Informal Consultation

Potential Enhanced Electricity Transmission Owner (TO) Incentives

Potential TO incentives for timely grid connection and minimisation of network constraint costs

Version 1.0

Issued 18th September 2009

Responses requested by 16th October 2009

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Executive Summary

This informal consultation seeks to explore at a high level whether there are benefits in pursuing potential approaches to enhance:

- the timely connections to the transmission networks, particularly in the context of the current 'Interim Connect and Manage' regime and;
- TO measures to contribute to the minimisation of network constraint costs which significantly have risen in recent years.

The overall objective of this consultation is to highlight all the potential measures to enhance the role of the transmission companies within the existing SO/TO interface arrangements and to consider whether further new or revised approaches to incentivising transmission companies in relation to some key transmission activities are desirable. These developments cover a spectrum of possibilities, some of which could be taken forward in the short term, namely for implementation by 1 April 2010, and some of which are probably areas for development in the longer term, which can then be built on in subsequent years.

This work interacts strongly with achievement of broader government energy policy objectives, reform of transmission access arrangements and the incentives being progressed through the parallel reviews, for example the consultation on the development of SO Incentives for constraints which was published on National Grid's website on 9th September and the consultation on Enhanced Transmission Investment Incentives published by Ofgem on 8th September.

The specific topics considered within this consultation are:

- potential incentivisation of earlier completion of local works associated with connecting new generation;
- potential changes to the current interface arrangements in place between the System Operator (SO) and Transmission Owner (TO) functions; and
- potential new or revised models for incentivising TOs in relation to activities which influence network constraints.

We are seeking high level views on the merits of progressing enhancements or changes to role of the TOs within the existing interface framework, revisions to existing incentive arrangements or the introduction of new incentive arrangements in these areas.

Responses to this consultation will be published on National Grid's website (unless a specific request is made not to) and all responses will be sent in full to Ofgem. Responses to this consultation are requested by 16th October 2009.

Responses to this consultation s
soincentives@uk.ngrid.com
by 16th October 2009

Section 1
Introduction

1.1 Introduction

1. There are currently three licensed electricity transmission companies in Great Britain. National Grid Electricity Transmission plc (herein known as National Grid) owns the high voltage transmission network in England and Wales. Scottish Power Transmission Ltd (SPTL) and Scottish Hydro Electricity Transmission Ltd (SHETL) each own high voltage transmission networks in Scotland. In the context of this document these roles are collectively referred to as Transmission Owners (TOs) and in this document SHETL and SPTL are referred to as “STOs”.

2. National Grid also undertakes the role of the National Electricity Transmission System Operator (SO) and has overall responsibility for the secure real time operation of the national transmission systems and the residual balancing of generation and demand.

3. The transmission companies are revenue regulated monopolies and their regulated activities are funded, and performance incentivised, through ‘price control’ arrangements. The price controls are specific to each company and currently reviewed by Ofgem every five years, with the current transmission price control period expiring in 2012. National Grid is also incentivised in relation to its management of the costs of balancing the system through the Balancing Services Incentive Scheme “BSIS” which has tended to be agreed annually.

1.2 Purpose of this Consultation

4. This informal consultation seeks to explore at a high level whether there are benefits in pursuing potential approaches to enhance:

- the timely connections to the transmission networks, particularly in the context of the current ‘Interim Connect and Manage’ regime and;
- TO measures to contribute to the minimisation of network constraint costs which significantly have risen in recent years.

5. The overall objective of the options covered by this consultation is to highlight potential measures to enhance the role of the TO within the existing SO/TO interface arrangements and to consider whether further new or revised approaches to incentivising transmission companies in relation to some key transmission activities are desirable. These developments cover a spectrum of possibilities, some of which could be taken forward in the short term, namely for implementation by 1 April

2010, and some of which are probably areas for development in the longer term, which can then be built on in subsequent years.

6. This work interacts strongly with achievement of broader government energy policy objectives, reform of transmission access arrangements and the incentives being progressed through the parallel reviews, for example the consultation on the development of SO Incentives for constraints[1] which was published on National Grid's website on 9th September and the consultation on Enhanced Transmission Investment Incentives[2] published by Ofgem on 8th September.

7. Ofgem has asked National Grid, following discussion with SPTL and SHETL to publish this consultation on an informal basis to seek the views of stakeholders and other interested parties as to the potential benefits.

8. The material presented in this document should not be taken as firm proposals from National Grid, SPTL or SHETL. It is simply meant to facilitate stakeholders' understanding of the high level possibilities and give them a means to assess the desirability of pursuing further potential measures to enhance the role of the transmission companies to better achieve specific outcomes. Depending on responses to this consultation, proposals for change may be brought forward for further consideration later this year.

9. There is potentially some interaction between the issues contained within this document and other areas of transmission arrangements which are currently under review and this interaction is explained below. Section 2 of this consultation also sets out how the potential incentives covered by this consultation are part of a wider set of incentives on transmission activities being progressed currently.

1.3 Scope and interaction with other reviews

10. Ofgem is leading on the development of an enduring framework for enhanced transmission investment incentives to encourage early anticipatory investment in transmission network capacity to ensure timely investment in wider transmission infrastructure. As highlighted in the previous section, Ofgem is progressing enhanced transmission investment incentives to put in place a regulatory framework for anticipatory network investment to encourage Transmission companies to invest in major network infrastructure ahead of full user commitment that could commence during the current price control period.

11. Building on the objective of ensuring the timely delivery of network investment covered in the above publication, **this consultation seeks**

[1] http://www.nationalgrid.com/uk/Electricity/soincentives/docs/

[2] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?file=September%20Consultation_090908.pdf&refer=Networks/Trans/ElecTransPolicy/tar

views in relation to the incentivisation of National Grid as TO in the first instance (and the STOs more generally) for earlier completion of local works associated with connecting new generation where customers desire this.

12. National Grid is currently leading the initial stages of industry engagement and consultation in relation to its SO incentives from April 2010. A key part of that review is to consider appropriate incentives on National Grid as SO to minimise constraint costs, primarily through the procurement and use of balancing services. As highlighted in the previous section, National Grid recently published a consultation on the development of SO Incentives for Constraints.

13. Consistent with the objective of minimising constraint costs across all timescales, **this consultation seeks views on potential changes to the interface arrangements between the SO and TOs and also whether further new or revised approaches to incentivising TOs to minimise constraint costs may be desirable.** These potential changes are designed to improve the management of System Capacity in relation to minimising constraint costs.

14. Following a long history of industry development and debate in relation to transmission access reform, in June Ofgem advised the Secretary of State for Energy to use his powers under the Energy Act 2008 to implement new transmission access arrangements to facilitate achievement of the government's renewable energy and climate change objectives. The Department of Energy and Climate Change (DECC) has recently issued a consultation in relation to enduring transmission access arrangements[3].

15. We are currently of the view that the transmission incentivisation issues considered in our consultation are unlikely to be undermined by new transmission access arrangements that may be implemented.

1.4 Document Structure

16. The remainder of this document is structured as follows:

- Section 2 sets out the background that has led us to bring forward this consultation on potential new or enhanced transmission incentives.

- Section 3 considers new or revised models of investment incentives associated with the timely connection of generation to the transmission system.

[3] http://www.decc.gov.uk/en/content/cms/consultations/improving_grid/improving_grid.aspx

- Section 4 considers potential developments in relation to the SO/TO interface arrangements which could contribute to minimising constraint costs.

- Section 5 considers potential for new models of direct incentives on TOs which may contribute to the minimisation of constraint costs

- Section 6 provides a consolidated list of consultation questions.

- The final page provides contact details in relation to this consultation and the SO incentives consultations.

1.5 Consultation Responses

17. Responses to this consultation will be published on National Grid's website (unless a specific request is made not to) and all responses will be sent in full to Ofgem. Responses to this consultation are requested by 16 October 2009.

Responses to this consultation should be sent to soincentives@uk.ngrid.com

by 16 October 2009

Section 2
Background and Key Drivers

2.1 Government's Energy and Climate Change Policy

18. The UK is committed to well documented 2020 and 2050 targets in relation to greenhouse gas emissions and renewable energy. The electricity sector has a major role to play in achieving these targets. Following its Energy White Paper, published in 2007, the Government published in July this year its National Strategy for Energy and Climate and its UK renewable energy strategy[4] which along with other measures sets out a path to meeting these targets.

19. The connection of significant amounts of low carbon generation to the electricity transmission networks is integral to achieving the UK's targets and therefore removing potential barriers to this and facilitating quicker connection has been and continues to be essential. The action areas set out by Government in the renewable energy strategy which are pertinent to Transmission Owners relate to:

- More strategic investment in the grid
- Investment in a new offshore grid
- Quicker and fair connection to the grid
- A smarter grid

20. The focus of Section 3 of this consultation is primarily associated with the third action area and considers the role that financial incentives on Transmission companies could play.

21. It is also useful to consider the progress and status of other aspects of the industry arrangements which influence connection and access to the transmission networks to provide context.

2.2 Transmission Access Review

22. Ofgem and the Department for Business, Enterprise and Regulatory Reform (now the Department for Energy and Climate Change (DECC)) established the Transmission Access Review (TAR) in August 2007 following publication of the Energy White Paper. The review considered the current arrangements for accessing the Transmission system from a technical, commercial and regulatory perspective. The review set out a number of high level principles upon which enduring access

[4] http://www.decc.gov.uk/en/content/cms/publications/lc_trans_plan/lc_trans_plan.aspx

arrangements should be based[5]. The review found that reform of the current transmission access arrangements and enhancements to the financial incentives on transmission companies are required to meet these principles.

23. Potential reforms to the transmission access arrangements were progressed by industry through normal code and charging governance routes. On 25th June 2009 the Gas and Electricity Markets Authority recommended to the Secretary of State that he use his powers under the Energy Act 2008 to facilitate reform of transmission access as, in its view, the industry had not delivered appropriate reform proposals. DECC has recently issued a consultation on transmission access reforms.

24. In relation to incentives on transmission companies, one of the TAR principles was agreed as:

"Transmission companies need to have appropriate incentives to respond to the long term demand for access signalled by generators. They need the freedom and incentives to invest ahead of full user commitment. They also require appropriate incentives to deliver new connections on time and to innovate so that they can deliver as much capacity as possible from the existing assets."

25. This has been a guiding principle in relation to defining the incentive areas considered within this document and also our approach to reviews of incentives in other related areas.

2.2 Interim Connect and Manage

26. On 8th May 2009 Ofgem issued a decision letter which established the approach of using derogations from the National Electricity Transmission Security and Quality of Supply Standards (the "SQSS") to facilitate the earlier connection of generation to transmission and distribution networks, for an interim period ahead of an enduring transmission access regime.

27. This effectively means that the current access model is 'connect and manage' where, following the granting of a derogation and completion of certain local works, generators may access the system ahead of wider reinforcement works which would otherwise have been required to comply with the requirements of the SQSS. This is a significant step toward connecting generation earlier, but means that the generation access rights sold are likely to significantly exceed the capability of the

[5] The principles are set out in the TAR Final Report http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=84&refer=Networks/Trans/ElecTransPolicy/tar

transmission network in the short to medium term which in turn will increase constraint costs over these timescales.

2.3 Constraint Costs

28. Even before Interim Connect and Manage was established, constraint costs in GB were at significant levels and are forecast to rise considerably, this was largely as a result of the introduction of BETTA. Prior to the introduction of BETTA, the commercial capability between England and Scotland (known as the Cheviot boundary) was specified in the Interconnector Agreement. The capability of the Cheviot boundary was determined by benchmarking analysis that reflected the Security and Quality of Supply Standard criteria under specific background conditions. At the time of the introduction of BETTA, the Cheviot boundary was restricted by a thermal and stability winter limit to a nominal 2.2GW transfer. The introduction of BETTA removed this commercial agreement and parties who had acquired internal Scottish access rights for existing, or soon to be commissioned, generation had these rights transferred into GB access rights under the Connection and Use of System Code (CUSC). However, the capability of the Cheviot boundary could not accommodate these new commercial requirements.

29. In response to both this, and the desire to connect significant amounts of renewable generation in Scotland, the relevant transmission companies have embarked on a programme of reinforcement and expansion (known as the Transmission Investment for Renewable Generation (TIRG) works) that goes some way to alleviate this transmission capacity shortfall. Furthermore, as highlighted in the previous section, Ofgem is progressing enhanced transmission investment incentives to provide an appropriate framework to facilitate additional investment within the current transmission price control which will further help to alleviate this transmission capacity shortfall.

30. Constraint costs in recent years have been exacerbated by outages required to complete the TIRG works and general reinforcement works necessary to connect new generation. The introduction of Interim Connect and Manage will allow increased levels of generation to connect before wider reinforcement works are completed. It is anticipated that this will result in increased constraint volumes and therefore constraint costs.

31. Constraint costs have also increased in recent years within the England & Wales networks. This has largely been driven by a combination of fault outages, unusual weather (flooding in Yorkshire and the South-West), and limitations in plant running with LCPD[6]. With the equipment that makes up the transmission network reaching the end of its operational

[6] LCPD is the "Large Combustion Plant Directive"

life there has also been an increase in the number of outages required to perform maintenance or replacement.

32. In a letter to National Grid in February 2009[7], Ofgem asked it to conduct an urgent review and consider measures that might reduce constraint costs and also consider whether the charging arrangements are equitable. National Grid has progressed modifications to the relevant commercial frameworks which seek to reduce constraint costs.

33. Over the past few years constraint costs have risen from £84m in 2005/06 to our latest projection for 2009/10 of £234m. Constraint cost forecasts are being considered as part of the SO incentives consultation process which is running in parallel with this consultation. However, it is clear that with an interim connect and manage regime that aims to connect additional generation capacity, the system will be increasingly congested and therefore constraint costs will continue to rise until additional system capacity can be constructed. It is appropriate to ensure that all measures which may contribute to minimising these cost impacts on consumers are considered.

2.4 Transmission Regulatory Incentives

34. The Transmission Price Control Review 4 (TPCR4) main price control which operates until 2012 provides the transmission companies with strong incentives to reduce their operating costs and to reduce the costs of investing in their networks. These incentives alone may not deliver the outcomes required to deliver Government's energy and climate change strategy. There are currently a number of initiatives considering what appropriate Transmission incentives might be going forward. Some of these may deliver changes in the shorter term (i.e. by April 2010) and some in the longer term.

35. As highlighted in the previous section, Ofgem is progressing enhanced transmission investment incentives to put in place a regulatory framework for anticipatory network investment to encourage Transmission companies to invest in major network infrastructure ahead of full user commitment that could commence during the current price control period. Ofgem has stated that this could be in place by 2010.

36. National Grid also has a System Operator incentive scheme (BSIS) that incentivises it to minimise the costs of operating and balancing the system which includes minimising constraint costs. This incentive is currently set annually and is under review in parallel with this consultation. One of the key issues for consideration within this separate consultation is whether constraint costs should be separately incentivised from other balancing costs and whether it is possible to

[7] http://www.ofgem.gov.uk/Markets/WhlMkts/EffSystemOps/SystOpIncent/Documents1/20090217Managing%20constraints.pdf

establish a longer term incentive from April 2010 (initially for 2 years). One of the drivers of constraints detailed within the recent BSIS consultation is the management of System Capacity[8], influenced by the TOs in relation to:

- Maintenance
- Repairs
- Fault outages
- Asset replacement
- System reinforcement
- Timing of completion of new demand or generation connections

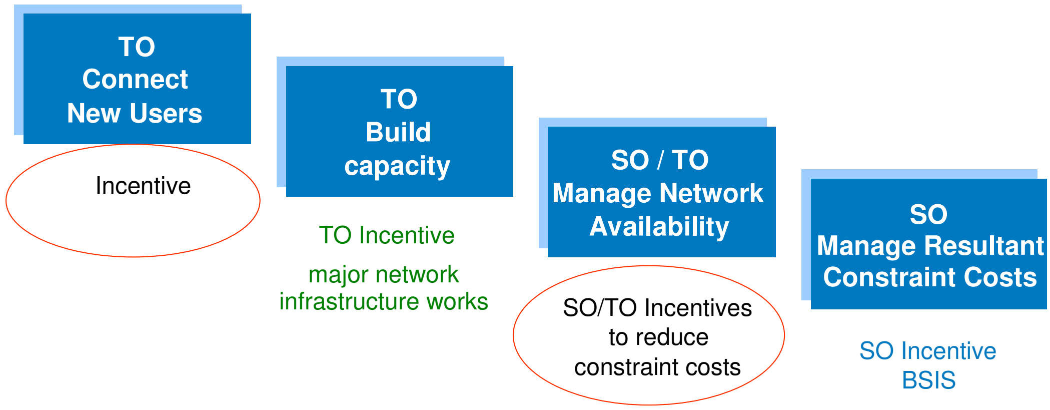
37. Ofgem is also conducting a major review of network price control arrangements through its RPI-X@20 project. This is considering holistically what the appropriate regulatory price control arrangements for networks should be going forwards. However the outcomes of this review will only be implemented from the next transmission price control review (2012) at the earliest.

2.5 This consultation and next steps

38. Against a background of achieving government energy and climate change policy goals, reform of transmission access arrangements and the likely short to medium term rise in constraint costs, this consultation considers whether potential measures to enhance the role of the transmission companies within the existing SO/TO interface arrangements are required or further new or revised transmission incentives are desirable. Specifically it considers potential developments and incentives around the timely connection of generation to the transmission systems and TO influences on constraint costs. These developments cover a spectrum of possibilities, some of which could be taken forward in the short term, and some of which are probably areas for development in the longer term.

39. The incentives considered in this consultation, in conjunction with incentives being progressed through the parallel reviews outlined above could come together to create a package of incentives covering major aspects of the transmission regime which align with achieving government policy objectives and delivering value to electricity consumers.

[8] Further detail on the drivers of constraints and their interactions can be found in section 2.5 of the consultation detailed above.



40. As transmission access developments become clearer over the course of the next few months, it may point to other areas in which transmission related incentives could be developed to complement an enduring transmission access regime.

41. Clearly transmission incentives are only one aspect of the broader commercial and regulatory frameworks which govern the GB transmission and wholesale market arrangements and National Grid continues to work with industry to develop these arrangements to better facilitate its licence objectives and the interests of consumers. National Grid is also committed to continuing to work closely with the STOs to identify practical ways within the existing frameworks to improve collaborative and co-ordinated working, information exchange and the sharing of best practices across a range of activities.

42. We are seeking high level views on the merits of progressing enhancements or changes to role of the TOs within the existing interface framework, revisions to existing incentive arrangements or the introduction of new incentive arrangements in these areas. . Depending on responses to the consultation, initial proposals may be brought forward later this year.

43. Responses to this consultation will be published on National Grid's website (unless a specific request is made not to) and all responses will be sent in full to Ofgem. Responses to this consultation are requested by 16 October 2009.

Section 3
Investment Incentives for Grid Connections

3.1 Introduction

44. Each transmission Licensee has a general licence obligation to develop an efficient, economic and co-ordinated transmission system which covers all of its licensed activities. Whilst the connection of new parties to the system is covered by this general licence obligation, the main transmission price control also provides both funding and financial incentives in relation to this activity (as well as others).

45. Given government's emphasis on the timely connection of new generation to the system, and the establishment of an 'interim connect and manage' transmission access regime being a potentially significant step to achieving this ahead of wider network reinforcements, this section of the consultation considers whether it is desirable and appropriate for the transmission price control investment incentives arrangements for the completion of local works to specifically incentivise timely grid connections. Investment incentives for wider works are covered within Ofgem's consultation on Enhanced Transmission Investment Incentives as highlighted earlier.

3.2 Current Connection Process

46. The current connection process starts with an application received by National Grid from the customer requiring a new connection. This is the trigger for National Grid to process the application and to make an offer to the customer within 90 days. During this 90 day period National Grid performs analysis on the request and by assessing the new application against all other active signed contracted connections determines how National Grid can meet the customer requested connection date considering both local works[9] (works required for physical connection) and wider system works (infrastructure works required to meet SQSS requirements).

47. Once an offer has been made to the customer there is a further 90 day period to allow for post offer negotiations where there is open dialogue between National Grid and the customer to either sign the offer as it stands or to make amendments that best meets the customer's requirements.

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[9] Further guidance on the definition of local works can be found in the document "National Grid Guidance on Interim Connect and Manage" - http://www.nationalgrid.com/NR/rdonlyres/428758BB-9578-4F57-847E-53E20063BCAE/35345/NationalGridGuidanceonICMv10.pdf

48. In Scotland this process is much the same apart from the STOs perform the analysis and work with National Grid to agree a connection date. This arrangement is then formalised in a contract between National Grid and the relevant STO.

49. Under the Interim Connect and Manage (ICM) regime, the works that play a part in determining the connection date are only those which are deemed ‘local’. The wider transmission reinforcement works required to make a fully compliant connection is no longer required to allow us to make a connection offer, but the non-compliant connection is subject to approval of a derogation against the SQSS by Ofgem. Once the customer signs their offer, National Grid submits this request for derogation.

50. Since the implementation of ICM, National Grid has contacted all those customers that had expressed an interest through the quarterly reports to advance their connection. As of September 2009, this totals around 5GW of new generation. In Scotland revised offers have been made to 450MW of generation with a further 900MW currently being processed. For England and Wales, approximately 1.6GW has submitted modification applications to advance their connection dates.

3.3 Factors which affect connection dates

51. Every project is unique and when looking at the total build programme there are many factors that can impact a proposed connection date. The extent to which each of these factors impact on the connection varies dependant on the type, location and timing requested connection. Under ICM a connection date is now only dependant on the completion of local works (subject to approved derogation) and hence less works are required therefore fewer system access and consenting is required but will still remain on the critical path for many projects. The key factors are described below:

Planning and consents

52. This is a major undertaking to achieve the planning and consents required to construct National Grid’s assets to facilitate a connection and is largely outside of National Grid’s control. The planning regime is currently undergoing significant reform following the recent passing of the new Planning Act. It is currently uncertain as to exactly how the new planning regime will operate in practice and, therefore, how it will influence timescales for progressing infrastructure consents.

Equipment manufacturing slots

53. With the large amount of world wide investment in electricity networks obtaining slots with manufacturers to produce the required equipment to install can have a significant lead time.

Financial exposure and risk

54. In the current regime, connection projects costs are delayed for as long as possible but just in time to meet the contracted connection date. The primary reason for this is that the customer wants to minimise the amount of securities National Grid requires it to lodge to secure the transmission investment. This is so that in the event that the project is terminated their termination fees are minimised and also so that very early on in a project (perhaps before financial closure is obtained) the customer is not required to find significant sums for securities.

Outages on the transmission network

55. With the current level of construction activity on the transmission systems due to the level of new generation connecting and the high level of asset replacement being undertaken to facilitate TIRG and the work that may come from the enhanced transmission investment incentives, it can be difficult to schedule outages as the demands for outages on critical circuits can be high and the availability of outages is generally low.

Economic and efficient investment

56. National Grid's licence obligations are to deliver economic and efficient investments. This means that the network we construct is based on just in time delivery once user commitment has been given.

3.4 Potential 'levers' to minimising local works lead-time

57. In each of the areas outlined above there are a range of approaches which could help to expedite factors that could influence connection dates, that generally increase costs and risks to both the TO (SPT in south of Scotland transmission area, SHETL in the north of Scotland transmission area and NGET in England and Wales) and potentially the connectee:

58. The TOs could start the planning and consenting process immediately following receipt of a signed offer, rather than working backwards from the connection date, or start the planning and consenting process on receipt of the application i.e. before an offer is made. This would lead to many aborted attempts as approximately only 1 in 3 applications make it to a signed offer. In extremis, we could proactively seek planning and consents for connections to the network ahead of any application where we deem there to be a high probability of a future connection requirement. This could lead to potentially high aborted costs on many projects as connection applications may not arrive. Also there could be a loss of credibility with the relevant planning and consenting authorities which would make real planning and consent requirements difficult to achieve.

59. The TOs could book earlier slots with manufacturers and commit to spending large sums of money much earlier than today in the connection process. This would require customers to financially secure larger sums of money much earlier than otherwise would be the case. If the customer was to terminate following a factory order, the TOs would seek to store and re-deploy the equipment into other suitable projects. Again taken to extreme, factory slots could be booked speculatively to have standard equipment manufactured to be used for a future application. The cost exposure is high and could result in having to store unused equipment for periods of time and finance capital expenditure much earlier than currently.

60. Generally committing larger sums of money into a construction project earlier on can advance a connection date e.g. with contractors – however the customer is exposed to higher termination costs before their own planning and consenting and financial security may be known.

61. In relation to construction works and outage requirements, construction works can be advanced by shortening the outage length where possible (e.g. by constructing temporary circuit bypass arrangements). This would allow for a quicker build and a shorter network access requirement. To further accelerate connections then this approach may need to be applied to many other projects to shorten their network access times to create the space for connection activities earlier in the outage programme. Additionally it may be possible, but more expensive to develop and construct on a ‘greenfield’ site to enable construction to proceed without the restrictions around physical access and other constraints that are imposed when working on an existing ‘live’ site. The majority of arrangements that are currently envisaged to accelerate outage requirements will require additional operating or capital expenditure.

62. Each of these areas has varying degrees of risk, cost and acceleration timescales associated with them that are dependent on the specific project in question. The purpose of highlighting these areas is to give some indication of the sorts of activities that could be employed in relation to the completion of local works to allow earlier connection dates to be offered.

3.5 TPCR4 investment incentives for ‘local works’

63. The current transmission price control settlement contains mechanisms for funding and incentivising capital expenditure (capex).

64. The TPCR4 capex arrangements for the STOs are different to those established for National Grid. National Grid’s price control settlement provides a ‘baseline’ capex allowance which is based on a scenario of expected generation connections (and demand changes) across a

number of defined zones. In most zones the 'baseline' for expected connections is zero. A unit cost allowance (UCA) is defined in respect of each zone to represent 25% of the average deemed efficient capex cost of providing a unit of local works associated with a unit of generation connection. UCAs vary by zone and are set out in the relevant transmission licences.

65. The UCA mechanism is intended to make an adjustment to the overall capex allowance that National Grid is managing within the price control period. It provides some additional capex in the event that more generation connects (net of demand changes and generation closures) than was assumed in the baseline scenario. The UCA also acts to reduce the capex allowance in the event that less generation connects than was assumed in the baseline scenario.

66. The operation of the UCA for a generation connection is as follows. The capital expenditure incentive effectively allows 75% of capex spent on the local works associated with the new connection to be passed[10] into the Regulatory Asset Value (RAV).. Hence funding for 75% of the capex required for a new connection is provided through the RAV at normal rates of return. The remaining capex is funded and incentivised through the UCA which provides a one-off revenue adjustment at the time of delivery (i.e. in the year following connection) based on 25% of an assumed average unit capex cost. The UCAs for National Grid include an allowance for financing the UCA assumed unit capex amount over an assumed capex spend period of 4 years leading up to connection.

67. The operation of these revenue adjusting mechanisms occurs in the 'background' and the results feed into the next price control review process and therefore do not alter actual revenues in the current price control period and therefore do not contribute to within-control transmission charge variations. However these arrangements do provide incentives on National Grid to:

- Finance capex at lower than the assumed cost of capital
- Find efficiencies at every stage in the process to reduce capital spend
- Forecast correctly demand changes and the closure of generation

68. Some of the incentives implicit in the current 'local works' element of the price control may not be consistent with the timely connection of generation, depending on the generator's desire for a prompt connection date. By analysing the current arrangements in more detail it can be shown that National Grid's price control :

- provides a significant downside if capex is incurred over a period greater than four years;

[10] Subject to a certain criteria being met and an efficiency test at the next price control

- provides a significant downside if capex is incurred in excess of the amount deemed in the UCA;
- provides no financial benefit for delivering a connection ahead of the customer need (i.e. the contracted delivery date);
- provides no incentive to agree an earlier delivery date even if a shorter duration connection is feasible; and
- provides a marginal benefit in spending capex as late as possible

69. In summary, the current price control for NGET as TO in E&W provides upside opportunity and downside risk in relation to incurring capex costs against the current UCA, and in respect of timescales, provides only a downside risk for delivering connections that take longer than 4 years in duration. However it is clear that the current price control does not encourage (in fact penalises) incurring higher than assumed capex costs to achieve earlier connection dates and does not encourage earlier capex spend that is likely to be required to achieve this.

70. Given that we are now in an interim connect and manage access regime, and there is uncertainty around what the enduring arrangements will be, we believe it would be possible to progress improvements to the TPCR4 investment incentives in the short term.

71. The TPCR4 capex arrangements for the STOs are different to those established for National Grid. For the STOs, Ofgem introduced local revenue drivers to adjust allowances to address differences between the generation assumptions Ofgem used to set the baseline allowances with what generation actually goes ahead. If generation growth is more rapid than the baseline then revenues for local connection works are adjusted dynamically during the price control period to ensure that the STO cash flow position does not deteriorate unduly if the volume of generation connections is higher than what has been assumed in the baseline. In effect, once the baseline volume of generation has been connected, additional allowances depend on the volume of extra generation connected, and also a proportion (75 per cent) of the actual costs of work-in-progress for the more advanced new connection projects. Ofgem also introduced deep revenue driver arrangements for the STOs. These revenue drivers are triggered when a specified cumulative amount of generation is signalled or connected in specified geographical areas. These arrangements allow for additional deeper infrastructure projects, that were not included when setting the baseline allowance, to be funded.

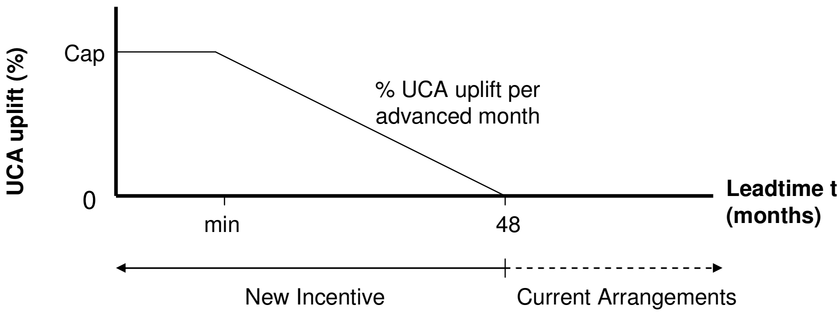
72. The STOs have indicated that they do not believe the issues identified in this section are applicable to their current price control arrangements, due to the significant differences in their price control arrangements.

3.6 Potential enhancement to National Grid's incentives

73. Notwithstanding the current price control incentives, National Grid is committed to connecting new customers to its network in an efficient and economic manner. Considering the incentive properties that are provided by the current price control arrangements it would be possible to further align these arrangements with customers' potential desires for timely connections.

74. Providing an incentive to agree to and complete local works in faster than normal timescales where customers want to connect quickly could provide benefits to consumers through increased competition and potentially lower carbon emissions. An incentive for local works would work in conjunction with investment incentives for wider works as covered within Ofgem's consultation on Enhanced Transmission Investment Incentives.

75. Such an incentive could be achieved through a relatively simple enhancement to the existing arrangements by establishing a sliding scale UCA 'uplift' which would apply to new connections which were delivered earlier than the current price control timescale assumption. In England and Wales this timescale assumption would be the 48 months that underpins the current UCA. This concept is described below:



76. As the UCA is effectively 'pay on delivery' (i.e. the actual connection date) then the transmission company will only qualify for the UCA uplift associated with the actual connection lead-time achieved. Therefore the incentive to deliver to the timescale originally agreed is maintained throughout the build period through to completion. The transmission company faces an exposure if it cannot deliver as it may not qualify for the UCA uplift and therefore may be penalised under the current price control mechanisms for overspend (i.e. the loss of the uplift would see National Grid pay any higher capex costs paid to achieve earlier connection dates) or longer than assumed duration.

77. Consider an example where a customer wants a generation connection in 36 months time under interim connect and manage. By establishing a sliding scale UCA uplift for a connection with an earlier lead time then National Grid would have an incentive to seek to identify ways of potentially achieving that specific connection in 36 months to qualify for the UCA uplift. If it believes it can meet this timescale then, it will enter

into a connection agreement (and design and build agreement) to this effect.

78. The incentive provided is for National Grid to seek to identify ways of achieving the customers' timescale requirement and acts to align the transmission company's interests with those of each individual connecting customer and, in a broader sense, government energy policy goals.

79. The potential advantages of enhancing the current arrangements are that it:

- provides an incentive for transmission companies to innovate to achieve the connection dates that customers desire;
- recognises that customers may require differing connection timescales;
- retains an overall incentive to minimise costs;
- recognises that the scope for achieving advancement may be different for each project (e.g. depending on planning consent requirements) and therefore potentially achievable timescales will vary between projects; and
- is relatively simple and could be relatively quickly progressed as it is an incremental change to price control mechanisms and therefore parameters such as efficient benchmark costs (UCAs), zonal differences, assumed lead-times for remuneration purposes and the feed into transmission charging are already established.

80. The potential disadvantage to such an incentive is that even with an incentive it may still lead to a situation whereby National Grid would only give an enhanced timescale where it would be definite that it could achieve the connection timeline. In addition, where significant additional costs are required for early connection the incentive may not be sufficiently strong.

Consultation Questions	
3/1	Do you believe there is a role for incentivising accelerated completion of local works and therefore the connection of new generation in England & Wales? Do you believe there is a requirement for such a role in Scotland?
3/2	Do you believe that the potential enhancement outlined which balances National Grid's current price control incentives in respect of timescales is an appropriate model, or are there others that should be considered? Given the incentive properties that are provided by the current price control arrangements in Scotland, do you believe it would be possible to further align these arrangements with customers' potential desires for timely connections?
3/3	Do you believe the potential incentive correctly balances the risk and reward/penalty for National Grid?
3/4	If you presently have future transmission connection interests, in

	principle, could you be seeking a grid connection date which is less than 4 years from signing the connection offer?

Section 4
SO/TO Interface Issues

4.1 Introduction

81. The availability of transmission circuits is one of the key factors that drives constraint costs. A separate consultation document discussing the development of SO incentives[11] in relation to constraint costs has been published by National Grid that provides a more detailed explanation of the various causes of network constraint costs. This consultation focuses on TO influences on constraint costs through network outages which generally reduce the capability of the network to transfer power flows.

82. All Transmission companies have to take circuit outages on their system to allow them to undertake construction and maintenance activities in an efficient and economic manner. These outages are planned and co-ordinated in a variety of timescales from multiple years ahead through to real time.

83. The current level of construction activity to reinforce the transmission systems is significant and will be significant for the medium term as new infrastructure is built to increase system capability and replace aging assets. As such there is a tension between taking outages to allow the construction work to proceed to increase system capability in the longer term to reduce congestion, and the short term constraint costs that arise as a consequence.

84. Against this background the scope for achieving significant reductions in constraint costs through further outage optimisation may be limited, but it is difficult to quantify this and would also prejudge the scope for technical innovations that may develop in response to appropriate incentives. Given constraint costs are ultimately paid for by consumers it is still appropriate to consider whether enhancements to the existing arrangements can contribute to reductions in constraint costs.

85. Clearly transmission incentives are only one aspect of the broader commercial and regulatory frameworks which govern the GB transmission and wholesale market arrangements and National Grid continues to work with industry to develop these arrangements to better facilitate its licence objectives and the interests of consumers. National Grid is also committed to continuing to work closely with the STOs to identify practical ways within the existing frameworks to improve

[11] http://www.nationalgrid.com/uk/Electricity/soincentives/docs/

collaborative and co-ordinated working from scheme inception to real time, information exchange and the sharing of best practices across a range of activities, such as:

- Outage nesting. It may be efficient to take a number of circuits out together without increasing the constraints imposed by taking one circuit out.;
- Reduction of Emergency Return to Service (ERTS) times. Such reductions allow circuits to be returned to service quickly if unexpected events, such as an unplanned generator outage, causes an increase in constraint costs;
- Working outside normal hours or increase manpower resources;
- Short term ratings. This method seeks to measure how long a higher loading is possible on a circuit post fault;
- Temporary bypass schemes when taking circuit outages;
- Hotwiring schemes. Hotwiring is the ability to operate a circuit at a higher temperature than its original design by using Aerial Laser Survey methods to assess circuits limiting factors;
- Meteorological Office Ratings Enhancement (MORE). Weather informed ratings seek to take advantage of actual weather conditions that may be markedly different from seasonal conditions used in calculating a circuits rating.

86. The areas covered in this section do not preclude such improvements, but instead look at limiting factors within the current arrangements that may require changes that are more fundamental and/or changes to the Transmission company licences. Indeed the areas covered in section 4 and 5 may improve collaborative and co-ordinated working, information exchange and accelerate the implementation of best practice.

87. In this context, this section starts by examining the current arrangements for co-ordinating and changing outage plans between the SO and STOs and seeks views on some potential changes which may make pragmatic improvements to these arrangements in the short term (i.e. have the potential for implementation by April 2010). This section then considers the SO/TO Interaction in England and Wales, again seeking views on some potential changes to these arrangements in the short term.

88. The current broad model discussed in this section is one where the SO and TOs collaborate to establish initial plans (e.g. for outages) and then the SO requests changes to those plans to reduce constraint costs. Section 5 of this consultation goes on to consider potential benefits in incentivising these changes. Section 5 also outlines and seeks views on an alternative broad model where TOs have direct incentives which align with constraint cost management, although this may form an area for development in the longer term.

89. The remainder of section 5 then goes on to highlight some issues associated with other aspects of the current arrangements in relation to the SO / TO interface which potentially have a link into incentives.

4.2 SO/STO outage co-ordination arrangements

90. The SO coordinates the development of transmission circuit outage plans in collaboration with STOs and generators. The rolling outage planning process, including timescales for exchange of outage data, is outlined in the SO-TO Code (STC)[12] for STOs and in the Grid Code[13] for generators. The process is iterative in nature, culminating in an agreed "Final Outage Plan", as defined in the STC, for the next financial year by calendar week 49 in the current year.

91. For the networks in Scotland, there are arrangements in place through the STC to allow the SO to request changes to the agreed Final Outage Plan as system circumstances change to ensure continued delivery of quality and security of supply standards and where changes may help to reduce constraint costs. For example this may be to re-align a transmission outage with a planned generator outage which has changed.

92. Any changes to the Final Outage Plan requested by the SO[14] allow the STOs to recover reasonably incurred costs from the SO at cost reflective rates. A nominal allowance of £1m is currently available to the SO (upon which it is incentivised) via the Transmission Licence[15] to make outage change payments to the STOs. The SO recovers this cost via the Balancing Services Use of System charges (BSUoS). The scope for cost recovery is currently limited to changes requested by the SO once the Final Outage Plan has been agreed i.e. changes to the plan developed in week 49.

93. In the current model, the facility for outage change therefore plays an important role in the continued delivery of quality and security of supply and minimisation of constraint costs. If outage changes could be further optimised, this may have a favourable impact on the costs of constraints and ultimately consumers, through reduced BSUoS charges.

Potentially limiting factors within the current SO/STO arrangements

94. As highlighted earlier, the scope for STO cost recovery for changes to the outage plan is currently limited to changes requested by the SO once the Final Outage Plan has been agreed i.e. changes to the plan developed in week 49.

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[12] Procedure STCP11
[13] Operating Code no. 2
[14] The definition of an 'outage change' is given in NGET's Transmission Licence, Special Condition AA5A, Part 2(ii), paragraph 21A.
[15] NGET's Transmission Licence, Special Condition AA5A, Part 2(ii), paragraph 15C put in place an allowance for outage changes (ON_t) of £1,000,000 in 2004/05 prices. The formula in paragraph 15C allows an adjustment to the term ONt using the $IRPI_t$ index which is defined in paragraph 15A.

95. Currently all transmission companies have strong incentives through their main price control to minimise the opex and capex costs. Therefore, the TOs have incentives to deliver construction and maintenance activities (which have an influence on constraint costs and/or their ability to respond to outage change requests) in an efficient and economic way which minimises the operational and capital costs that they incur rather than the total costs that consumers face which includes the costs of constraints.

96. At the year ahead stage, a significant amount of effort is spent by both National Grid and the STOs to optimise the outage plan before it becomes the Final Outage Plan. However, one STO has highlighted the issue of outage change costs incurred in year 1 (i.e. prior to the development of the final outage plan in week 49) which are not currently recompensed (e.g. the STO may incur additional costs if co-ordination discussions in year 1 lead to changes to contractual arrangements for carrying out the work).

97. The current 'within year' timescale for the SO requesting changes to the Final Outage Plan does not always allow all outage changes requested by the SO to be agreed and implemented by the STOs because there is insufficient time from the request to allow optimal re-scheduling of the outages within the plan year.

98. A further issue is that the SO may identify an opportunity where starting an outage (for example) a week earlier could reduce constraint costs but the STO is unable to accommodate the requested change because of lack of availability of skilled resource and/or equipment.

99. The table below shows the annual outage[16] change costs paid by the SO to the STOs over the last four years.

Year	Historical Outage Change Costs
2005-06	£0.5m
2006-07	£0.4m
2007-08	£0.6m
2008-09	£0.3m

100. The table shows that the outage change costs paid for actual outage changes have been significantly lower than the nominal annual allowance of £1m. There are a number of reasons for not being able to fully utilise the annual allowance including insufficient lead-time from the request to allow optimal re-scheduling of the outages within the plan year and an inability to accommodate the requested change because of lack of availability of skilled resource and/or equipment.

[16] The vast majority of the costs are actual costs paid against invoices received during the financial year but, where the invoices have not been received, an estimate of the outage change costs is made.

Potential changes to current outage SO/STO co-ordination arrangements

101. Potential changes that could enhance the effectiveness of the outage change process could therefore be to:

- extend the current duration of the Final Outage Plan through changes to the STC, for example move to 2 years; and
- allow outage change costs to be remunerated over an extended window through changes to NGET's Licence.

102. Such changes to the licence and STCs would be relatively easy to implement, although it would have a short-term impact on resources as initially two Final Outage Plans would need to be agreed together as the transition is made. Such an impact on resources would need to be considered before assessing whether this change could be implemented for April 2010.

103. Extending the current arrangements in this way could provide some incremental benefits for constraint reduction by creating a greater scope for optimising the outage plan and accommodating requested changes where re-planning or resources is the limiting factor in the shorter-term e.g.

- Bringing outages forward or moving them back
- Nesting of outages
- Aligning with generator outages

104. Whilst this can be done presently, as the present mechanism allows for some consideration of SO issues in the development of the Final Outage Plan, the current incentive drivers on the STOs are to reduce opex and capex costs which may not be consistent with reducing constraint costs. Allowing remuneration of changes in planning timescales ahead of 'current year' could be a positive step to mitigating some of the potential limiting factors highlighted above, but potentially has the downside of encouraging a starting plan which is less aligned with SO considerations.

105. More broadly, continuing with a structure based on cost remuneration at ex-ante defined rates provides no incentive for the STOs to take additional risk (e.g. agree to reduce outage duration and hence reduce contingencies, or work assets harder) or innovate to reduce constraint costs. These issues lead to the debate on the potential benefits of incentivisation and also the overall 'model' which is discussed in Section 5.

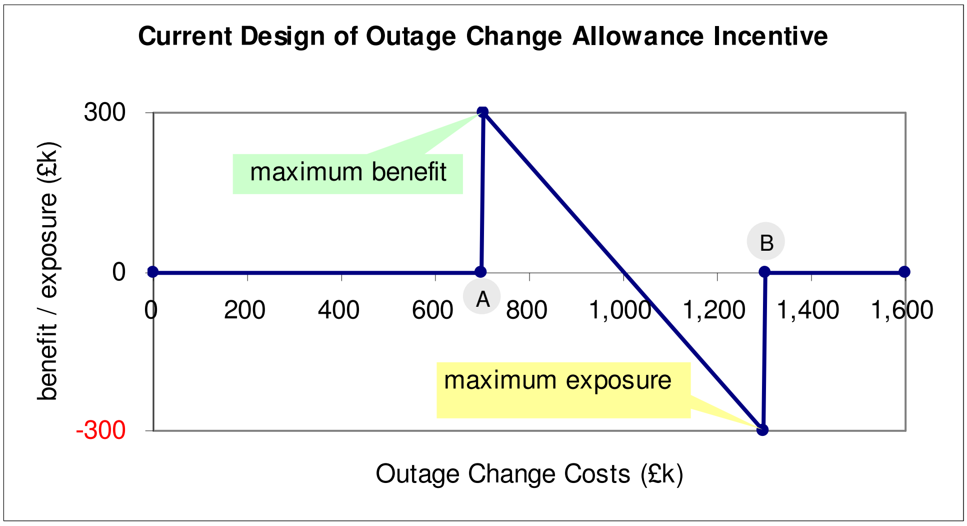
Consultation Question	
4/1	Do you think it is appropriate to extend the current outage change arrangements in the way described? Please outline any relevant

	issues that have not been highlighted.

4.3 Current SO incentivisation of STO Outage Change Allowance

106. The outage change allowance of £1m per year referred to above is available for National Grid to spend with the STOs in the pursuit of reducing constraint costs, which if successful, benefits both National Grid through the SO BSIS scheme and consumers through lower BSUoS charges. It is an incentivised allowance and National Grid's licence[17] states that, if the actual (or reasonably expected) costs differ from the £1m allowance by more than £300k (i.e. if such costs are outside the range £0.7m-£1.3m), it must notify the Authority of this 'outage cost adjusting event'. This notification triggers the process for a full cost pass-through and removes any financial risk or benefit to National Grid if the outage change costs are in excess of £1.3m or less than £0.7m.

107. If the actual costs incurred are within the range £0.7m - £1.3m, National Grid recovers the £1m allowance (adjusted for inflation) regardless of the level of the actual costs incurred within this range. Consequently, the SO may benefit if the actual costs incurred are less than £1m (but greater than £700k) or may be exposed to additional costs if the actual costs incurred are greater than £1m (but below £1.3m). This incentive effect is shown below.



108. Notwithstanding the SO's wider obligations to ensure compliance with the SQSS and operate the system in an efficient and economic operation, from an incentivisation perspective, the following observations can be made:

- If the costs incurred are £700,000 (point A), National Grid recovers the full allowance amount of £1m and hence benefits by £300k

[17] Special Condition AA5A Part 2 (iv), paragraphs 22 (a) (i) and 23 (a)

through the incentive; however, if the costs incurred are £699,999 (or less), National Grid only recovers this amount as a cost pass-through and the incentive is effectively turned off.

- If the costs incurred are £1,300,000 (point B), National Grid recovers the allowance amount of £1m but is exposed to the additional £300k through the incentive; however, if the costs incurred are £1,300,001 (or more), National Grid recovers this full amount as a cost pass-through and the incentive is effectively turned off.

109. In both cases, the 'cliff edge' discontinuity in the incentive potentially creates perverse incentives. It is worth noting that, despite the above potential perversities, the outturn costs in each of the last four years have been 'pass through' due to a significant annual under-spend against the £1m target meaning the costs fall outside of the 'incentivised' range.

110. Notwithstanding this, whilst the outage change arrangements are under review, it seems reasonable to consider whether the current form of incentive on the SO in relation to outage change costs remains appropriate or whether an incentive structure without 'cliff edges' is perhaps more appropriate. Additionally, if the scope that the change allowance is remunerating is expanded (i.e. over two years), it may be appropriate to review the level of change allowance.

Consultation Question	
4/2	Should the current SO incentive in relation to the outage change allowance be reviewed to remove potential perverse incentives, and are there any relevant issues arising that have not been described above?

4.4 SO/TO Interaction in England and Wales

111. For the network in England and Wales, internal 'transmission procedures' are in place for exchange of outage data between the relevant departments within National Grid. These procedures are similar to the outage planning procedures in the SO-TO Code. There is currently no outage change allowance for recovery of reasonably incurred outage change costs for National Grid as it is assumed that benefits can be derived through the BSIS scheme to outweigh the costs.

112. Again, whilst the arrangements between TO and SO are under review, it is worth considering how the incentive interactions operate between National Grid's BSIS scheme and its opex incentives.

113. Currently National Grid's controllable SO (opex) costs are incentivised on a sliding scale basis around a target (which was set for 5 years at

TPCR4) but with sharing factors which align with those on its BSIS scheme. This is currently 25% on the upside and 15% on the downside. The rationale is to provide the SO with the same exposure to internal and external costs and therefore promote efficient arbitrage between its internal opex costs and external balancing costs. In practice this means that if it can reduce balancing costs and therefore derive benefits through BSIS by increasing opex (e.g. employing more staff) then it has an incentive to do this, at least of annual basis on which the BSIS scheme is presently set.

114. For activities that are deemed "TO", a different incentive arrangement is in place. A target allowance was set at TPCR4 but (effectively) with 100% sharing factors as National Grid is wholly exposed to opex increases or decreases around this allowance. This provides a strong incentive to reduce opex costs.

115. There are circumstances when incurring additional TO opex is likely to have benefits for reducing balancing costs. At one end of the spectrum it might be to instigate weekend or 24hr working to enable a circuit to be returned to service earlier than planned in response to a change in an interacting generation outage. At the other, it may be the establishment and deployment of technologies and techniques such as temporary bypasses.

116. The presence of different sharing factors and hence "incentive rates" between TO opex costs and SO opex / balancing costs therefore potentially has a distortionary effect. This may act to stifle opportunities to reduce constraint costs through incurring additional costs which are currently deemed and accounted for as TO opex.

117. In the short term, one possibility to alleviate this potential distortion is to allow specific 'TO opex' additional costs which are incurred, in certain circumstances, to be deemed 'SO controllable opex costs' and therefore pass through the internal SO incentive. The specific circumstances would be where an amount of additional TO costs has been demonstrably incurred in pursuit of a reduction in balancing costs e.g. the reduction of constraints. This would provide a consistent incentive rate between additional internal costs (irrespective of whether they are labelled as SO or TO) and external balancing costs. Clearly the circumstances could be defined tightly and could be subject to ex-post Authority approval and potentially pre-defined limits. A potential method of doing this would be to extend the Outage Change Allowance, as described in section 4.3, to England and Wales.

118. The benefit of aligning the internal SO and TO incentives in relation to specific activities that reduce balancing costs is that it ensures that the opportunities to reduce balancing costs are not stifled by the different structural arrangements that are in place between activities that fall into either TO or SO categories purely for regulatory purposes. We note that Ofgem has recognised the potential distortionary effects of different

incentive rates in its recent "Initial Proposals" for DPCR5. The potential downside to such alignment is the removal of the stronger incentive on the TO to reduce controllable costs, i.e. 100% sharing factors.

Consultation Questions	
4/3	Should the current incentive distortions between National Grid's SO and TO activities be addressed in the short term (i.e. ahead of TPCR5)?
4/4	What are your views on the potential solution suggested and what controls would need to be put in place?

4.5 SO Driven Capital Expenditure on STOs

119. The STC[18] currently contains provisions for liaison between National Grid and the STOs in relation to the identification of potential capital schemes that either reduce constraint costs or mitigate the risk of constraints occurring.

120. In addition, the Scottish TOs also consult the SO on their capital schemes and in response to derogations on whether there is opportunity to carry out extra works that are more economic and efficient. In response, National Grid as SO may request the relevant TO to alter their scheme design to incorporate works to reduce constraint costs.

121. Such capital projects would not be part of the STO's baseline capex allowances agreed at TPCR4 and as such the relevant STO would need to seek additional capex funding from the Authority. Additionally the STOs would have to find resources and time to fit the additional scheme into their capex plans. There is currently no mechanism to facilitate prioritisation of this work against other necessary works that the STOs will also be undertaking.

122. These process and prioritisation issues ultimately contribute to the leadtime for capital works that that have been identified as having constraint cost benefits and therefore may act to delay constraint cost savings from being realised.

123. A potential improvement to this arrangement is to provide a ring-fenced capex fund that can be allocated by the SO, potentially with justification of schemes provided to Ofgem on a case by case basis. It may also be possible to develop a financial incentive for the TOs to ensure appropriate prioritisation of the capital scheme, particularly where large constraint savings are forecast. The incentive could relate directly to some share in the forecast benefits, or could be indirect e.g. through an enhanced rate of return on the capital scheme. The incentive would be

[18] National Grid liaises with the STOs, in accordance with the obligations laid down in Section D of the SO TO Code and the processes described in STCP16-1 and STCP 18-1.

linked to the commissioning date of such a scheme such that earlier delivery offers the most financial benefit to the STO. In theory, such proposals could be extended to National Grid as TO in England and Wales, although clearly in such a circumstance it would be necessary for Ofgem to approve the scheme.

Consultation Questions	
4/5	What are the issues associated with a model where the SO has a capex ‘pot’ that it could spend on TO schemes to reduce balancing costs and, in principle, is this something that you would support?
4/6	In principle, would you support the development of incentives that encourage SO driven capital schemes to be prioritised for delivery by TOs?

Section 5
Aligning TO and SO Incentives

5.1 Introduction

124. As set out in the previous section, all transmission companies have to take circuit outages on their systems to allow them to undertake construction and maintenance activities. In the current phase of significant transmission construction, combined with increasing generation connections, it is inevitable that constraint costs are at significant levels and rising.

125. The current model places the role of managing constraint costs with National Grid as SO and it is incentivised to do this through exposure to constraint costs via the BSIS scheme. It manages constraint costs through the procurement and use of balancing services, co-ordination of its own transmission system activities in E&W and through collaborative working the with the STOs in relation to co-ordinating activity on the Scottish networks. The latter is governed by the procedures under the STCs which include the arrangements described in the previous section. In this current model, although the STOs necessarily influence constraint costs through their operations, they do not have any exposure to constraints through explicit incentives or through their price control arrangements.

126. The contemplation of forms of TO incentives, for all transmission companies, which ultimately align with SO incentives of minimising constraint costs logically arises because the TOs are already subject to other incentives, provided by their main price controls, in relation to activities that contribute to the occurrence of constraints. Currently all transmission companies have strong incentives through their main price control to minimise the opex and capex costs. Therefore the TOs have incentives to deliver construction and maintenance activities (which have an influence on constraint costs and/or their ability to respond to outage change requests) in an efficient and economic way which minimises the operational and capital costs that they incur rather than the total costs that consumers face which includes the costs of constraints.

127. In addition to potentially providing a balance and alignment of incentives on TOs in relation to total cost minimisation, the potential benefit of some form of TO incentivisation is that, in general terms, it promotes TO oversight in relation to constraint costs as well as SO oversight. Incentives contribute to an environment and provide additional stimulus for technical innovation and for companies to seek out and deploy new ways of working. Whilst it may be argued that incentives should not be

necessary to achieve this, from a pragmatic perspective they play a role in making it more likely.

128. This section outlines options for TO incentivisation within three high level incentive approaches, all of which have the overall objective of managing constraint costs, but each achieving it in a different way. The three approaches are:

Approach 1 - incentivise specific outage change activity
Approach 2 - incentivise the availability of transmission capacity
Approach 3 - incentivise minimisation of network constraints

129. The first incentive approach builds on the existing model where the STOs respond reactively to SO requests to move and change outages. As this is incremental change, this could be considered to be a development potentially achievable in the short term (i.e. could be implemented by April 2010). The second and third approaches move progressively away from the current model and would see TOs being incentivised to be proactive in the management of outages to reduce constraints, but raise a number of difficult issues that would need to be addressed and further developed. These could, therefore, perhaps be considered potential developments in the longer term (i.e. potentially implemented in April 2011).

5.2 Approach 1 - Incentivising Outage Change Activity

130. One of the key interactions between TO activities and constraint costs is in relation to the management of planned transmission outages which can reduce the transfer capability of the system and therefore cause constraint costs. Two options for incentivising STO's in relation to this activity with an objective of it contributing to the overall minimisation of constraint costs are outlined below. These could be considered additional to the potential developments to existing outage change arrangements highlighted in the previous section.

STO Recovery of costs "plus"

131. This option would build on the current cost remuneration arrangements for outage changes and allow the STOs to recover an amount which includes an uplift (e.g. 15%) in excess of the reasonably incurred costs. There are no explicit 'performance measures' required under this option as the incentive property is to accommodate as many change requests as possible to maximise the additional uplift which could be considered a small share of the benefit that their actions have led to. There would be no downside for rejecting outage changes requests that couldn't be accommodated.

STO Proportion of outage change requests met

132. This option would incentivise the STOs on a sliding scale risk/reward basis to meet to a target proportion of the outage changes that are requested by the SO. The performance measure would require a clear definition of an outage change request and also of the criteria for meeting such a request.

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133. The main considerations with these options under approach 1 are that:

- they are relatively simple incentive to define and measure;
- incentivises activities directly in the STOs control;
- may increase the likelihood of an outage change request being accommodated as general capability may be increased in response to an incentive; and
- outage change requests is a narrow scope and wouldn't directly incentivise innovation in other areas of outage and work management which may benefit constraint costs. It is worth noting that an incentive is not explicitly required to drive this type of innovation, rather such an incentive would reinforce the focus on such innovation.

5.3 Approach 2 - Incentivising transmission capacity availability

134. This second broad approach is about defining the outputs that are required from TO networks to contain constraint costs whilst allowing the TOs the scope and freedom to choose how best to carry out their maintenance and construction activities. This approach could be implemented for all TOs, although as discussed previously in England & Wales there is a level of incentivisation already for the TO via the BSIS scheme.

Boundary/circuit capability incentive

135. The TO would be incentivised to maintain a level of transmission capacity across a number of key boundaries (e.g. Cheviot) or key circuits (where they presently do not form part of a boundary) over a long-term period (e.g. 5 years). The capability of a boundary can be measured as a function of the transmission capability along a number of core transmission system circuits.

136. The incentive would work by setting a target capability level over a long-term period taking account of planned investment to increase the capability on a boundary/circuit and typical outages on the boundary/circuit for such investment and normal maintenance. The target capability could be measured over a seasonal or annual basis,

with the TO being rewarded or penalised depending on performance against the target.

137. This type of incentive would encourage TOs to maximise capability on key boundaries/circuits over the longer-term, for example by:

- Reducing outage periods by changing working patterns;
- Reducing the overall outage requirement by the bundling of multiple tasks into single outages;
- Reducing the impact of outages by using techniques such as live line working;
- Investing in TO equipment to increase boundary capability (e.g. new intertrip schemes);
- Encourage the use of dynamic ratings to potentially work assets harder
- Bringing forward investment to increase capability earlier than originally planned.

138. The main considerations with this type of incentive scheme are that:

- it would influence the TO to manage the impact of outages by actions such as reducing the overall outage requirement by the bundling of multiple tasks into single outages;
- it would encourage the TO to consider innovative ways of investing to reduce constraint costs;
- such a scheme aligns TO and SO incentives, giving both parties an interest in removing boundary/circuit constraints and reinforces close liaison and communication between SO and TOs to reduce constraint costs;
- the TO may be incentivised to maximise transmission capability that may be of no value to the SO because of constraints elsewhere on the system (which are not covered by a key boundary/circuit) or the generation background (i.e. generation outages mean a boundary/circuit capability is not causing constraints);
- identifying the boundaries or circuits that cause the most constraint problems. This could be done years ahead of real time, but as time goes on those circuits may change. From time to time it may therefore be necessary to amend the incentive;
- the increase in capability may have implications on the reliability, for example due to the overuse (and subsequent deterioration) of certain assets or the asset not being adequately maintained. This could either be addressed by the TO's current licence obligations or having an additional incentive around security and reliability; and
- the need to find a suitable method to measure the capability of a boundary/circuit in real time.

Boundary 'Outage Weeks' Incentive

139. An incentive would be developed to minimise the total duration of outages on system boundaries. This differs from the boundary capability model as there is no requirement to determine the maximum MWh capacity for a boundary or to measure its current level. The SO would contribute to determining the boundaries to be included in the scheme and the outage 'volume' either on a seasonal or annual basis.

140. The outage quotes would be determined on a rolling basis for a five year window to allow the TO to effectively coordinate system access in investment timescales. A shorter time horizon would risk incentivising a TO to defer outages, benefiting against the investment scheme in the delivery year, delaying the outage to a year that is yet to be incentivised.

141. The main considerations with this type of scheme is that:

- it would influence the TO to manage the impact of outages by actions such as reducing the overall outage requirement by the bundling of multiple tasks into single outages;
- the TO may be incentivised to reduce an outage length that may be of no value to the SO because of constraints elsewhere on the system (which are not covered by a key boundary) or the generation background (i.e. generation outages mean a boundary capability is not causing constraints);
- there is an inherent incentive to postpone work or outage from plan and re-plan for subsequent years rather than extend current outage, which may not be the efficient solution;
- the security and reliability on the system could possibly be reduced with this option due to the overuse of certain assets or not taking certain assets out for maintenance, but this could either be addressed by the TO's current licence obligations or having an additional incentive around security and reliability; and
- it is unlikely to incentivise incremental boundary capability, indeed may act as a perverse incentive to take outages to increase boundary capability.

5.4 Approach 3 - Direct TO Incentivisation of constraints

142. The third approach is to directly incentivise TOs to reduce network constraints through a risk/reward based incentive which would provide upside and downside exposure the TOs in relation to the impact they have on constraints. The TO would be rewarded for reductions in constraints and bear an exposure to increases in constraint around an agreed target. This approach could be implemented for all TOs, although as discussed previously in England & Wales there is a level of incentivisation already for the TO via the BSIS scheme.

143. There are a number of ways of parameterising 'constraints' in the context of a TO incentive and three possibilities are set out as follows:

- **Constraint costs** - using the methodology developed for BSIS to determine a constraint cost target based on forecast volumes and constraint resolution prices would provide the TOs with similar risk/reward exposure to actual constraint costs as the SO;
- **Constraint volumes** - this places a MWh constraint volume target, against actual outturn constraint volumes. To remove the exposure of the price of balancing services used to resolve constraints a pre-determined price could be set against the constraint volume to allow a financial risk/reward exposure.
- **Cost weighted constraint volumes** – building on the option above, the forecast constraint volumes are costed ex-ante against a set of reference prices to 'weight' the impact of different outages on constraint costs. The outturn volumes are then measured against these same ex-ante reference prices and therefore provides a risk/reward exposure based on the weighted reference prices acting as a proxy for actual constraint costs. Such weighting would allow the TO to focus their attention on more expensive outages.

144. The direct incentivisation of network constraints should encourage the widest consideration of the activities and optimisations that could be undertaken by the TOs to achieve lower constraints, if the incentive can be designed appropriately, such as:

- Optimising outage placement to reduce total costs
- Nesting of outages
- Aligning transmission outages with generator outages
- Total cost based prioritisation for outage changes
- Innovations to avoid some outages altogether e.g. provision of bypasses
- Efficient and effective use of resources to minimise total costs
- Timely outage completion
- Work acceleration / shorter outage durations (e.g. weekend / night-time working)
- Development of contingencies (e.g. if an outage overruns) and early return to service times
- Use of dynamic ratings to increase capability of remaining circuits

145. However it would also be important to ensure that such an incentive does not perversely incentivise the deferral of network reinforcement that is required to reduce constraint costs in the longer term.

146. There is a significant amount of complexity that would need to be worked through to design an appropriate incentive under this approach as

- not all factors that influence constraints are within the control of the TOs;
- there may be measurement and allocation issues created by the inherent nature of an interconnected network;
- there may be information sharing issues associated with ringfenced roles.

These are outlined briefly below:

Impact of Drivers Outside the Control of the TO

147. There are a number of volume and price drivers that influence constraint costs:
    - Generation and demand pattern
    - System capacity
    - Price of balancing services used to resolve constraints

148. The main driver that is in the control of the TOs is system capacity. This includes the intact system capability, outage requirements and fault outages. Limitations in system capacity limit the volume of power flows across the system, resulting in constraints. The duration of outages on the system for construction or maintenance activities (or as a result of faults) can have a direct impact on constraint volumes and hence costs. Hence the aim of such an incentive would be for the TO to focus on minimising constraint volumes, and hence reduce constraint costs.

149. However, although the TO has some influence over constraint volumes, there are also a number of other drivers that are outside of their control, such as generation pattern and prices of balancing services. Therefore the structure of the incentive would need to take this level of control into consideration.

Allocation of Constraints between TOs

150. The allocation of constraints to an individual TO can generally be performed using a pre-described methodology. However, there are potential complications for specific situation such as constraints across jointly owned boundary circuits such as the Cheviot boundary (jointly owned by National Grid and SPT) or for interaction of constraint boundaries across TO footprints. This may have implications for whether an incentive can be appropriately targeted on individual TOs.

Measuring TO Impact on constraints

151. There are a number of actions that could be undertaken by the TO that reduce the risk of exposure to the constraint costs e.g. reduction in emergency return to service times that would reduce post fault volumes being incurred but only if the fault happens. Measuring constraint

volumes would therefore not capture these benefits and yet these are important aspects to managing risk exposure that should be encouraged.

Information Sharing with STOs

152. Information sharing between the SO and STO is also key to managing outages in a coordinated manner. The STC sets out the information that can be shared and this covers five key areas[19]:

- General Transmission Information
- Transmission Information required for the configuration and operation of the National Electricity Transmission System
- User Data
- Investment Planning Data
- Construction Projects

153. With respect to user data, it may be possible for the SO to provide additional information that would help the STOs plan their outages, specifically the provision of generation planned outage information. This information would allow the STOs to co-ordinate their outages with generator outages at the initial planning stages and as the plan progresses toward real time allow the STOs to keep this plan under review and make suggestions to the SO on ways to better manage outages. Therefore, the provision of generator outages would allow the STOs to be more proactive and allow them to better assess when to plan outages at the initial planning stage.

154. At present generation outage data is confidential to National Grid and therefore this outage co-ordination is done by the SO after the STO has made their initial plan, and subsequently as generator outages change the SO can request the STO to make changes to their outage plans.

155. We understand that the sharing of market sensitive information such as generation planned outage information with the STOs may not currently allow them to comply with the EU 3rd package and therefore alternative approaches could be adopted e.g. tripartite planning meetings between SO, TOs and Generators.

Consultation Questions	
5/1	In principle, do you believe that there is a role for establishing TO incentives, in the shorter term, in relation to managing SO outage change requests to enhance the operation of the current model?
5/2	More broadly, what are your views on the potential longer term development of alternative models for incentivising TOs with

[19] http://www.nationalgrid.com/NR/rdonlyres/C95D42E6-D9D3-4D8A-B7F659B53D738E6/35260/STC_Schedule_3_GoActive.pdf

	regard to their influence on network availability / constraints?

Section 6
Summary of Consultation Questions

Incentivising Timely Grid Connection	
3/1	Do you believe there is a role for incentivising accelerated completion of local works and therefore the connection of new generation in England & Wales? Do you believe there is a requirement for such a role in Scotland?
3/2	Do you believe that the potential enhancement outlined which balances National Grid's current price control incentives in respect of timescales is an appropriate model, or are there others that should be considered? Given the incentive properties that are provided by the current price control arrangements in Scotland do you believe it would be possible to further align these arrangements with customers' potential desires for timely connections?
3/3	Do you believe the potential incentive correctly balances the risk and reward for National Grid?
3/4	If you presently have future transmission connection interests, in principle, could you be seeking a grid connection date which is less than 4 years from signing the connection offer?
SO/TO Interface Issues	
4/1	Do you think it is appropriate to extend the current outage change arrangements in the way described? Please outline any relevant issues that have not been highlighted.
4/2	Should the current SO incentive in relation to the outage change allowance be reviewed to remove potential perverse incentives, and are there any relevant issues arising that have not been described above?
4/3	Should the current incentive distortions between National Grid's SO and TO activities be addressed in the short term (i.e. ahead of TPCR5)?
4/4	What are your views on the potential solution suggested and what controls would need to be put in place?
4/5	What are the issues associated with a model where the SO has a capex 'pot' that it could spend on TO schemes to reduce balancing costs and, in principle, is this something that you would support?
4/6	In principle, would you support the development of incentives that encourage SO driven capital schemes to be prioritised for delivery by TOs?

Aligning TO and SO Incentives	
5/1	In principle, do you believe that there is a role for establishing TO incentives, in the shorter term, in relation to managing SO outage change requests to enhance the operation of the current model?
5/2	More broadly, what are your views on the potential longer term development of alternative models for incentivising TOs with regard to their influence on network availability / constraints?

Contact details

To register your interest in receiving future communications on this consultation process please email: soincentives@uk.ngrid.com

On the web:
New dedicated web pages for this process are available at the following addresses:

Electricity Incentives: http://www.nationalgrid.com/uk/Electricity/
Gas Incentives: http://www.nationalgrid.com/uk/gas/

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