Promoting choice and value
for all gas and electricity customers

System Operator incentive schemes from 2013: initial proposals

Consultation - supplementary appendices

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Publication date:	27 July 2012	**Team:**	Markets
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Overview:

This paper comprises supplementary appendices which provide supporting detail to our initial proposals for incentives on the gas and electricity System Operators (SOs) from April 2013.

This paper sets our initial proposals for incentives on the gas and electricity System Operators (SOs) from April 2013. Our proposals are based on RIIO (Revenue = Incentives + Innovation + Outputs) principles for regulating monopoly energy companies.

We put forward proposals for a range of incentives for gas system costs and outputs, and for electricity outputs, covering a period of up to eight years. For the electricity costs scheme we propose a different approach, moving away from complex modelling and focussing more on establishing principles and monitoring outcomes with financial incentives consistent with this approach.

We seek views on all aspects of these proposals and in particular whether they will encourage the right behaviours from the system operators and provide value for money for present and future consumers.

*Responses are sought by **21 September** to inform final proposals later this year.*

Context

These initial proposals form part of our work to regulate monopolies effectively. We consider that it is important for both the electricity and gas markets that the role of the System Operator (SO) is correctly identified and that the SO has the appropriate tools available to it to undertake this role.

Any interventions in the market by the SO can lead to costs being incurred, both directly by the SO and more widely by the market. Since consumers ultimately bear these costs it is important that they are efficient. The SO also has a wider role than its core balancing activities and we consider that it is important that the SO has the appropriate incentives to play a full role in delivering a sustainable energy system.

This work builds on previous material published in both SO incentive schemes and RIIO-T1 documents.

Associated documents

- System Operator incentive schemes from 2013 initial proposals: Overview. 27 July 2012, Ref 106/12: http://www.ofgem.gov.uk/Markets/WhlMkts/EffSystemOps/SystOpIncent/Documents1/IP%SO%2013.pdf

- RIIO-T1: Initial Proposals for National Grid Electricity Transmission plc and National Grid Gas plc, 27 July 2012, Ref 104/12: http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/RIIO%20T1%20Initial%20Proposals%20for%20NGGT%20and%20NGET%20Overview%202707212.pdf

- Decision on the concept for the implementation of the Environmental Discretionary Reward for the electricity transmission owners and system operator, 4 July 2012: http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/RIIO-T1%20-%20Environmental%20Discretionary%20Reward%20(EDR)%20decision%20letter.pdf

- System Operator incentive schemes from 2013: principles and policy, 31 January 2012, Ref 12/12: http://www.ofgem.gov.uk/Markets/WhlMkts/EffSystemOps/SystOpIncent/Documents1/SO%202013%20Principles.pdf

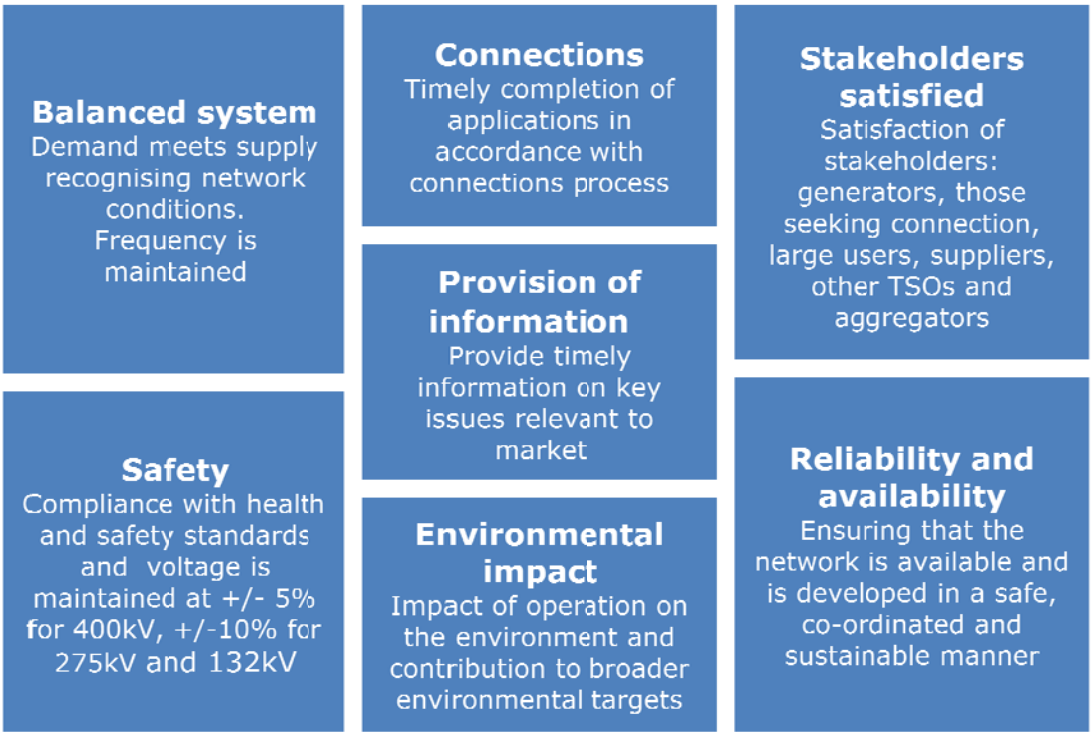
- System Operator incentive schemes from 2013, 14 June 2011, Ref 77/11: http://www.ofgem.gov.uk/Markets/WhlMkts/EffSystemOps/SystOpIncent/Documents1/SO%20incentives%20from%20April%202013%20Inital%20Views%20Consultation.pdf

Contents

Appendix 2 – Electricity outputs and output incentives

2.1. In this Appendix we provide more detail of the electricity outputs and output incentives discussed in the Overview document. By way of context, Figure 1 summarises the outputs that we proposed the SO should be expected to deliver in our January consultation. We discuss each of these in turn below.

Figure 1: Proposed electricity SO outputs



Safety

Workplace safety – background and our proposal

2.2. NGET (as both SO and TO) is required by legislation to design and operate its network to ensure the safety of the public and its employees. The HSE monitors and enforces performance in this area as determined by legislation. In our January consultation we set out, as with our RIIO-T1 proposals in respect of the TOs, that we would not include any additional output requirements within the electricity SO regulatory framework with respect to this aspect of safety.

2.3. We continue to consider that adequate monitoring of this output is already in place and so we do not propose to implement an incentive on workplace safety for the electricity SO from April 2013.

Operational safety: system voltage correct – background and our proposal

2.4. In our proposals we set out the requirements on NGET as SO to maintain the voltage of the electricity system within specific limits. We also noted the role of the HSE in respect of any breach by the company in respect of its legal obligations in respect to safety. We therefore set out our initial view that we would not develop a separate output incentive scheme in respect of maintaining voltage requirements.

2.5. There was only one response on this issue. RenewableUK suggested that there was a need for an incentive on system voltage as the SO might be tempted to pass through the costs of managing voltage profiles to generators, either through more onerous operating conditions or by reducing access to the system.

2.6. Whilst we note RenewableUK's views, we consider that its concerns can be addressed through effective monitoring of system voltage levels. Hence, **we do not propose to implement an incentive on operational safety for the electricity SO from April 2013**.

Environmental impact

2.7. In our January consultation we set out our views on how the SO might be encouraged to play a full role in meeting the environmental challenges faced by the energy sector.

Broad environmental impact – background and our proposal

2.8. In our January consultation we set out that we would consider a reputational incentive on the SO in respect of a broad environmental output relating to how the SO is contributing to the delivery of the low carbon economy.

2.9. Respondents were keen to ensure that any incentive related only to actions that were additional to those that the SO has to undertake to comply with legislation. Several respondents suggested that an incentive should be reputational rather than financial. EDF Energy (EDF) pointed out that the SO cannot favour one generating technology over another (due to discrimination requirements) so that its scope for action was limited. RenewableUK indicated that it would support a financial incentive linked to progress in decarbonising electricity.

2.10. Under RIIO-T1 we are putting in place a key environmental incentive, the Environmental Discretionary Reward (EDR), with a funding amount of £32 million over the period of the price control. In our February 2012 consultation on the EDR we proposed that it would focus on the electricity TOs[1]. However, following this

[1] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=152&refer=Networks/Trans/PriceControls/

consultation, we have decided to incorporate the electricity SO into the EDR, as set out in our July 2012 EDR decision letter[2].

2.11. The purpose of the EDR is to sharpen companies' focus on strategic environmental considerations and encourage corporate and operational culture change to facilitate growth in low carbon energy. The EDR will be based on:

- Scoring a level to be determined on an environmental balanced score card, comprising six key strategic and operational environmental issues.

- Publishing an annual executive level planning statement and consulting on that statement.

2.12. Of the key strategic and operational environmental issues on the environmental balanced scorecard, consultation respondents emphasised the SO's role in three of the six scorecard categories:

- Category 2: involvement in whole electricity system planning for low carbon future, including integration with Distribution Network Operators (DNOs) and involvement in development of demand side interactions.

- Category 3: approach taken to connections for low carbon generators.

- Category 5: development of approaches to demand side response and 'smarter' networks, including storage and best use of existing network.

2.13. We are developing a robust scorecard approach to the EDR which will judge companies' performance clearly and effectively. To achieve a high score, companies will have to show that they have exceeded legal requirements and 'business as usual' activities. The scorecard will incorporate the role of the SO under the three categories set out above. We will consult further on this in the summer.

2.14. We also note that the majority of responses preferred a reputational to a financial incentive in this area. However, responses to the February consultation on EDR strongly supported the concept of a financial reward component, as well as acknowledging the important reputational element of the scheme. On balance, our view is that a financial reward is an appropriate incentive for companies that can demonstrate that their performance goes beyond compliance with their legal requirements.

[2] http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/RIIO-T1%20-%20Environmental%20Discretionary%20Reward%20(EDR)%20decision%20letter.pdf

Transmission losses – background and context

2.15. The optimal level of transmission losses to society is where the costs of avoiding losses are equal to the benefit of doing so. The benefit is roughly equivalent to the energy price (which already includes the carbon cost). The objective of a transmission losses incentive on the SO is to ensure it plays a full role in working to achieve this optimal level. We consider that this means:

- NGET is incentivised to take account of the economic cost of losses in its decision making.
- NGET should promote transparency and reduce uncertainty regarding the levels and causes of transmission losses.

2.16. However, we recognise that NGET only manages a small proportion of the volume of energy (the ~ 3% that it manages in the Balancing Mechanism).[3]

2.17. Annual losses on the transmission system historically have been around two per cent of demand. However, these are expected to increase, particularly as a result of new generation locating at the extremities of the network.

2.18. In 2011/12 transmission losses were significantly higher (6.2 TWh) than forecast (4.5 TWh) and higher than historic levels. One of the drivers of this increase has been coal generation (mainly located in the north) being "in the money" and replacing southern CCGTs in the merit order.

2.19. Currently, NGET as system operator is the only market participant that has an explicit financial incentive with regard to transmission losses. Under the current incentive scheme, a target volume is set with any difference between the target and the actual level (either positive or negative) being multiplied by a wholesale reference price to give a cost. This cost is then added to or subtracted from the total incentivised balancing scheme costs.

2.20. The increase in the level of transmission losses for 2011/12 compared to the forecast (against which the incentive scheme target was set) has resulted in a cost of £65m being added to the total incentivised balancing scheme cost.[4]

Transmission losses – our consultation proposals and responses

2.21. In our January consultation we outlined that we considered that retaining the current financial incentive on the SO was appropriate as the incentive ensures that

[3] Approximately 60% of transmission losses are the result of the distance electricity travels from the point of generation to the point of demand. Approximately 40% of losses are associated with system assets (e.g. transformers).
[4] As the current scheme is set for a two year period this figure may change, but this gives a reasonable view of the effect that the increase in losses may have on the current scheme.

NGET as SO looks for ways to reduce transmission losses when procuring the services it needs to balance the system.

Transmission losses – summary of NGET's proposals

2.22. NGET believes that its scope to minimise losses is small and questions whether a volume incentive on losses is appropriate. Nonetheless, it has submitted a proposal that is designed to overcome some of the problems associated with the current scheme. Under its proposal, the target volume of losses for a year would be based on the historic level of losses for the previous year plus an adjustment based on the ex post calculation of the loss factor adjusted change in metered generation and demand at each node between the current year and the previous year. NGET proposed that the loss factors required for this calculation would be calculated ex ante, probably on the basis of the previous year's generation and demand and some average representation of the network. To reflect the limited control that NGET considers it has over transmission losses, it proposed that the sharing factors for this scheme should be 20%.

Transmission losses – our proposal

2.23. The changing mix of plant types on the GB system will make it increasingly difficult to forecast or control the level of losses. For example, the increasing capacity of wind plants in Scotland is likely to increase losses and yet it is unlikely to be appropriate for the SO to constrain these plants off to reduce the volume of losses.

2.24. We are also concerned that the scheme proposed by NGET (or any scheme that focussed on those elements of losses that the SO can control e.g. via the actions it takes in the Balancing Mechanism) would be complex and difficult for stakeholders to understand. Further, even over the eight year scheme period, any financial incentive is unlikely to yield material results in terms of lower losses, given the relatively limited scope for actions by the SO. Therefore, **our proposal is to remove the current financial incentive and replace it with a reputational incentive** that will build on the reputational incentive proposed under RIIO-T1.

2.25. This RIIO-TI incentive proposes that in the first year of RIIO-T1, the TOs set out their strategy for reducing losses to a level that is lower than it might otherwise be (while recognising that as more remote generation connects to the network losses are likely to increase). This strategy might include, for example, how the TOs will take any trade-offs between price and loss levels into account when procuring transmission equipment. In each subsequent year of RIIO-T1 the TOs will be required to report on the implementation of this strategy and to make a best estimate of the difference that they have made to transmission losses.

2.26. To complement this information, we propose that the SO should also have to estimate the difference they have made to transmission losses and to publish information on the overall losses and an explanation of the key drivers of the level of losses.

Business carbon footprint – background and our proposal

2.27. As set out in our January consultation we are not minded to introduce a separate SO output incentive associated with the SO's business carbon footprint. We remain of the view that the RIIO-TI proposals, particularly the EDR, provide sufficient incentives in this area and that a separate output incentive could result in double-counting of outputs. **We do not propose to implement an incentive on business carbon footprint for the electricity SO from April 2013.**

Connections

Background and our proposal

2.28. Efficient and timely connections to the electricity system are important for a number of reasons, not least so that new sources of generation can come online promptly to meet security of supply and environmental objectives.

2.29. In our January consultation we set out that we consider that the financial output incentive being placed on NGET under RIIO-T1 also captures NGET's role as SO as well as its role as TO. Given this it was our initial view not to propose any further incentive in this area.

2.30. SSE agreed that efficient and timely connections should not be incentivised but suggested that if this was an area where Ofgem felt improvement was required this should be delivered via the introduction of a licence condition on efficient and timely connections. RenewableUK considered that the increasing number of diversified smaller generation plants there was a growing role in coordination and customer service, which might be incorporated into the mix of incentives.

2.31. Incentives on connections are being included within the RIIO-TI framework and so **we do not propose to implement an incentive on connections for the electricity SO from April 2013**.

Reliability and availability

2.32. Having a reliability output category for both the SO and the TO in electricity is important to ensure that all parties play a full role in delivering a sustainable energy sector. A key component of this is ensuring that the network is available and that it can be developed/reinforced in a safe, co-ordinated and sustainable manner.

2.33. In our January consultation we set out that we consider that this is an output where both the SO and the TOs are jointly responsible for delivery. Under RIIO-T1 the TOs are required to have in place a network access policy (NAP). This policy clarifies what the SO, and other stakeholders, can expect from the TOs insofar as their actions affect the availability of the transmission network. Work is continuing to fully develop robust network access policies.

2.34. As part of the delivery of this output we consider that the SO and the TOs should take account of behavioural and investment interactions and carefully consider the trade-offs between capital and operational expenditure when aiming to deliver this output. Our January consultation set out two incentives that we might place on the SO to facilitate the delivery of this output. These were in respect of the management of processes and procedures and demonstrating that the SO is taking into account its interactions with TOs, especially with respect to network investment.

Management of processes and procedures – background and our decision

2.35. In our January consultation we set out how we considered that the SO can influence the availability and reliability of the network through its involvement in various regulatory processes it is either involved with or has responsibility for. Further we set out that we were minded to require the SO to deliver a statement that demonstrates how it will approach the various processes and procedures that it is (or may wish to be) involved with. This statement could then form a benchmark (along with stakeholders' views) as to how effectively it is meeting its stated objectives.

2.36. Whilst we continue to believe that it is important for the SO to strive to improve the availability and reliability of the network, **we have decided to progress this requirement as part of the NAP work being undertaken under RIIO-T1** rather than as part of the SO incentives. In addition, similar types of issues are also being considered as part of the "Integrated Transmission Planning and Regulation" (ITPR) project.[5]

2.37. Ofgem's ITPR project will consider whether improvements are needed in the longer-term to the electricity SO's role and incentives as system planner across the whole of the national electricity transmission system. It is also considering whether

[5] See paragraph 2.40 below.

the current governance arrangements, relationships with other parts of National Grid and with other transmission parties in GB, can best deliver system planning.

Demonstrate taking account of interactions with TOs, especially with respect to network investment

2.38. There are a number of areas where the SO and the TOs currently work together but where we consider the regulatory framework could be improved to encourage greater value for money for consumers. This is particularly true with network planning and investment, which is fundamental to the ongoing operation of the network and minimising constraint costs.

2.39. In our January consultation we set out that we were minded to have a reputational incentive with respect to how effectively the SO engages with the TOs and the TSOs. A key component of such a reputational incentive would involve the SO developing a policy statement outlining how it will engage TOs. Such a policy statement would complement the NAP that the TOs are required to produce and adhere to under RIIO-T1. Together, these two policy statements would facilitate greater transparency

2.40. We also noted that we would consider the need for specific incentives to promote coordination in network investment decisions through other related workstreams. In this respect, in March we started work on the ITPR project.[6]

2.41. As in the case of the management of processes and procedures, **we have decided to progress this requirement as part of the Network Access Policy work being undertaken under RIIO-T1** rather than as part of the SO incentives.

2.42. In addition, NGET has come forward with proposals for commercial arrangements between it and non-NG TOs that would incentivise them to reduce the constraint costs associated with changes in TO outage plans. These proposals are discussed further in Appendix 3.

Stakeholders satisfied

2.43. In our January consultation we set out that we considered that there was merit in the SO being subject to a stakeholder satisfaction survey in a similar way to that proposed for the TOs under RIIO-T1. However, we considered that the TO survey will capture the stakeholders that are relevant for the SO and therefore did not consider a separate survey was needed.

[6] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=101&refer=Europe

2.44. In response to our consultation, RenewableUK emphasised the need to differentiate between categories of stakeholders and to ensure that feedback from aborted projects is taken into account. SSE argued that the stakeholder satisfaction survey must be targeted to appropriate stakeholders, with the responses weighted appropriately, and that stakeholders should be consulted on the form of the survey. It further considered that the survey must distinguish between SO and TO activities and that the results of the survey must be published.

2.45. Having considered this issue further, we consider that it is important that the customer/stakeholder views relate to each company's performance. We consider that this can effectively be achieved through the RIIO-T1 stakeholder survey financial incentive which we propose should cover both SO and TO issues. Further details on the incentive scheme can be found in the NGET RIIO-T1 initial proposals consultation that is also published today. **Our proposal is that there should be no additional incentive scheme in the SO regulatory framework.**

Balanced system

2.46. Balancing the electricity system and ensuring the appropriate frequency is maintained are fundamental to the successful operation of the system. As such, as set out in our January consultation, we consider that it is appropriate that there are incentives in place that encourage the SO to manage these two roles in an efficient and value for money manner.

2.47. In our January consultation we set out that we consider that retaining a strong cost incentive on the electricity SO to minimise the cost of balancing the system is appropriate. However, we also noted that we consider that there is a case for having complementary output incentives relating to system balancing and system frequency.

2.48. In line with our proposal not to continue with cost incentives on energy balancing and constraint costs, **we are not proposing to proceed with introducing output incentives on system balancing and system frequency.** However, we will monitor how these output measures develop over time as part of our broader monitoring and enforcement initiative. For example, we will be asking NGET to report on deviations from the statutory frequency limits on a monthly basis.

Provision of information to the market

General information provision

2.49. We set out in our January consultation that we consider NGET as SO is uniquely positioned to provide information to the market on a range of energy issues including how the system is operating as well as more general information that could be useful to the sector. We also noted that there are already legal requirements for NGET to produce this information and therefore we were not proposing to have a separate output incentive scheme for this information. We also noted that in the

event of non compliance we have a number of actions available to us and also that views on the information provided will be captured through the stakeholder survey.

2.50. **We do not propose, therefore, to have general information provision output incentive**.

SO-SO interactions

2.51. In our January consultation we said that we wanted National Grid (NG), as owner of the gas and electricity SOs, to demonstrate that it is taking account of the interactions between the SOs when making decisions under the SO regulatory framework.

2.52. Respondents to the consultation expressed some concerns in this area, arguing that there are legal restrictions on the commercial information that can be shared between the two SOs. The AEP and EDF considered that there might be benefits in sharing information, subject to the legal restrictions. EDF mentioned in particular the sharing of forecasts of intermittent generation, given its likely impact on gas-fired generation. NG was of the view that it was a complex topic and considered that it was unlikely it would be feasible to make any changes before April 2013.

2.53. We are still of the view that there are merits to greater interaction between the gas and electricity SOs, particularly as there is likely to be an increase in interdependencies between gas and electricity operations as more intermittent generation connects to the network. However, we will need to consider carefully the implications of SO-SO information sharing, taking into account the BSC, Grid Code, Section 105 of the Utilities Act 2000 and the views of stakeholders. So **we do not propose to make any proposals on SO-SO interactions from April 2013 at this stage**.

Information on renewable generation – our proposals and respondents' views

2.54. In our January consultation we also set out that we consider that NGET as SO is uniquely placed to provide timely information to the market about the level of renewable generation (principally wind generation). We noted that this information will be particularly important to facilitate the move to a sustainable energy sector. We further proposed that an output incentive on renewable generation forecasts should be introduced.

2.55. Respondents were generally supportive of the introduction of a renewable forecasting output incentive. However, the AEP pointed out that the benefits in terms of self-balancing may be limited if there is only a single national forecast. It also expressed some concerns about the proposal, arguing that NGET is already indirectly incentivised in this area through its balancing cost incentive. SSE did not agree that there should be a financial incentive since renewable forecasting was a core part of

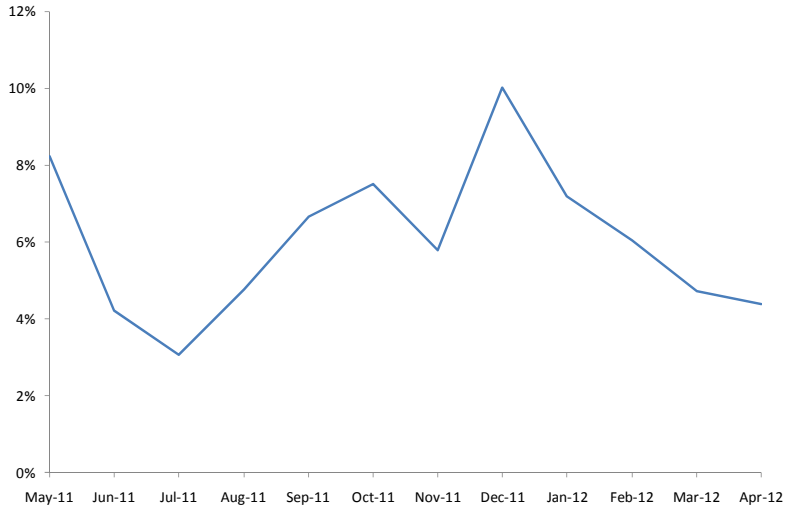
the SO role but stated it would welcome the introduction of a licence condition to require the publication of information.

2.56. Npower supported the proposal but was concerned that there should be no overlap with existing funding of forecasts. EDF suggested that there would be merits if the incentive related to sharing a day-ahead forecast with National Grid Gas and highlighted the fact that accurate forecasts at the day ahead and within day stage will help the market to self dispatch plant to ensure that demand is met.

Information on renewable generation – NGET's proposals

2.57. NGET has proposed that it should be incentivised with respect to the accuracy of its day-ahead wind forecasts on a monthly basis. It is proposing using the mean absolute error (MAE)[7] as the output index. The target for each month would be set by reference to the historic accuracy of its forecasts over the period May 2011 to March 2013.[8] As Figure 2 shows, over the past year NGET has achieved monthly MAE's of between 3% and 10%. NGET proposes that the monthly targets should be fixed for four years to give it a continuing incentive to produce high quality forecasts in a period when it will become increasingly challenging to maintain and improve forecasting accuracy.

Figure 2: NGET's historic MAE

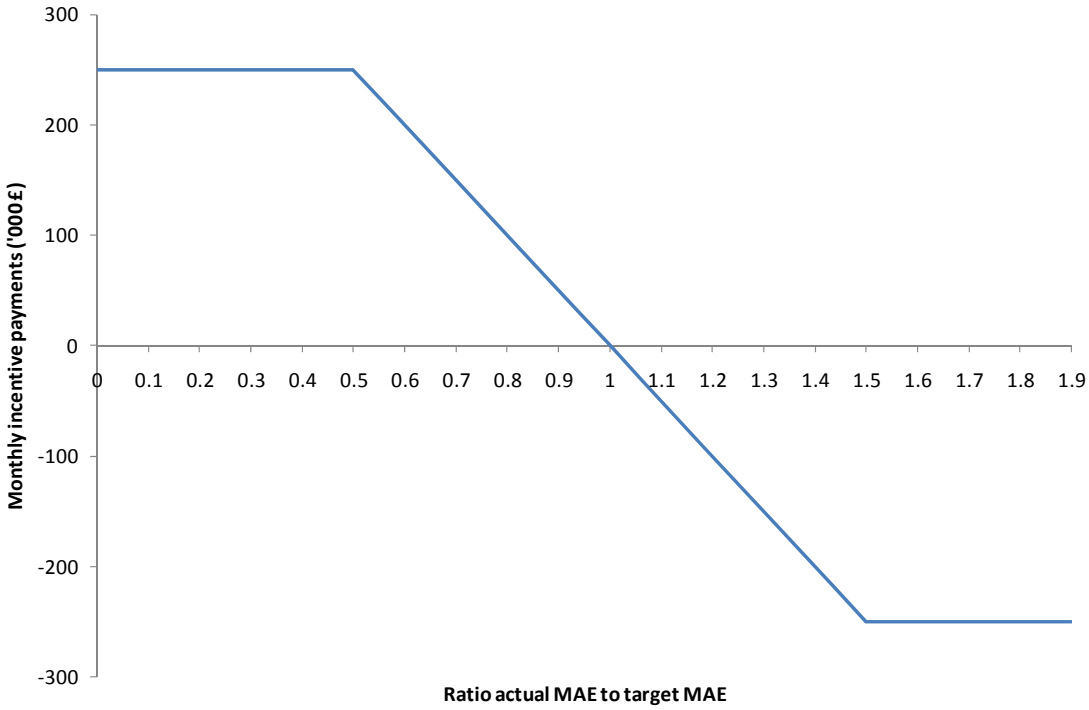


2.58. NGET further proposes that the cap and floor of the incentive should be symmetric. As shown in Figure 3 below, the maximum loss to which it would be

[7] The MAE measures the average magnitude of the errors in a set of forecasts, without considering their direction i.e. whether there has been an under- or over-estimate.
[8] So, for example, the target for March would be based on the average of NGET's forecasting performance in March 2012 and March 2013, and that for May on its performance in May 2011 and 2012. However, the target for April would be based only on April 2012.

exposed would be £250k per month and this would be payable if the MAE of its forecasts in a month is more than 1.5 times the monthly target. Conversely, it proposes that the maximum gain from which it could be benefit would also be £250k per month, which would be payable if the MAE of its forecasts in a month is less than 0.5 times the monthly target. In between these limits, the incentive payments would change linearly. NGET's financial proposals are illustrated below.

Figure 3: Renewables forecasting incentive



Information on renewable generation – our proposal

2.59. Accurate forecasting of renewable output will become increasingly important as the volume of intermittent renewable generation increases. Not only will it enable stakeholders to balance their positions more accurately, if they choose to rely on NGET's forecasts, it should also enable NGET to minimise the costs of operating reserve. For example, a more reliable forecast should reduce the extent to which NGET takes actions to ensure that plant are in a position to provide reserve when it subsequently transpires that this reserve was not required as renewable generation was higher than forecast.

2.60. NGET's proposals relate to improving the accuracy of the forecast of renewable output for the following two days that it currently produces at 5pm each day. NGET, for its own internal purposes, produces additional forecasts at 5am, 11am and 11pm (all GMT) and we would welcome stakeholders' views on whether it would be more appropriate for NGET to publish, and be incentivised against, one of these other forecasts. We note that this might be an interim measure since NGET is

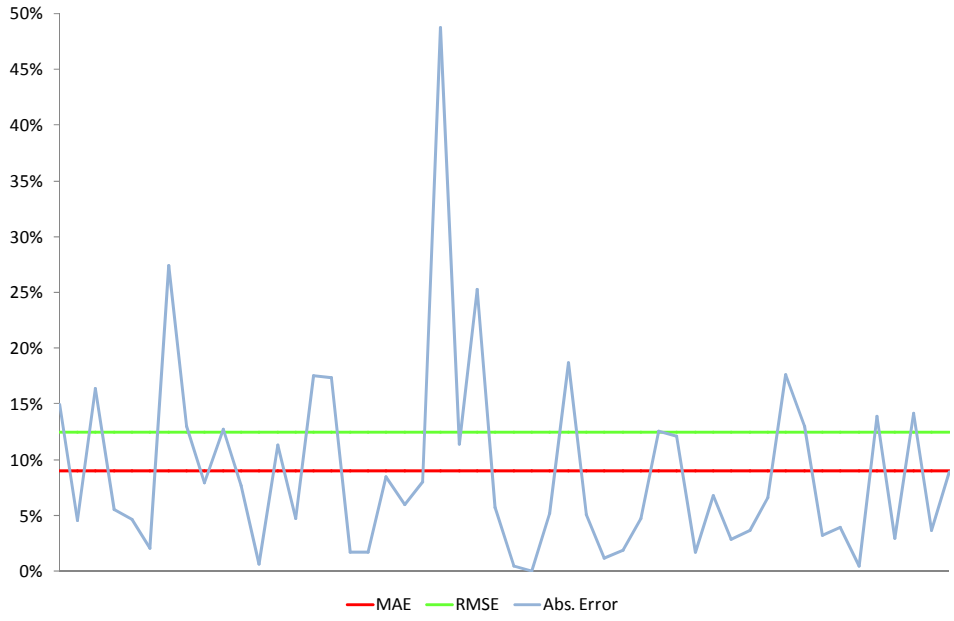
proposing to increase the number of forecasts it publishes to two in 2013/14 and four by 2015/16.

2.61. We would also like stakeholders' views on whether it is sufficient for NGET to publish a national renewable output forecast or whether there is a need for regional forecasts. We note, in this respect, that NGET proposed to use regional forecasts to derive a target for constraint costs. We recognise, however, that regional forecasts are likely to be less accurate than a national forecast (since accuracy generally improves as the area of forecasting increases) and that NGET currently focuses on national forecasts. Accordingly, we would not propose to introduce an incentive based on regional forecasts initially even if we were to introduce a licence requirement to publish regional forecasts.

2.62. **Our proposal is to introduce a renewables forecasting incentive** broadly along the lines proposed by NGET. However, given that this will be a new scheme, **we consider that it would be appropriate for the scheme parameters to be set initially only for a two year period**.

2.63. NGET's proposed output measure (MAE) is one of two metrics commonly used to measure the accuracy of renewable forecasts. The other common metric is the root mean square error (RMSE), which gives more weight to extreme outcomes i.e. where there is a very large over- or under-shoot in the forecast. We illustrate the difference between the two measures in Figure 4 below, which shows an imaginary set of 50 renewable forecasting errors that has a MAE of 9% and a RMSE of 12.4%. However, this difference is strongly influenced by the single day with a forecasting error of nearly 50%. If the error on this day was only 10%, then the RMSE would fall by 2 percentage points whilst the MAE would only fall by 0.8 percentage points.

Figure 4: Example of difference between MAE and RMSE



2.64. We are currently minded to accept NGET's proposal to use the MAE as the appropriate output measure but would welcome stakeholders views on which of these two measures they consider more appropriate.

2.65. We do not consider it appropriate to have targets that vary by month although we agree that the incentive payments should be calculated on a monthly basis to provide NGET with an incentive to improve all its forecasts. However, recognising that it is generally easier to produce more accurate summer forecasts than winter forecasts, we are currently minded to introduce separate summer and winter targets.[9] An alternative, simpler, approach would be to set an annual target. Given our proposals regarding caps and floors, see below, an annual target would still provide the SO with incentives to minimize forecasting errors in each month.

2.66. This means that we are consulting on four options for the renewable forecasting incentive (2 output index options x 2 target options), as shown in Table 1 below. In all four options, the targets for the first year are approximately 0.5 percentage points below the level of accuracy that NGET has historically achieved. We consider that all four options represent challenging but achievable goals.

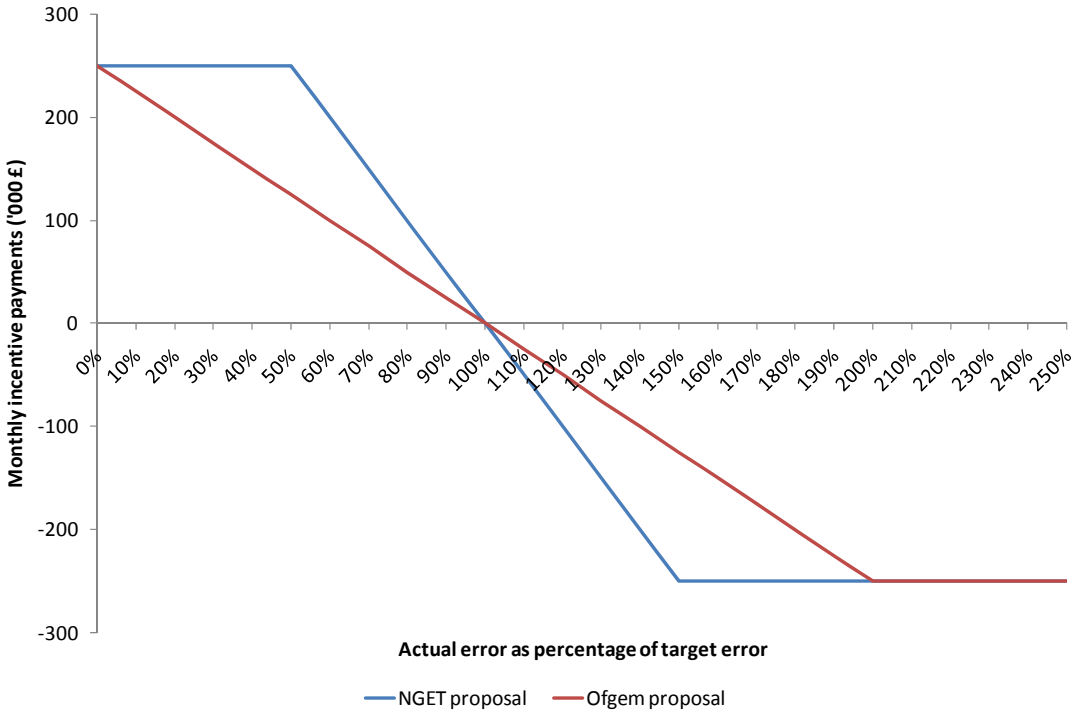
Table 1: Options for the renewables forecasting incentive

	Output index	Targets	Target level	
			2013/14	2014/15
Option 1	MAE	Seasonal	Winter 6.25% Summer 4.75%	Winter 5.5% Summer 4.5%
Option 2	MAE	Annual	5.5%	4.5%
Option 3	RMSE	Seasonal	Winter 9.25% Summer 6.75%	Winter 7.75% Summer 5.75%
Option 4	RMSE	Annual	8.0%	6.75%

2.67. In terms of the parameters for the scheme, we consider that the potential rewards and penalties should be material relative to the costs of the forecasting activity if the incentive is to be meaningful. Ideally, it would be calibrated based on evidence of the benefits to stakeholders, but this evidence is lacking (stakeholder views would be very welcome). In addition, the scheme should be designed so the probability of being outside of the cap and floor (where the incentive is ineffective) is minimised. Taking this into account, we propose to broaden the range of outturns that lie between the cap and floor but keep the maximum reward or penalty as proposed by NGET. **Our proposal is that the monthly cap of £250,000 would only be reached if there was no error in the forecasts and the monthly floor of -£250,000 would only be reached if the error in the forecast was twice the target.** Our incentive payment proposal is shown in Figure 5 below.

[9] Not only does NGET's historic performance show this trend, but it is also evident in a range of international studies.

Figure 5: Renewable forecasting incentive payment proposals



SO Innovation

2.68. In its March 2012 RIIO-T1 submission, NGET submitted an innovation strategy that outlined how it intended to utilise innovation funding to drive improvements in its business and address the fundamental issues that its stakeholders have identified as areas where innovation could have the greatest positive impact.

2.69. NGET considers that funding should be available to the SO, as it is to the TO, through the new mechanisms introduced by RIIO-T1. It therefore considers that the SO should be able to participate in the Network Innovation Allowance (NIA) and Network Innovation Competition (NIC).

2.70. It is our proposal that the SO should also be able to access the TO innovation funding (as determined in the RIIO-T1 Final Proposals document). Further details concerning the innovation stimulus can be found on the innovation section of the Ofgem website (http://www.ofgem.gov.uk/networks/nic/pages/nic.aspx).

Appendix 3 – Electricity cost incentives

3.1. In this Appendix we provide more detail of the electricity cost incentives discussed in the Overview document.

3.2. NGET is currently incentivised to minimise the costs associated with energy balancing, constraints management and black start through:

- buying and selling electricity in the Balancing Mechanism.
- entering into balancing service contracts.
- entering into contracts for ancillary services.

3.3. As described further below, there is currently a single (bundled) cost incentive – the Balancing Services Incentive Scheme (BSIS). The current incentive began in April 2011 and covers transmission losses as well as balancing costs.

The current SO cost incentive

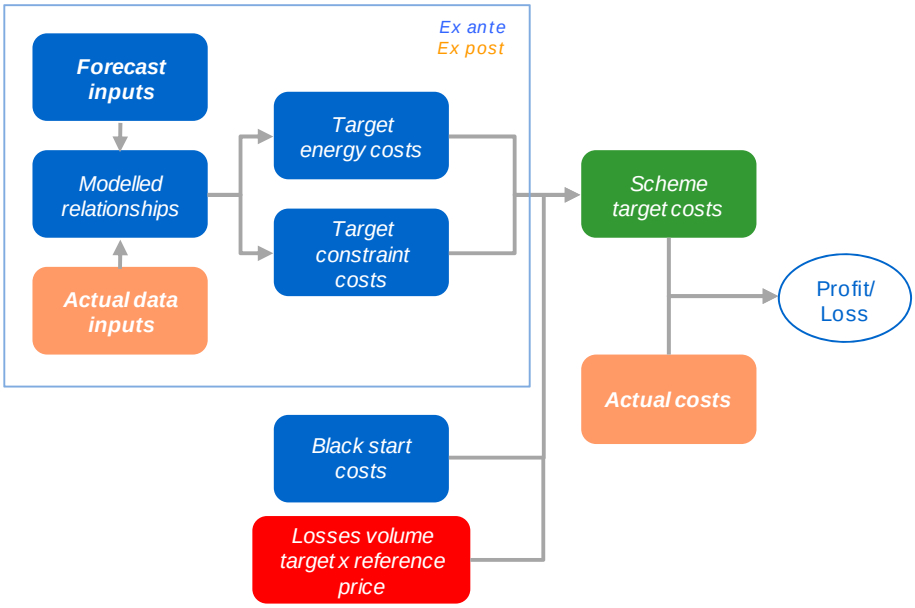
3.4. From 2008 to 2011, growing volatility in SO costs meant that it was increasingly difficult to set an appropriate target for SO costs on an ex ante basis. Recognising this fact, in April 2010, we put in place a licence obligation on NGET, as SO, to cooperate with a comprehensive review of its incentive methodology, including its models and modelling approach. As a consequence of the review substantial changes were made to the incentive methodology.

3.5. A key aspect of the current methodology is that it allows the target to flex to take into account the impact of unpredictable and uncontrollable external factors affecting the SO's cost base, thereby reducing the scope for windfall gains and losses. This is achieved by allowing the incentive target to be adjusted at the end of the scheme period for these factors. This means that NGET should be incentivised more actively to manage the costs within its control and that actions it undertakes to reduce its costs are not diluted by external factors.

3.6. The models that are used as part of the incentive scheme have been redeveloped in an attempt to capture more accurately the drivers of NGET's costs relative to previous schemes. Specifically, NGET has improved its modelling of energy costs and has replaced its suite of bespoke constraints models with a single model that considers the GB system as a whole. Another important change in methodology was that we accepted that ex post actuals should be use in the models for those costs over which NGET has little or no control. The structure of the current incentive scheme is shown in Figure 6 below. As the figure shows, the target is built

up from separate models for constraint costs and energy balancing costs plus an agreed allowance for black start costs[10].

Figure 6: Current balancing cost incentive scheme



3.7. The target for constraint costs is determined by comparing the generation costs estimated using a despatch model (Plexos) when constraints are ignored to the generation costs when the effects of constraints are included. At present the despatch model incorporates a highly simplified representation of the constraints on the GB network. Most of the inputs to the despatch model were set before the start of the incentive schemes but for those inputs over which NGET has little or no control e.g. generator fuel prices, the inputs are determined ex post.

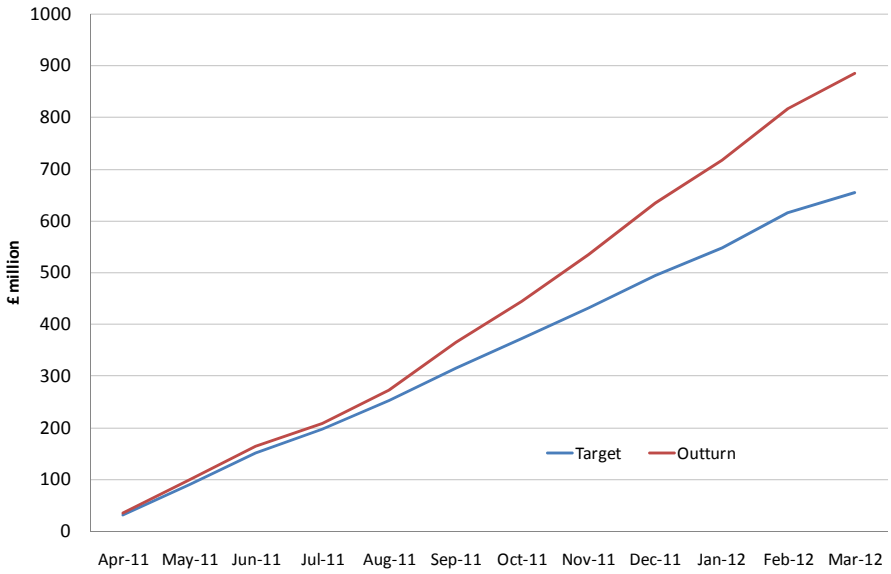
3.8. The target for energy balancing costs is determined from a suite of interlinked models. However, unlike the constraints model, which is based on modelling the entire GB energy system from the bottom up, the energy balancing models reflect modelled relationships of specific cost elements that are derived from a statistical analysis of historic data. In this sense, they are top-down models. As for the constraint models, there are both ex ante and ex post inputs to the energy models.

3.9. For 2011/12, the total target (energy balancing costs, constraint costs, black start and losses) was approximately £654 million, whilst actual costs were some £230 million higher, as can be seen from Figure 7. For the first few months of the scheme the target reasonably reflected actual costs, but since then it has struggled to reflect changes in the market. This is particularly the case with respect to

[10] Contracts to enable NGET to reenergise the network in the event of a major system outage.

constraint costs, which have increased significantly beyond what was predicted by the models used to forecast costs under the scheme.

Figure 7: Performance of the current incentive scheme



3.10. The performance of the schemes deteriorated substantially in April and May 2012 due to what appears to be an error in the constraint model. This has moved the target level of costs up to several billions of pounds. If this was to be applied, NGET would move from a predicted loss of £50 million over two years to a gain of £50 million. This is clearly not acceptable and, with our agreement, NGET is currently consulting on changes to the methodology for 2011-13 to correct this error as well as other adjustments it considers desirable. Under the licence requirements, such changes would apply retrospectively from April 2011.

Our consultation proposals and respondents views

Overall scheme

3.11. In our January consultation we proposed that the regulatory framework for the SO incentive scheme from April 2013 should be set for eight years but that specific schemes might be set for a shorter period and there might be mechanisms to allow changes to be made to individual schemes. We listed a series of factors that we would take into account when deciding on scheme length: alignment of SO-TO interactions, impact on risk and company financeability, incentive effect of uncertainty mechanisms, predictability of costs and outputs, confidence in data and modelling and consistency across incentive schemes.

3.12. The views of respondents were generally that an eight year scheme would be inappropriate and that the length of individual schemes should reflect the

predictability of costs and risks. Several respondents emphasised the uncertainty surrounding the development of the electricity market between 2013 and 2020 and the difficulties that this implied for setting meaningful financial incentives. Npower stated that long term incentives would only be appropriate for reputational incentives. E.ON and SSE suggested that longer term schemes should be postponed until the regulatory framework is stable and the new incentives have proven to be effective.

Cost incentive

3.13. In our January consultation we proposed that the cost incentive should consist of two four year phases, and that balancing costs should continue to be bundled into a single scheme. We further proposed that the target should be determined using the current methodology, albeit with refinements to the treatment of cost drivers and modelling, and that the sharing factors for the cost incentive should be 40-50%.

3.14. Respondents agreed that a bundled cost scheme continued to be appropriate. EDF indicated that the incentive needs to ensure that interactions with any capacity mechanisms and contracts for differences feed-in tariffs (CfD FIT) are limited and, in particular, that any incentive for short-term balancing should be kept separate from longer term capacity arrangements to ensure security of supply is maintained and there are no cross subsidies between the two mechanisms. ScottishPower suggested that the SO should not be exposed to costs for areas it cannot control such as short notice transmission or generation outages. SSE believed that we needed to provide more evidence in order to determine whether the proposed sharing factors are appropriate. The AEP accepted that as, revisions to the methodology are still being made, it may be appropriate to have a 4+4 incentive.

SO-TO interactions

3.15. In our January consultation we indicated that we expected SOs to take account of SO-TO interactions when making decisions about output delivery. We noted that in electricity, where the ownership of the SO is separate from that of the Scottish TOs, aligned output and cost incentives are necessary but not sufficient to encourage joined up consideration of long term consumer costs. Accordingly, we proposed that the SO should be able to pay the Scottish TOs compensation if the Scottish TOs change their behaviour to deliver overall cost savings to customers.

3.16. Respondents generally supported the idea of a payment mechanism to incentivise cost savings. However, RenewableUK suggested that a reputational incentive, in combination with more stringent measures in the event of underperformance might be sufficient. Whilst SSE agreed with the idea of a payment mechanism, it suggested that it would need to be reviewed every year for the first two years because there is little alignment between the SO and the Scottish TOs. Scottish Power also supported a payment mechanism plus a licence requirement on the TOs to have due regard to requests from the SO to change outage plans, but only if there is a mechanism for the TOs' outputs to be adjusted via a mid-term review. Npower and AEP had concerns regarding the complexity of such an arrangement and the need for transparency but broadly supported the proposals.

Uncertainty mechanisms

3.17. In our January consultation we discussed the fact that the treatment of uncertainty can influence the potential for windfall gains or losses or undermine incentives on the SO to reduce costs. We therefore proposed an approach to uncertainty that is consistent with the RIIO principles but recognised the difference between the SO and TO roles. To mitigate the impact of uncertainty, we proposed a combination of mid-term reviews and specific and general uncertainty mechanisms. The specific uncertainty mechanisms would relate to factors that could be identified in advance of the scheme starting whilst general uncertainty mechanisms would deal with unforeseen events.

3.18. In addition, we proposed to limit NGET's exposure to risk through the continued use of sharing factors and caps and floors. However, we considered that the caps and floor should be widened from the current scheme to ensure that they do not undermine the incentive properties of the overall scheme.

3.19. Most respondents considered that they needed additional information about how the mechanisms would work before they could understand what impact they might have. E.ON expressed a concern that previous reopeners had only worked to increase costs to customers. It was further of the view that the sharing factors should be reduced and that the caps and floors should not change significantly.

3.20. Npower argued that the need for uncertainty mechanisms under longer term schemes suggested that shorter term incentives might be more appropriate unless it could be demonstrated that longer term schemes would deliver stronger incentives to minimise SO costs. SSE accepted the need for uncertainty mechanisms but suggested that we should be strongly adverse to reopening the scheme. It argued that general uncertainty mechanisms should only cover low probability, significant impact events. EDF suggested argued that volume changes should not be a trigger for uncertainty mechanisms, since NG should be able to mitigate this risk (for example, with better forecasting).

NGET proposals

Overall scheme

3.21. NGET has proposed that the overall eight year SO balancing services incentive cost scheme should be broken into three phases: two years, two years and four years, with fundamental reviews to the models taking place between each phase.[11] Incentive payments would, however, be determined on an annual basis rather than at the end of the scheme, as is the case under the current two year scheme.

[11] The exception to this is the renewables forecasting incentive, for which NGET proposes a two phase scheme: four years plus four years.

3.22. NGET further proposes that its risk exposure should increase over the three phases with the sharing factors, caps and floors changing between phases as shown in Table 2 below.

Table 2: NGET's overall SO incentive scheme parameter proposals

Phase Period	Phase Length	Sharing Factors	Cap and floor (£m)
Apr 2013 to Mar 2015	2 years	30%	+/-£30
Apr 2015 to Mar 2017	2 years	40%	+/- 40
Apr 2017 to Mar 2021	4 years	50%	+/- 50

3.23. As part of NGET's proposals for specific incentive schemes, it included a number of mechanisms that allow for incentive longevity, including volatility adjusters, price adjustment mechanisms and volume adjusters. The risks have been further managed through the scheme parameters in terms of scheme length, sharing factors and caps/floors.

3.24. Notwithstanding the above, NGET considered that an element of residual risk remains. It therefore undertook an exercise to better understand the financial risks that it considers it will face from its SO external activities over the forthcoming RIIO price control period and how the risk that it faces from its SO role determines the return on equity it requires. As a result, it considers that an additional premium of approximately £8 million per annum is required to cover the residual risk. NGET did not specify a means by which this premium should be remunerated.

3.25. In addition, NGET proposed that the current income adjusting event mechanism should be retained to deal with unexpected events or circumstances outside its control for which funding is not included in the scheme. It furthermore proposed that there should be a general uncertainty mechanism that would allow the schemes to be revisited if major changes to the market occur. As examples of such market changes, NGET mentioned electricity market reform, Project TransmiT, the electricity cash-out review and European developments.

Energy modelling

3.26. For the first two year phase of the incentives, NGET has proposed building on its current methodology and models. NGET would then undertake a fundamental review of the energy models to determine whether they remained fit for purpose and, if not, come up with new proposals for the second two year phase. This process would be repeated before the start of the final four year phase of the incentive.

3.27. The energy models are based on an historic analysis of the drivers of the various cost elements that contribute to balancing costs (apart from constraints and black start). Consequently, NGET has proposed that the coefficients used in the models should be updated each year including the most recent data in the analysis and dropping the oldest data. NGET envisages that it would present its proposals for

coefficient adjustments, together with an estimate of their materiality, to Ofgem and the industry one month before the start of a new incentive year. Unless the Authority directed otherwise within 28 days, the revised coefficients would be adopted for the following year.

3.28. NGET has also proposed that if the updated model coefficients would have given a target for the previous year that is more than £2 million in either direction from the target actually used to determine incentive payments, then the updated model would be applied retrospectively to determine its incentive payments.

3.29. In terms of other amendments to the current models for the first two year phase, NGET has proposed that:

- ex post Balancing Mechanism bids and offers should be used (rather than the current ex ante estimates which it argues produce highly unreliable estimates of energy imbalance costs).
- a temporary variable should be included in the frequency response and operating reserve models for 2014 to take account of the increase in the largest infeed to 1800 MW that will occur in this year.
- half-hourly wind adjustment factors should be included in the operating reserve model (rather than the current monthly adjustments).

3.30. For the longer term, NGET has identified a number of market developments that may necessitate changes to the models for the second and third phases of the incentive scheme, including: a possible need for locational reserve holdings in areas of high wind, the modelling of start-up contracts for gas-fired power stations, changes in the short term operating reserve (STOR) market, interactions between constrained margin management and wind output levels, changes in the types of frequency response providers, reactive power volume reductions as DNOs take more control of local issues and increasing interactions between margins and footroom[12].

Constraint modelling

3.31. NGET is proposing to move to a much more detailed representation of the GB network including 621 nodes (rather than the current 33) and 130 boundaries (rather than the current 13). It considers that this is necessary because the current model configuration is too coarse to capture many of the localised constraints that actually occur.

3.32. In addition, NGET is proposing changes to a number of the key inputs to the model, including using:

[12] Footroom refers to the output reduction capability that NGET needs to have available in order to unexpected increases in system frequency.

- ex post generator availability data (rather than year-ahead assumptions based on OC2 outage data which it argues are highly inaccurate).
- a regional, instead of national, representation of wind output to reflect the increasing role that wind plants will play in meeting demand.
- demand forecasts that are produced shortly before the start of each incentive year (for the current two year scheme, the demand forecast for both years was produced before the start of the scheme).
- ex post data on the output of commissioning plants (since their output is driven by testing needs rather than market fundamentals).
- ex post data on interconnector flows, instead of relying on highly simplified merit order stacks to model external systems.
- boundary capacity limits that are updated every six weeks to take account of improved information on network availability.

3.33. NGET is also proposing a change to the discount factor (41%) that is currently applied to the constraint costs produced from the modelling, which is designed to reflect the savings that can be achieved from using constraint contracts as well as Balancing Mechanism actions to resolve constraint. NGET argues that the current model very significantly (by around 60%) under-estimates the level of constraint costs and that at best (taking into the proposed changes to the model listed above) the model is likely to under-estimate constraint costs by around 25%. On this basis, NGET proposes that the discount factor should be changed to an uplift factor of 33% i.e. to set the target level of constraint costs the model's estimate of constraint costs would be multiplied by a factor of 1.33 and that this factor should be fixed for two years.

3.34. As for energy modelling, NGET is proposing that the ex ante model assumptions should be reviewed and updated each year with NGET bringing forward proposals in the last month of an incentive year and the Authority having the power to reject the proposed changes. The most important changes that NGET has identified might need to be made are to the boundaries included in the model (to reflect changes in generating capacity and network upgrades). Similarly, NGET proposes retrospective changes to the assumptions should be used to determine its incentive payments where the materiality of the changes is more than £2 million in either direction, just as it has proposed for energy modelling.

SO-TO interactions

3.35. NGET is proposing an adjustment to the way in which its incentivised balancing costs are currently calculated to reduce its exposure to changes in constraint costs that are caused by alterations in network outages on grids that are not owned by National Grid. It argues that it has little control over the volume of constraints caused by such changes, since maintenance decisions are primarily the responsibility of the relevant TO. Accordingly, therefore, NGET's proposal is to model the impact that outage changes have on constraint costs by comparing the estimated costs based on expected network availabilities with estimated constraint costs when the actual network availabilities are included in the model.

3.36. In the first instance, this adjustment would apply to changes in the outage plans of the Scottish TOs but NGET's proposal is that the same adjustments should be applied to, for example, offshore TOs and any other new, independent TOs. Under its proposal, NGET would be protected from 95% of the impact on constraint costs of outage changes on its incentive payments.

3.37. A further element of NGET's proposal, is that it would enter into commercial arrangements with non-NGET TOs that would result in payments being made to the TO where it adjusted its network outages in a way that reduced the constraint costs. Conversely, where changes in network outages lead to increase constraint costs, the TO would make payments to the SO. NGET proposes that the magnitude of these payments would be equal to the reduction in its exposure to these costs.

Black start

3.38. NGET is proposing that its black start allowance should no longer be calculated on a contract-by-contract basis but instead should be market based. By this NGET means that the required number of black start contracts should be fixed in advance, based on the methodology statement for determining black start volumes that NGET produced under Special Condition AA5J of its licence. NGET is proposing this change in approach because it anticipates that over the course of the eight year incentive period, it will need to sign a number of black start contracts with new stations since some of the plants that are currently providing black start are likely to close.

3.39. NGET also proposes that a generic cost per contract would be set based on an ex ante estimate of the annualised costs of a new black start plant, which would be indexed to inflation. To the extent that a black start service continues to be provided by existing plants, the target would be adjusted to reflect both the lower direct contract costs associated with such plants and any additional costs associated with ensuring that the service can be provided at all times (warming contract costs).

Our proposals

Energy balancing and constraint costs

3.40. We have been concerned for some time about the likelihood of SO costs increasing and becoming more volatile (for example, constraint costs following "connect and manage"). The revised approach to setting a target for SO incentivised balancing costs, based partly on ex post inputs, was an attempt to address this problem. However, whilst the various models used to set electricity SO targets appear to have performed reasonably well over the period April to August 2011, their performance since then has been relatively poor.

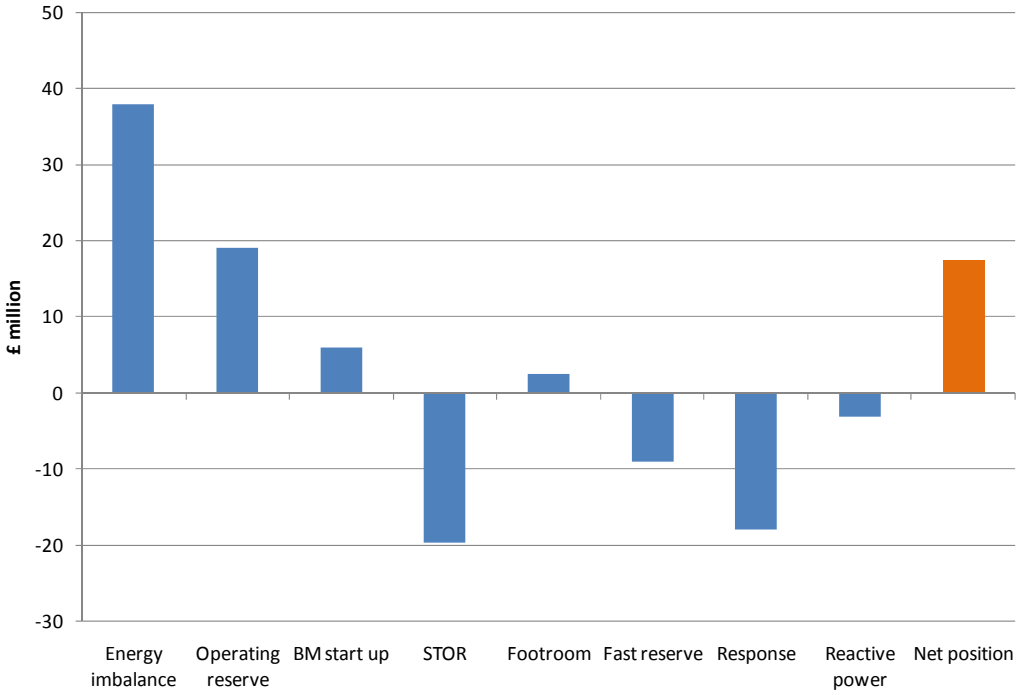
3.41. We have been working with National Grid to see whether the energy balancing and constraint models could be made more robust and fit for purpose, particularly in the context of a longer term incentive. We are not convinced that this has been achieved. NGET appears to share at least some of these concerns as can be seen

from its proposals for a three phase scheme, with fundamental reviews between phases in addition to annual updates.

3.42. As an example of the problems with the models, NGET has proposed that, even taking into account the model enhancements discussed above, a 33% uplift adjustment should be applied to the constraint cost target produced by its constraint model for 2013/14 and that this adjustment factor should be revised each year based on the performance of the model. This represents a stark contrast to the basis on which the current constraints target was based, where analysis carried out by NGET prior to the start of the scheme suggested that its costs were lower than those predicted by the model, due to the fact that it could contract ahead of time to resolve constraints at a lower cost than it would incur via the Balancing Mechanism. We do not consider that it would be appropriate to incentivise NGET on the basis of model results that underestimate constraint costs by approximately one third and where the adjustment factor appears so uncertain from year to year.

3.43. Moreover, whilst the combined suite of energy balancing models has performed relatively well in the sense that NGET's costs remain within the incentivised range, we do not have confidence that the models are robust. As Figure 8 below demonstrates, the individual models have not performed particularly well but some models have over-estimated costs whilst others have under-estimated costs and hence the net costs have been relatively close to actual costs. Nonetheless, for the 2011/12 scheme year the two main constituent models (energy imbalance and operating reserve) have under-performed by 60% and 40% respectively. Over an eight year time frame, such discrepancies could lead to significant windfall gains and losses.

Figure 8: Differences between actual and target costs for the energy balancing models (April 2011 to March 2012)



3.44. We have a further concern regarding the energy models, which relates to the fact that they are not based on market fundamentals but on a statistical analysis of past events. Even in a static market, modelling the energy market in this way would be challenging; but the GB market will not be static over the next eight years. In a market that is changing as the generation mix changes and as market arrangements change, it is a task that we believe is near impossible using an historic statistical approach. For this reason, even if NGET made significant improvements to these models now, they are unlikely to be robust enough for an eight year scheme and would require a fundamental review at least every two years to ensure they keep up with changes in the market.

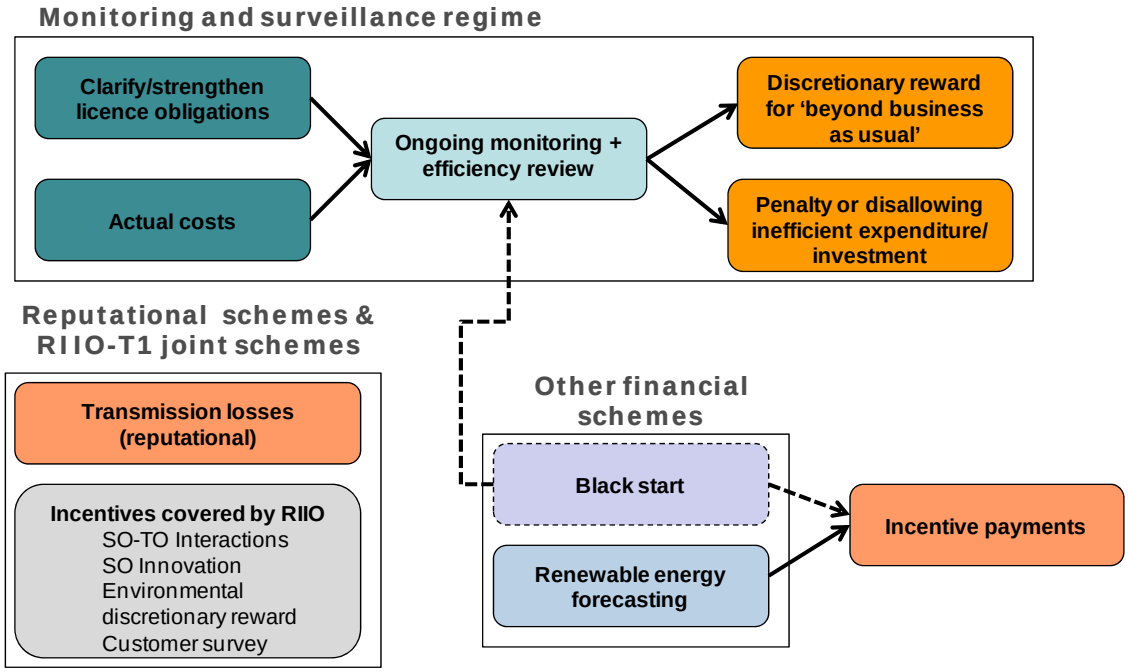
3.45. We have also taken into account stakeholders' arguments that the models used by NGET to forecast its energy and constraint target costs are too complex and opaque and that this makes it difficult for them to comment meaningfully not only on proposed schemes but also on NGET's performance against the schemes.

3.46. For example, several attendees at the March 2012 workshop on Electricity Market Reform (EMR) synergies and conflicts of interest said that the current SO incentives regime was complex and opaque. Four respondents to the consultation on the same issue also commented on the current SO incentives regime. All four commented on the complexity of the schemes, and concerns were raised about the possibility that there may be (unspecified) perverse outcomes. One respondent speculated as to whether the complexity of the current schemes meant that only NGET fully understood them.

3.47. We note that NGET's attempts to improve the robustness of its models for the 2013 incentive scheme increase their complexity and opacity. In this context, NGET's proposal to amend parameters with only one month's notice to the Authority would further increase the information asymmetry between Ofgem and NGET. It would require a substantial resource increase in monitoring and modelling expertise for the Authority to be in a position to respond, and there would be no opportunity to take into account the views of stakeholders. Generally, NGET's proposals appear to reduce transparency and its engagement with stakeholders from an already low level. The potential retrospective application of changes would further weaken the predictability of scheme costs for market participants.

3.48. For all these reasons, **our proposal is to remove the current cost incentive on energy balancing and constraint costs**. On this basis, Figure 9 provides an overview of our proposals for the entire electricity SO incentive regime from 2013/14.

Figure 9: Overview of proposed electricity SO regime from 2013/14



3.49. We propose to rely on monitoring NGET's SO costs and taking enforcement action if we believe that there is material evidence that the costs are not economic or efficient. To that end, we propose to develop further our approach to monitoring SO costs.

3.50. When monitoring the SO's balancing costs, our emphasis will be on ensuring that NGET meets its obligations under Standard Licence Condition C16 to "co-ordinate and direct the flow of electricity onto and over the national electricity transmission system in an efficient, economic and co-ordinated manner". We already

receive detailed and regular data from NGET on its balancing costs and can formally request additional information under Standard Licence Condition B4.[13]

3.51. Consequently, if we identify that balancing costs are developing in a way that does not seem justified by market fundamentals, we could launch an investigation into these costs and request further information, including explanations for the costs, that we deem necessary from NGET. We are considering whether there might be merit in convening an industry standing group that would be called upon to review the data and make recommendations to the Authority regarding the balancing costs that we had identified as anomalous.

3.52. Whilst we could taken enforcement action if the Authority was satisfied that NGET had contravened the requirements of Standard Licence Condition C16, such a finding would enable us to fine NGET, but it would not enable us to disallow the pass-through of the inefficient costs. The result being that consumers would still face inefficiently high costs. For this reason, and because we consider that it would be appropriate for us to be able to intervene before costs had reached a level sufficient to warrant a breach of licence investigation, we are also considering whether we should introduce a new licence condition, equivalent to Special Licence Condition D9[14], which would enable us to disallow balancing costs that the Authority deems to be inefficient.

3.53. As well as ensuring that the level of balancing costs remains efficient and economic, we are keen to encourage the SO to play a full role in delivering and operating a sustainable energy system. As more wind capacity is connected to the system, it is likely that the SO's role will become more complex and that a "business as usual" approach will lead to steadily increasing SO costs. Consequently, we also wish to ensure that NGET is encouraged to be more innovative in its approach to controlling SO costs. To that end, **we also propose to introduce a discretionary reward scheme** under which NGET will be able to earn significant rewards (potentially millions of pounds) if it takes actions well beyond business as usual which lead to a clear and quantifiable benefit to customers. The aim of the scheme is to shift the SO's focus from the details of the modelling and the scheme to actually "making a difference" in the way in which it operates the system.

3.54. Each year the SO would be able to provide evidence to us of its performance against the reward scheme's requirements. We would complete an assessment of performance which would be considered by a panel, who would have discretion to determine the level of any reward made up to a cap. For any individual submission, we are proposing to set a cap at, say, 25% of the net benefit of the actions undertaken. In other words, if the SO manages to reduce the costs of balancing the

[13] This condition requires NGET to furnish to the Authority, in such manner and at such times as the Authority may reasonably require such information as the Authority may reasonably require or necessary for the purpose of performing its functions conferred on it.

[14] **Special Licence Condition D9**: The Authority may issue direction that certain capital expenditure is deemed inefficient. Prior to that the Authority shall issue a notice to the licensee specifying: (a) the capital expenditure that the Authority proposes to deem inefficient; (b) the reasons why the Authority considers that the capital expenditure is inefficient; and (c) the date, being no less than 28 days from the date of the notice, by which the licensee may make representations to the Authority in respect of the notice.

system by £10 million, the SO would keep £2.5 million. Over the course of the eight year incentive scheme period, we are proposing that there would be a cap of £25 million per year.

3.55. The reward would be paid on an ex post basis – the SO would have to demonstrate both that it has implemented actions that meet the reward scheme criteria and that the actions have delivered measurable net benefits for consumers. In order to qualify for a reward, the SO would need to prove that its actions meet three criteria: (i) there is no overlap with other incentives, including those provided under RIIO-T1[15]; (ii) the actions represent a material departure from "business as usual" actions and (iii) the actions will provide enduring benefits to consumers. The background against which this assessment would be made would include a balanced portfolio of cost mitigation measures by the SO, not solely reliance on short-term markets.

3.56. We consider that the scheme should cover a number of areas, all related to reducing the costs of balancing the system on a sustainable basis, which might include:

- Innovation in contracting approaches or market arrangements including, for example, new types of contracts or widening the types of market participants who can provide a service e.g. enabling new forms of demand side participation;

- Entering into arrangements with distribution network companies that enable the SO to access lower cost balancing options (for example by using distribution assets to provide balancing services);

- Reforming the regulatory and/or market arrangements and business practices so that the same level of security can be achieved at lower cost, for example building on the targeted N-1 approach to security on some infrastructure; and

- Developing innovative approaches to balancing the system in the presence of increased levels of intermittent generation.

3.57. As part of NGET's proposals for specific incentive schemes, it included a number of mechanisms that allow for incentive longevity (e.g. volatility, price and volume adjusters). The risks have been further managed through the scheme parameters in terms of scheme length, sharing factors and caps/floors. In its Business Plan, NGET set out its view that it considers that an ex ante risk premium is required to recover the residual risk within its proposals. We do not consider that such a premium is justified for the reasons set out in the Overview document. Nonetheless, we recognise that the gas and electricity systems will go through significant change over the coming years. Therefore, we are proposing a new

[15] Such as the Environmental Discretionary Fund or the Innovation Fund.

uncertainty mechanism to deal with such changes, which will replace the current income adjusting event mechanism. Our proposed uncertainty mechanism is explained in the Overview document.

Black start

3.58. The costs associated with black start are broadly self-contained and largely independent of those associated with energy balancing and constraints. In the past they have constituted a relatively small proportion of NGET's incentivised balancing costs but NGET is forecasting that they will increase by approximately a factor of four due to the need to contract with new service providers. We accept that at least some of the current service providers will close their plants over the course of the incentive scheme and that the costs of black start provided by a new plant, which will need to recover its capital costs as well as its operating costs, are likely to be higher than those of an existing plant, whose capital costs are fully-written down.

3.59. NGET's estimate of the number of black start contracts it will require going forward is based on the black start methodology statement that we have approved. We therefore accept its proposals regarding the volume of black start contracts.

3.60. **In view of the likely increase in black start costs, we are considering continuing with a financial incentive on black start costs**, broadly along the lines proposed by NGET. In other words, the target would be set by reference to the annuitized costs of a new peaking plant, with adjustments to take account of the different costs associated with existing contracts, and an allowance for testing costs. This scheme would remain in place throughout the eight year incentive scheme with the target costs being adjusted each year to take account of changes in the underlying cost drivers. To derive the initial target, we would estimate the likely costs of a range of different options for providing black start capability, based on the best available technologies and taking into account the reduction in risks that a black start contract provides.

3.61. However, the scheme would differ from that proposed by NGET in four respects. First, we think it would be appropriate to take into account any other ancillary service revenues that the plant might be receiving. For example, if a contracted plant were also providing operating reserve, then the availability payments that it received for this service should be deducted from the black start cost target. Second, we consider that it would be more appropriate to link the annuitized cost allowance for new peaking plants to a power station cost index rather than to general inflation. Third, rather than adjusting the number of stations per zone to reflect the fact that contracts need to be put in place on average 18 months prior to the expiry of any existing contract, irrespective of when new contracts are actually signed, we consider that new contract costs should only be included within the target from a date eighteen months before they start providing the service. Fourth, rather than incentive payments being made annually, we propose they should be accrued over a four year period. We consider that this approach will encourage NGET to be more innovative in the way that it contracts for black start by allowing it to trade off potential losses from one year with gains in subsequent years.

3.62. Since we are proposing to remove the over-arching balancing costs incentive, it would be necessary to set sharing factors, caps and floors for this scheme. In view of the fact that our proposal would be to index the target to the development of its underlying cost drivers, we would set the cap and floor as a fixed percentage of each year's target. This would ensure that NGET continues to face symmetrical incentives throughout the incentive scheme period. On the basis of NGET's historic black start performance, we would propose that the cap and floor should be +/- 10% of each year's target and that the sharing factors should be 25%. So, for example, if the target was £40 million, NGET could earn a maximum of £4 million if its actual black start costs were £24 million or less and would face a penalty of £4 million if its actual black start costs were £56 million or above.

3.63. However, we are also mindful of the importance for system security of black start provisions and the fact that the locational requirements associated with black start may limit the extent to which competitive tendering is effective. In addition, given the difficulty in setting an ex ante target due to a lack of evidence from NGET that its actions to date have mitigated the risk of future cost increases, there appears to be a significant risk that such a scheme would lead to windfall (or even perverse) profits for NGET. For these reasons, **we are also considering whether it would be more appropriate to remove the cost incentive and rely instead on monitoring NGET's procurement process** as part of the broader monitoring approach outlined above. We would welcome views on which approach is more appropriate.

SO-TO interactions

3.64. We are aware that NGET's ability to control constraints that arise in non-NGET networks is limited and that non-NGET TOs can play an important role in determining the overall level of constraint costs. We therefore see considerable merit in (and need for, to enable the SO and TOs to meet their licence obligations to develop "efficient, economic and coordinated" networks) arrangements to ensure that the actions of one TO (or the SO) are coordinated with those of the others to ensure the overall outcome is economic and protects the interests of consumers (who bear the costs). However, the proposals that NGET has made are under-developed and involve significant overlap with broader work that is being undertaken in relation to network access (the NAP) under the RIIO-T1 price control. For these reasons, **we have decided to progress the SO-TO interaction proposals as part of the NAP work being undertaken under RIIO-T1** rather than as part of the SO incentives. As such, we will consider how effectively the constraint cost issues identified here are addressed by those NAPs. The TOs and SO are working on the NAP and will be meeting in August to continue development.

Appendix 4 – Gas outputs and output incentives

4.1. In this Appendix we provide more detail of the gas output schemes discussed in Section 5 of the Overview Document.

Overall structure of schemes

4.2. As set out in our January consultation, the objectives, principles and policies of the gas SO regulatory framework are to be set for eight years (from April 2013 to March 2021) in line with the RIIO-T1 timeframe.

4.3. Our initial proposals are for the structure and parameters of the majority of the gas SO incentive schemes to be in place for eight years. Some of these schemes will have specific mechanisms in place to allow for changes to be made within the incentive period. These are explained in more detail as part of our proposals for the specific incentive schemes.

4.4. As part of NGG's proposals for specific incentive schemes, it included a number of mechanisms that allow for incentive longevity (e.g. volatility, price and volume adjusters). The risks have been further managed through the scheme parameters in terms of scheme length, sharing factors and caps/floors. In its Business Plan, NGG set out its view that it considers that an ex ante risk premium is required to recover the residual risk within its proposals. We do not consider that such a premium is justified for the reasons set out in Section 6. Nonetheless, we recognise that the gas and electricity systems will go through significant change over the coming years. Therefore, we are proposing a new uncertainty mechanism to deal with such changes, which will replace the current income adjusting event mechanism. Our proposed uncertainty mechanism is explained in more detail in Section 6.

Safety

Workplace safety – background and our proposal

4.5. NGG as owner and operator of the National Transmission System (NTS) is required by legislation to design and operate its network to ensure the safety of the public and its employees. The HSE monitors and enforces performance in this area. The output for NGG in relation to safe gas transmission, including in its role as SO, is for it to comply with its safety requirements. This mirrors its obligations with the HSE and therefore reflects the existing safety regime. In our January consultation we said we did not intend to attach an incentive to this SO output, as compliance with these requirements is the minimum level of delivery that we would expect. As such, NGG's performance in this area will still remain subject to ex post scrutiny in case of any potential breaches.

4.6. Our proposals in this area were not commented on explicitly by respondents to our January consultation. **We propose not to implement an output incentive on workplace safety for the gas SO from April 2013.**

Operational safety – background and our proposals

4.7. Under its Safety Case, NGG in its role as SO is required to procure Operating Margins (OM) gas. Requirements for OM gas are determined through network simulation analysis. The requirement is for the physical delivery of additional gas to maintain safe pressures within the NTS during a System Event, until other measures take effect. The proposal in our January consultation was not to introduce a specific output incentive to cover the volumes of OM required by NGG as this is covered by NGG obligations under its Safety Case. NGG agreed with this view. **We propose not to implement an incentive on operational safety in respect of the volumes of OM for the gas SO from April 2013**.

4.8. NGG also had a licence requirement (Special Condition C25 (C25)) to promote competition in the provision of OM gas, but the obligations under this condition have now lapsed. In our January consultation we indicated that NGG should be looking to facilitate the provision of OM gas from new providers and that it was appropriate that it has in place a reputational incentive to encourage it to do so.

4.9. In its Business Plan, NGG has proposed that OM costs be subject to a pass through arrangement and that a reputational incentive is put in place to ensure transparent reporting on how it continues to facilitate development of a competitive market for OM services.

4.10. **We propose to update C25 so that NGG has an appropriate and up to date reputational incentive in place to promote competition in the procurement of OM services.** We will work with NGG to ensure that there is a licence condition in place from April 2013 that achieves this, and ensures that an appropriate reporting regime is introduced that ensures transparency in this area. This reporting regime will need to include details of the types of providers, the volume of OM procured from each provider, and the average availability and utilisation costs by type of service provider.

4.11. NGG is also currently incentivised to minimise the cost of the provision of OM gas, the future of this incentive is discussed in Appendix 5.

Environmental impact

4.12. In our January consultation we set out our views on how the SO might be encouraged to play a full role in meeting the environmental challenges faced by the energy sector.

Broad environmental output incentive – background and our proposal

4.13. In our January consultation we stated that we would consider if there are opportunities to align with the RIIO-T1 proposals on a broad environmental measure for the gas SO. A broad environmental measure would be aimed at aligning the SO's incentives with the achievement of the UK renewable and carbon reduction objectives.

4.14. Respondents to our consultation suggested that it was unclear what a broad environmental measure would entail. The responses were mainly focussed on the role that the electricity SO could play in the decarbonisation of the electricity sector. NG suggested that a reputational incentive that covered both the gas and electricity be introduced.

4.15. The RIIO-T1 broad environmental measure, the Environmental Discretionary Reward, will focus mainly on the electricity sector because there are more clearly identifiable opportunities for the electricity TOs to contribute to wider environmental objectives than there are for the gas TO. These opportunities are mainly related to the role the TOs play in the need to connect large quantities of new generation, much of which is from renewable sources.

4.16. Considering the responses to the consultation and the RIIO-T1 position we do not consider there is a strong case to place an output incentive on NGG based on its contribution to the wider environmental objective. We feel that in order to introduce such an output incentive there would have to be some clearly identified aspects of its operations where the gas SO could be expected to make a contribution. We do not feel that this is the case at this time. **We therefore do not propose to implement an incentive on broad environmental impact for the gas SO from April 2013**.

Direct emissions (natural gas venting) – background and context

4.17. As SO, NGG vents gas as part of its operation of the system, which results in leakage of methane (a potent greenhouse gas emission). Currently, NGG is only incentivised to reduce the emissions resulting from compressor venting, as it has previously been considered that this covers a significant proportion of its emissions. Under Special Condition C28 of its transporter licence, NGG is currently investigating in more detail the sources and scale of the emissions caused by its operation of the NTS more broadly, including venting activities from assets other than compressors.

4.18. Decisions about how best to manage operational emissions, including venting, involve a significant degree of interaction between NGG's SO and TO roles. Broadly, emissions can be reduced either through changes in operational procedures or capital investment in operational equipment. The former is generally considered an SO matter, whilst the undertaking and maintaining of capital investments is largely a TO role.

Direct emissions (natural gas venting) – our consultation proposals and responses

4.19. In our January consultation we outlined our intention that the incentives on NGG (across SO and TO functions) will ensure it considers both operational and investment solutions to provide the most effective and long term value for money solution for consumers. Our view was that to achieve this NGG should continue to be financially incentivised to reduce its venting emissions through the SO regulatory framework. We set out that the SO incentive could relate to compressor venting only or to a wider category of venting activities. Under its RIIO-T1 price control framework Ofgem is also allowing funding for the TO to implement a programme of capital investment that may help to reduce emissions.

4.20. We set out that we expect the SO financial incentive scheme to be set for eight years. This scheme length will encourage the SO to focus on the long term and will allow for interactions with the TO, and its eight year price control, to be effectively managed.

4.21. Two respondents commented on our proposals for a financial incentive on natural gas venting. The AEP suggested that a specific financial incentive for venting may not be appropriate because NGG is committed to reducing its emissions as part of its corporate responsibility framework. SSE suggested that an incentive on venting is unnecessary because NGG is already incentivised to reduce leakage through the shrinkage incentive.

Direct emissions (natural gas venting) – summary of NGG's proposals

4.22. Under its Scheme of Work[16] NGG is currently undertaking projects that will improve the accuracy of venting measurement from sources other than compressors. NGG does not expect to complete these projects in time to incorporate its findings into the venting incentive scheme from 2013. NGG's proposal is to initially retain the incentive structure in its current form, and develop a more robust methodology incorporating the results from the Scheme of Work once the projects are completed.

4.23. NGG's proposed interim incentive structure is similar to the structure of the current scheme. The target would be based on historical volumes, calculated as the average venting volumes of the last two years minus an efficiency factor of 1.74%[17]. The incentive would include a 10% deadband around the target, no caps or floors, and the emissions above or below the deadband would be valued at DECC's non-traded price of carbon (as with the current scheme). In addition, NGG is proposing a 50% sharing factor to align the venting incentive with the Shrinkage incentive.

[16]Special Condition C28 "Requirement to develop and undertake a Scheme of Work to facilitate the establishment of a long term external gas system operator incentive to reduce targeted greenhouse gases".
[17]The 1.74% efficiency factor is based on emission reduction targets for the EU ETS sectors.

4.24. Once the Scheme of Work is finalised, NGG is proposing to develop an enduring incentive scheme that incorporates the findings from these projects. The annual baseline target would be set according to a methodology defined ahead of each incentive year. The enduring incentive would also include a 10% deadband around the baseline volumes and emissions above or below the deadband would be valued according to the prevailing price of carbon (non-traded sector).

Direct emissions (natural gas venting) – our proposal

4.25. As set out in our January document, we consider it appropriate for the gas SO to take full responsibility for the environmental costs of natural gas venting in the long term and therefore, we consider that NGG should continue to be financially incentivised to reduce its venting emissions through the SO regulatory framework. The shrinkage incentive does not aim at reducing venting emissions, since it targets the cost of gas and electricity used to run compressors, CV shrinkage and unaccounted for gas.

4.26. **Our proposal is to have a financial incentive on natural gas emissions.** We set out in our January consultation our intention to develop incentive schemes that encourage the SO to focus on the long term. We have therefore developed proposals that we consider achieve this aim. Our current view is that at a minimum this incentive will cover venting from compressors and we will expand the scope of the coverage of the incentive according to the conclusions from the Scheme of Work that NGG is currently undertaking. A key component of this is to ensure that the Scheme of Work is completed in sufficient time so that the results can be incorporated into a revised scheme by April 2015, at the latest.

4.27. The threshold will be based upon venting from compressors and potentially expanded to include other assets, as identified following the results from the Scheme of Work, and it will consider the effects of investment to replace compressors that is driven by environmental legislation, as well as venting driven by obligations to ensure the safe and compliant operation of the NTS.

4.28. We agree with NGG that a steadily declining threshold is appropriate. The efficiency factor of 1.74% proposed by NGG is based on the annual factor used in the EU Emissions Trading System. We do not consider this to be an appropriate basis upon which to set the reduction rate/efficiency factor. The EU ETS covers carbon dioxide (CO_2) whereas the GHG emissions incentive target covers methane – two different greenhouse gases. One tonne of methane is far more damaging to the environment than one tonne of carbon dioxide[18], making it more effective to reduce methane levels over a more rapid timescale. Furthermore, projected reductions in methane emissions in the energy sector are far greater than the CO_2 emission reduction target in the traded sector[19]. Evidence also seems to suggest that reducing

[18] The global warming potential of methane is about 21 times greater than carbon dioxide over a 100 year period, and even greater over a shorter timescale.
[19] DECC's projection of methane emission reductions is about 80% by 2020 from 1990 levels. The target within the EU Emissions Trading System is a 21% reduction of CO_2 emissions compared to 2005 levels.

methane is more cost-effective than reducing CO_2[20]. Finally, as part of RIIO-T1, we expect (and have allowed funding for) the Transmission Operators to invest in equipment that could potentially contribute towards methane emission reductions.

4.29. We propose that the scheme does not contain a deadband around the target, reflecting our view that improved measurement and better understanding of the sources of venting as a result of the Scheme of Work shall reduce the uncertainties associated with venting volumes.

4.30. Our latest information suggests that the Scheme of Work will not be completed until December 2012. Due to the points raised in the previous paragraphs, and given the objective of moving to a venting threshold based on critical use only (e.g. venting associated purely with safety requirements), we propose a reduction rate substantially greater than the one proposed by NGG. Until the Scheme of Work is completed, we therefore propose to set a short term threshold based on the current threshold (3007 tonnes) minus 5% per year.

4.31. We disagree with NGG's proposal to set a short term target based on the average volume of the last two years. NGG has improved its performance against the venting incentive over the last two years, achieving venting levels within the deadband in 2011/12. We believe that the incentive should encourage continuous improvement and NGG should not be rewarded for emissions being still above the existing threshold. Therefore, the current target minus a reduction rate of 5% per year provides a better baseline in the short term. Once we receive information from the Scheme of Work, we may consider revising the reduction rate to apply over the incentive period.

4.32. In terms of the structure of the scheme, we have considered two options. The first option is an asymmetric structure, NGG would be penalised for emissions above the threshold according to DECC's non-traded price of carbon, but it would not be rewarded for volumes of gas vented below the threshold[21]. This approach reflects our intention that NGG starts working towards the full internalisation of its environmental costs from venting and is not rewarded for venting.

4.33. The second option is an incentive that would retain the same structure as the current scheme, with no caps and floors, emissions above or below the threshold being valued at DECC's non-traded price of carbon and no sharing factors, but without a deadband around the threshold. Figure 10 sets out both options.

[20] http://www.diw.de/documents/publikationen/73/diw_01.c.343362.de/diw_wr_2009-32.pdf

[21] The valuation of these emissions takes into account that one tonne of methane has a global warming potential equivalent to 21 tonnes of carbon dioxide when evaluated over 100 years. Since methane is a much shorter-lived gas, its relative impact over shorter periods is proportionately higher.

Figure 10: Options for a Greenhouse Gas Emissions Incentive*

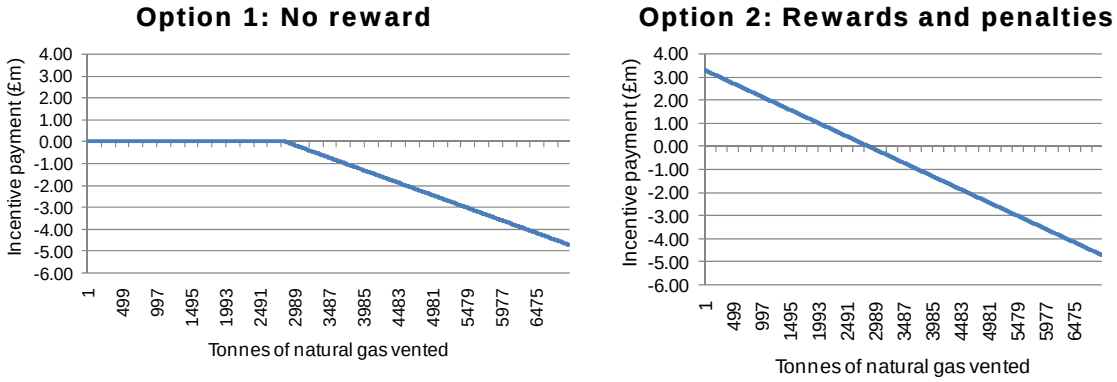


*Figure 10 shows the target for 2013/14 calculated as the 2012/13 target (3007 tonnes) minus a 5% efficiency factor.

4.34. Table 3 provides a summary of our proposals:

Table 3: Summary of proposals for the greenhouse gas emissions incentive

Target:

- Short term threshold (until March 2015, at the latest):
  - Threshold for 2013/14: current target (3007 tonnes) minus 5% efficiency factor.
  - Threshold for 2014/15 (if adequate results of Scheme of Work are not available): Threshold for 2013/14 minus 5% efficiency factor.
- Forward-looking efficiency factor potentially recalculated if we receive adequate data from the Scheme of Work.

Structure:

- No sharing factors
- Emissions valued at DECC's non-traded price of carbon
- Two options:
  - Option 1: Downside only scheme.
  - Option 2: Reward for venting below the target, penalty for venting above the target. No deadband around the target.

4.35. Of the two options outlined above, **we are minded to implement option 1.** Our long-term aim is for NGG to fully internalise the environmental costs associated

with venting[22], consistent with the polluter-pays principle, and option 1 goes some way in moving towards this ambition. Before we fully transition to such a scheme, we need a better understanding of, and better data on, NGG's venting activities and volumes.

4.36. The data currently collected and reported by NGG does not form a sufficient basis upon which to set a symmetrical incentive, where NGG has the potential to receive a reward. We are mindful that in the EU ETS most companies have profited from allocations that turned out to be excess to needs, and in Phase 1 in particular this was largely attributed to inadequate data, a situation we still face with respect to methane venting. Furthermore, funding available to the TO and potentially to the SO through the TO innovation funding mechanisms, may contribute to reducing methane levels for the SO. We do not want to reward NGG for methane reductions due to investment undertaken by the TO and already funded under RIIO.

4.37. We are however open to consider arguments in favour of option 2, but only if and when adequate data on both emissions and technology performance options are presented that enable a fully informed evaluation. We welcome Stakeholders' views on our proposed options.

Connections

Background and context

4.38. Efficient and timely connections to the transmission system are important since they ensure that new sources of gas supply are able to enter the transmission system and new customers are able to have their demands for gas met. A number of market participants that are looking to connect to the NTS have raised concerns with Ofgem regarding the lack of a clear process regarding connections to the NTS. Whilst NGG as TO is responsible for building any assets that are required for a new connection, or modify an existing connection, it is important that NGG as a whole works to ensure efficient and timely connections to the system.

4.39. There a number of stages involved in getting a connection to the gas NTS. NGG through its role as SO can play a key role in the process for providing prospective new connectees with an offer setting out the terms and condition for connection to the NTS. A modification to the UNC (UNC 373) that puts in place a process for connection applications has recently been approved by the Authority and will be implemented from 01 August 2012.

[22]See page 25: http://www.ofgem.gov.uk/Markets/WhlMkts/EffSystemOps/SystOpIncent/Documents1/NGG%20SO%20Incentives%20-%20April%202011%20-%20Final%20Proposals%20Consultation.pdf

Our consultation proposals and responses

4.40. As part of the RIIO-T1 process an NGG output measure was proposed relating to its process for providing connection offers. The output measure associated with this was that NGG meets its obligation regarding the connection process set out in legislation and licences. No financial incentive was attached to this output.

4.41. Under RIIO-T1 NGG's performance in all aspects of connections, including providing connection offers, will form part of the assessment under its customer satisfaction output. Performance under the customer satisfaction output will be assessed by means of a survey and could result in financial rewards or penalties.

4.42. In our January consultation we set out that we would consider whether there was scope for a financial incentive on connection performance on NGG in respect of its SO role. This incentive would be in addition (and complementary) to the RIIO-T1 proposals.

4.43. Five respondents touched upon our proposals for a gas connections incentive. The AEP, Eon and Npower suggested that there may be no need for an additional incentive in this area if UNC 373 is implemented. Npower mentioned that a reputational incentive could be considered. SSE suggested efficient and timely connections are part of the SO role and should not be financially incentivised, and it would agree to the introduction of a licence condition on this output. The GSOG agreed with an eight year financial incentive where NGG's connection performance is assessed as part of the customer satisfaction survey, but noted the need to speed up the development of a sustainable governance framework dealing with all aspects of the connection process.

Summary of NGG's proposals

4.44. NGG has proposed that a reputational reporting incentive is introduced in relation to the production of connection offers. On the basis that UNC 373 is implemented, NGG proposed that it publishes information relating to the achievement of the key steps included in the UNC 373 process (including and in additional to the reporting requirements envisaged within the modification) in order to provide transparency to all and enable third parties to measure its progress.

Our proposal

4.45. **We propose not to introduce an incentive on the performance of the SO in the connection process.** We consider that given the implementation of UNC 373 and the evidence provided by NGG on its performance over recent years there is no requirement to introduce an output incentive. However we will monitor NGG's performance against the requirements of UNC 373, based on the information it publishes under the requirements of UNC 373, and may revisit this issue within the regulatory period should NGG's performance be deemed inadequate. We would also note that NGG in its Business Plan has proposed to publish additional information compared to that proposed under UNC 373. We welcome this proposal and expect

NGG to publish this additional information. In addition, should stakeholders have concerns with NGG's performance in this area we would expect that it would be reflected in the stakeholder survey.

Reliability and availability

Background and our proposal

4.46. NGG in its role as both SO and TO has a requirement to make capacity available on the NTS such that gas is able to flow from the point of entry onto the NTS to the point of exit off the system. In doing this NGG must ensure that safe levels of pressure and quality are ensured. There are clear operational roles that need to be undertaken by the SO. These include the operation of compressors and the commingling of gas, thereby limiting the volume of CV shrinkage. The way that the SO uses the existing assets on the system is a key part of ensuring that the output is delivered.

4.47. For the most part, making capacity available is a TO role and is discussed in more detail in the RIIO-T1 initial proposals for NGG. However, NGG has a number of different options for making capacity available (including investing in new network capacity or seeking a commercial solution to manage any capacity management issues) and NGG's SO function has a role to play in making these decisions. This is particularly the case where the capacity can be provided by means other than investment in physical assets. In our January consultation we set out that NGG should amend its methodology statement for the provision of incremental capacity[23] to ensure that the decisions it makes about how it chooses between the different options for providing capacity are clearly set out.

4.48. Most responses to the consultation did not directly address our proposals in this area. The GSOG suggested that there should be more transparency on how NGG chooses the options to satisfy incremental capacity, and that this strategy should be linked to the governance for new connections.

4.49. **Our proposal is that NGG will introduce a methodology statement that provides more clarity about how it makes decisions between different options for providing capacity.** We do not think the decision on this can be made in isolation from those on the other aspects of NGG's capacity provision. As the provision of capacity is mainly a TO issue we will address this as part of our proposals for RIIO-T1.

Stakeholders satisfied

4.50. As discussed in the section on 'Stakeholders satisfied' for the electricity SO, in RIIO-T1 we have decided to put in place a primary output on the TOs that relates to

[23] Which it is required to have in place under Special Condition C15.

customer/stakeholder views of each company's performance. As with electricity, we think it is appropriate for the RIIO-T1 stakeholder survey financial incentive to cover both SO and TO related issues. The potential customer coverage of the gas network company's survey would be appropriate in its role as both SO and TO. Further details on the incentive scheme can be found in RIIO-T1 initial proposals for NGG. **There will be no additional output incentive scheme in the SO regulatory framework.**

Balanced system

Background and context – Residual balancing

4.51. One of the key outputs that NGG has in its role as SO is in respect of residual balancing. When shippers (in aggregate) do not maintain a balance NGG is required to buy and/or sell gas in the On the day Commodity Market (OCM) such that the system is in balance (broadly this means demand=supply). NGG has legal and licence obligations to maintain system balance and to operate within safe operational limits. However, because NGG has some choice regarding how it fulfils these requirements, NGG's residual balancing activity has been incentivised through the gas SO incentives.

4.52. The current SO balancing incentive comprises two elements; a price performance measure (PPM) and a linepack performance measure (LPM).

- The Price Performance Measure (PPM): incentivises NGG to minimise the impact of trades that it takes to balance supply and demand on the market on a daily basis.
- The Linepack Measure (LPM): incentivises NGG to ensure that the volume of gas in the system (the linepack) at the end of each trading day is similar to that at the start of the gas day.

4.53. The SO role as residual balancer interacts with system cash out. Where the SO takes balancing actions that exceed the default cash out (buy or sell) prices, the price of these actions sets the daily cash out price. Therefore, the SO can influence the prices at which out of balance shippers are "cashed out", meaning its actions influence the incentives on shippers to balance their portfolios.

4.54. Our proposal on the balanced system output is clearly strongly linked to our views on a potential residual balancing cost scheme. We therefore discuss these jointly in this section.

Summary of consultation proposals – Residual balancing

4.55. In our January consultation we set out that we consider it appropriate for NGG as SO to continue to be financially incentivised to limit the change in linepack on a daily basis. This maintains the principle of "polluter pays" in respect of the calculation of cash out prices, ensuring that the costs of balancing the system are directed at those shippers that are out of balance. However, we set out that we were

considering removing the PPM incentive in favour of an incentive that encouraged NGG to minimise the overall costs of maintaining daily linepack rather than one that is primarily focused on encouraging NGG to limit the impact of its balancing trades. An incentive focussing on the overall costs could result in NGG taking actions that were not necessarily close to the market price and therefore could have a greater effect on cash out prices, which could result in shippers having a greater incentive to balance their own positions.

4.56. Since our January consultation proposals we have continued to develop our views on the residual balancing output, and we are able to provide more detail of what we consider are the objectives of this output incentive. The residual balancing output should encourage the SO to undertake its role as residual balancer as efficiently as possible. This means that:

- the SO should have incentives to ensure that its actions are taken at least cost.
- for the most part residual balancing actions should be taken on the same gas day as the imbalance occurs so out of balance shippers on that day bear the cost of balancing actions.
- the actions taken by the SO should provide shippers with strong economic incentives to balance their portfolios.
- the incentive on the SO should be compatible with how the balancing role may evolve over the longer term.

4.57. Underpinning these objectives is a presumption that, for the most part, it is more efficient for shippers to balance their portfolios rather than have large volumes of balancing actions undertaken by a, necessarily reactive, residual balancer. There have been some concerns raised that over the last few years shippers are becoming increasingly out of balance, in particular at the beginning of the gas day. The objectives are also intended to reflect the industry consensus that over the RIIO-T1 period the flows on the gas network will change considerably and that this may require the balancing role of the SO to evolve.

4.58. In putting forward these objectives we recognise that the SO role as residual balancer does impact on the incentives of shippers and, potentially, on gas market prices. Historically, the requirement to limit this impact has been a prominent consideration in developing the balancing incentive. We need to consider whether the limiting of these impacts per se delivers the most efficient outcome in terms of balancing the system, particularly in a world where the changing flows on the gas network may mean that it becomes necessary for the residual balancer to be more active. However, we are keen that the incentive will limit market impacts where these lead to inefficiencies.

Summary of consultation responses – Residual balancing

4.59. Seven respondents made a direct reference to our proposals on a residual balancing output/cost scheme. Most of the respondents were not directly opposed to the incentive based on the minimisation of balancing cost, but four pointed out that the current incentive worked well and/or was well understood by the industry. The GSOG supported the introduction of a cost minimisation incentive noting that it

would result in greater incentives on shippers to be in balance, whilst EDF noted that it may provide more flexibility for NGG to deal with daily imbalances. However, SSE noted that shipper imbalance is something that would be better dealt with through our gas Significant Code Review work rather than through SO incentives and stated a preference for an incentive that encouraged the SO to trade close to the market price.

4.60. The AEP noted that if a cost minimisation incentive were to be introduced then the parameters should not be set for eight years, whilst Npower suggested it would like to better understand the merits of the proposal. EON stated that there should be more industry consultation before any cost minimisation incentive was introduced and EDF said that such an incentive should not require the introduction of products that the industry may not want.

4.61. NGG argued that because the gas balancing arrangements are different from electricity then it would be difficult to introduce a cost minimisation balancing incentive for the gas SO. NGG noted that there is no "gate closure" and no correlation between the volume of gas bought or sold by the SO and the volume delivered by the market. NGG also considered that a cost minimisation incentive would increase NGG's intervention in the market and change shippers' incentives to balance their positions. Also, NGG considered that it does not have data to forecast the required volumes for this incentive.

4.62. In addition, GSOG and SSE supported our proposal to maintain an incentive on NGG to maintain daily linepack, whilst Npower noted it has some concerns regarding a linepack incentive as it considers that NGG appears to have only partial control over linepack.

Summary of NGG's proposals – Residual balancing

4.63. NGG does not consider that a cost minimisation incentive would drive appropriate residual balancing behaviour. It has therefore proposed that the style of the incentive is similar to the current residual balancing incentive with an annual cap and floor whereby a performance measure scheme, based on daily linepack change and price spread, represents a proxy for a market cost minimisation scheme. Its proposals are for an eight year scheme:

- The linepack performance measure would build on the current methodology:
  - to ensure the target remains fit for purpose the daily linepack performance measure target would be calculated annually and set on the previous year's average shipper imbalance.
  - NGG considers that this is appropriate as the levels of linepack change are inherently linked to the level of shipper imbalance.
  - the threshold for the linepack performance measure would be maintained at 1.5mcm (lower if the target for a given year is relatively low).
  - an adjustment mechanism would deal with exceptional events which influence opening linepack. Such an adjustment would apply where the

closing linepack volume is eight mcm higher or lower than the opening linepack volume on any day.

- The daily price performance measure would be linked to recent market price volatility in the form of a pence per therm daily target which NGG proposes is recalculated annually unless it is below the prevailing default cash out margin.
    - The annual target would be based on 40% of the average market price range from the previous year.
    - Its performance would be measured by the absolute price spread rather than converted to a percentage of the System Average Price (SAP) as now.
    - NGG considers that an absolute price spread calculated annually would be more reflective of prevailing market price volatility conditions as the balancing conditions on any day are not necessarily directly linked to the size of SAP but instead driven by market volatility.
        - NGG notes that for 2011/12, the average market price range was 3.6p/therm, which would give a target value of 1.44p/therm (compared to the current measure of within 1.5% of SAP, which equates to 0.75p/therm at a SAP of 50p/therm).
    - NGG also notes that the default cash out differential is defined as a fixed value in pence per therm, rather than a percentage of SAP.
        - NGG therefore considers that it is appropriate for the price spread target in the residual balancing incentive to also be in pence per therm.
        - Further, NGG considers that the price spread target should be no lower than the level of the cash out differential in order to allow the residual balancer to set an appropriate incentive for the market to self-balance.
- In relation to the risk and reward value of the total scheme NGG has proposed a maximum daily value based on:
    - estimating the volume of shipper imbalance if the residual balancer took no action, and subtracting the linepack performance measure threshold value.
    - valuing that volume at the default marginal cash out differential as a proxy for the value of linepack.
- NGG proposes that the calculation of this value is updated annually (currently it would give a daily value of £8,951). NGG considers that this is a proxy for the value of avoided costs and therefore for the value added by the residual balancer.
- NGG proposes that the incentive framework is set for eight years, with the targets being adjusted annually in accordance with the principles set out above.
- NGG also proposes a midpoint review at four years, to determine whether the scheme is delivering the desired outcome and the relationships between price spreads remain valid.

4.64. NGG considers that this proposal will promote efficiency in the gas market as a whole by ensuring that performance targets reflect those elements of residual balancing which it can control and forecast. It also considers that its proposals will provide an incentive scheme that will encourage it to balance supply and demand in an efficient manner, minimising its impact on the market over the RIIO-T1 period.

Our proposal – Residual balancing

4.65. **Having considered NGG's proposals and the consultation responses our view is that it is not a priority to introduce a cost minimisation residual balancing incentive at the current time**. A number of stakeholders (including NGG) consider that the current framework of the residual balancing scheme remains fit for purpose in that it incentivises NGG to minimise the impact of its balancing trades on the market. We also recognise that the introduction of such a cost incentive would be complicated.

4.66. **We therefore propose to put in place a financial output incentive scheme for eight years that is based on the current scheme.** However, we also propose that an uncertainty mechanism is put in place that enables the Authority to reopen the scheme (but not within its first four years) should costs increase significantly leading to a proposal for a cost minimisation scheme or should within day flows on the system change to the extent that the balancing role of the SO on the day has altered so much that the scheme is no longer fit for purpose.

4.67. We have considered the changes to the parameters of the current scheme that NGG has proposed and have the following concerns.

4.68. NGG has proposed that the PPM and LPM measures and the target value of the scheme are updated annually based on outcomes from the previous year. We have two main concerns with this approach: firstly we do not consider that the previous year's balancing performance by the market is necessarily representative of the following year's. For example, difficult weather conditions in one year may have a significant impact on balancing which are then not repeated in the following year. Secondly, a number of stakeholders have raised concerns regarding the general (and increasing) complexity of the SO incentive schemes (albeit mainly in respect of electricity). With this in mind we consider that NGG's proposals add a level of complexity to the residual balancing scheme for which it is not apparent that there would be a commensurate benefit. Most notably, putting in place this incentive scheme for eight years, and fixing the absolute values of the targets for that period, would provide a very clear indication to market participants as to what the role of the SO is in residual balancing and give the SO certainty as to what it should be working towards.

4.69. NGG also proposes that the PPM is amended to an absolute value compared to the current methodology of a percentage away from SAP. We have concerns (which are also linked to this being set based on the previous year's data) that this will not reflect the value of the SO's actions in the current year. For example, if prices are significantly higher in the previous year compared to the current year then the PPM target will be significantly greater than may be appropriate. We also note that based on a set of illustrative values, NGG's proposal would have the effect of doubling the value of the current PPM target. We do not consider that this is appropriate.

4.70. In addition, NGG has proposed that the lower level of the PPM is limited by the default cash out price. We do not consider that this proposal is consistent with the objective of the scheme being to limit the impact of NGG's balancing trades on the

market. In particular, we have concerns that this proposal provides the incentive for NGG to trade at prices above the default cash out price thereby always setting a cash out price when it enters the market.

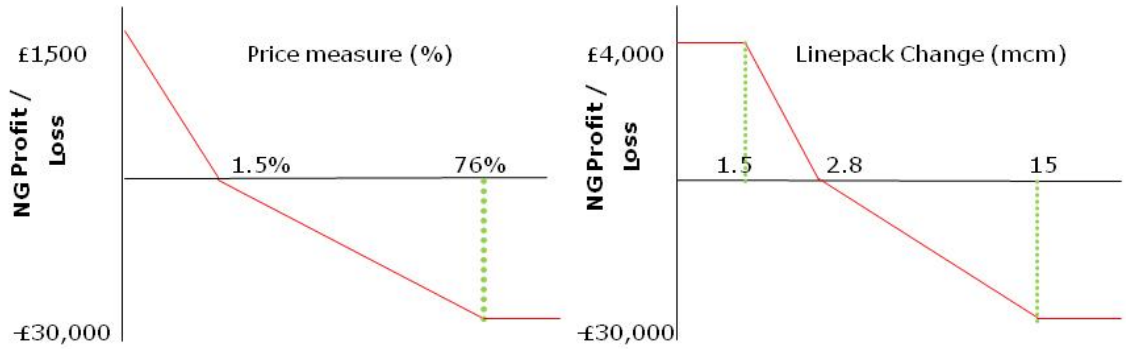
4.71. Regarding NGG's proposals for updating the value of the scheme, whilst we recognise that there may be benefits in linking the potential payments to NGG to the value it is providing we have concerns that NGG's methodology effectively doubles the current value of the scheme. In addition, as noted above we have concerns regarding the volatility that may result from the annual recalculation of the figures.

4.72. In putting forward our proposals we have also taken into account the views of stakeholders which recognise that despite the scheme being tightened over recent years NGG continues to outperform the scheme.

4.73. **Our proposals are therefore for the current scheme and all of its associated parameters to be put in place for each of the eight years from April 2013 to March 2021.** These are illustrated in Figure 11, annual payments would be capped at £2m and a floor would be at -£3.5million.

4.74. We consider that this provides an incentive on NGG to continue to improve its performance in light of expectations of changing flows (including increasing volatility within day) on the network. We also consider that this proposal provides more predictability in respect of NGG's role as residual balancer.

Figure 11: Proposals for Residual Balancing incentive scheme



Background and context – Unaccounted for gas

4.75. Unaccounted for gas (UAG) is that energy which remains unallocated after accounting for all measured inputs and outputs from the NTS: Own Use Gas

consumption, CV shrinkage and the change in the NTS linepack[24]. NGG is required to purchase UAG on behalf of all system users. Prior to April 2012, NGG was incentivised to minimise the volumes of UAG and the price at which it purchases these through the SO shrinkage and/or separate volume incentive.

4.76. From April 2012, the direct financial incentive on the SO to reduce UAG volumes was removed in favour of a licence condition requiring it to investigate the causes of UAG and report on this work. This change was made because it was unclear to what extent NGG could directly influence the levels of UAG. Currently the work that NGG is required to undertake, and report on, under this condition is (at least) meter validation and data analysis.

Summary of consultation proposals and responses – Unaccounted for gas

4.77. In our January consultation we set out our view that NGG has an important part to play in minimising the level of UAG, and that NGG should have an output incentive on UAG. We are particularly keen to promote transparency and understanding about UAG as a step to ensuring levels are reduced across the industry. Our view was that it might be appropriate to retain an updated version of the UAG licence condition introduced in April 2012. Further we said that if the work undertaken by NGG under the UAG condition suggested further measures to incentivise UAG were appropriate, we would consider other options for a UAG incentive, including a financial incentive, at a later date.

4.78. Two respondents made a direct reference to our proposals on UAG. The AEP supported a reputational incentive and noted that reporting is important to ensure NGG continues to give this issue due attention. SSE considered that the current levels of UAG were unacceptable and that action must be taken by NGG to reduce these levels.

Summary of NGG's proposals – Unaccounted for gas

4.79. NGG has proposed that the current licence condition is retained for the eight year period, as it considers that this encourages NGG to undertake projects to identify the causes of UAG. It notes that in recent years the main contributors to the volume of UAG have been meter errors and inherent meter tolerances. NGG also notes that whilst it has a meter assurance role, the NTS connected meter assets are predominantly owned by Distribution Networks, Terminal Operators or large industrial end consumers. NGG is proposing to continue to investigate the causes of UAG through activities including meter validation witnessing and data investigations. NGG recognises that as a party to all the agreements and as a recipient of component data, it is in the best position to apply analysis to this data and to share the results of this analysis with the meter owners and, where required and appropriate, the wider community. NGG considers that this approach should serve to

[24] Whilst we note that even when the system is in balance there may be Unaccounted for Gas, we consider that it is an important component of ensuring that market participants are able to balance their own portfolios.

keep levels of UAG down and mitigate risk costs to shippers which could be passed on in turn to consumers.

4.80. NGG proposes that twice yearly reporting on its UAG activities is included as a requirement within the incentive. NGG also acknowledged that it is appropriate to include a review of whether the scope of activities remains correctly focussed during the period of the incentive.

Our proposal – Unaccounted for gas

4.81. **We consider that it is not feasible to introduce a financial incentive on NGG with regard to the volumes of UAG from April 2013**. Our view is that with the current information available it is not clearly established the extent to which NGG, in its role as SO, can directly influence the levels of UAG. Further, the levels of UAG are very volatile and consequently setting a credible target volume for UAG is impractical. For these reasons we cannot be confident any financial incentive payments would reflect NGG performance in reducing volumes of UAG rather than windfall gains (or losses). We have therefore focused our initial proposals on measures to promote transparency and understanding about UAG.

4.82. We continue to consider that NGG has an important role to play in identifying the causes of UAG and promoting transparency about UAG. NGG is well placed to do this because of its unique access to data regarding gas flows over the NTS. We therefore propose to update the current UAG licence condition so that NGG is required to undertake and report on relevant projects in this area. In addition, given the concerns raised by shippers concerning the volumes of UAG, we also consider that NGG should provide information in respect of the actual volumes of UAG.

4.83. We also think that wider industry stakeholders can play a role in helping to indentify the causes of UAG and promote transparency. These stakeholders have substantial industry expertise and this could be a valuable tool to help improve understanding of UAG. We understand that stakeholders are at a substantial informational disadvantage compared to NGG as they do not have access to the same data, particularly data on the flows of gas across the NTS. To help overcome this disadvantage and enable wider stakeholder contribution to the understanding of UAG we propose to facilitate cooperation between stakeholders (or their appointed third party), including the sharing of data. If necessary we will amend NGG's licence to set out the ground rules for this cooperation.

4.84. **We therefore propose to put in place a reputational incentive for eight years on NGG in respect of identifying the causes and reporting on the volumes of UAG.** We consider that this incentive should be based on the current licence condition, but should be extended to include NGG facilitating the help of wider industry stakeholders in investing the causes of UAG. We consider that it may be appropriate to require NGG to establish an industry workgroup to take forward this work. The licence condition will also include the requirement on NGG to report on the volumes of UAG that have occurred.

4.85. We propose to put in place this incentive for the eight year period. However, we expect that significant progress will have been made in reducing the levels of UAG in much shorter timescales. When the work undertaken by NGG or wider stakeholders identifies solutions to reducing the levels of UAG we will consider, along with NGG and industry, the most appropriate way for those solutions to be implemented. This will include deciding whether to introduce any further incentives on NGG as SO with regard to volumes of UAG.

Provision of information

Background and context

4.86. NGG in its role as SO produces and makes public large volumes of information that are used for various purposes by a large number of stakeholders. The range of information provided by NGG falls into a number of categories which include:

- Information on short term gas market conditions – for example its day ahead demand forecasts.
- Information on long/medium term market and network conditions/development – for example the ten year statement and winter outlook.
- Information about its internal process/decision making – for example its methodology for the provision of incremental capacity.

4.87. In some cases NGG is required by licence to provide this information, in other cases it provides it because it is deemed to be of value to stakeholders. NGG is funded for the provision of this information through its "SO internal cost" allowance. This allowance covers the operating cost for the function performed by the SO[25]. For some aspects of its information provision, such as day ahead demand forecasting, NGG is currently incentivised to improve the quality of its information provision through the SO incentive scheme. This is discussed further in the following section. NGG is also currently incentivised on the accuracy and timeliness of the publication of data on some key data screens it provides on its website and on the accuracy of its day ahead demand forecasts.

Summary of our consultation proposals and responses

Availability and timeliness of information on website

4.88. In our January consultation, we proposed removing the current SO financial incentive on the availability and timeliness of the provision of a number of key items of gas market data. Our view was that the provision of this information to acceptable

[25] SO internal costs are part of NGG TO's totex. Our decision on NGG's allowance for SO internal costs can be found in our RIIO-T1 initial proposals for NGG.

standards was business as usual going forward and should be adequately funded through SO internal costs. Further, it is unclear that the relatively small payments available to NGG under the current scheme structure effectively incentivise improvements in performance. Instead of a financial incentive, we proposed that a reputational incentive be introduced on the provision of market information.

Forward looking market information

4.89. NGG[26] currently publishes a number of documents that relate to a forward looking view of the market. Most notably these are the Ten Year Statement, Winter and Summer Outlooks and Transporting Britain's Energy. We also note the additional information that NGG is required to provide as a result of the implementation of the Third Package. Given the importance that is placed on these documents by the industry and more widely, we considered that a licence requirement for the eight year period is placed on NGG in respect of the provision of this information.

Transparency in respect of SO-TO interactions

4.90. Given the overlap between NGG's SO and TO functions we consider it important that NGG is transparent about the interactions between these functions, including any trade-off made by NGG. Our January consultation set out that we were considering requiring the gas SO to report to the Authority on how it manages the interaction between its SO and TO functions, including any trade-offs it makes between actions taken by each function, to ensure as much transparency as possible in respect of these actions.

Summary of NGG's proposals

Availability and timeliness of information on website

4.91. NGG considers that the current financial incentive has worked effectively to improve performance over the last six years such that the feedback it receives suggests that its customers are broadly happy with the level of service that they are currently receiving. NGG therefore considers that it would be appropriate to remove the financial incentive with respect to the availability and timeliness of the critical market data that it publishes on its website, and for this to be replaced with a reputational incentive based upon the existing performance levels. NGG proposes a licence condition requiring it to report to Ofgem and industry on its website performance on a monthly basis, providing information on the following areas:

- the overall availability of the system: comprising the same parameters as the current scheme namely keeping three screens (prevailing view, data item explorer and report explorer) available with a monthly target of 99.30% availability with as little downtime as possible.

[26] Some of these publications are in conjunction with NGET.

- the timeliness of the critical market data published: this would cover how timely its updates are in respect of publishing four key data items: (Predicted Closing Linepack, National Forecast Flow, National Physical Flow, and Forecast NTS Throughput). The monthly target benchmark for timeliness being 90.50% of updated within ten minutes of the start of the hour.
- the utilisation of the site by customers.
- any significant events that occurred within the month.

4.92. NGG considers that this will allow market participants to monitor and review its performance in this area, compared with its current performance.

4.93. NGG also set out its proposal to engage with stakeholders later this year in respect of its information provision strategy. Following feedback from this engagement process, NGG expects to propose an overall information provision strategy reflecting Stakeholder requirements. It considers that it may then be appropriate to also review the data publication incentive arrangements given wider industry developments.

Forward looking market information

1.2. NGG has not put forward any proposals in this area.

Transparency in respect of SO-TO interactions

1.3. NGG has not put forward any proposals in this area.

Our proposals and next steps

Availability and timeliness of information on website

4.94. **Our proposal is to remove the financial incentive on NGG with regard to the availability and timelines of certain key data items and introduce a reputational incentive in its place.** We consider that this activity can be considered business as usual and should be funded through the SO internal costs. Further, the extent of information provided and the way in which the NGG website is used are very different compared to the situation when the current incentive structure was devised. We think that Stakeholder views are a more important influence on the extent and quality of information provided by NGG than an incentive in the current form.

4.95. NGG already has a strong reputational incentive in place on the quality of its information provision. This is an area of NGG's activity that a wide variety of stakeholders value and where NGG's performance is relatively transparent. Therefore stakeholders take an active interest in this area and make their views known, both to NGG and ourselves, when they consider NGG's performance to be inadequate. We therefore propose to build on this by introducing a more formal reputational incentive on NGG with regard to the provision of market information. We propose to put a licence requirement on NGG to have in place an information strategy, this must

include a description of how NGG takes stakeholders' views into account and how it will continue to do so. This will ensure that NGG continues to ensure its information provision develops in line with its stakeholders' expectations and requirements. We will also require NGG to review its performance on a periodic basis and to report on its information provision performance on a monthly basis. We would also note that NGG's performance in this area will be covered as part of the customer satisfaction survey.

Forward looking market information

4.96. **Our proposal is that given the importance of this information to the industry and more widely, a reputational incentive should be placed on NGG to publish this information.** We consider that given the amount of information that NGG produces it would be extremely helpful to users for a list of this information to be set out in a single place. We will work with NGG to consider whether the most appropriate place for this to be set out is within its transportation licence or if there is an alternative location that would better enable the list to be kept up to date. We will also work with NGG and stakeholders to ensure the contents of the list ensure the most benefit to users.

Transparency in respect of SO-TO interactions

4.97. We consider that the main SO-TO interaction in gas is in respect of the provision of capacity. The transparency requirement in respect of this will be covered by the requirement for NGG to provide transparency around the decision it makes when providing new capacity as set out above in our proposal on the reliability and availability output. **It is our proposal that we will not implement an additional output incentive on transparency in respect of SO-TO interactions.**

Demand Forecasting

Background and context

4.98. NGG publishes national gas demand forecasts over a range of timescales. This information assists market participants to make efficient decisions in balancing their supply and demand positions. Currently, NGG is incentivised in respect of the accuracy of its gas demand forecast published at 13:00 on the day ahead.

Summary of our consultation proposals and responses

4.99. We recognise the importance that users place on the accuracy of NGG's demand forecasting. In our January consultation, we proposed that a financial incentive on the accuracy of NGG's gas demand forecasting should be retained and that this incentive should be set for an eight year period. A longer term incentive should encourage NGG to look at taking actions where the benefits in term of improved forecasting would only become apparent over the longer term.

4.100. Two respondents commented on our proposals for gas demand forecasting. Both the AEP and SSE touched on having different targets for different periods of the year. The AEP suggested tighter targets for the winter, whilst SSE suggested the incentives have four distinct forecast error periods (winter, autumn, spring, summer).

Summary of NGG's proposals

4.101. NGG believes it may be able to deliver more value to stakeholders if the incentive was expanded to include more of its published forecasts. In addition to the day ahead 13:00 forecasts, NGG proposes to widen the range of forecasts covered under the demand forecasting incentive scheme to include forecasts that NGG already publishes at D-5, D-4, D-3 and D-2.

4.102. NGG considers that the current method of measuring forecasting performance, as a percentage of demand, is susceptible to the windfall impacts of unseasonably high or low demand, and therefore proposes that its performance should be measured by the average absolute daily error (in mcm). NGG proposed an overall annual target that encompasses all the demand forecasts to be incentivised (from D-1 13:00 to D-5) and takes into account seasonal differences (summer and winter), giving more weight to forecast errors in winter, and to forecasts closer to real time (highest weight to D-1 13:00 and lowest weight to D-5).

4.103. NGG expects that a number of factors (such as the continued increase in the number of fast cycle storage sites, and CCGTs flexing their output to reflect variations in wind generation) will make demand forecasting more challenging in the future. NGG therefore proposes that an uncertainty mechanism is applied to adjust the incentive target to reflect actual demand volatility.

4.104. NGG is also proposing the introduction of a new financial incentive on a D-1 13:00 Non Daily Metered (NDM) demand forecast. NGG's proposal is for an incentive that measures its performance compared to the accuracy of the existing NDM forecast produced according to the UNC provisions and published at the same time.

Our proposal and next steps

4.105. **Our proposal is for a financial incentive on the accuracy of NGG's D-1 13:00 demand forecast.** We agree with NGG and stakeholders that the current performance measure creates a risk of windfall gains or losses when demand is exceptionally low or high. We also agree that the current incentive does not provide an incentive to forecast winter demand more accurately than summer demand. We therefore propose a performance measure that weights the daily forecast error by the proportion annual demand accounted for by each day's demand. This performance measure gives more weight to errors incurred in days of higher demand (e.g. winter) without the need to introduce separate targets for each season, as set out in Table 4.

Table 4: Comparison of current and proposed demand forecasting performance measures

Current performance measure (percentage error)	$Forecast\ error_t = \left(\frac{\sum_{d}^{D} \lvert DADF_d - AD_d \rvert}{\sum_{d}^{D} AD_d} \right) \times 100$
Proposed performance measure (weighted average error – mcm)	$Forecast\ error_t = \sum_{d}^{D} \left(\lvert DADF_d - AD_d \rvert * \frac{AD_d}{\sum_{d}^{D} AD_d} \right)$

Where:

d: first day of incentive year

D: final day of incentive year

$DADF_d$: day-ahead forecast (mcm) on day d

AD_d: actual NTS throughput (mcm) on day d

4.106. We believe that the incentive should encourage continuous improvement over the length of the scheme. We consider that continuous improvement of demand forecasting in a context of increasing volatility means that the SO is able to learn and adapt to a more challenging environment, accomplishing similar levels of performance every year. We would also note that we are proposing a financial incentive on NGET as electricity SO in respect of its forecast of renewable generation. NGET will be publishing this improved forecast on its website, which NGG as gas SO will be able to use to produce its gas demand forecast. We are proposing to maintain the current demand forecasting target, converting the current percentage target (between 2.75% and 3.1%[27]) into the new proposed measure (in the region of 7.5 mcm), with a maximum payment of £10m for a zero forecast error and a penalty floor of £-1.6m. We propose to set the target for eight years.

[27] The target in 2012/13 includes an adjuster for new injection capability of short cycle storage facilities connected to the NTS at Holehouse Farm, Aldbrough, Holford Byley and Hilltop Farm. The target could increase from 2.75% up to a maximum of 3.1%, depending on the new injection capability connected.

4.107. We have considered stakeholders' views on the possibility of introducing incentives on the accuracy of NGG's D-2 to D-5 demand forecasts. We have observed the difference in forecast accuracy between NGG's incentivised forecast (D-1 13:00) and its other forecasts, and we believe there is scope for improvement. **We therefore propose to introduce an incentive on the accuracy of NGG's D-2 to D-5 demand forecasts.** Our current view is that there should be a bundled performance measure across the four forecasts, calculated as the average of the forecast error of each individual demand forecast, as shown in Table 5:

Table 5: Proposed performance measure for D-2 to D-5 demand forecasts

$$Forecast\ error_{D-2\ to\ D-5} = \frac{\sum_{t=2}^{5}\left(Forecast\ error_{d-t}\right)}{4}$$

Where:

$$Forecast\ error_{d-t} = \sum_{d}^{D}\left(\left|DF_{d-t} - AD_{d}\right| * \frac{AD_{d}}{\sum_{d}^{D} AD_{d}}\right)$$

d: first day of incentive year

D: final day of incentive year

DF_{d-t}: demand forecast (mcm) on day d-t

AD_{d}: actual NTS throughput (mcm) on day d

4.108. The target would need to be set to be challenging enough to drive a considerable improvement in performance. After the D-1 13:00 demand forecasting incentive was introduced in October 2006, NGG's performance improved significantly, with a reduction of the forecast error of over 28%. We expect to observe similar improvements in NGG's D-2 to D-5 forecasts after the introduction of an incentive, although we acknowledge that earlier forecasts are likely to be less accurate. Taking account of this, we propose to set the target for 2013/14 at 14.38 mcm, and for 2014/15 at 12.78 mcm, which represent improvements of 10% and 20% respectively over NGG's average performance in the last three years.

4.109. The scheme would reward NGG with a maximum payment of £10m for a zero forecast error and would have a floor of -£0.5m. We propose that as this is a new scheme it is initially set for two years. While the incentive would bundle together the forecasts from D-2 to D-5, NGG's performance would be published for each separately to promote transparency and help inform resetting the scheme in 2014.

4.110. We note that during the consultation process to develop SO incentives from April 2013, stakeholders have again raised concerns regarding the lack of accuracy of non-daily metered (NDM) demand forecasts. This issue has been raised previously, most notably during the development of the incentive schemes to apply from April 2010. At that time it was agreed that NGG has a very limited role in the development of this forecast and therefore it was not appropriate to incentivise NGG regarding the accuracy of this forecast. **For the same reason, we continue to consider it is not appropriate to incentivise NGG in respect of the production of this forecast.** However, we consider that NGG in its wider role should look to assist industry to continue to investigate the issues involved and raise these with the industry at an appropriate forum.

Maintenance

4.111. Over a period of time, stakeholders have raised concerns regarding NGG's maintenance planning and in particular its decisions to reschedule maintenance at short notice. Although, we did not include a specific proposal regarding maintenance in our January consultation, SSE and the AEP raised the issue.

Summary of NGG's proposals

4.112. In its Business Plan, NGG notes that stakeholders have asked it to improve its flexibility, in particular, with regard to how and when it carries out maintenance on the NTS. In response to these requests, NGG has set out the following approach, including the introduction of incentives to promote flexibility where it is valued by its stakeholders and encourage efficient planning on the NTS:

- earlier and better communication of its outage needs to affected parties to enable better alignment of outages.
- a financial incentive to reward good performance where it can reduce the number of changes made to its year ahead Maintenance Plan compared to a benchmark based on historic performance.
- a financial incentive to use an efficient level of Maintenance Days.
- ensuring all parties are aware of the services it offers allowing them to pay the incremental costs of working flexibly outside normal working practices or making outages to meet their needs where this is of particular value to them (e.g. taking outages outside normal working hours such as at weekends).

4.113. In respect of an incentive on the reduction of the number of changes to its Maintenance Plan, NGG has proposed that its year ahead plan could form a baseline from which any changes are defined. NGG proposes that where it reduces the level of changes that affect directly connected customers compared to historic levels it is rewarded, and penalised where it exceeds the baseline levels, subject to caps and floors. It has yet to consider how to account for customer initiated changes which impact multiple parties and multiple changes relating to a particular maintenance job.

4.114. In terms of the scope of the incentive, NGG notes that the types of changes can generally be categorised into date changes, flow changes and cancellations. NGG's proposal is that this incentive covers date changes and cancellations. Also, only those maintenance activities that directly impact its customers should be captured. Thus, the following activities would be within the scope of the incentive: routine maintenance; planned asset replacement and reinforcements; and in-line inspections.

4.115. NGG has proposed that the target should be based on the historic number of changes made over a three year period. However, given that it does not currently have sufficient data to set the target in such a way, it proposes for the first year the target is based on 2012/13 data only, and for the second year it is based on 2012/13 and 2013/14 data. NGG has not proposed any value for the incentive, but has proposed that it should be reviewed after two years.

4.116. In respect of an incentive on the number of maintenance days, NGG proposes to measure the difference between a target number of maintenance days and the actual number in respect of its activities concerning remote valve operations and in-line inspections (ILIs). NGG proposes that each day is valued at £50,000 with an overall annual limit of ±£1million, i.e. equivalent to 20 days. Again, NGG proposes that the scheme is reviewed after the first two years.

Our proposal and next steps

4.117. We recognise the concerns of a number of stakeholders regarding NGG's maintenance planning and in particular the potential for stakeholders to incur financial loss as a result of NGG making short term changes to its Maintenance Plan.

4.118. In respect of two of the areas that NGG has put forward in its Business Plan: earlier and better communication of its outage needs and ensuring all parties are aware of the services it offers regarding paying incremental costs for additional services; we consider that these are services that NGG should undertake as "business as usual". **We therefore do not consider that it is appropriate to put in place an output incentive scheme in these areas.** However, we consider that it is important that stakeholders are satisfied with the service that NGG offers and therefore consider that these areas should be covered within the Stakeholder Survey.

4.119. **Our proposal is that a financial output incentive could be placed on NGG in respect of changes it makes to its Maintenance Plan and using an efficient level of Maintenance Days.** However, as recognised in our January consultation, when introducing any new incentive we need to be satisfied that we can set the baseline for performance at an appropriate level. In particular, we are aware of the impact that the introduction of an incentive scheme will have on a company's focus and therefore we need to ensure that any initial benefits that accrue as a consequence of introducing a new scheme do not result in over rewarding the company. A further key concern in respect of setting an incentive in respect of the number of maintenance days is to ensure that NGG is still incentivised to carry out an efficient level of maintenance, that is, that the incentive does not result in NGG

simply reducing the amount of maintenance it undertakes. Our initial proposals for financial output incentives in these two areas are discussed below.

Maintenance days

4.120. In its Business Plan NGG provided no evidence regarding the information necessary to set the target baselines for the maintenance days scheme. NGG has subsequently provided Ofgem with the following information.

4.121. In respect of remote valve operations, NGG notes that maintenance days on critical valves are required when the bypass on the site is not sufficient to accommodate the capacity requirements of the end users during maintenance as per the applicable Exit Agreement. As critical valve maintenance is required every year and therefore the workload is relatively stable, NGG has proposed that a simple benchmark to be used for the target could be the number of maintenance days required for maintaining critical valves in previous years. Based on its current assessment NGG considers it currently requires 47 maintenance days for critical valve maintenance annually. It proposes that this target is fixed with adjustments made as sites are commissioned, de-commissioned or the number of customers affected by the site works changes, but is otherwise fixed for the first two years of the scheme.

4.122. In respect of in-line inspections, NGG notes that the number of days required to complete the work is dependent on a number of factors, such as: pipeline location, length and number of affected customers. NGG considers that it would be inappropriate to use a benchmark based on the total number of days used for ILIs in previous years, as the number required to be carried out varies from year to year. NGG therefore proposes that a benchmark for shorter runs (up to 10km) of 4.5 days and for longer runs (more than 10km) of six days is set. NGG also proposes that the benchmark for ILI runs is multiplied by the number of customers affected.

4.123. We would note that the data provided to us by NGG gives a benchmark for shorter runs of 4.45 days and 5.825 days for longer runs. We would also note that NGG's data shows on average 122 maintenance days as a result of ILIs over the last two years. We also note that NGG has not provided us with details of the number of affected customers. However, we are concerned that introducing such a dimension to the calculation of the target would over complicate the initial incentive, with no obvious benefit.

4.124. Based on the information provided by NGG, we consider that the target could be calculated as follows:

Target number of Maintenance Days per year = Target number of Maintenance Days for ILI per year + Target number of Maintenance Days for Valve Operations

4.125. With the target number for the ILIs calculated as:

$$\text{Target number of Maintenance Days for ILI per year} = \sum_{\text{Each Short ILI run}} \text{Benchmark for Short ILI run} + \sum_{\text{Each Long ILI run}} \text{Benchmark for Long ILI run}$$

4.126. We agree with NGG's proposals regarding the form of the data to be used to set the benchmark. However, based on the information provided to us by NGG and our view that any initial target should ensure that the company is not over rewarded, our proposal is that the target for maintenance days for valve operations and ILIs should be as set out in Table 6. These targets set out the same level of improvement required from the baseline data provided as set out previously for the new demand forecasting scheme (i.e. 10% in year 1 and 20% in year 2). Based on the data that NGG has provided, this would equate to a target in the region of 150 days for 2013/14.

Table 6: Proposed targets for Maintenance Days

Incentive year	Target for each ILI Short run	Target for each ILI Long run	Target for Valve Operations
2013/14	4.005	5.240	42.3
2014/15	3.560	4.660	37.6

4.127. NGG has proposed that each day that changes from the target is valued at £50k, with an overall limit of ±£1 million (i.e. allowing for a maximum increase or decrease of 20 days away from the baseline). NGG has not provided any evidence as to why it considers each day should be valued at £50k.

4.128. Our initial view is that £50k seems a relatively high payment for NGG to receive for each day's reduction in maintenance. Our view is that £20k may be a more appropriate level of payment. This would enable the overall limit to remain at ±£1 million, but would enable up to 50 days change to be covered.

4.129. **Our initial proposal is for a financial incentive to be implemented in respect of the number of maintenance days.** The target would be calculated as set out above. We **propose a value of £20k for each day higher or lower than the target, with a cap and floor of ±£1 million per year.**

Change in maintenance days

4.130. In its Business Plan, NGG provided no evidence regarding the information necessary to set the target baseline for the scheme. NGG has subsequently provided Ofgem with the following information.

4.131. During the 2011 maintenance season NGG instigated changes to a formal maintenance notification at an offtake site on 25 occasions, of which ten were at direct connect sites. NGG noted that some of these changes could relate to the same piece of maintenance, where NGG requests a change on more than one occasion. This compares to 139 total formal maintenance notifications. NGG has also provided us with some data in respect of the 2010 maintenance season, when NGG instigated 16 changes to 109 formal notifications.

4.132. We recognise the concerns that users have with NGG changing pre agreed maintenance plans. However, we also have a number of concerns with setting an incentive based on the information that is currently available to us. These concerns are:

- The data we have only gives a snapshot and therefore may not be particularly reliable against which to set a financial incentive.
- The data we have shows significant variation between the two years, and is therefore difficult to use to set a baseline figure.
- An incentive that only relates the direct connects (as per NGG's proposal) could result in NGG focussing on minimising such changes at the expense of changes in other areas of its Maintenance Plan.
- To what extent should the incentive include NGG's proposed changes to maintenance plans when they are agreed by the user?
    - We would note that if NGG is incentivised to reduce changes only when the user does not agree, this creates a perverse incentive on the User to not agree.
- As outlined by shippers, it is difficult to place a value on the incentive, as the costs to shippers of a change to a maintenance plan may be significant.

4.133. Given the above, our proposal is for a financial incentive that is as simple and as transparent as possible, but one that we consider should reflect the concerns that have been raised by shippers. Based on our previous discussion regarding setting targets for new incentives, the following illustrates how such a scheme could operate. For 2013/14 the target could be 18 NGG instigated changes to a formal maintenance notification, and 16 for 2014/15, based on a baseline taken as an average of the two years of data. The value for each change to this baseline could be £50k, with a cap and floor of ±£0.5 million (i.e. a total of ten changes in either direction) per year. We will continue to work with NGG to ensure that the data on which any baseline is set is fit for purpose.

4.134. **We agree with NGG that both of the maintenance schemes should be set for two years. They should be reviewed in time for a scheme, as appropriate, to be set for implementation from April 2015**.

Provision of enhanced services for NTS users

4.135. In its Stakeholder Engagement consultation, NGG noted that it currently accepts requests for additional services where it can accommodate them whilst maintaining the safe and efficient operation of the network, for example by

facilitating higher ramp rates or accepting shorter notice periods than provided for by existing contractual provisions.

4.136. In its SO Business Plan, NGG noted the interaction between any incentive in this area and the network flexibility uncertainty mechanism included in its RIIO-T1 Business Plan. It considered that it may be appropriate to consider introducing products and/or financial incentives for these types of services, such as shorter notice periods and higher ramp rates, as and when they are valued by customers.

4.137. NGG has not proposed an incentive in this area. Instead, it proposes to work with its stakeholders to develop new services/products that they would value. When these services have been developed, it may then by appropriate to incentivise their delivery in order to drive value for consumers.

4.138. It is our proposal that we will not implement an output incentive in respect of enhanced services for NTS users at this stage.

4.139. In our January consultation, we set out the objectives of the new SO regulatory framework. Further, we stated that in meeting these objectives the SO should take a proactive approach and anticipate future developments. We consider that this is a particular area where NGG's role in this regard is key and we support the development of potential enhanced services products, particularly where the continued provision or expansion of these services drives a network cost. We therefore expect NGG to work with stakeholders to ensure that provision is made for their future needs. When additional requirements are identified we will consider, along with NGG and industry, the most appropriate way for those solutions to be implemented. This may include deciding whether to introduce any further incentives on NGG as SO with regard to the provision of enhanced services for NTS users.

SO Innovation

4.140. In its March 2012 RIIO-T1 submission, NGG submitted an innovation strategy that outlined how it intended to utilise innovation funding to drive improvements in its business and address the fundamental issues that its stakeholders have identified as areas where innovation could have the greatest positive impact.

4.141. NGG considers that funding should be available to the SO, as it is to the TO, through the new mechanisms introduced by RIIO-T1. It therefore considers that the SO should be able to participate in the Network Innovation Allowance (NIA) and Network Innovation Competition (NIC).

4.142. **It is our proposal that the SO should also be able to access the TO innovation funding (as determined in the RIIO-T1 Final Proposals document).** Further details concerning the innovation stimulus can be found on the innovation section of the Ofgem website: http://www.ofgem.gov.uk/networks/nic/pages/nic.aspx.

Appendix 5 – Gas cost incentives

5.1. In this Appendix we provide more detail of the gas cost incentive schemes discussed in Section 5 of the Overview Document.

Gas balancing cost incentive scheme

Background and our proposal

5.2. Our proposals on the introduction of a potential residual balancing cost incentive scheme are closely linked with those on the balanced system outputs. **In Appendix 4 we set out that we propose to continue with the residual balancing incentive in its current form and will consider the potential benefits of moving to a residual balancing cost incentive in the future, should we consider that there is sufficient within day volatility to justify such a review.**

Shrinkage cost incentive scheme

Background and context

5.3. NTS Shrinkage refers to gas and electricity that is used to operate NTS compressors for system operation purposes (Compressor Fuel Usage - CFU) energy that is delivered but cannot be billed due to local differences in the calorific value of gas (CV shrinkage) or gas unaccounted for by the entry and exit measurement and allocation processes (unaccounted for gas). Shrinkage gas and electricity needs to be bought by the SO in its capacity as Shrinkage Provider under the Uniform Network Code (UNC).

5.4. The objective of the incentive is to incentivise the efficient purchase of the elements of shrinkage gas. We consider that this means:

- NGG should seek to minimise the cost at which it purchases gas and electricity whilst limiting the risk to which it exposes consumers to.
- NGG should have incentives to reduce the volume of elements of shrinkage where it is able to influence these.

Summary of our consultation proposals and responses

5.5. In our January consultation we set out that we considered the shrinkage cost incentive scheme should take the same form as the current scheme, in that it is a bundled scheme in respect of the volume of compressor fuel usage, CV shrinkage and Unaccounted for Gas, with the volumes then being multiplied by a reference price to form a target. We also set out that we would set, as appropriate, the methodology for setting the parameters (target, sharing factors, caps, floors) or the parameters themselves for eight years from April 2013.

5.6. We also set out the need to develop the methodology for setting and updating the targets, which would require NGG to update its modelling methodology in respect of compressor fuel usage and future gas flows. We noted that NGG's plans to further roll out its electric driven compressor replacement programme need to be fully captured within its shrinkage costs. Given these close interactions with the TO we set out our proposal to increase the sharing factor for the Shrinkage cost scheme to between 40 and 50 per cent.

5.7. Three respondents supported the continuation of a cost incentive for shrinkage. The AEP noted the need to ensure the roll out of electric driven compressors is reflected in the target.

Summary of NGG's proposals

5.8. NGG has proposed that the scope of the shrinkage incentive should broadly remain unchanged with UAG remaining included and the SO incentivised to minimise overall costs through a bundled cost minimisation target. NGG has proposed changes to certain elements in order to seek to address Stakeholder concerns and reduce the potential for windfall gains/losses, such that the SO is rewarded/penalised for costs that are manageable and neutral to those costs over which the SO can exert limited or no control. NGG's proposed changes can be summarised as:

- Shrinkage volume target would be split into two parts. First, baseline volumes would be set on a quarterly basis using the best available forecast nine months before the start of the quarter; second, there would be an adjustment related to differences between outturn and forecast volumes.
- The fixed baseline volume cost target would be set ahead of time at a forward reference price. The short term cost target would be set at a prompt reference price.
- The introduction of an energy efficiency component to ensure the incentive maintains an efficient level of CFU and CV shrinkage given that the short term adjustment will now be based on outturn volumes. NGG considers that when volumes change significantly from forecast, this would reduce the potential for windfall losses and gains and would reflect an appropriate trading strategy.
- NGG proposes to consult upon a methodology statement each year to derive the energy volume target for compressor usage and CV shrinkage.
- Moving the baseline energy reference price to the average of quarterly reference prices for the nine month period ahead of the delivery quarter. NGG considers that this would align the electricity and gas price reference periods and that utilising a price reference period closer to delivery reduces the potential for windfall gains and losses. NGG also considers that this would result in the inclusion of more liquid products and would apply a consistent approach for each quarter.
- Applying a month ahead price to the adjusted volume and including a swing uplift calculated as a fixed target cost allowance.
- Pass through a number of costs incurred as a result of procuring electricity required for its electric driven compressors.
- Including a single environmental performance measure based on the Traded Price of Carbon. NGG considers that there are a range of environmental schemes that change over time and can lead to inappropriate incentives

where emissions prices are different for gas and electricity use. NGG proposes that its proposed simplification of the impact of these schemes will ensure consistent incentivisation on using the government's Traded Price of Carbon as a basis for an environmental adjustment based on NGG's performance. NGG also proposes that performance associated with the Carbon Reduction Commitment Energy Efficiency Scheme (CRCEES) and EU Emissions Trading Scheme (EU ETS) are excluded from the incentive performance.

- NGG proposes an annual incentive within an eight year framework, with an increased sharing factor of 50%, aligning with the TO incentive, and increasing the cap and floor to ±£10 million per annum.

Our proposal and next steps

5.9. We propose to implement a cost incentive in respect of NTS Shrinkage for the gas SO from April 2013 for eight years.

5.10. Our proposals are for an incentive scheme that takes the same format as the current scheme, but with a number of enhancements that we consider will enable it to be set for an eight year period. The scheme will therefore incentivise NGG to minimise its cost of procuring gas and electricity for its shrinkage requirements (compressor fuel usage, CV shrinkage and UAG) and also to incentivise it in respect of its efficient use of its compressors and in minimising the volumes of CV shrinkage. As set out in Appendix 4, we propose a separate arrangement in respect of UAG volumes, whereby NGG should seek to identify the causes of UAG.

5.11. In its Business Plan, NGG proposed to put in place a methodology statement that would enable it to forecast a baseline volume of three components of shrinkage. However, it did not provide any detail regarding the information that would be contained within the statement or the process for how the methodology would be updated.

5.12. We agree with NGG that it would not be possible to set a target volume for the baseline level of Shrinkage for each of the eight years at the outset of the scheme. We also agree that putting in place an agreed methodology would enable the volume to be calculated on a pre-agreed basis and therefore would overcome this issue. NGG has subsequently provided Ofgem with a draft of its methodology. Based on the information provided by NGG, Ofgem considers that the methodology should contain the following detail:

- UAG: for each quarter the target would be based on the average volume in the previous quarter and this methodology would only be amended if directed by the Authority as a result of new information regarding the drivers of UAG.
- CV Shrinkage: would be based on the current methodology with the same carve outs that currently exist. NGG would consider the effects of any new supply source on CV Shrinkage, and if appropriate would request that the Authority directs an update to the methodology to take account of the effect of the new supply source.

- CFU (gas and electric): calculated based on NGG's regression model of CFU vs. actual flows, using historic data. The coefficients from the regression will be updated on an annual rolling basis.
- CFU (review): By May 2016 NGG should consider whether its regression model approach remains fit for purpose and if not develop an alternative approach to be implemented from April 2017. If its regression model is retained for 2017 and beyond, NGG should, as appropriate, keep it under review.
- CFU (electric drive rollout): detail as to how NGG's electric drive replacement programme will be incorporated, including how the resultant reduction in gas CFU, and increased efficiency of compressor usage will be accommodated.

5.13. In order that stakeholders are able to understand how the shrinkage volume target will be calculated for 2013/14, we consider it appropriate that NGG consults with stakeholders on its methodology statement prior to the Authority issuing its Final Proposals towards the end of 2012. This consultation will also need to explain how NGG proposes that the methodology is applied to its forecast of volumes for 2013/14. This will enable the Authority to approve the methodology statement as part of its Final Proposals.

5.14. Once the methodology is in place, we also propose that it is subject to an annual audit requirement. The obligation would be for NGG to hire independent auditors (at its cost) to verify that it has correctly applied the methodology.

5.15. We also agree with NGG's view that the forward price benchmarking methodology should be adjusted to better align with NGG's energy purchases. **Our proposal is therefore that for each quarter the reference price for the baseline volume should be determined using the daily average of the quarterly forward price over the preceding nine month window[28].**

5.16. NGG has proposed that the baseline volume is then adjusted to take account of the actual volume procured and that this volume should be priced at a short term reference price. Correcting the volume target in this way means that NGG would be incentivised against the actual volume, which we agree is appropriate in respect of UAG. To ensure that NGG is incentivised in respect of efficient volumes of CFU and CV Shrinkage, we agree with NGG that the outturn volumes should be corrected to provide this incentive. In respect of CV Shrinkage, given the carve outs in the baseline methodology, we consider that NGG should be incentivised against the baseline volume and therefore an adjustment to the actual volume should be made accordingly. Regarding shrinkage volumes, we agree that these volumes are dependent on actual flows and therefore the actual volumes should be adjusted based on actual flows. This, albeit with an extra step, provides the same volume incentive for CFU as under the current scheme.

5.17. NGG proposes that this short term volume should be priced at a month ahead reference price and in addition a swing allowance should be added. NGG proposes

[28] Prices quoted in the ICIS European Spot Gas Markets report.

that this swing allowance should be a fixed £7.2million allowance. This compares to a £2.2m figure for day ahead and within day trades at the current uplift value[29].

5.18. **Our proposal is that this short term volume should be priced at a short term reference price.** As we have set out previously we have concerns regarding the necessity of the swing uplift. We therefore consider that this should not be included as part of the cost allowance. In order to take account of short term changes in volume, it may therefore be appropriate to use a shorter term reference price than month ahead. We would welcome views on whether using a reference price based on the week ahead price would provide an appropriate reference.

5.19. NGG has also proposed that a number of additional ancillary costs that it incurs in procuring shrinkage are passed through. NGG considers these costs are: TNUoS, DNUoS, electricity supplier and market costs. **Our proposal is that NGG should pass through these costs**.

5.20. NGG also proposes that its energy efficiency volume is priced at the traded price of carbon in order to give an environmental target adjustment. **Our proposal is that this adjustment is not included in the scheme target cost.** NGG's compressors are already subject to the EU ETS[30] and CRC Energy Efficiency schemes[31] which provide NGG with incentives to incorporate the environmental efficiency dimension into its decisions.

5.21. As outlined in our January document, we consider that it is appropriate to align the SO's incentive with respect to shrinkage with the TO's incentive rate, i.e. efficiency factor. Under RIIO-T1 our current proposal is for an efficiency factor of 45%. **Our proposal is for the same sharing factor to be applied with respect to Shrinkage.** We will do further analysis on the target after NGG's consults with stakeholders on its methodology statement, and on that basis, we will consider whether NGG's proposal to increase the cap and floor is appropriate.

5.22. A summary of our proposals for the Shrinkage cost scheme is included in Table 7.

[29] The value of the uplift for 2012/13 is 0.1185p/KWh. The £2.2m figure is obtained by multiplying the net volume of day ahead and within day trades in 2011/12 by the value of the uplift in 2012/13.
[30] Details on this scheme, including implementation of Phase III of the EU ETS scheme can be found at www.decc.gov.uk/en/content/cms/emissions/eu_ets/eu_ets.aspx
[31] Details on this scheme can be found at www.decc.gov.uk/en/content/cms/emissions/crc_efficiency/crc_efficiency.aspx

Table 7: Summary of our proposals for a Shrinkage cost incentive

	Long term	Short term
Volume	UAG: 90 day historic rolling average	UAG: Outturn
	CV Shrinkage: (as in methodology statement) – based on network analysis	CV Shrinkage: (Outturn – energy efficiency level)
	CFU: (as in methodology statement) – based on network analysis (initially continuation of regression modelling)	CFU: (Outturn – energy efficiency level)
Price	Nine month rolling average	Short term (e.g. week ahead)
Environmental costs	No environmental adjuster included	
Other costs	Pass through those NGG has no control over	
Sharing factors	+/- 45%	
Cap/floor	To be determined after NGG's consultation on methodology statement for setting the target.	
Length	8 years	

2013/14 Shrinkage incentive

5.23. We note that because of the inclusion of a forward reference price in the Shrinkage incentive, provision was made in NGG's transporter licence for the reference price to be in place during 2012/13 for the procurement of shrinkage gas to be delivered in 2013/14 based on the current incentive[32]. We would therefore expect that NGG's current forward procurement of shrinkage gas takes into account this reference price. However, we recognise that our initial proposals set out an alternative reference price for the procurement of gas, and also a forward reference price for the procurement of electricity that is more forward looking than the current incentive scheme. Following the outcome of this consultation, should our Final Proposals be for reference prices that amend those currently provided for in the transporter licence, we recognise that we may need to make interim provision, such that the reference price is not amended midway through NGG's procurement period.

[32] Because of the month ahead nature of the current forward price for electricity procurement, there is no similar provision in NGG's transporter licence.

Operating Margins Cost Incentive Scheme

Background and context

5.24. As we discuss in Appendix 4, NGG procures operating margins gas as part of its SO role. Operating margins gas is the volume of gas that NGG is able to call on in a variety of circumstances, one example being to maintain system pressures in the event of system failure. The volume of gas to be procured is determined as part of its Safety Case. NGG currently has in place a cost incentive scheme regarding the overall cost of the OM gas it procures. NGG has an annual cost allowance that covers charges for both the availability of gas and for utilisation of the available volumes[33].

5.25. The objective of this incentive scheme is that once the required volume of operating margins has been determined under its Safety Case, NGG procures this gas at least cost. NGG procures this gas via an annual tender round and any gas it cannot procure through the tender can be sourced from NGG's own LNG terminal at regulated prices set out in its licence[34].

Summary of our consultation proposals and responses

5.26. In our January consultation we set out our view that the operating margins cost incentive should take the same form as the current incentive scheme. By extending the scheme length beyond the current two year scheme the SO will be incentivised to explore opportunities for entering into longer term contracts with potential operating margins providers and explore potential new sources for operating margins gas.

5.27. Our view was that it was unlikely that a cost target could be set for the full eight year period but agreeing a methodology for determining a cost target fit for purpose for an eight year scheme was possible. We also said that the sharing factors for any cost scheme should be +/- 20%, similar to the current sharing factors applied to OM costs. Unlike proposals for some other cost/output schemes we did not propose to increase the sharing factors to be in line with those of the TO price control because there is limited interaction between the procurement of OM gas and NGG's TO activity.

5.28. Three respondents to our consultation commented on our proposals for an OM procurement cost scheme. The AEP suggested we were not clear as to whether we had proposed a reputational or financial incentive. It supports a long term incentive and suggested that NGG is allowed to enter into long term contracts although it was uncertain that setting a methodology for eight years would be appropriate. NGG

[33] As NGG mainly utilises OM gas for safety reasons the cost allowances cover both availability and utilisation so that NGG has an incentive to take into account unit charges for using the gas when procuring OM gas.
[34] Special Condition C3 of NGG NTS's licence sets out the price cap for NGG's LNG storage services procured for the provision of operating margins.

supported maintaining an OM cost scheme but had a concern that any proposals should not incentivise it to minimise the OM volumes that are a Safety Case requirement. SSE stated its support for continued use of existing methodologies within the context of longer term schemes.

Summary of NGG's proposals

5.29. NGG is currently undertaking a review of OM to ensure that the definitions and calculation methodology remain fit for purpose for the RIIO-T1 period. This review will not be concluded until autumn 2012. NGG therefore proposes that there should be no financial incentive for OM for 2013 and that the costs of OM are passed through. NGG considers that arrangements, including the option of introducing a financial incentive for the remainder of the RIIO-T1 period, should be discussed further once its review is completed.

Our proposal and next steps

5.30. Having considered this issue further and taken account of NGG's proposals and the consultation responses, we think that it may not be appropriate at the current time to put in place a cost incentive in respect of NGG's procurement of OM gas. There are a number of reasons why we have reached this view:

- The volume procured by NGG is set by the requirements of NGG's Safety Case.
- The value of the OM activity is relatively low (< £20m per annum).
- The results of the review that NGG is currently undertaking in respect of the provision of OM will not be known in time to set an April 2013 incentive.
- The requirement to continue to develop contestability in OM backed by regulated prices should be sufficient to ensure value for consumers without a separate financial incentive.

5.31. **It is our proposal that we will not implement a cost incentive on operating margins gas for the gas SO from April 2013.** In Appendix 4 we set out our proposal for a reputational incentive in respect of operating margins. As part of this incentive NGG will be required to report on the costs that it is incurring in respect of the provision of OM. Should the costs reported increase from the current levels, or should we consider that the costs incurred do not represent value for money for consumers we will then reconsider whether it is appropriate to put in place a cost incentive. We will also reconsider this decision in light of the outcome of NGG's review of its procurement of OM.