capability.

8.18. It is possible that operational standards could change, potentially increasing the reported boundary capability without requiring new investment. At an operational level, some increases in boundary capability might not be sustained over prolonged periods, and would only be used until sustainable solutions are implemented.

8.19. It would be important to determine exactly how TOs' delivery, and price control revenues, are tied to changes in boundary capability. It may be appropriate to distinguish between permanent (or sustainable) increases and temporary increases in boundary capability, and perhaps to exclude some types of changes from contributing to what counts as delivery.

8.20. The remainder of this section proceeds on the basis that secondary deliverables are defined by reference to increases in boundary capability. A corresponding approach could be developed if secondary deliverables were defined in terms of projects for the installation or upgrade of specified transmission network assets.

Initial agreement on secondary deliverables at the price control review

8.21. We propose that some secondary deliverables linked to increases in boundary capability are included as part of the outputs agreed at the price control review. We also recognise that we would need some flexibility to vary what is required, and what is funded over the price control period. We discuss this further later in the chapter. For those secondary deliverables agreed at the price control review, we would include forecasts of the expected (efficient) costs of delivering them as an input to setting base revenue.

8.22. To justify expenditure forecasts, TOs will need to set out which network investment projects they would need to undertake to deliver the increase in boundary capability. However, we would not hold companies to deliver specific projects as set out in plans; they would have leeway to achieve the agreed increase in different ways if available.

8.23. The company's business plan will need to include information on what boundary capacity increases would be justified in the interests of current and future consumers. We will provide further guidance in March 2011. We would expect companies to justify proposed secondary deliverables by reference to the potential benefits and costs. Potential benefits include impacts on future constraints costs, the contribution to Government energy policy and statutory targets and enabling a greater use of relatively low-cost generators. Costs include the construction costs and the costs arising from network outages during the construction phase.

8.24. We would expect companies to consider different options, especially in relation to the timing of potential reinforcement work, and different scenarios. To properly consider the issues and to develop proposals that are in consumers interests', the three electricity TOs will need to work with the SO (though any sharing of information has to be carefully controlled due to the generation interests of the Scottish companies).

8.25. Prior to proposing investment plans for funding consideration under the TII framework, the TOs had undertaken a joint transmission system study (the ENSG study[37]) to identify the investment scenarios that may be needed by 2020. The proposed scope and timing of individual reinforcements was informed by cost-benefit analysis for the GB system undertaken by NGET, and the three TOs have subsequently developed the proposed projects in more detail.

Risks of double-counting in base revenue

8.26. The RIIO handbook identifies risks of double-counting in funding secondary deliverables given a secondary deliverable may naturally be encouraged under the core incentives of the price control regime. Apart from secondary deliverables, there are several other elements of existing or proposed regulatory arrangements which may encourage TOs to bring about sustainable increases in boundary capability. For instance the work that TOs carry out to meet output requirements for new connections may increase boundary capability if more capacity is built than is required for the connection.

8.27. To avoid double-counting, any expenditure forecast made for secondary deliverables should take account of expenditure that is necessary for the delivery of other outputs and any potential benefits under financial incentive schemes.

[37] http://www.ensg.gov.uk/assets/ensg_transmission_pwg_full_report_final_issue_1.pdf

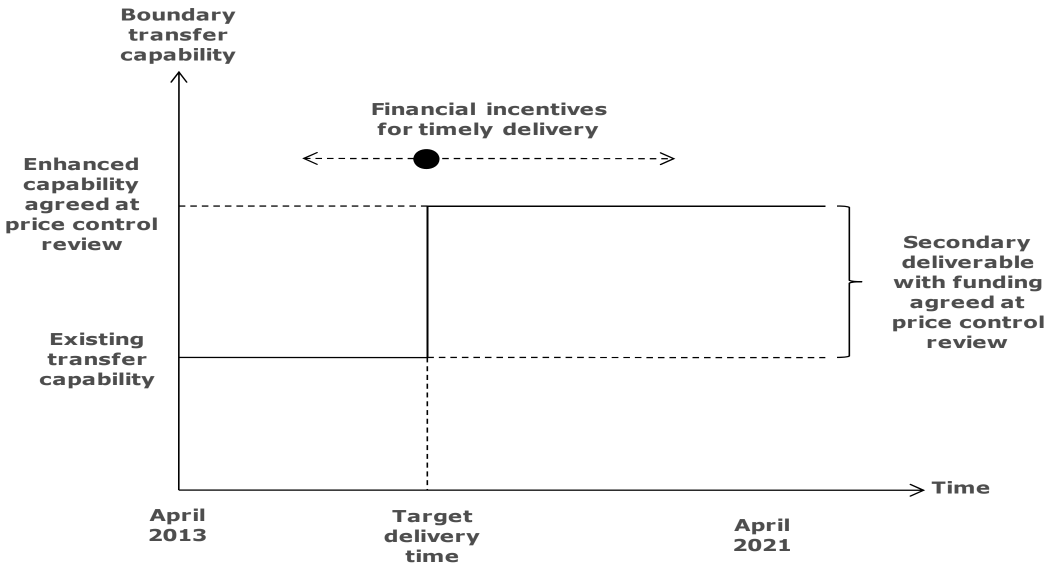
Arrangements to encourage timely delivery – financial incentives

8.28. Regardless of whether secondary deliverables are defined in terms of increases in boundary capability or the installation of new assets, we would agree a realistic target delivery date. We would like to encourage TOs to reach decisions in relation to the timeliness of delivery that are in the interests of consumers. For instance, a faster delivery timescale — or avoiding late delivery— may only be achievable with additional expenditure on construction activities. But late delivery of planned network reinforcement may expose consumers' to higher constraint management costs and over the period of the delay. Because consumers are exposed, at least in part, to both construction costs and constraint management costs, it is in consumers' interests for TOs to strike a sensible balance between the costs of faster and slower delivery timescales.

8.29. When we discuss timely delivery in this context, we refer to the time taken to achieve an increase in boundary capability, once it has been agreed and funding arrangements established. There is a separate question about whether increases in boundary capacity are proposed and, where relevant, agreed in a timely way. This is not discussed here but is relevant to the discussion in the sub-section below on ‘Uncertainty mechanisms and other arrangements to bring flexibility’.

8.30. We would seek to develop arrangements under which transmission companies would have appropriate financial incentives around the timeliness of delivery of increases in boundary capability, which reflect the impacts of later delivery on constraint management costs (or another measure of the harm to consumers from later delivery). Figure 8.1 illustrates two points: a secondary deliverable related to boundary transfer capability, and financial incentives for timely delivery.

Figure 8.1 Secondary deliverable and incentive for timely delivery



8.31. In order to develop effective arrangements, we will need to consider interactions with other price control outputs and with the incentives on the electricity SO.

8.32. In the case of NGET, timeliness of delivery may affect NGET's external operating costs of system operation, which include constraint management costs. To the extent that NGET as SO is exposed to variations in these costs, it may have a profit incentive to avoid delays in completion, since such delays could increase the constraint management costs it faces. Similarly, NGET may have a profit opportunity from delivering an increase in boundary capability earlier than planned, eg reduced constraint management costs.

8.33. However, the current suite of incentive arrangements for NGET may not be sufficiently effective. At present, NGET's exposure to variations in the costs of delivering increases in boundary capability is likely to differ from its marginal exposure (if any) to variations in the external operating costs of system operation. This is because of differences in the efficiency incentive rate applied to different categories of costs (for example TO capital expenditure and SO external costs) and because of the use of dead-bands and caps and floors on NGET's exposure to the SO external costs.

8.34. We consider that there may be potential benefits arising from the ability of the SO and TOs to make decisions based on more compatible financial incentives. NGET has recently released, for consultation, initial proposals for a two-year SO incentive scheme commencing in April 2011.[38] Going forward, we will be considering both

[38] Gas system operator incentives – initial proposals consultation 2011/12
http://www.nationalgrid.com/NR/rdonlyres/E0A2DD71-7EFC-4B2A-95E0-

NGET's initial proposals and consultation responses. We intend to issue our final proposals in early 2011, setting out the way forward with respect to these incentives. We also expect NGET to put forward its ideas (including a work plan) as to how it intends to manage the transition from a two-year to a longer-term SO incentive scheme. We will also be considering whether there is the need for any changes to the relationship between the SO and TOs.

8.35. Chapters 3 and 4 set out our proposals in relation to primary outputs for network reliability and availability, including on incentives to minimise constraint costs from electricity TO activities. We have suggested an approach in which each of the TOs would be exposed to the impacts of its actions in respect of planned network outages insofar as these affect the costs of external operating costs of system operation. Arrangements developed to encourage TOs to take adequate account of constraint costs in respect of planned outages could also be applied in the case of delays to the delivery of agreed increases in boundary capability.

8.36. We would need to develop other ways to encourage a transmission company to deliver agreed increases in boundary capability in a timely way. This might include a regime of penalties for late delivery. Penalties might be specified upfront, for example based on estimates of the harm to consumers from delays. Alternatively, we could operate a policy in which we retain discretion to impose penalties in the event of late delivery. We would then provide guidance on the circumstances in which a penalty would apply and how the level would be set. It may also be possible to provide a specified reward for early delivery, but whether this is in consumers' interests will depend on whether we can forecast the benefits to consumers from earlier delivery, for example lower constraint management costs.

8.37. It may be appropriate to define some exclusion provisions to capture circumstances in which it would not be appropriate and in consumers' interests to penalise companies for delays. However, these would need to be limited so as not to undermine the financial incentives on the TOs for timely delivery.

8.38. We invite views on how to encourage the timely delivery of agreed secondary deliverables, taking account of interactions with the primary outputs for network reliability and availability and the role of the SO.

Provisions for non-delivery or agreed delays

8.39. We will need to set out rules on how we would treat non-delivery within the price control period. We will set out guidance on the circumstances where penalties would apply and how we would calculate them. We envisage arrangements along the following lines.

8.40. If the TO can show that it was/is not in consumers' interests to deliver the increase in boundary capability, any penalty for non-delivery would be limited to no more than recovering the costs the company has avoided through non-delivery. We

52CDE2746420/43997/GasSOInitialProposals201112.pdf would apply no penalties in respect of timeliness of delivery. We could potentially commit to a policy of refraining from clawing back the full value of the work avoided through under-delivery as a reward to the company for not progressing with unnecessary investment. We would have to design this mechanism carefully in order to avoid encouraging unnecessary projects.

8.41. If the TO can show that it was in consumers' interests to defer delivery until the next price control period, we would include the corresponding secondary deliverable as part of the requirements of the next price control. No penalties for late delivery would apply. No additional funding would be made available, to prevent consumers' from paying twice.

8.42. If the TO cannot show that the non-delivery was in consumers' interests, we would impose a penalty with two elements:

- (i) revenue adjustment based on costs of work avoided to ensure that the company has not profited from the non-delivery
- (ii) additional penalty to deter, set based on the harm to consumers of non-delivery.

Delivery timescales spanning more than one control period

8.43. It is possible that some projects to increase boundary capability would have a timeframe that extends into the subsequent price control period. For example, some of the large reinforcement projects that are being considered under the TII framework are planned to include up to three years of pre-construction work, and some are planned to include up to eight years of construction work.

8.44. We will need to set out upfront the treatment of any projects that span more than one price control. Where possible, we will seek to break proposed boundary capability increases into stages that can be split between price control periods. If this is not sufficient, we would provide commitments on elements of the funding and incentive arrangements until the projects are completed, even if this extends into the next price control period. Commitment might be needed on:

- the total revenue allowance for the secondary deliverable
- the efficiency incentive rate applied to over and under spends
- the rules on how early or late delivery would be treated

8.45. Without these commitments, there may be uncertainty about how the reinforcement may be treated at the next price control review. This uncertainty could, in turn, lead the transmission company to delay work and prevent the company from adopting delivery approaches that provide value for money.

Uncertainty mechanisms and other flexibility arrangements

8.46. At the price control review, it will be uncertain what increase (if any) is needed in boundary capability at each GB transmission boundary to meet consumer interests. For example, the location and timescales of accommodating new generation will be uncertain.

8.47. The potential scale of expenditure on wider works is large. For example, the TOs estimate that the projects that are being considered under the TII framework will cost over £5billion[39]. The potential impact of delayed investment may also be large, eg constraints costs from capacity limitations. In this context, we need some flexibility to allow the extent to which boundary capability is to be increased, and the associated revenue allowance, to vary (as information is revealed) during the eight-year price control period.

8.48. We propose to use uncertainty mechanisms to bring this flexibility. The role of uncertainty mechanisms would not simply be to adjust allowed revenues for variations in required spend but also ensure that there is flexibility in the secondary deliverables companies need to deliver.

8.49. Extra to agreed increases in boundary capability provided with committed price control funding, four options that may be used to bring this flexibility are:

- Option (a): Potential **trigger mechanisms** through which the required capacity and associated revenue allowance would adjust mechanistically during the price control period according to pre-specified trigger criteria.
- Option (b): We would have provisions to allow us to make **within-period determinations** to approve additional increases in boundary capability, and to provide associated upfront funding during the price control period.
- Option (c): Provisions under which the TO would have flexibility to choose what level of increase in boundary capability to deliver (up to an agreed maximum). This would be subject to the investment being compatible with the company's **network planning policy** that we would have to approve. Funding for the increases in boundary capability would be provided through a **volume driver** calibrated at the price control review in light of forecasts of the unit costs of increases in capacity.
- Option (d): An upfront **utilisation incentive scheme** such that a transmission company would be able to choose what increase in capability to develop at a specific transmission boundary and would bear financial risks (penalties and rewards) related to subsequent boundary transfers at that boundary.

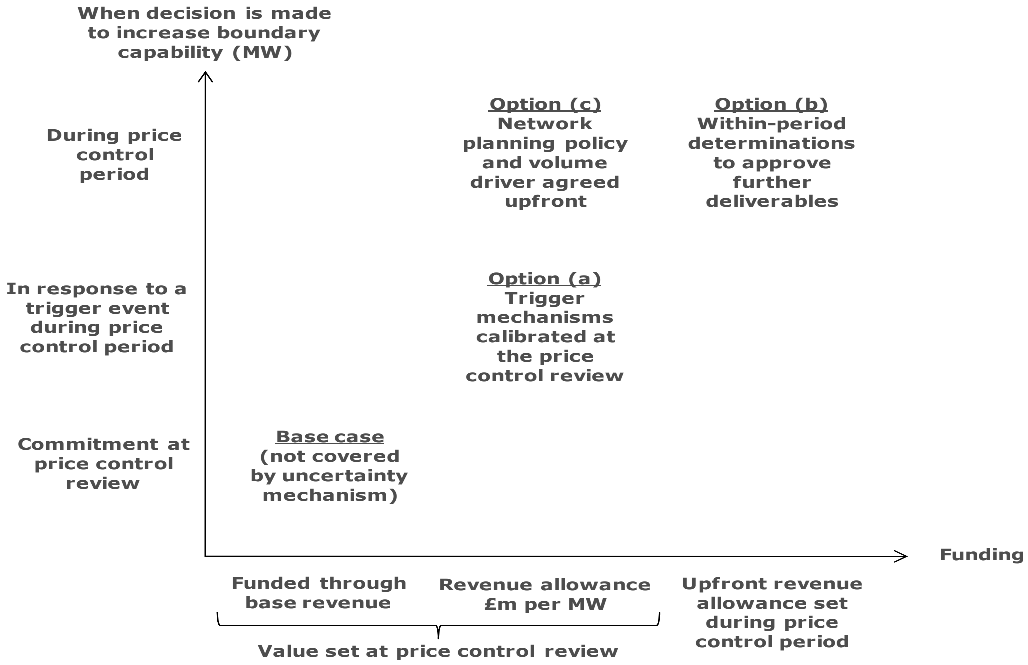
8.50. We suggest a combination of (a), (b) and (c) could bring benefits to consumers. We could use the revenue trigger in cases where a relevant trigger point is identified. Extra flexibility could come from the volume driver and network planning policy. It may be appropriate to combine this with the option for within-

39 http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/TAR/Documents1/100118_TOincentives_final_proposals_FINAL.pdf

period determinations where a large amount of additional consumer funding would be at stake. We would look to TOs to set out in their business plans how these options could be applied in the specific circumstances of their networks and to justify their preferred options.

8.51. Figure 8.2 illustrates how these mechanisms may be combined with secondary deliverables specified at the price control review. It shows the points in the process at which the funding is agreed and at which the decision is made to undertake the construction work.

Figure 8.2 Potential uncertainty mechanisms for electricity wider works



8.52. We have reservations about option (d). It has some attractive properties, but it may prove difficult to develop an incentive scheme along these lines that can be relied on to work in the interests of consumers, either as a complement or substitute to the other options above. We welcome further views on this.

Option (a): trigger mechanisms calibrated at the price control review

8.53. At the price control review, a TO may identify that the need case for a potential increase in boundary capability depends on certain things happening over the price control period. In these circumstances, it may not be in consumers' interests to commit to that increase in boundary capability at the price control review. Instead, the requirement for the increase in boundary capability could be made contingent on a 'trigger' event if a clear justification for the increase in boundary capability would arise from that event happening. The nature of any trigger event would be case-specific, but could, for example, relate to:

- planning permission granted for a set of potential generation projects
- maximum power transfer at the transmission boundary reaching a specified level.

8.54. Under this option, we would estimate the costs of the increase in boundary capability at the price control review and if the trigger event occurs, the TO's allowed revenue for the remaining years of the price control, and subsequently its regulatory asset value, would adjust to reflect this. The revenue adjustment would be mechanistic, based on a specification set at the price control period. It would not require significant administrative work during the price control period.

8.55. An example of this approach is the set of revenue triggers used in TPCR4 for reinforcement projects by SP Transmission Limited and Scottish Hydro Electric Transmission Limited. If a certain level of additional generation capacity is connected in a certain zone of the network, then the TO is given additional funds to reinforce the boundary between that zone and the next.

8.56. We propose to include this option as one of the uncertainty mechanisms we could use in appropriate circumstances. These circumstances include a clear link between the trigger event and the need for the increase in boundary capability, and the ability to make a reasonable estimate of the costs of that increase at the price control review. We propose that companies set out, as part of their business plans, how such a mechanism could be applied to the potential network reinforcement work they have identified.

Option (b): within-period determinations to approve further deliverables

8.57. We may require retaining the option to approve, during the price control period, proposals from TOs to develop further increases in boundary capacity beyond those agreed at the price control review. This option may be the most effective way to tackle the following risks:

- the risk that consumers are exposed to costs, for example constraint costs, arising from delays in transmission companies starting work on network reinforcement projects
- the risk that increases in boundary capacity which are agreed at the price control review and funded by consumers turn out not to be necessary, for example because forecast new generation projects do not materialise.

8.58. This could work through an annual (or biennial) approval process or through a provision for companies to submit proposals at any time if certain conditions are met. Under this approach, we would estimate, as part of the approval process, the (efficient) expenditure requirements of the additional deliverables and reflect these in changes to allowed revenues for the remainder of the price control period, and subsequently in the regulatory asset value.

8.59. This option would allow us to defer decisions on what increases in boundary are in consumers' interests, or on the timing of such increases, until more information on the need for these increases is available. This may be particularly valuable in cases where the potential consumer benefits from starting work to (further) enhance boundary capability are dependent on forecasts of the generation and demand background.

8.60. This approach would also allow a phased approach to wider reinforcement work, under which commitment is given at the price control review to fund a certain amount of work (ideally linked to increases in boundary capability) with approval for further stages of work dependent on when the previous stage is complete and latest information on the need for the next stage.

8.61. This mechanism would be similar in some ways to the TII framework that is being used alongside TPCR4 (and its roll over year). However, there are differences. The TII framework assesses the specific projects that are designed to overcome issues with particular boundary capabilities. The option proposed here would assess progress towards overcoming boundary capability limitations, with less emphasis on the details of the projects. Also, the TII framework is limited to funding work up to the end of 2012-13. The proposed mechanism could commit to funding for longer durations.

8.62. Some comparisons can also be drawn with the deep reinforcement revenue drivers for SHETL under TPCR4. The unit cost allowances were set at the price control review, but there was a provision for reviewing these figures during the price control period once more accurate cost estimates were available.

8.63. Developments such as changes in generation connections might affect the need for network reinforcement. So, under this option, it would be important for TOs to remain aware of developments. They would need to develop plans for potential projects to increase boundary capacity that they could bring to us during the price control period. We propose that, under this option, TOs would have an additional obligation, with two parts. They would have to:

- maintain an up-to-date network development plan
- develop proposals for increases in boundary capacity where these would be in consumers' interest. We would require sufficiently detailed proposals to allow us to take an informed approval decision

8.64. We recognise that this work imposes potentially significant costs. We would provide up front funding as part of base revenue set at the price control review. The level of funding would need to take account of the scale of work that we expect the TOs would need to do to fulfil this role. We may also need to ensure that the SO is able to provide the information that the Scottish TOs would need.

Option (c): network planning policy and volume driver agreed upfront

8.65. Option (b) described above would provide considerable flexibility. We would be making decisions on specific increases in boundary capability during the price control period. This could bring a significant administrative burden. It would also bring risks of micro-management.

8.66. An alternative way to provide flexibility would be for each TO to be given some discretion as to the level of additional boundary capability to deliver, subject to safeguards to ensure that it takes reasonable decisions about what to deliver, with increases in capability remunerated on the basis of cost estimates made at the price control review.

8.67. This option would have the following elements:

- At the price control, the TO would propose a network planning policy that it would use to decide whether to proceed with projects to deliver additional increases in boundary capability beyond the levels agreed at the price control review. This policy would include information on how the company would consider the need case for potential projects that can increase boundary capability, with particular attention to the case for starting a project now rather than waiting to the next price control period when we would have greater opportunity to assess whether it is necessary to commit consumer funding to the project.
- We would need to be satisfied that the proposed network planning policy is in consumers' interests. If not, this option would not be available to use.
- At the price control review, we would determine a unit cost allowance that would apply to increases in boundary capability (if any) that the company chooses to deliver in addition to what was agreed at the price control review. For instance, if the unit cost allowance was £10 per MW and the company delivered an additional 50MW, it would be entitled to an additional £500. We would probably need to set different unit cost allowances for different transmission network boundaries.
- The company would take decisions, during the price control period, on potential increases in boundary capability beyond the level agreed at the price control review based on up-to-date information.
- We would monitor the company's compliance with its policy. If we found that the company had taken decisions that were not reasonably compliant with its policy, whether through action or inaction, we would take action to protect consumers. We could disallow the full application of the revenue driver for relevant projects, or we could impose a financial penalty reflecting an estimate of the harm to consumers. This harm could come through consumers' exposure to the costs of funding projects that were not needed or potentially the constraint costs from failure to proceed with an investment project that the policy would require.
- The company would not be exposed to any ‘ex post efficiency review’ to decide whether investment projects undertaken by the company were in consumers' interests. The relevant test would be limited to whether projects undertaken were compatible with the network planning policy agreed at the price control review.

- We would decide, at the price control review, a threshold for the maximum increase in boundary capability that could be funded through this mechanism (for each boundary). For relatively large increases in boundary capability, with relatively large cost implications for consumers, it may not be appropriate to rely on this mechanism to ensure increases in boundary capacity are limited to those that are in consumers' interests, and it may be better for us to review these directly — either at the next price control review or during the price control period under option (b) above.

8.68. Our current thinking is that this approach could bring valuable flexibility without the same degree of regulatory intervention and administrative burden as option (b). At least for RIIO-T1, where this approach would be new, we see it as a complement rather than as substitute to option (b), with the maximum threshold above determining the balance between what increases in boundary capability would be funded through this option and what could potentially be approved and funded under option (b). We are keen to receive views of stakeholders.

8.69. Under this option, we would expect each TO to provide a proposed network planning policy and values for volume drivers as part of the business plan submissions. We recognise that it would require time and effort at the price control review to establish these, in particular to estimate appropriate unit costs for the volume drivers. This approach may be most relevant for specific transmission boundaries where its benefits would be particularly high.

Option (d): company discretion subject to utilisation incentive scheme

8.70. The three options above involve mechanisms or processes through which changes are made to the boundary capability that a TO is required to deliver. An alternative approach is to develop a financial incentive scheme under which a TO would choose what increases (if any) in transfer capability to deliver at each network boundary, and would be penalised or rewarded according to the extent to which the increase in boundary capability has been used (within a given timescale).

8.71. Under this option, a set of baseline levels of boundary capability would be agreed at the price control review. These could either be the existing capabilities or increases which we are confident would be in the interests of consumers', based on information in companies' business plans. The company would then be able to choose to deliver any additional levels of boundary capability subject to the rules of the financial incentive scheme.

8.72. There are different ways in which such an incentive scheme could be developed. One approach would involve a company that chooses to deliver increases in boundary capacity above the baseline receiving additional allowed revenues that comprise the combination of two elements.

- A unit cost allowance for increases in boundary capability, which is estimated at the price control review for each network boundary that the scheme is applied to, based on an understanding of what investment projects could be carried out

to increase capability. The relevant allowance may be non-linear – for example a rate of £X per MW up to 3000MW and £Y per MW thereafter.
- A financial penalty or reward, which applies on top of the unit cost allowance, and depends on a measure of the extent to which use is made of any increase in boundary capacity. For example, this could be a measure of the maximum power transfer in excess of the baseline capability set at the price control review, taken over a defined period of time after the capacity increase has been completed.

8.73. Apart from at the price control review, such an incentive scheme could be introduced as part of a within-period approval process under option (b) above. Under this approach it would be the responsibility of companies, rather than us, to take the decisions on what increases in boundary capability to deliver. The approach might reduce the administrative burden compared to option (b) although these benefits may be limited if it would need to be applied on a boundary-by-boundary basis, for example to estimate expenditure requirements and to calibrate the incentive scheme.

8.74. We do not currently propose to develop such an incentive scheme. We have a number of concerns about the ability of such a scheme to work in the interests of consumers. However, we would welcome worked proposals if stakeholders consider that such an approach could be a valuable substitute to, or would complement, the other options discussed above. The potential downsides of any such incentive scheme would depend on its details. At this stage, we summarise below a number of potential concerns.

8.75. First, whether an increase in boundary capability is in the interests of existing and future consumers may depend on its use over relevant asset lives. This could be in the region of over forty years. If the incentive scheme is based on utilisation over a short period time this could paint a misleading picture of its value. Furthermore, there will be a significant time lag (possibly ten years) between a company starting pre-construction work on a project, in response to the incentive scheme, and the asset being ready to make a contribution to boundary capacity. This suggests that the incentive scheme would need to operate over a period of time that is significantly longer than the price control period. There are limitations as to the effectiveness and credibility of very long-term incentive schemes that would need to sit outside the price control package. For example, whether we could rely on the promise of a financial penalty or reward in 25 years' time to encourage TOs to take appropriate investment decisions today.

8.76. Second, in order for companies to make use of the scheme, given the potential financial downsides, they will need to have the opportunity to earn significant financial rewards. We are concerned that the level of financial rewards may be a high price for consumers to pay for what is, in essence, a way to improve the generation and demand forecasts against which decisions on network investment are made. There may be cheaper ways to get better demand forecasts.

8.77. It may prove difficult to calibrate incentive schemes in a way that does not simply give TOs a chance of a very high profit from an investment project for which the uncertainty over future utilisation could be very limited. Furthermore, the opportunity to earn such profits may deter a TO from providing us with high-quality information and useful forecasts as part of its business plan at the price control review. TOs may face financial incentives to overstate the uncertainty as to whether a proposed increase in boundary capability would be useful, to ensure that the proposed increase would qualify for the incentive scheme rather than being funded at expected cost through the price control review.

8.78. There may be cheaper ways to insure consumers against the risks of under utilisation of new assets. For example, there may be a role for third parties acting in the capacity of competitive insurance providers to underwrite the risks of low utilisation. This idea may be unprecedented in price control regulation, but may offer a more cost-effective way to protect consumers than an upfront utilisation incentive scheme.

8.79. There are also risks of distortions to company behaviour. For example, there could be a financial incentive for the SO to use new NGET assets that are subject to the incentive scheme in preference to existing assets, so that utilisation rises, even if there were no operational justification.

8.80. Finally, we are concerned about the potential for complexity under such a scheme, and the consequent risks of unintended consequences.

Other options

8.81. We welcome views on any further uncertainty mechanisms or arrangement for wider reinforcement works that may be in the interests of consumers.

Appendices

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Appendix 1 – Consultation questions

Chapter 1

Question 1: Do you have views on the approach we have undertaken to developing the outputs framework?
Question 2: Do any of our proposed output measures present potential difficulties in ensuring the submission of accurate and comparable data?
Question 3: Are there any aspects of our proposed outputs framework where the reporting requirements are likely to lead to disproportionate regulatory costs?
Question 4: Do you have any views on whether in principle it is appropriate to consider requiring the companies to do more to verify their regulatory reports?
Question 5: Should we introduce an independent examiner for the TOs to improve regulatory reporting?

Chapter 2

Question 1: Do you have any views on the primary output and secondary deliverables for electricity and gas transmission safety?
Question 2: Are these appropriate areas to focus on and are there any other areas that should be included?
Question 3: Do you agree with the proposed approach to setting safety incentives?

Chapter 3

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

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

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

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

(4) is there a need to review the procedure for incorporating the full cost of cancellation to the TOs?

Chapter 4

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

Question 2: Do you have views on whether additional transparency and separation should be provided between the TO and SO roles?

Chapter 5

Question 1: Do you have any views on the environmental outputs outlined?
Question 2: Are these the appropriate areas to focus on and are there any other areas in which primary outputs and secondary deliverables should be set?
Question 3: Do you agree with the proposed approach to setting environmental incentives?
Question 4: Do you have any views on what the TOs 'full role' in a low carbon economy may involve by the year 2020?
Question 5: What role is there for a primary output in RIIO-T1 on TO's contribution to the UK's environmental and energy objectives and what type of incentive would be most effective to drive TOs delivery in this area?
Question 6: Do you have any additional views on RenewableUK's proposal for a specific low carbon economy output including the form and size of such a reward mechanism?
Question 7: Do you have views on the relative roles of the TO and SO in relation gas shrinkage and venting, and how we might align the incentives between the two parties?
Question 8: What incentives should companies face to manage their carbon footprint?
Question 9: What incentive should be put on TOs in relation to losses?
Question 10: What are the options to avoid any perverse impacts on network development to connect renewable generation?
Question 11: Do you agree with the principle of full internalisation of environmental costs? To what extent should the output for SF6 move towards this objective?

Chapter 6

Question 1: Do you have any views on the primary outputs outlined for customer satisfaction?
Question 2: Are these the appropriate areas to focus on and are there any other areas that should be included?
Question 3: Do you have comments on the proposed approach to setting incentives related to the customer satisfaction outputs?
Question 4: Should the incentives apply to National Grid for good performance as system operator as well as in its transmission operator role?

Chapter 7

Question 1: Do you have any comment on the key principles we have identified for the delivery for connections?
Question 2: Do you have any comment on the interactions with the other workstreams, in particular Project TransmiT, for electricity transmission connections?
Question 3: Do you have any views on the existing arrangements for gas transmission?
Question 4: Do you consider any specific obligations and /or incentives are required for gas transmission?

Chapter 8

Question 1: Do you agree that there is a need for secondary deliverables that relate to wider reinforcement work on electricity transmission networks?
Question 2: Do you agree with our proposed approach to the specification of these secondary deliverables?
Question 3: How should we encourage timely delivery and deal with non-delivery?
Question 4: Have we identified appropriate options for bringing flexibility, over the price control period, to the secondary deliverables that TOs should deliver and to the revenues that they receive for this delivery? Which options work best for consumer interest? How would this depend on the circumstances?
Question 5: Do you agree with our plan to not develop proposals for an asset utilisation incentive scheme (option (d)), and to focus, instead, on the other options?

▪

Appendix 2 – Overview of NGG's capacity obligations and incentives NTS entry and exit points

NTS Entry Capacity

1.1. NTS Entry Capacity at each Aggregate System Entry Point (ASEP) is defined as the capacity in the NTS, where a user is treated as utilising in delivering gas to the NTS (and the Total System) at that ASEP.[40]

1.2. The UNC and GT Licence require NGG to offer capacity at entry points in four forms:

- Firm non-incremental entry capacity as specified in the licence, which is referred to as 'baselines'. NGG offers this firm capacity for sale through entry capacity auctions.
- Incremental obligated entry capacity refers to additional capacity that can be released via the Quarterly System Entry Capacity (QSEC) auctions when user commitment signals the need for capacity beyond the baseline levels. NGG has an obligation to deliver this capacity within 42 months, except as described in chapter 4.
- Non-obligated entry capacity, which is capacity that NGG NTS has elected to make available over and above the baseline. NGG NTS can make this available at auction via the entry capacity regime of its own accord or it can make it available in response to a signal for incremental capacity to avoid having to invest. NGG NTS essentially keeps 50 per cent of the revenue from the sale of such capacity under the operational buy-back incentive.
- Interruptible entry capacity which can be curtailed when there is an entry capacity shortfall. Users bid for this capacity for a particular day seven days before delivery.

1.3. When operating the NTS, NGG may find itself in a position where it cannot meet the capacity obligations that it has sold. In such a situation there are several commercial and operational tools available to NGG. NGG is incentivised in its SO role to adjust its entry capacity obligations via two entry capacity incentive schemes:

- the incremental entry capacity buy-back incentive scheme that relates to incremental obligated entry capacity released as part of the long-term capacity auctions that have occurred since 1 April 2007
- the entry capacity operational buy-back scheme that relates to all other entry capacity excluding interruptible entry capacity.

1.4. NGG has two main options to deliver incremental entry capacity. It can:

- invest to increase NTS capability – this results in increased capex costs but reduces the likelihood that NGG will have to buy back capacity to meet its obligations, or
- accommodate the increased obligations by better utilising the existing network – this saves on capex costs but results in a greater risk of having to buy back capacity

[40] UNC Section B 1.2.3 (a)

1.5. The incremental entry capacity buy-back scheme applies to the costs incurred in meeting obligated incremental capacity released for sale as part of the long-term capacity auctions that have occurred since 1 April 2007. The scheme is characterised by the following parameters:

- a target cost of zero
- a 100 per cent exposure to the buy-back costs, subject to a cap on NGG's NTS exposure of £4 million a month and £36 million a year
- a prohibition on NGG NTS paying more than £0.52 per kWh per day for buying back capacity within the scope of the scheme

1.6. In addition, the incremental entry capacity scheme also provides NGG with access to a permit system to further incentivise the timely delivery, or in some cases, the early delivery of capacity. The incremental entry capacity buy-back scheme grants NGG 12 permits, with each permit allowing NGG to extent the lead time of up to 100 GW of capacity by up to six months. Additional permits can be earned by NGG agreeing to deliver capacity earlier than the default lead time.

1.7. The entry capacity operational buy-back incentive allows NGG to increase its revenue if it can contain the costs of buy-back of entry capacity. However, if NGG incurs high entry capacity buy-back costs, then, other things being equal, the entry capacity operational buy-back incentive acts to reduce SO revenue.

1.8. In practice, the amount that NGG earns from the operational buy back incentive is determined by how it performs against a defined performance measure. The performance measure is calculated from the costs of entry capacity buy-back less revenues from the sale of certain entry capacity products, amongst other things.[41] The entry capacity costs and revenues that form part of the incentive are summarised in Table A2.1.

Table A2.1 Entry capacity costs and revenues forming part of the entry capacity operational buy-back incentive scheme

Entry capacity costs	**Entry capacity revenues**
Buy-backs Capacity management agreements Section I liabilities Locational buys on the on-the-day commodity market (OCM)	On-the-day-sales Interruptible sales Overruns Locational sells on the OCM

Note: NGG can also scale back the interruptible product to manage network risk but there is no cost associated with this action.[42]

1.9. If NGG's performance matches the target level for the operational buy back incentive it does not earn any revenue from the incentive. If NGG outperforms the incentive then it earns 50 per cent (the sharing factor) of the difference between the target and the value of the performance measure, subject to a limit of £18 million (the cap). If NGG underperforms against the target then its revenue is effectively decreased by 50 per cent of the difference between the target and the value of the performance measure, subject to a limit of £18 million (the collar).

[41] This includes revenue from entry overrun charges, revenue from locational sell actions and physical renomination incentive charges.
[42] NGG, Proposed reliability outputs straw man submitted to reliability and safety working group.

1.10. Furthermore, if NGG did not make capacity available in accordance with these obligations it would also be in breach of its licence conditions.

NTS exit capacity

1.11. NTS Exit capacity is defined as capacity in the NTS which a user is treated as utilising in offtaking gas from the NTS at that NTS Exit Point. Under the UNC, exit capacity is comprised of three elements:

- NTS Exit (Flat) capacity, which is capacity which a user is treated as utilising in offtaking gas from the NTS at a rate which (for a given daily quantity) is even over the course of a day
- NTS Exit (Flexibility) capacity, which is capacity which a GDN User is treated as utilising in offtaking gas from the NTS to the extent that (for a given daily quantity), the rate of offtake is not even over the course of the day
- NTS Off-peak exit (flat) capacity which is daily exit flat capacity that is subject to curtailment.

1.12. Exit capacity is released in accordance with both the UNC and the GT Licence. NTS Exit (Flat) Capacity consists of both baseline NTS exit (flat) capacity and incremental exit capacity.

1.13. In the enduring period, NGG (from 2012) is subject to the incremental exit capacity buy-back scheme that incentivises NGG to provide incremental enduring exit (flat) capacity allocated under the user commitment framework of the reformed exit regime. The incremental exit capacity buy-back scheme is characterised by the same parameters as the incremental obligated entry capacity buy-back scheme:

- a target cost of zero
- 100 per cent exposure to the buy-back costs, subject to a cap on NGG's NTS exposure of a £4 million a month and £36 million a year
- a prohibition on NGG NTS paying more than £0.52 per kWh per day for buying back capacity within the scope of the scheme
- access to the same permit scheme that applies to incremental obligated entry capacity to further incentivise the timely delivery of capacity (as described above).

1.14. Other than this scheme, NGG is not subject to incentives on NTS exit (flat) capacity beyond the obligations imposed by the GT Licence to use all reasonable endeavours to make capacity available and to meet '1 in 20' peak day capacity demand.[43]

[43] We also note that GTL includes an exit capacity buy-back and interruptions incentive scheme that applies until the start of the enduring period (1 October 2012). In the enduring period, NGG can claim back certain buy-back costs but these relate primarily to user behaviour (as advised by NG as part of the reliability and safety working groups see: NGG, Proposed reliability outputs straw man submitted to reliability and safety working group)

Appendix 3 – Proposed changes to NOMs to reflect our secondary deliverables

1.1. This appendix contains further information on our proposed secondary deliverables for electricity and gas transmission. It highlights the difference between how these deliverables are currently reported under the NOMs and our proposed developments for RIIO-T1. We are seeking comments on these proposed developments.

Electricity transmission

Asset risk (asset health, criticality and replacement priorities/risk)

1.2. We propose to use asset health, criticality and replacement priorities as secondary deliverables.

1.3. An asset health index (HI) provides a framework for collating information on the health (or condition) of network assets and tracking changes in network health over time. We consider it a useful indicator of potential future reliability and safety issues. Asset health, criticality and replacement priorities should be used by the TOs to identify capital programs for the forthcoming price control.

1.4. TOs currently report asset health based upon remaining useful life. Assets are placed into one of the categories shown in Table A3.1a. We consider that a HI definition, that reflects only the condition of the asset, is more appropriate as an assessment of time to replacement, should only be made after considering an asset's condition and criticality. It also eliminates the element of circularity that is introduced when both the HI and replacement priority refer to a period of time.

1.5. We propose that asset health should be defined based on the scale shown in Table 3.1b. This approach is consistent with that used in the DPCR5 network outputs reporting.[44]

Table A3.1a – Current HI – remaining useful life

0-2 years
2-5 years
5-10 years
>10 years

Table A3.1b – Proposed HI definitions for secondary deliverable

HI Band	Definition
HI1	New or as new
HI2	Good or serviceable condition
HI3	Deterioration, requires assessment or monitoring
HI4	Material deterioration, intervention requires

44 For further detail see chapter 2 'Instructions for completing network outputs reporting' in the document 'Electricity distribution price control network asset data and performance reporting – Regulatory instructions and guidance: Version 1' http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/DPCR5/Documents1/Electricity%20Distribution%20NADPR%20RIGs.pdf

	consideration
HI5	End of serviceable life, intervention required

1.6. Criticality provides a measure of the consequence of failure an asset. The criticality of an asset is based on system, safety and environmental considerations. These considerations are:

- system criticality is based on the impact of the transmission system not delivering services to customers and any impact on the safety of the public or the smooth operation of the UK services and economy
- safety criticality is based upon the risk of direct harm to personnel or the public as a result of asset failure (for example conductor drop, asset fire or explosion)
- environmental criticality is based upon the environmental impact caused by asset unreliability or failure, taking into account the sensitivity of the geographical area local to the asset

1.7. Based upon the rating for each of these categories, a substation or circuit can then given an overall criticality rating (see Table A3.2). We consider that the current definitions are suitable for including criticality as a secondary deliverable however for consistency with the other indices we propose that a C1 rating be defined as low criticality and a C4 rating defined as very high criticality[45].

Table A3.2 – Criticality definitions

Rating	**Definition**
C1	Low
C2	Medium
C3	High
C4	Very high

1.8. The replacement priority indicates how TOs prioritise asset replacement decisions. It is a function of the asset health and the criticality of the substation or circuit where the asset is located.

1.9. Replacement priority is currently measured in terms of remaining years of use (see Table A3.3a). For RIIO-T1, we are seeking comment on whether the set of definitions shown in Table 3.3b are more appropriate. The replacement category will continue to be derived from the HI and criticality data.

Table A3.3a Replacement priority

No. of years before replacement
0-2 years
2-5 years
5-10 years
>10 years

Table 3.3b Risk definitions

Rating	Definition
RI1	Very low risk
RI2	Low risk
RI3	Medium risk
RI4	High risk
RI5	Very high risk

1.10. TOs can also provide further information within the commentary to explain the reasons behind their replacement decisions. TOs should articulate the case for spending a marginal pound on one asset over another and include information on the risk trade-offs made between the different asset categories.

[45] This differs from the current NOMs definitions. C1 previously denoted 'very high' criticality. It now denotes 'low criticality. 'Very high' criticality should be given a 'C4' rating.

Average circuit unreliability (ACU) and system unavailability

1.11. We propose to use ACU as a secondary deliverable to ensure that the primary output, ENS, will continue to be delivered in future price controls. All TOs should collect this on a monthly basis and report this at asset type level.

1.12. ACU provides data to show the impact of asset unreliability on the network which could be an indicator of the decline of overall asset health.

1.13. ACU measures the percentage of hours the network is unavailable due to outages (both planned and unplanned) caused by functional failures. Functional failures are defined as unreliability events which result in unavailability of the network due to outages which cannot be deferred until the next planned intervention and include:

- enforced unreliability outages taken at less than 24 hours notice (unplanned unavailability)
- planned unreliability outages taken after 24 hours notice

1.14. NGET report the total ACU figure for all assets and provide this figure broken down for each month of the reporting year. NGET also captures this data at asset type level (transformers, switchgear, overhead lines, underground cables, protection and control). SHETL and SPTL do not currently capture the information at this level. We propose that all companies report ACU at total asset and individual asset level in future. We also propose that the monthly breakdown is provided.

1.15. We propose that TOs forecast this system unavailability and ACU for one year ahead, rather than for the duration of the price control period. This is because many outages are caused by weather events and this makes it difficult to forecast accurately eight years ahead.

1.16. We also propose to capture system unavailability due to planned non-reliability outages as a secondary deliverable. This is consistent with our proposed primary output, ENS, which also includes planned outages. System unavailability should be monitored as a means of assessing trends that may impact on likely future performance of the primary output.

1.17. System unavailability is a measure of the percentage amount of time for which circuits are unavailable. We consider it a useful secondary deliverable as it shows the impact on the network from all types of outages. System unavailability is derived from:

- system unavailability due to planned user connection outages (planned outage where more than 24 hours notice given due to user connection issues)
- system unavailability due to planned construction outages (planned outage where more than 24 hours notice given due to construction issues)
- system unavailability due to planned maintenance outages (more than 24 hours notice given due to maintenance issues, excluding those due to reliability).
- ACU (see below)

Faults and failures

1.18. We also propose to use faults and failures as secondary deliverables. A fault is an event which causes plant to be automatically disconnected from the HV system for investigation and further action if necessary.

1.19. TOs report the number of faults for:

- weather related trips and delayed auto-recloser (DAR) faults
- non-weather related trips
- faults requiring an outage of more than three hours

1.20. A failure usually indicates where an asset needs replacing. Failures are defined specifically for each asset type below.

1.21. The number of assets which have had faults or failures is reported under Standard Licence Condition B17 Network Output Measures. This data is not currently forecast. We do not propose to change this as the low volumes involved would make this difficult to forecast meaningfully.

Gas transmission

1.22. An HI provides a framework for collating information on the health (or condition) of network assets. Criticality provides a measure of the consequence of failure of assets typically measured in terms of system, safety and the environmental implications. By combining asset health and criticality, TOs can develop replacement priorities that determine capital replacement priorities.

1.23. NGG currently reports on measures of asset health and criticality under Licence Condition C13 Network Output Measures (NOMs). However, we are proposing that these measures be further developed for RIIO-T1 to provide a more consistent framework to that outlined for electricity transmission (and developed as part of DPCR5).

1.24. The NOMs currently categorise NGG's assets into five primary asset groups based on the key reason for the asset. These are entry points, exit points, compressors, pipelines and multi-junctions. Each primary asset is supported by secondary assets that are installed to protect/minimise the risk of principle components failing.[46] Secondary assets are categorised into 47 groups, with some secondary assets supporting more than one primary asset.

1.25. Asset condition is currently reported for each of the 47 secondary asset groups based on a 'time frame on work required' (see Table 3.4a). Secondary assets are also assigned a criticality profile and criticality level. Replacement priorities/risk are not currently reported.

1.26. As noted for electricity transmission, our initial view is that asset health should be defined purely on the basis of asset condition. A time frame on work required is

[46] NGG submission to reliability and safety working group, 7 September 2010

more appropriate for an asset once its criticality has been considered. Our proposed definitions for asset health are shown in Table 3.4b.

Table 3.4a – Current HI – remaining useful life

0-2 years
2-5 years
5-10 years
>10 years

Table 3.4b – Proposed HI definitions for secondary deliverable

HI Band	Definition
HI1	New or as new
HI2	Good or serviceable condition
HI3	Deterioration, requires assessment or monitoring
HI4	Material deterioration, intervention requires consideration
HI5	End of serviceable life, intervention required

1.27. We also consider that the criticality framework used in the current NOMs should be further developed. Our view is that a measure of criticality that is consistent with electricity transmission needs to be applied. A measure of criticality should be capable of ranking identical assets on different parts of the network. Our view is that this should be based on the reliability, safety, environmental and financial consequences of asset failure.

1.28. We note that in some cases (for example remote isolation valves) the criticality of the asset may be the same regardless of where it is situated. In these cases we would still require NGG to demonstrate how prioritisation decisions are made when spending a marginal pound.

1.29. Our proposed criticality definitions are shown in Table 3.5.

Table 3.5 – Criticality definitions

Rating	Definition
C1	Low
C2	Medium
C3	High
C4	Very high

1.30. Based on the asset health and criticality of an asset, NGG should then develop replacement priorities/risk measures.

1.31. Replacement priority is currently measured in electricity transmission in terms of remaining years of use (see Table 3.6a). We would welcome views on whether the set of definitions shown in Table 3.6b are more appropriate. The replacement category will continue to be derived from the HI and criticality data.

Table 3.6a – Replacement priorities

0-2 years
2-5 years
5-10 years
>10 years

Table 3.6b – Risk definitions

RI	Definition
RI1	Very low risk
RI2	Low risk
RI3	Medium risk

RI4	High risk
RI5	Very high risk