RIIO T1 nationalgrid

Annex B – Delivering connections and capacity

National Grid
Gas Transmission

May 2012

Target audience

All stakeholders

About this annex

This annex contains updated information in relation to our proposals surrounding the delivery of connections and incremental capacity.

Annex B – Delivering connections and capacity

Table of Contents

Overview

1. Our RIIO-T1 business plan, submitted to Ofgem in March 2012, was based on a number of assumptions around the timing and likelihood of customer requests for incremental capacity to facilitate expansions to existing, or the connection of new supplies and demands onto the gas National Transmission System (NTS). In response to the uncertainty surrounding these assumptions, along with the need to mitigate the risk of long lead times introduced by the Planning Act (2008) ("the Planning Act") and progress customer requests to align the connections and capacity processes, our business plan proposed a number of changes in relation to the release of incremental capacity[1].

2. The majority of the changes can be made to the regulatory framework through the licence and are workable in their own right, with the exception of the proposal to reduce our obligated lead time to 24 months[2]. Where a Development Consent Order under the Planning Act is required, existing obligated lead times cannot be met and therefore shortening the obligated lead time will only exacerbate the risk of not meeting the lead time. To manage this we are proposing that each customer wanting to signal either entry or exit incremental capacity would be required to enter into a bi-lateral contract (a Pre-Capacity Agreement "PCA"). This PCA contract would set out a timeline through to capacity release and therefore provide more certainty to project developers, with transparency of all the process steps and deliverables required from both parties. This would be accompanied by a phased user commitment that would ramp up in line with progression through the process culminating in full user commitment through a formal capacity signal.

3. We understand from our stakeholders that where they have entered into a PCA and undertaken the associated obligations (some of them financial), they would want assurance that the incremental capacity delivery they are underwriting cannot be allocated to someone else. A Uniform Network Code (UNC) modification would be required to facilitate this and we have therefore been developing and discussing these proposals with our stakeholders.

4. Stakeholders share our view that it seems unlikely that any required UNC modification would be implemented by April 2013 (i.e. in time for the start of the RIIO-T1 period). We have been working to develop alternative options that could be employed in the interim period to ensure that the commercial regime continues to interact with the regulatory regime appropriately. From all of the possibilities we have explored, there are two potential options that we are proposing could be utilised: controlling the release of incremental capacity through an amendment to the drafting of the relevant Methodology Statements, or continuing to use the existing permit scheme concept.

5. These two interim options allow the regulatory regime to interact appropriately with the commercial framework but, crucially, could not ensure the allocation of incremental capacity to the signatory of a PCA. This interim solution could endure if stakeholders do not require incremental release to be restricted to the signatory of a

[1] Refer to our March 2012 RIIO-T1 business plan, Detailed Plan, Annex B paragraph B39 for more information.
[2] Our current obligated lead times are 38 months for the delivery of incremental exit capacity, from the July annual application window and 42 months for incremental entry capacity.

PCA, however if this is not acceptable the UNC modification (or an alternate) can continue to be developed in parallel to industry timescales.

6. In conjunction with the above discussions, we have also engaged with our stakeholders about our proposed incentives in relation to the delivery of connections and capacity. The results of our stakeholder engagement have informed our thinking and helped us to develop our proposals for inclusion in this document.

Proposals

7. In relation to the enduring solution that would apply if a UNC modification to align the capacity and connections processes were implemented:

   (a) **We propose that a financial incentive is introduced to incentivise the early delivery of incremental capacity where the amended date for delivery of that capacity is valued by the customer, or penalise the late delivery of capacity (post the obligated lead time) if the amended date does not meet customer requirements**. This would contribute to the assessment of the risk / reward balance when considering whether to accelerate construction and deliver the incremental capacity early and also encourages us to release incremental capacity early where no construction is required. This scheme also penalises us where the capacity delivery is deferred and not in line with customer requirements, thus discouraging late delivery.

8. In order to ensure the regulatory and commercial frameworks work together appropriately from the beginning of the RIIO-T1 period, we are proposing two potential options that could be employed in the absence of a full UNC modification being implemented and therefore form an "interim" solution:

   (a) **Control the release of incremental capacity through pre-requisites specified in the Methodology Statements.** Drafting could be incorporated into the Methodology Statements specifying that incremental capacity would be released with a 24 month lead time, from an October capacity allocation, where a PCA has been signed and all the relevant steps within that contract have been met. In the absence of a PCA a reasonable endeavours obligation would be in place.

   (b) **Continuation of the use of permits.** An allowance of permits could be provided to enable the lead time associated with the release of incremental capacity to be managed in the absence of a UNC modification. If this option was adopted we propose that a combined allowance across entry and exit of 7,804[3] permits (commensurate with the risk associated with our assessment of the customer projects likely to come forward) is provided to cover both for the rollover year and the first year of the RIIO-T1 period, with a value of £39.02m. Each permit would have the ability to delay one GWh/day of incremental capacity for one month at a cost of £5,000 each and permits could be earned for accelerating one GWh/day of incremental capacity for one month at a revenue of £5,000 each. We are prosing that we are allowed to go overdrawn by a factor of 50% (i.e. 3,902 permits) and that our financial exposure is capped at +£30m and collared at -£10m over the two year period.

[3] This would replace the existing allocation of 1,440 (GWh/month) permits on entry and 2,190 (GWh/d) permits on exit which currently apply for the rollover year.

9. In order to incentivise our other activities in the area of connections and capacity:

    (a) **We propose that a reputational reporting incentive is introduced in relation to the production of connection offers**. UNC modification 373, if implemented, will introduce formal timescales for the production of connection offers into the UNC[4]. Stakeholders wish to see how this process works in practice before any financial incentive is introduced in this area. We are therefore proposing that we publish information relating to the achievement of the key steps included in the UNC modification 373 process (including and in addition to the reporting requirements envisaged within the modification) in order to provide transparency to all and enable third parties to measure our progress.

    (b) **We propose that a reputational reporting incentive is introduced in relation to our progression through pre-capacity application activities for incremental capacity release.** Stakeholders were supportive of our proposal that a definitive target should not apply to the time taken to progress through pre-capacity application activities, as this could reduce flexibility in an area where there is currently much uncertainty. We therefore propose that we report annually on the time it takes us to progress through the key milestones identified in the PCA contract, thus providing visibility to all parties and allowing our progress to be measured against others.

This document

10. The release of incremental capacity interacts with many of the System Operator (SO) external incentives; however as the connection and capacity activities are also strongly linked to the Transmission Owner (TO) function of the business, we have included the detail of our proposals in this SO submission, to be read in conjunction with our March 2012 TO RIIO-T1 business plan (Detailed Plan, Appendix B). This annex contains:

    (a) Our updated thinking, following on from our March plan, covering our incentive proposals and options that could be implemented in the interim period to ensure the regulatory and commercial frameworks continue to interact appropriately.

    (b) Further development of our proposed generic revenue driver methodology (including how we take decisions to balance investment and risk) and unit cost library.

    (c) For ease of reference, a copy of our March 2012 RIIO-T1 business plan proposals in this area.

[4] If UNC modification 373 is not implemented, we have indicated that we would still implement the principles.

May 2012 update

Background

11. In order for a User to physically input gas to, or offtake gas from, the system, both a physical connection to the NTS and commercial capacity rights are required. These are applied for through two separate and distinct processes, which currently have no recognised formal interaction between them.

12. In order to obtain a physical connection, the customer enters into bi-lateral discussions with us. We then design, build and operate the connection facility, with the work fully funded by the customer. As each connection is different, the intermediate deliverables and therefore overall process can vary for each. It typically takes around three years to design and build a connection but this is dependant on the complexity of the specific project. Currently anyone can apply for a connection and the governance around the process is our obligation under The Gas Act 1986 (as amended) to comply with any reasonable request for a connection.

13. The processes for acquiring commercial capacity rights are governed by the UNC. Customers have expressed frustration that currently the connections process is ad hoc in nature and not subject to established timescales, milestones or costs. Customers have also expressed dissatisfaction with the capacity and connection processes being separate, saying that this makes these processes confusing and difficult to navigate. They wish to see both processes developed so that they are closer aligned, more transparent and more certain[5].

14. The introduction of the Planning Act has lengthened the time it will take to deliver incremental capacity (where reinforcement is required) and will drive higher costs into the earlier part of the process[6]. For any projects where a Development Consent Order is required we will not be able to deliver incremental capacity within the current obligated lead times. This therefore potentially exposes end consumers, NTS users and NGG to high constraint management costs, as we would need to buyback capacity rights in constraint situations where the customer has been connected in line with the obligated lead time, before network reinforcement has been delivered.

15. Indications are that it can take up to seven years to design and deliver network reinforcement requiring a Development Consent Order for incremental capacity delivery[7]. Our operating licence contains default lead times for the delivery of incremental obligated capacity of 42 months and 38 months[8] for entry and exit capacity respectively. Bi-lateral discussions must therefore take place before a formal capacity signal is received in order to clarify the requirements of both parties, and must continue throughout the process to ensure need cases are aligned and capacity is delivered in a timely manner.

16. The concept of permit schemes currently exists in relation to incremental capacity which allows us to use permits to defer the obligation to deliver incremental capacity, or earn permits by taking on the obligation to release incremental capacity early

[5] Please see Appendix A to this document for an overview of the stakeholder engagement timeline on this topic.
[6] Please refer to our March 2012 RIIO-T1 business plan, Detailed Plan Appendix B paragraphs B16-B32 for more information of our understanding of the impacts of the Planning Act.
[7] The seven years would run concurrently with the three years to deliver the connection.
[8] 42 months from a March QSEC auction and 38 months from the July annual application window.

where the customer values it. The quantity of permits used or earned is relative to the obligated lead times and quantity of incremental capacity applied for. Each permit has a monetary value which is cashed out at the end of the price control period, therefore potentially rewarding us to identify and deliver incremental capacity early where the customer(s) would value it, or to endeavour to meet the obligated lead times for more challenging projects.

17. Our March 2012 RIIO-T1 plan included a number of proposals that would deal with the Planning Act whilst facilitating the overarching objective of delivering connections and capacity together, in the most efficient lead time, in a transparent and more certain manner. We proposed that the introduction of a mandatory bi-lateral contract (PCA) for parties wishing to signal incremental capacity would enable the customer and NGG timelines to be aligned, with connections and capacity being delivered together. This process would set out a timeline from initial contact through to capacity release and therefore provide more certainty to project developers, with transparency of all the process steps and deliverables required from both parties. This would also assist with achieving the aims of the Infrastructure Planning Commission who have told us they would expect to receive one, or two interlinked, application(s) for a Development Consent Order for the customer project and gas pipeline. The PCA would incorporate a phased user commitment that would ramp up in line with progression through the process culminating in full user commitment through a formal capacity signal via the existing auction and/or application methods.

18. Stakeholders have previously indicated to us that they would want the release of incremental capacity to be restricted to the party that has funded the necessary preparatory work through the PCA. This requires a change to the UNC, so we have been developing proposals and discussing these with our stakeholders, along with some of the accompanying incentives that would encourage efficient delivery.

19. It is unlikely that a UNC modification will be implemented in time for the start of the RIIO-T1 price control period in April 2013. However, we still need to develop a process that meets the requirements of the Planning Act and which will allow us to respond effectively to customer requests for incremental capacity. In light of this we have been considering alternative options that could be employed as an interim measure to achieve the same aims of aligning customer and NGG timelines, recognising the implications of the Planning Act, without the need for a UNC modification. We believe this is a sensible approach to take as it removes the reliance on the UNC modification to enact a workable solution for the impending price control period, whilst allowing that UNC modification to be carefully considered by industry through the appropriate governance.

20. We have identified two potential interim options that allow the regulatory regime to interact appropriately with the commercial framework but, crucially, could not ensure the allocation of incremental capacity to the signatory of a PCA. This interim solution could endure if stakeholders do not require incremental release to be restricted to the signatory of a PCA, however if this is not acceptable the UNC modification can continue to be developed in parallel to industry timescales.

Our proposals

21. In order to ensure the regulatory and commercial frameworks work together appropriately from the beginning of the RIIO-T1 period, we are proposing two potential options that could be employed in the absence of a UNC modification and therefore form an “interim” solution:

(a) **Control the release of incremental capacity through pre-requisites specified in the Methodology Statements.**

(b) **Continuation of the use of permits.**

22. In relation to the enduring solution that would apply if a UNC modification to align the capacity and connections processes were implemented **we propose that a financial incentive is introduced to incentivise the early delivery of incremental capacity where the amended date for delivery of that capacity is valued by the customer, or penalise the late delivery of capacity if that amended date does not meet customer requirements.**

23. Our overarching objective is that our customers receive excellent customer service, with a key component of this being the receipt of a timely connection onto the NTS. Our first management response is therefore to continue our bi-lateral discussions with customers to ensure we are fully engaged with them at every step of their project. This ensures that they are fully aware of the deliverables and key steps within the process. We already work to the principle that understanding the needs of our customers is essential if we are to provide the services that are important to them. We first commissioned customer research in 2009 and have received constructive feedback which has enabled us to focus on delivering the right services in the right way for our customers. Please refer to the Customer Satisfaction section of the System Operator External Incentives Plan for information on the customer satisfaction incentive. We believe that the introduction of incentives in the area of timely connections is likely to lead to improvements in customer service overall, however targeted action still has a part to play so:

(a) **We propose that a reputational reporting incentive is introduced in relation to the production of connection offers.**

(b) **We propose that a reputational reporting incentive is introduced in relation to our progression through pre-capacity application activities.**

Capacity delivery – enduring solution

23. In our March 2012 RIIO-T1 business plan, we proposed that in conjunction with the requirement for customers to sign PCAs where they wish to signal incremental capacity, we would shorten the obligated lead time for the delivery of incremental capacity (from 38[9] months for exit and 42 months for entry) to 24 months, from an October capacity allocation, to cover construction activities only. The 24 month obligated lead time covers the time it takes for us to undertake a standard construction project, i.e. two build seasons over a 24 month period.

24. The 24 month obligated lead time from an October capacity allocation is also linked to the annual run of the Price Control Financial Model (PCFM) which Ofgem are introducing for RIIO-T1 to calculate NGG's allowed revenue. This model will be run once a year and Ofgem have told us that this annual run of the PCFM will be carried out in November of each year, enabling allowed revenue (and therefore customer charges) to be adjusted from the following April. Aligning the obligated lead time with the running of the PCFM allows us to ensure that we receive the allowed revenue

[9] 42 months from a March QSEC auction and 38 months from the July annual application window.

stream (as defined by the stage two revenue driver[10]) in line with the beginning of the construction season. This is essential as the level of capital expenditure we are forecasting is likely to be required over the RIIO-T1 period would leave us unable to finance our business without this.

25. We believe that where the customer would value delivery of incremental capacity in timescales shorter than this, we should be incentivised to deliver this capacity early. This would align with customers signalling where they require capacity from a month other than the default capacity start date of October ahead of 24 months, preserving the principles introduced through UNC modification 376[11]. It must be recognised, however, that delivering capacity in a shorter timescale than our obligated lead time may have an additional cost associated with it.

26. Conversely, where we expect that incremental capacity delivery may take longer than two build seasons and this does not meet customers' expectations, there should be a mechanism in place to manage this.

27. We considered a number of options that could be utilised in this area:

(a) No direct incentives – we could be exposed to buybacks for the late delivery of incremental capacity with no incentive for delivering capacity early. Given that delivering incremental capacity early would generally involve a level of increased cost and / or risk, the lack of an incentive in this area will potentially make the risk / reward balance of delivering capacity early unattractive.

(b) Retain the permit schemes that are currently in place – this has the advantage of both incentivising early delivery and having a set scheme in place for the deferred delivery of incremental capacity.

(c) Hardcode an incentive for the early delivery of incremental capacity in the licence and be exposed to buybacks for late delivery or permits for deferred delivery that does not meet customers' requirements – this has the advantage of incentivising early delivery whilst having a set scheme in place for late delivery of capacity. The incentives around early and late delivery, however, would not be symmetrical.

(d) A scheme where both a target related to the late delivery of capacity and incentive for early delivery are calculated utilising our buyback modelling assumptions with reference to the value that the customer places on that capacity. This has the advantage of being symmetrical for both the early and deferred delivery of capacity.

28. In our March 2012 RIIO-T1 business plan we indicated that our preference was option (d) as this retains the principle of the current permit scheme, whereby there are defined mechanisms in place, but also takes into account locational sensitivities. When investigating this further following on from our March 2012 RIIO-T1 business plan, we considered an additional option:

---

[10] Refer to the 'Generic revenue driver methodology and unit cost library' section of this document on page 30 for information on how the stage two revenue driver will be calculated.

[11] UNC modification 376 was raised to increase the level of choice available to Users when applying for Enduring Annual NTS Exit (Flat) Capacity, allowing for applications to request a non-October start date. Note that the obligated lead time under the licence is unchanged (i.e. 36 months from the October following capacity release, which equates to 38 months from the July annual application window).

(e) Set an incentive scheme which accounts for the costs that would be incurred through accelerating construction, both construction costs and capital expenditure financing costs, plus an incentive on top.

24. We consider this additional option the most appropriate, as it provides the most accurate reflection of the costs incurred and have consulted with our stakeholders on this option.

Stakeholder engagement

25. We have been discussing the processes surrounding connections and capacity, and options for improving them, throughout our Talking Networks activities. Please refer to Addendum A for a brief timeline overview.

26. Within our most recent stakeholder engagement, a number of stakeholders were concerned that our proposal to shorten the obligated lead times to 24 months would reduce flexibility:

"The proposed process will have a lead time of 24 months provided a user commitment is given prior to October. However, this does not take account of non-October starts as requested in modification 376 nor flexibility as to when customers can signal a User Commitment. The proposed methodology curtails customer choice and will present a barrier to entry for new CCGT investment."
SSE, May 2012 stakeholder engagement consultation response

27. This perception that our proposal will reduce the flexibility envisaged by UNC modification 376 is incorrect. UNC modification 376 was raised to increase the level of choice available to NTS Users when applying for Enduring Annual NTS Exit (Flat) Capacity, allowing for applications to request a non-October start date whilst remaining consistent with the obligated lead time and user commitment principles of capacity release.

28. Our proposed incentive does not affect the ability for NTS Users to signal incremental capacity requirements with a non-October start date and retains the obligated lead time principle. The proposed incentive recognises that, in the case where delivering to a non October lead time means bringing that delivery forward, there will be a cost associated with that.

29. Stakeholders also had questions about the mechanics of the incentive:

It was questioned which party would pay the incentive and which party received the penalty.
UNC Transmission Workgroup meeting, 1st May 2012

30. In line with the current permit scheme, we believe this incentive should be provided for through an adjustment to our allowed revenue, which affects all Users' charges, as this is reflective of the principle that bringing capacity to the market early or delaying it can affect the supply mix and competition. We also note that an incentive covering financing and construction costs could potentially place a considerable financial burden on a single party and therefore discourage the customer from applying for an early delivery date.

Capacity delivery incentive proposal

31. In relation to the timeline between capacity application and capacity delivery, where the customer would value delivery of incremental capacity in timescales shorter than the default obligated lead time (24 months from an October capacity allocation), we should be incentivised to deliver that capacity early. Conversely, where we expect that the capacity delivery will take longer than this and the customer places a value on receiving the capacity in the obligated lead time, there should be a mechanism in place to manage this. It must be recognised, however, that accelerating capacity delivery to provide it quicker than the standard 24 month lead time (covering two build seasons) does have a cost and an incentive will be required to manage the risk / reward balance of delivering that capacity early.

32. In response to our stakeholder feedback and the question of who funds the incentive, we have reassessed the detail of this incentive. In our stakeholder engagement activities we proposed that such an incentive would need to cover the financing costs of delivering the capital expenditure before an appropriate adjustment to our allowed revenue has taken place (i.e. that the second year of costs would be incurred before we have had the allowed revenue adjustment and therefore this would need to be financed from elsewhere), along with the actual costs of accelerating that construction.

33. We believe that an incentive based on these parameters would be sufficiently large to make it unrealistic for the affected customer to be able to fund it themselves and therefore this is something the wider industry would pay for. It seems unreasonable, however, to ask the wider industry to fund these extra financing costs on top of our allowed revenue, when we believe there are other viable options. We therefore propose instead that our baseline capitalisation rate is set at 55% (rather than the 57% included in our RIIO-T1 business plan). This would mean that a higher proportion of our allowed revenue associated with baseline allowances would be received as ‘fast money’ in the year of expenditure, thereby adjusting our cash flow and enabling us to fund construction works before an adjustment to the allowed revenue to fund the incremental capacity has been made as a result of the revenue driver being triggered, where this is required[12]. This proposal would allow us to design the incentive such that it only needs to cover the costs of acceleration.

34. In order to calculate a value for this we have considered the costs that would be incurred if the second year of expenditure were to be accelerated in order to deliver the incremental capacity one year early. Based on our experience of accelerating projects we believe it would cost approximately 10% of the construction cost to accelerate by one year if that contract was agreed in a timely manner i.e. that we are not seen as a distressed buyer and do not have issues with Compulsory Purchase Orders etc[13].

35. Accelerated project delivery requires the planned compression of project timescales under market conditions that will not render National Grid a distressed buyer. Inflating project costs by 10% to accelerate delivery by a year cannot however, be applied in all cases. For example, during construction of the South Wales Expansion Project in response to a customer signal for incremental capacity, we were required to accelerate delivery of the Milford Haven to Aberdulais pipeline in a period where the market for contractors was severely stretched (as a result of several other major

[12] NB even though the relevant adjustment to the allowed revenue may not have taken place, there will still need to have been a user commitment before this level of expenditure is incurred.

[13] Acceleration costs will differ from project to project but this is our assessment of a reasonable average.

pipeline projects being completed at that time in both the UK and abroad). This overheated market placed new challenges when tendering the neighbouring Felindre to Brecon pipeline which was subsequently awarded to the existing contractor. In practical terms, this required acceleration of the works on the Milford Haven to Aberdulais pipeline, in order to achieve completion in 2006 instead of the originally planned 2007. This was necessary to ensure resources could be released to work on the next pipeline at the start of the 2007 construction season. In this particular scenario, the combination of tight timescale and stretched market conditions meant that National Grid became an unavoidably distressed buyer.

36. A distinction needs to be made between the concept of planned acceleration discussed above and project 'catch-ups', where for some reason project timescales have slipped from the critical path and there is a need to recover the situation. In the case of Milford Haven there was no programme float[14], as a result, any slippage in the programme had to be recovered to ensure the project delivery deadline was achieved. Inevitably, this involved 'accelerating' the specific activity that had not progressed in line with our planned timeline as a result of factors outside of our control, e.g. severe adverse weather. It is important to note however, that this type of acceleration is a reactive / event-driven process and quite different from planned acceleration and is not included in our 10% assessment of planned acceleration cost.

37. When considering what would constitute construction costs to consider the cost of planned acceleration, we have looked at the phasing used in our March 2012 RIIO-T1 business plan:

Years funded by stage one revenue driver				Years funded by stage two revenue driver		
T-5	T-4	T-3	T-2	T-1	T	T+1
2%	5%	5%	5%	35%	46%	2%

38. We have assumed that when accelerating construction, the second years' worth of activities (year t in the above table) would be accelerated into the first year of construction (year t-1 in the above example) and therefore 46% of the construction costs would be accelerated by one year. The cost of acceleration therefore would be 10% of the cost of the second year of construction i.e. 4.6%.

39. We have applied this methodology to the projects in our RIIO-T1 business plan that would require incremental capacity to calculate the average cost of acceleration across those projects, based on the capacity that each of the set of projects has been designed to deliver.

[14] There was an immovable deadline to meet and no contingency built into the plan.

[Table deleted]

40. This shows that the average cost to accelerate the second year of construction across the projects in our business plan is £10,426 per month. We therefore propose that the incentive scheme is based on the value of £10,000 per GWh/d per month (09/10 prices).

41. In order to provide clarity of the effects of this proposal we have again looked at the projects in our plan, considering the cost of accelerating those projects by one month (i.e. considering 4.6% of the total construction cost) and comparing this against the value we would gain for accelerating those projects for 12 months under the existing permits scheme and the value that would be gained through the proposed new incentive. This demonstrates that the proposed incentive is commensurate with the cost of acceleration, providing a small incentive on top of the cost recovery.

[Table deleted]

42. Our proposed incentive has been calculated based on the cost of acceleration, however we consider that the incentive scheme should be symmetrical and therefore equal values would apply as the penalty for late delivery.

43. Our proposed scheme parameters are:

(e) Zero target

(f) 100% sharing factors on National Grid

(g) No caps and collars

(h) £10,000 per GWh/d per month delayed or accelerated

(i) Proposed for the whole of the RIIO-T1 period

(j) The incentive will be ‘cashed out’ annually

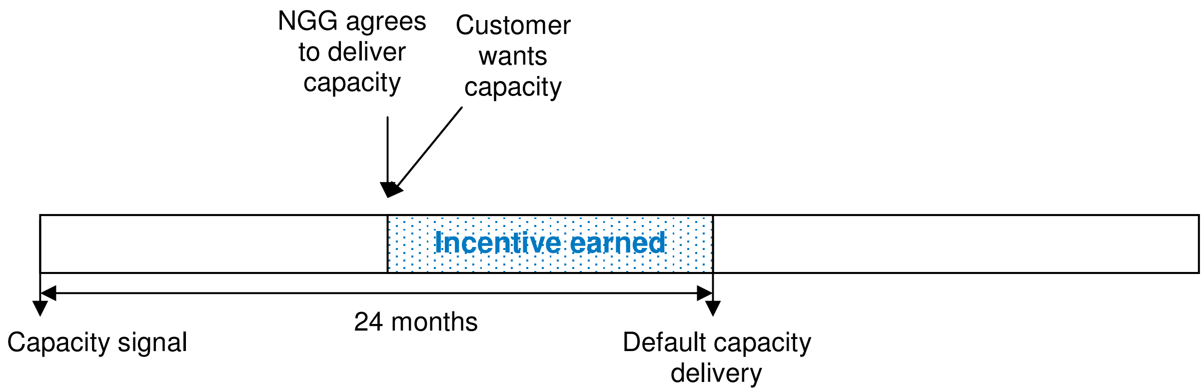
(k) Incentive will be ‘played’ prior to the formal capacity application method i.e. we will indicate our ability to deliver in the invitation letter for the relevant auction / application window

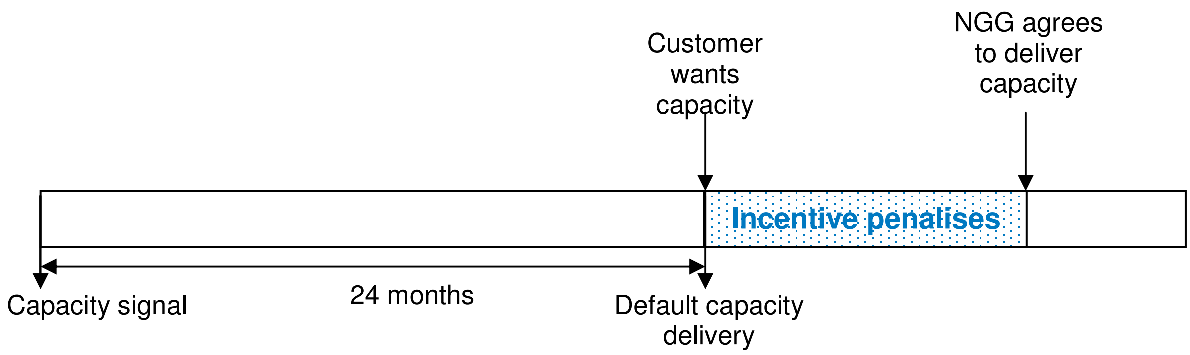
(l) The reward will only apply where the customer values it and the penalty will only apply where we cannot meet the obligated lead time, or a later date requested by the customer

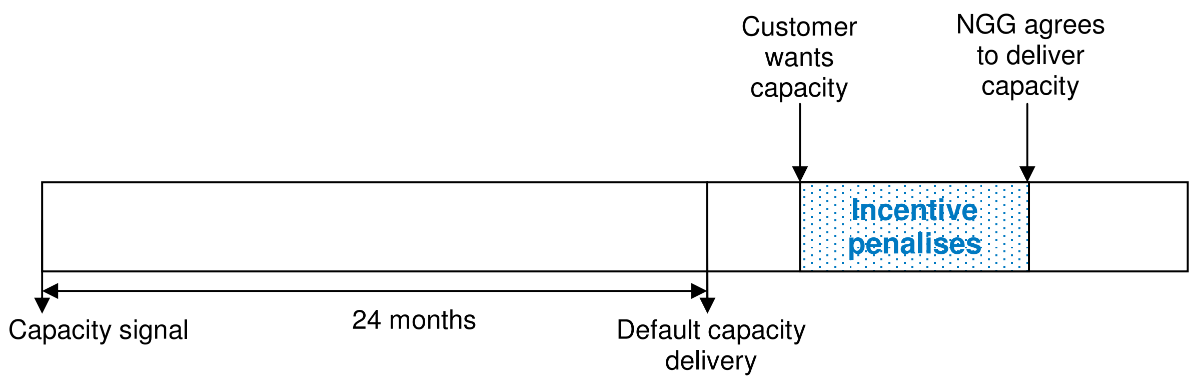
(m) The incentive is proposed in conjunction with a change to the baseline capitalisation rate to 55%.

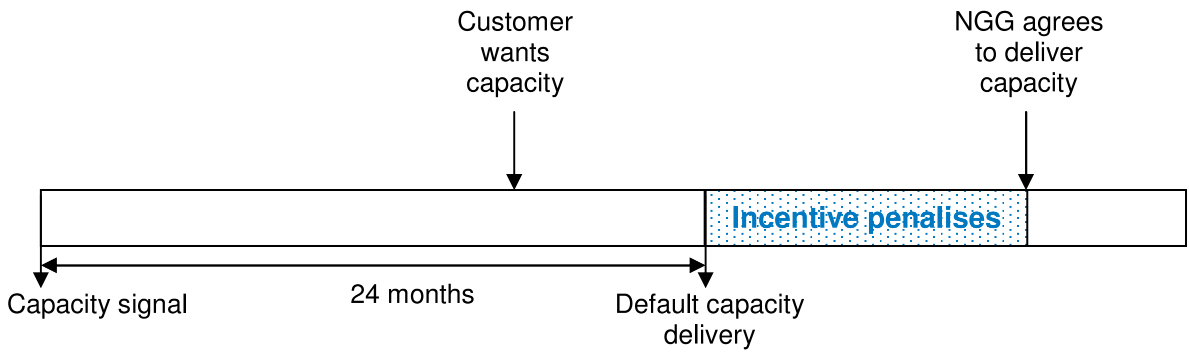
44. We propose that the incentive will only be activated where the customer values that capacity, i.e. where we have indicated that we can deliver early and the customer would want the capacity early, or where we have indicated that we cannot deliver to the obligated lead time or later and this does not meet the customers’ requirements. For the avoidance of doubt where we cannot deliver to the obligated lead time or later but the customer does not want the capacity in that time (and therefore is unaffected

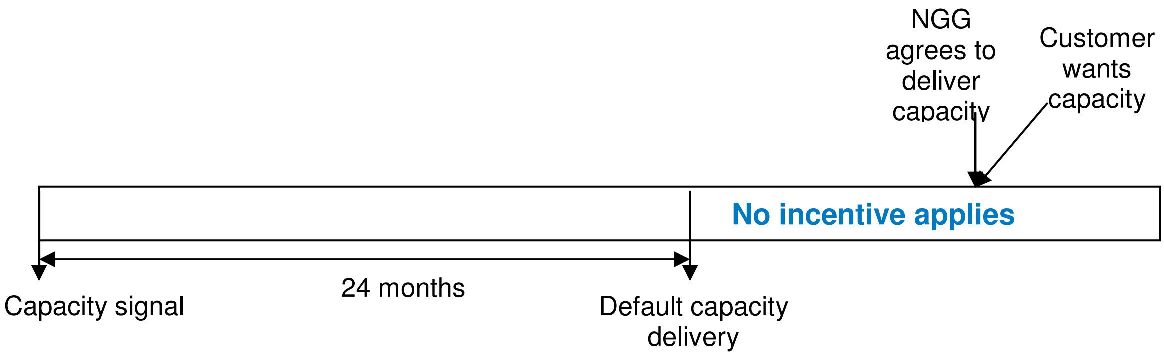
by our build timeline), then the incentive would not apply. This is demonstrated in the following diagrams.

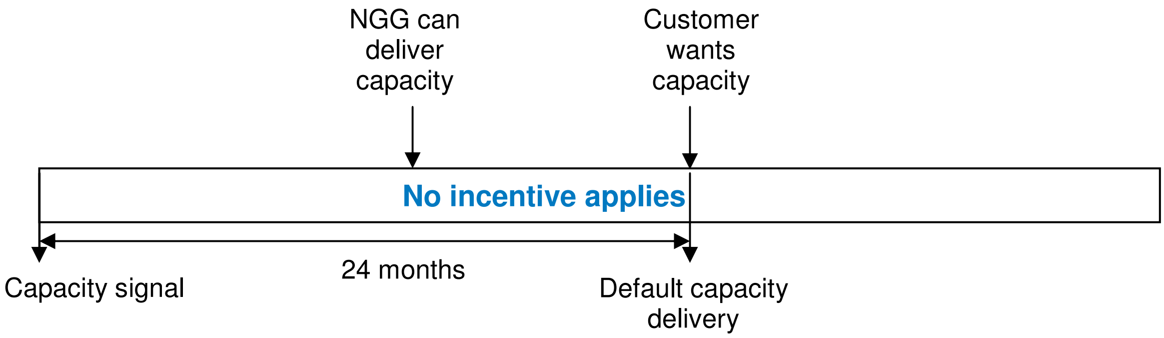




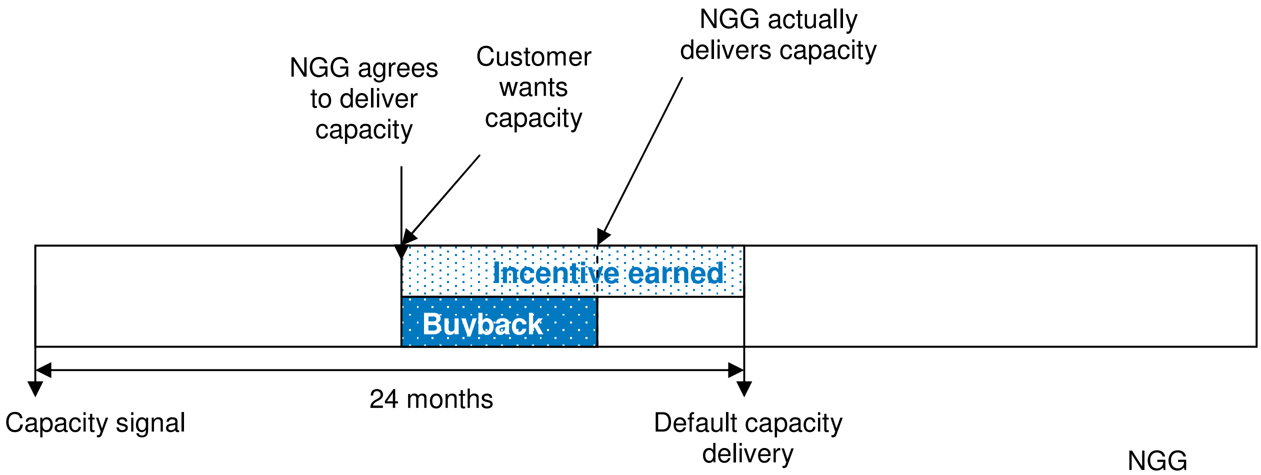


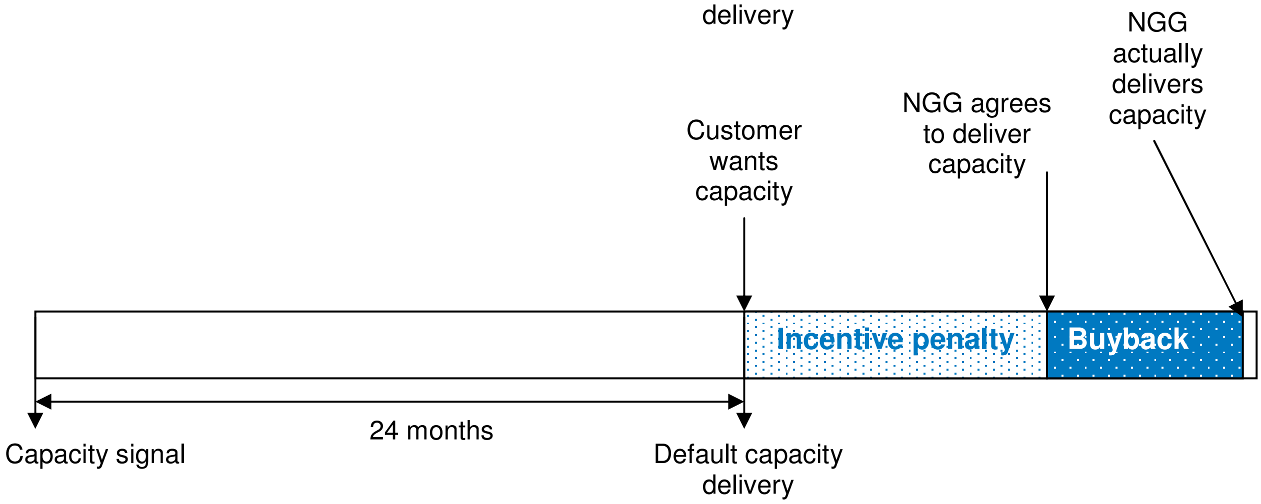






45. The incentive will be 'played' prior to the formal capacity application process, i.e. we will indicate our ability to deliver in the invitation letter prior to the auction or application window. This is completely analogous to the mechanics of the current 'permits' scheme. If the customer then places an application that shows they value the capacity within the timescales where application of the incentive has been indicated, the incentive would be activated and our obligated lead times would be altered accordingly. If we are then unable to deliver within the adjusted obligated lead times, the buyback regime principles (as proposed in Annex A – Buybacks / Constraint Management) will apply, as demonstrated below.





46. In relation to the customers' readiness to flow, where a customer is not ready to deliver or offtake gas then we will not be obliged to buyback. This principle currently applies within the UNC.

Capacity delivery proposals – interim solution

Background

50. As noted previously within this document, our March 2012 RIIO-T1 business plan proposed a number of changes to the regulatory regime relating to the release of incremental capacity. The majority of the changes can be made to the regulatory framework through licence drafting and do not depend on changes being brought forward to the commercial regime. The notable exception is our proposal to reduce our obligated lead times within the licence to 24 months from an October capacity allocation. Where a Development Consent Order under the Planning Act is required, existing obligated lead times cannot be met, therefore shortening the obligated lead time will only exacerbate the risk that is currently faced. We have therefore proposed that complementary changes would be required to the commercial framework and have been discussing our proposals with industry.

51. These commercial changes must be progressed under the governance of the Uniform Network Code (UNC) in conjunction with the industry. We have developed the outline of a proposal, based on the concept of aligning the connections and capacity processes and have been discussing this with industry. We cannot continue under the current regime without making any changes at all, as the impact on project delivery timelines as a result of the Planning Act places a considerable risk of exposure to constraint management costs on end consumers, NTS Users and NGG.

52. It is unlikely that these commercial changes will be in place for April 2013 and certainly not in time for Initial and Final Proposals.

Views were sought on whether April 2013 implementation seemed achievable; Shippers were not sanguine in respect of this and a reluctance to provide a more positive response indicated that more clarity was required.
UNC Transmission Workgroup meeting, 1st May 2012

53. Given that further work is needed on the detail of the potential commercial changes and further industry discussion is required, we have been investigating a number of options that could be implemented in the interim period (in the absence of a UNC modification) to ensure the commercial regime continues to interact with the regulatory regime appropriately. This activity has been carried out since our 1st May 2012 workshop and therefore has not been discussed with stakeholders at this point.

54. In addition, as noted previously, the interim arrangements could become an enduring solution if stakeholders indicate that they do not want to ensure the incremental capacity is allocated to the PCA signatory, in which case a simpler UNC modification, or no change to the UNC, could be considered.

55. The potential options that we have considered are summarised below:

(a) **24 month lead time with capacity release conditions specified in the Methodology Statements**. The risk associated with the introduction of the regulatory changes without a UNC change could be managed through drafting being incorporated into our Methodology Statements to introduce conditions for the release of incremental capacity. The Methodology Statements would be modified to state that the obligated lead time of 24 months from an October capacity allocation would only apply to entry or exit points where a bi-lateral PCA between NGG and a customer has been signed and the steps within that contract met. *[Text deleted].*

(b) **Default arrangements**. Without any of the proposed changes we would be left with our default position. This means that a customer could signal for incremental capacity at any time through an entry capacity auction or exit capacity application and we would be obliged, subject to the Methodology Statements, to release the capacity within the obligated lead times, which we would not be able to achieve where a Development Consent Order is required. The connection of customers on to the NTS prior to the delivery of network reinforcement would lead to an increased reliance on capacity buybacks to manage constraints on the system. We do not support this option as we do not believe we could ensure compliance with our 1 in 20 obligations in relation to exit capacity, but it has been included as this will become the default position if no action is taken.

Annex A – Buybacks / Constraint Management considers that one of the alternative options discussed here will be implemented and therefore does not take account of the risk associated with this default position in our proposed buyback target. If no alternative arrangements were implemented and the default situation continued, the buyback target would need to be revisited to reflect this significant increased risk of constraint management costs. We note that there would be some sites where, for safety reasons, we would not be able to allow connection without either the necessary system reinforcement being completed or suitable arrangements being agreed with the site to cease taking gas as and when necessary to ensure safe control of operations on the network.

(c) **Lengthen or remove obligated lead times**. We could propose a Licence amendment to extend the obligated lead time to 72-84 months to align with the Planning Act timescales. This would provide customers with early certainty but would require them to financially commit very early in their project lifecycle, potentially creating a barrier to entry. Stakeholders have already stated this would be an undesirable option. Alternatively we could remove obligated lead times from the licence and negotiate them on a one to one basis with customers. We recognise, however, that this could reduce transparency and certainty for customers. Both options (lengthen or remove obligated lead times) were not supported by industry and therefore we have ruled them out.

(d) **Discretionary incremental release**. We could make use of existing wording in the UNC and Incremental Entry Capacity Release Methodology Statement (IECR) which allows us to release incremental entry capacity on a discretionary basis. There is no equivalent option for incremental Exit capacity and so this option is not viable.

(e) **Existing lead times remain in the licence in conjunction with a permits allowance.** The risk associated with the current regulatory regime and the proposed changes could be managed through the continuation of the use of permits, which would then be replaced with the new regulatory arrangements if an associated UNC modification is implemented. A permits allowance would be set, sufficient to manage our assessment of the risk associated with lead times, with customers being provided information prior to a capacity auction / application window that permits will be used / earned and thus the obligated lead time adjusted.

56. Of these five options presented, we do not believe that options (c) or (d) are workable as option (c) has been ruled out by the industry and option (d) is only applicable for entry capacity. Additionally, we have reservations around the continuation of option (b) as we do not believe that this is compatible going forwards with our safety case. We have, however, included option (b) in our consideration of the options as it is the default position. Our initial assessment of options (a), (b) and (e) is included below:

	Our initial view
Methodology statements	Removes risk from end consumers. Mitigates risk on NTS Users and NGG. Improves transparency and certainty for NTS Users through the PCA. Allows full alignment between the Planning Act and the incremental capacity regime. *[Text deleted].*
Default arrangements	Places high risk on end consumers, NTS Users and NGG and does not improve transparency or certainty for NTS Users. This does, however, allow earlier connections thereby benefiting security of supply (but at a cost which may be considered prohibitive). This option places the consequences of misalignment of the Planning Act and the incremental capacity regime wholly onto NGG, without any commensurate increase in funding and potentially impacts our ability to ensure compliance with our 1 in 20 obligations.
Permits	Lowers risk on end consumers, mitigates risk on NTS Users and NGG to some extent. Gives some improvement in transparency and certainty for NTS Users and allows better alignment between the Planning Act and the incremental capacity regime.

57. We have included the detail of both of the preferred interim solutions below.

Permits proposal

58. The licence could be drafted to include two sections relating to obligated lead times. One would apply in the absence of a UNC modification with the other applying if a UNC modification linking incremental capacity allocation to a PCA signatory is implemented. In the absence of a UNC modification, we could retain the current lead times in the licence and have an appropriate permits allowance to manage the delivery risk associated with the Planning Act. Permits applied in TPCR4 and the volume of permits has been pro-rated in the rollover year, although it should be noted that the allowance for the rollover year is of insufficient volume to be effective in managing any risk. We have therefore developed a proposal for an allowance to apply for the remainder of the rollover year and the first year of RIIO-T1. Note we would expect the licence modifications that would take effect from 1st April 2013 to amend the current rollover allowance for permits such that this outcome could be achieved.

59. We have taken a view of the projects we believe are likely to manifest bids in the rollover year or year one of the RIIO-T1 period. Our view is based on customer intelligence, publicly available TEC dates (Transmission Entry Capacity for the customer's electricity connection) and planning permission information, where available. We have used this information to calculate our permit allowance proposal, taking a number of sensitivities into account:

    (a) The value of each permit – whether this should be equal to the current entry permit values (£5,000) or equate to our proposed new capacity delivery incentive (£10,000), defined in paragraph 40

(b) The lead time that should be covered – whether we should cover the risk from the obligated lead time until our date of delivery, or from the customer's requested date for first gas until our date of delivery

(c) The level of capacity that should be covered – whether we should cover up to 150% of the obligated level[15] or up to the customer's capacity requirements.

60. For those projects we think will apply for incremental capacity in the rollover year capacity application processes, we have taken only the value of the current entry permit scheme (rather than the proposed new incentive) into account but have accounted for both options within sensitivities (b) and (c) above.

61. For those projects we think will apply for incremental capacity in the first year of the RIIO-T1 period, we have considered the effects of using both the current permits value (£5,000) and the proposed new capacity delivery incentive value (£10,000). In relation to sensitivity (c) above, however, we have not accounted for the risk of making available 150% of the obligated level, as either the customer's capacity requirements are already higher than this level, or the requirements are at a new point on the system, where the obligated level is currently zero. Note, there is no pre-set level for the amount of capacity we are obliged to release on exit, but we would expect the level of capacity applied for by the customer to be commensurate with the level accounted for in the revenue driver calculations.

62. Our analysis provides the following results[16]:

[15] Currently in relation to entry capacity the UNC states that incremental capacity may be released in accordance with the provisions in UNC B2.2 and B2.3. One of the provisions of these sections is that incremental price steps will be offered up to a level not less than 150% of the obligated amount

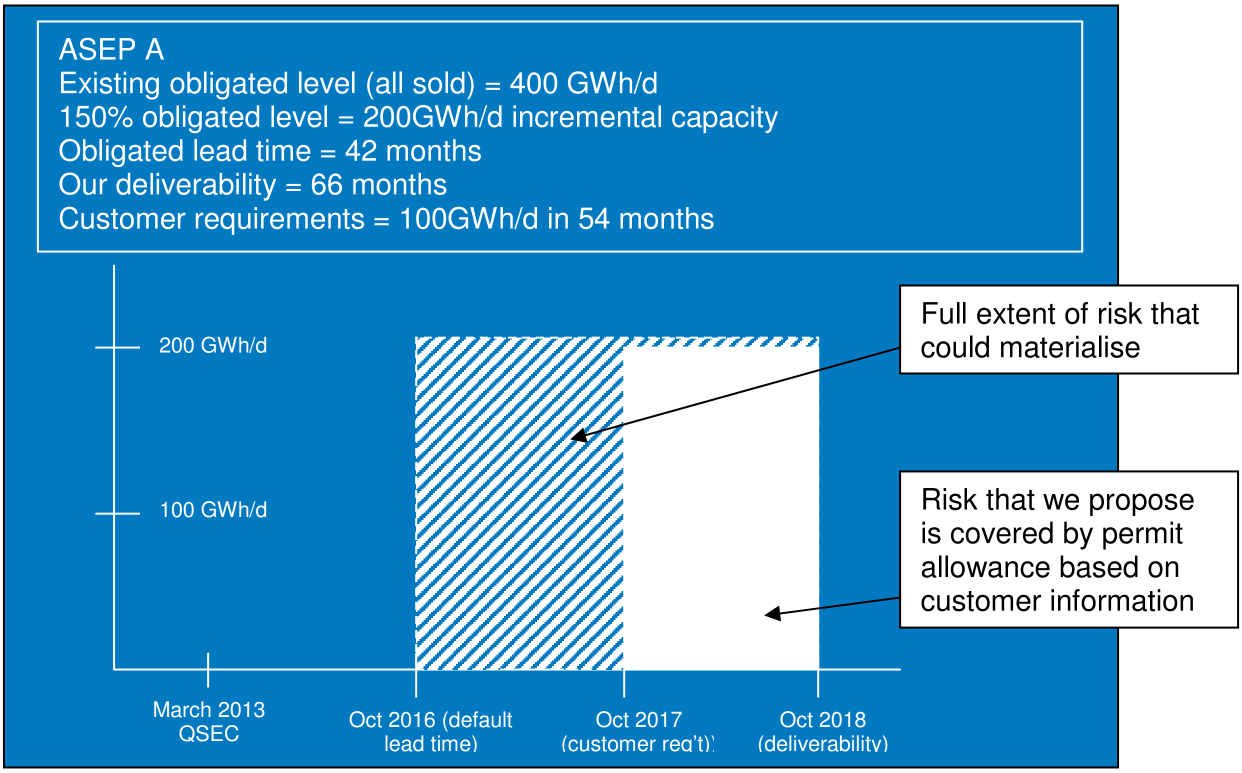
[16] Please refer to Appendix B for more information relating to these customer projects

[Table deleted]

63. When using permits within the TPCR4 period, we base the number of permits required on the time difference between the obligated lead time and our achievable delivery date and, in relation to entry capacity, the potential for users to apply for 150% of the obligated level for existing ASEPs. Applying the same assumptions to the projects referred to above would result in a requirement for 24,476 permits with a value of £122.38m for the two year period. We believe this in an unrealistic financial allowance.

64. This level of permits would not be required if users bid for capacity on a date later than our obligated lead time, or for less than 150% of the obligated level. We therefore propose that we use the sensitivities of the customer’s first gas date and 150% obligated capacity level to calculate an allowance. We feel this is an appropriate assumption as the first gas date is more certain than the capacity level as it ties into other aspects such as TEC dates and planning permission. Capacity levels can change at short notice and we have seen examples of this in the past.

65. The potential exposures to risk are demonstrated below:



66. We believe it is not efficient to be given an allowance that equates to the higher level of risk, but the principle of being able to go overdrawn must be allowed as customers will be able to, and therefore could, bid for differing levels and start dates of capacity than previously indicated to us. We account for this possibility in the auction / application window invitation letter and therefore would be implicitly going overdrawn although it should be noted that permits would only actually be used where there is a corresponding capacity allocation.

67. We propose that we use the sensitivities of the customer’s first gas date and 150% obligated capacity level to calculate a permits allowance, which would lead to an allowance of 7,804 permits for the two years. We propose that the value applied to entry permits in the TPCR4 control continues, i.e. £5,000 per permit, and so this equates to a value of £39.02m (09/10 prices) for the permit allowance. This proposal

is predicated on the basis that we can go overdrawn and that in the absence of a UNC modification by the end of the first year of RIIO-T1 we would need to negotiate an allowance for the following year of the price control period. This proposal is based on the analysis presented in this document and therefore if an external factor outside of our control resulted in a considerably different outturn of events, we would need to revisit our proposal.

68. We recognise that there should be limits on our ability to go overdrawn, else this could be perceived as creating an ability for us to indicate a 'worst case' lead time for all projects. There are a number of options that could be implemented to manage this:

(a) A financial penalty for going overdrawn to discourage this unless absolutely required. Any financial penalty would need to have a suitable collar attached to it in order to reflect the considerable risk that we could face under this proposal, as customers' changing capacity requirements, combined with the lengthening of lead times as a result of the Planning Act, are outside of our control.

(b) A cap on the volume of permits that can be overdrawn.

(c) A secondary allowance of permits, with zero value, that can be used once the permits with the financial value have been used. In this case overdrawing above this level would not be permitted.

69. We believe that a combination of (a) and (b) above provides a sensible approach whereby enough of a discouragement to going overdrawn is provided, without exposure to considerable risk due to factors largely outside of our control. We therefore propose that there is a cap of 50% of the volume of the initial allowance (i.e. 3,902 permits) by which we can go overdrawn. The financial impact of this is considerable, so we also propose that our financial exposure is limited to reflect the level of control we have over this exposure, with a collar of -£10m applying across the two years. We also propose that the upside is capped at +£30m over the two years.

70. In summary, our proposal in relation to permits for use as an interim solution to manage the risk associated with delivering incremental capacity in the rollover year and first year of the RIIO-T1 period is:

(a) **A permits allowance of 7,804 permits is granted for the rollover year and first year of RIIO-T1, replacing the existing allocation for the rollover year;**

(b) **Each permit allows the deferred delivery of one GWh/d for one month and extra permits can be earned for the early delivery of incremental capacity;**

(c) **Each permit has a value of £5,000 (09/10 prices) and is subject to RPI indexation;**

(d) **There is a limit on going overdrawn, equating to 50% of the original allowance (i.e. 3,902 permits);**

(e) **There are caps and collars on our financial exposure across the two year period of +£30m and -£10m respectively with 100% sharing factors on National Grid; and**

(f) **Permits will only be used or gained where there is an indication, in the form of a capacity application, that the customer values that capacity within the amended lead times.**

Methodology Statements proposal

71. Incremental entry capacity and exit capacity are released in accordance with the Licence, the UNC and with reference to the Incremental Entry Capacity Release (IECR) and Exit Capacity Release (ExCR) Methodology Statements ("the Methodology Statements"). The Methodology Statements include the criteria by which we will accept applications for incremental capacity from NTS Users received through the processes defined in the UNC. The Methodology Statements currently contain provisions such as requiring that entry or exit points are listed in the licence and that a revenue driver is in place before incremental capacity will be allocated.

72. Our March 2012 RIIO-T1 business plan proposed that obligated lead times are reduced to 24 months (from an October capacity allocation). This could be facilitated in the licence by stating that a 24 month obligated lead time would apply in accordance with the provisions set out in the Methodology Statements (i.e. that a PCA has been signed and all the steps within it met) and in all other cases incremental capacity would be delivered on a reasonable endeavours basis in accordance with the Methodology Statements. This could then be reflected in the drafting of the Methodology Statements.

73. In order to facilitate this we would need to update and consult on the Methodology Statements. The timescales would provide for discussions to be held with industry in summer 2012, followed with the formal consultation in the autumn, which then allows for the documents to be submitted to Ofgem in a timescale that would allow a decision to be made alongside the publication of Final Proposals.

74. *[Text deleted]*

75. The Methodology Statements would be building on existing conditions for capacity release and would be stating a condition under which we will release capacity. They will not restrict a User's ability to apply for that capacity in the first place and hence will not be inconsistent with the UNC. This is analogous with the drafting already in the Methodology Statements whereby we have processes defining, subject to our overriding statutory and licence obligations, whether to release capacity and the level of capacity to allocate in accordance with the provisions of the UNC.

76. **In summary, our proposal in relation to using the Methodology Statements as an interim solution is that drafting would be incorporated into the Methodology Statements to clarify that:**

(a) **Where a PCA has been signed, and all relevant steps met, incremental capacity will be released with a 24 month obligated lead time from an October capacity allocation; and**

(b) **Where a PCA has not been signed, incremental capacity will be released on a reasonable endeavours basis in accordance with the principles in the Methodology Statements.**

77. For clarity, we are proposing that either of the interim options (the changes to the Methodology Statements or the use of permits) would be employed until a UNC modification is implemented and that both options would apply to the remainder of the rollover year and the first year of the RIIO-T1 period. If NTS Users, however, do not want the incremental capacity to be tied to the PCA, the UNC modification could potentially be withdrawn or simplified. Alternatively if NTS Users support the development of a different UNC modification, either of the interim solutions could continue into the future with suitable amendments (for example, selecting the use of permits as an interim scheme and then continuing to use it on an enduring basis would lead to a requirement to reassess the required number of permits).

Pre-capacity application incentive

Background

78. The Planning Act requires that a number of steps are undertaken in support of any proposed development prior to an application for a Development Consent Order being submitted. We have previously presented to industry our understanding of the timescales associated with these process steps[17]. Through our Talking Networks activities that informed our RIIO-T1 business plan, stakeholders asked whether the timelines associated with these activities could be optimised. In particular stakeholders asked whether certain elements could be run concurrently rather than end to end, such as the optioneering and routeing processes. As we currently understand the requirements, the stages must run end to end to ensure full and proper engagement with all stakeholders. There is the possibility, however, that the process will become more streamlined as greater experience is gained. Stakeholders have noted that the timelines around this process must be flexible enough to cope with any future efficiencies and innovations.

79. In order to avoid the situation whereby a NTS User commits to capacity rights prior to obtaining planning permission, therefore introducing a risk that the NTS User will have committed unnecessarily (and potentially triggered reinforcement) if this planning permission is not granted, our proposed changes to the regulatory regime envisage that planning permission activities will be completed before a formal capacity signal is submitted. We therefore refer to this part of the process as pre-capacity application processes.

80. There are a number of options that could be considered to incentivise our activities in this area, to ensure we are optimising activities where we can, but bearing in mind stakeholder requests for the process to be flexible:

    (a) Given that many of the required activities to be undertaken prior to the submission of a Development Consent Order are unlikely to be entirely within our control (for example that the level of stakeholder engagement will be dictated by the stakeholders involved and precedents set by others) it could be argued that an incentive in this area is inappropriate.

    (b) The timelines we have presented through our stakeholder engagement activities, informed by other parties' experiences, reflect our current understanding of the Planning Act requirements. It may be the case that as our experience of the Planning Act activities grow, we are able to optimise some of these activities. The introduction of a reputational

[17] Please refer to our March 2012 RIIO-T1 business plan, Detailed Plan Appendix B paragraphs B16-B32 for more information in our understanding of the impacts of the Planning Act.

incentive, whereby we report on our progress against these timescales on a quarterly basis would ensure that our progress is fully transparent.

(c) It may be appropriate to introduce a financial incentive on the pre-capacity application processes in order to encourage optimisation of these steps. As shown in our RIIO-T1 business plan, however, the costs for these steps when compared to the cost of capacity delivery activities are relatively small and so it would be difficult to set a meaningful and proportionate incentive. It would also be difficult to set the target timeline from which any financial incentive would operate due to the uncertainty surrounding these activities.

81. In consideration of the above options, we believe that option (b) whereby we would be required to provide transparency on our progress on key milestones would be the most appropriate way forward given the continuing uncertainty around this process. We asked stakeholders for their views on this.

Stakeholder engagement

82. Stakeholders generally shared the same position:

"SSE are supportive of a reputational and reporting licence requirement but are not supportive of a financial incentive due to the uncertainty around the process."
SSE, May 2012 stakeholder engagement consultation response

83. In addition stakeholders could see the value of using a reputational reporting incentive, potentially in advance of alternative arrangements:

"Reputational incentive reporting should clearly show how these parameters evolve over time."
Energy UK, May 2012 stakeholder engagement consultation response

84. Some stakeholders had specific views about the use of reputational reporting incentives:

"When using a reputational incentive it will be important to ensure that the reporting metrics are clear, transparent and relevant."
EdF Energy, May 2012 stakeholder engagement consultation response

85. We agree with our stakeholders' views in this area whereby a reputational reporting incentive retains the flexibility required whilst allowing stakeholders to gauge how performance is evolving over time.

Pre-capacity application incentive proposal

86. **We propose that a reputational reporting incentive is introduced within our licence in relation to the time taken to progress through pre-capacity application activities.**

87. The introduction of an obligation in our licence would require us to report on the time taken to progress through key stages of the activities undertaken prior to and including the submission of a Development Consent Order (where required) up to the point where an NTS User is able to provide a formal capacity signal. These key

activities would be linked to the steps included in the generic PCA[18], for example identification of preferred route corridors, completion of the Environmental Impact Assessment and stakeholder engagement activities. The generic PCA will be a public document and therefore linking the reporting incentive to steps within this agreement makes that information transparent and meaningful to all. This allows the industry to review our overall performance, compare their particular projects against the industry average and consider whether it would be appropriate to introduce an incentive to the overall timeline.

88. Given that it will take time to progress through the steps that will be reported on under this obligation, it will be some time before there is a meaningful data set gathered together and we therefore propose that the reputational reporting incentive should apply for the first four years of the RIIO-T1 period and its appropriateness should then be reviewed.

Connection offers incentive

Background

89. In its January 2012 strategy document[19], Ofgem stated that in order to promote timely and efficient connections, it was considering the introduction of a financial incentive to encourage the SO to deal with all connection applications in a timely manner in conjunction with the TO. There is a clear regulatory expectation that an incentive is introduced in this area, however much of what Ofgem are seeking through an incentive will be delivered through UNC modification 373[20].

90. UNC modification 373 proposes that formal steps are introduced into the UNC to define the deliverables and timescales associated with the delivery of connection offers. This UNC modification is currently with Ofgem awaiting determination. We believe UNC modification 373 is in the best interest of connecting parties and therefore we will look to introduce as many of the principles as we can if it is not implemented into the UNC.

91. Taking the regulatory expectations into account, along with the development of UNC modification 373, we have considered a number of options that could be introduced to incentivise our activities in this area:

(a) UNC Modification 373, if implemented, will introduce defined steps and timescales into the UNC in relation to the delivery of connection offers. Given that we will be obliged under the UNC to comply with these timescales, one option is that there is no additional incentive placed on connection offers within the licence. This, however, provides no incentive to deliver ahead of those obligated timescales, where possible, which may be valued by the customer. Having no incentive in place also would not appear to meet regulatory expectations.

(b) Given that defined timescales in relation to connection offers are likely to be introduced into the UNC as a result of UNC modification 373, one option could be to introduce a downside only incentive, penalising only where those timescales are not met. This, however, would already constitute a breach of the UNC so it does not seem appropriate that there is a

[18] As referenced in paragraph B33 of Appendix B to our March 2012 Detailed Plan.
[19] System Operator incentive schemes from 2013: principles and policy.
[20] Subject to Ofgem approval.

secondary penalty placed on the failure to deliver and this would not provide any incentive to deliver early.

(c) The timescales included within UNC modification 373 have been agreed through a process of industry discussion and reflect our current ability to deliver connection offers. It may be the case that during the 8 year RIIO-T1 period, new initiatives make it possible for us to enable these timescales to be optimised and connection offers delivered quicker in some cases. It may therefore be appropriate for an incentive to be introduced to encourage the seeking out of these innovative developments in order to deliver offers quicker, which may be valued by customers.

92. For the reasons stated above, we do not think that options (a) or (b) are viable and so we have based our discussions with our stakeholders around option (c).

Stakeholder engagement

93. In April and May 2012 we engaged with our stakeholders in relation to our proposals on the topic of connection incentives. This engagement was carried out through the publication of a stakeholder engagement consultation along with a special meeting of the Transmission Workgroup on 1st May 2012 to discuss its content.

94. Within our engagement activities, we described how UNC modification 373 has been developed by the industry and that it reflects our current ability to deliver connection offers. We suggested that there could be innovative developments in the future that allow us to deliver certain offers in a shorter timescale and therefore we could be incentivised to find innovative approaches and potentially shorten these timescales in the future. Such an incentive framework could be based on a calculation of total number of offers delivered early divided by total number of offers delivered and then multiplied by a financial amount. We did not propose that any downside incentive should apply, as this would be provided for by the threat of breach of the UNC. Some stakeholders were unsure of the reasoning for an incentive in this area.

[A stakeholder] thought it rather premature for consideration of any incentive, pointing out that if National Grid NTS believed it could do better at this early stage then it should automatically demonstrate that in its performance.
UNC Transmission Workgroup meeting, 1st May 2012

95. Other stakeholders specifically highlighted the interaction between any incentives and UNC modification 373:

"Given that UNC Mod 373 is not yet implemented (at the time of writing), never mind in operation, we believe it is too early to consider specific incentives in this area. Until we have had projects progress through the new process, we will have no feel for how stretching the targets will be for National Grid."
E.On, May 2012 stakeholder engagement consultation response

96. Stakeholders tended to concur with the view expressed above, stating that it is too early to introduce a financial incentive in this area, but that it may be sensible to have some sort of incentive to encourage early delivery where possible and allow stakeholders to measure our progress.

"Reporting of the number of applications and timescales for delivery of offers is already included in Mod 373. Reputational incentive reporting should clearly show how these parameters evolve over time."
Energy UK, May 2012 stakeholder engagement consultation response

97. Broadly most stakeholders that expressed a view in this area thought that it would be appropriate for a reputational reporting incentive to be introduced for the first few years of the RIIO-T1 control, followed by a financial incentive if this consequently appears appropriate.

Connection offers incentive proposal

98. **Taking on board the feedback from our stakeholders, we are proposing that a reputational reporting incentive should be implemented for the first two years of RIIO-T1; this should then be reviewed to consider whether a financial incentive would be appropriate from that point onwards.**

99. The purpose of a reputational incentive is to provide transparency to the industry of our progress against the key milestones in the connections process. This allows industry to review our overall performance, compare their particular projects against the industry average and consider whether it would be appropriate to raise any modifications to the timescales. UNC modification 373 already contains some reporting requirements within it, specifically that we should publish on a quarterly basis:

    (a) The number of Competent Connection Applications for Connection Offers (received in the previous quarter and the cumulative total for the calendar year in question);

    (b) The cumulative total for the calendar year in question of Full Connection Offers made in accordance with the timescales set out within the UNC; and

    (c) The cumulative total for the calendar year in question of Initial Connection Offers made in accordance with the timescales set out within the UNC.

100. We propose that our requirement to report on our progress in relation to issuing connection offers would include the information listed above (as envisaged by UNC modification 373) and in addition we would report on:

    (a) The average time taken to deliver Initial and Full Connection Offers; and

    (b) The cumulative total for the calendar year in question of requests made by National Grid for an extension to the Connection Offer Deadline.

101. We propose that this information be reported on via our website in order that it is accessible to all and that the obligation to do this is contained within our licence.

Generic Revenue Driver Methodology and Unit Cost Library

102. In our March proposals we detailed a two stage revenue driver process:

(a) The stage one revenue driver (triggered on signature of a PCA, and calculated with reference to the NTS Transportation Model) would provide funding for the pre-construction activities, including any necessary planning applications (estimated at 17% of total cost)

(b) The stage two revenue driver (triggered by a formal signal for incremental capacity) would provide funding for the remaining construction activities (estimated at 83% of total cost).

Stage two revenue driver – calculation methodology

103. The stage two revenue driver will be calculated in line with a generic methodology, included in Addendum 3 to this document, and will use a library of unit costs agreed at the start of the RIIO-T1 period to cost individual project components.

[Text deleted]

104. *[Text deleted]*

105. *[Text deleted]*

106. *[Text deleted]*

[Text deleted]

107. *[Text deleted]*

(a) *[Text deleted]*

(b) *[Text deleted]*

(c) *[Text deleted]*

108. *[Text deleted]*

109. *[Text deleted]*

[Table deleted]

[Text deleted]

110. *[Text deleted]*

[Table deleted]

111. *[Text deleted]*

[Text deleted]

112. *[Text deleted]*

(a) *[Text deleted]*

(b) *[Text deleted]*

(c) *[Text deleted]*

113. *[Text deleted]*

(a) *[Text deleted]*

(b) *[Text deleted]*

114. *[Text deleted]*

115. *[Text deleted]*

116. *[Text deleted]*

117. *[Text deleted]*

118. *[Text deleted]*

(a) *[Text deleted]*

(b) *[Text deleted]*

[Text deleted]

119. *[Text deleted]*

[Table deleted]

[Text deleted]

120. *[Text deleted]*

[Text deleted]

121. *[Text deleted]*

[Table deleted]

122. *[Text deleted]*

123. *[Text deleted]*

Impact on constraint risk management

124. As part of the process for calculating and agreeing revenue drivers to fund the provision of incremental capacity, we outline our intention to assess the impact of incremental capacity (and any infrastructure provided) on the inherent constraint risk on the NTS. This assessment will feed through into the SO capacity management incentive scheme to reflect the change in risk (positive or negative) in the incentive target (either up or down), as set out in Annex A – Buybacks and Constraint Management.

Addendum 1: Stakeholder engagement timeline

1-1 The topics of connections and capacity have been discussed throughout our RIIO stakeholder engagement activities, being one of our main areas of focus along with network flexibility. The discussions we have undertaken with stakeholders are summarised below and full details are available on our stakeholder engagement website.[21]

1-2 Preliminary engagement consultation, summer 2010 – stakeholders highlighted connections as an area that they wished to talk to us about.

1-3 Stage one engagement workshops, November 2010 to January 2011 – initial discussions held to understand concerns and requirements. Two points were highlighted:

"A key problem area is the impact of planning on the entire process; National Grid should be more innovative and should work together with the network users to overcome problems in this area."

"Attendees felt that the key issues for customers here are: timescale, cost, clear planning with milestones, communications and reliability."

1-4 Stage two engagement consultation and workshops, April 2011 – A number of potential service improvement options were presented that had been developed since the last round of engagement. Stakeholders highlighted that a major concern was the alignment of connections and capacity and initial high level principles for this were suggested. We were asked to consider the interactions between the RIIO process and UNC modification 373 (raised March 2011 by E.On).

1-5 Stage three engagement workshops, consultation and targeted meetings (e.g. GSOG), November 2011 – We acknowledged customer requests to align processes and talked about the implications of the Planning Act on delivering capacity. Stakeholders agreed to our proposal that the industry develop a solution to both issues, but said that we should make sure 373 is allowed to go through first. It was noted that regulatory arrangements should not drive commercial change and this should be discussed via the established industry workgroup.

1-6 UNC Transmission workgroup, January 2012 – we presented 5 options to deal with aligning the connections and capacity processes and the Planning Act. We indicated our initial preference (contractual alignment of timescales) would form the basis of our March submission. We were asked to go away and work up more detail and return in April.

1-7 UNC Transmission workgroup, 1st May 2012 – we brought forward the detail of our proposal. Some concern was expressed over certain elements but asked us to come back in June with a draft modification proposal and bi-lateral (Pre-Construction Agreement) contract.

1-8 There was clear industry feedback that they were keen for UNC modification 373 (connections process) to run its course before bringing in the capacity implications. Surety of the direction of the regulatory discussions was also required before looking in detail at the capacity implications, which resulted in the above timetable.

[21] www.talkingnetworkstx.com

Addendum 2: Customer projects

[Table deleted]

Addendum 3: Generic revenue driver methodology

Draft Generic Methodology for Calculating Entry and Exit Capacity Revenue Drivers

3-1 This document reflects our thinking on the high level principles that would need to be incorporated within the Generic Revenue Driver Methodology, consistent with the capacity and connections process proposed within our RIIO-T1 price control submission. Further development of these principles and appropriate consultation will be required once the governance mechanism through which this will be progressed is known.

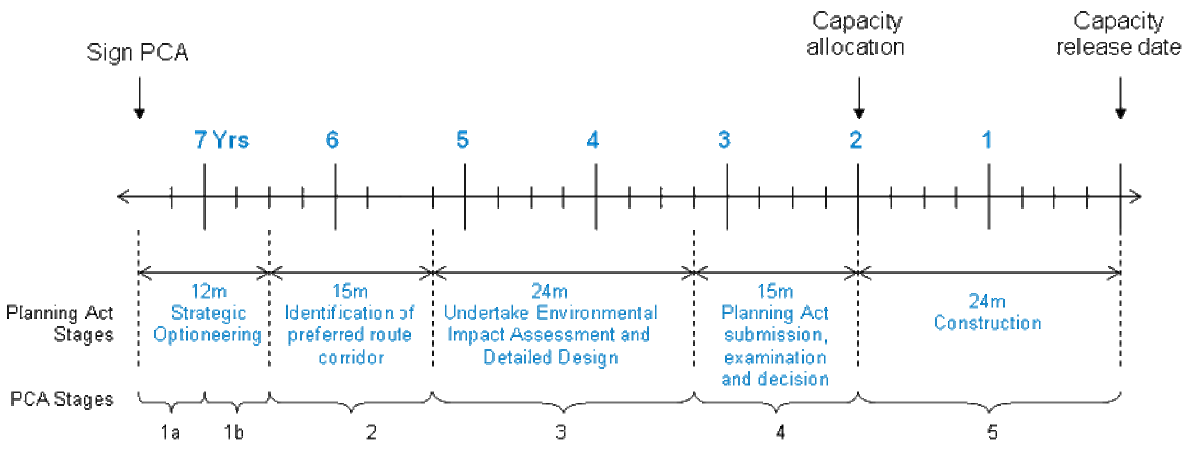
3-2 Revenue drivers have historically been used to allow National Grid Gas (NGG)'s allowed revenue to increase where it has accepted incremental capacity obligations. This increased revenue is required for NGG to undertake the full range of activities necessary to deliver incremental system capability to support the increased capacity obligation (for example, engineering design, planning, asset build, commercial contracting etc.).

3-3 As a result of the implementation of the Planning Act (2008) significant costs have been moved to earlier in the planning process to a time period that, crucially, is ahead of the point when NGG receives a firm user commitment signal for incremental capacity (and hence receives the funding required to undertake these activities).

3-4 In response to the changes introduced by the Planning Act, (and taking account of customer feedback on the previous capacity and connections processes), NGG has proposed a revised capacity and connection process in its RIIO-T1 price control submission. An NTS User[22] requiring incremental capacity will be required to sign a bi-lateral Pre Capacity Agreement (PCA). The PCA commits the relevant user(s) and NGG to commencing a multi-stage process which, if taken to conclusion (and subject to successful receipt of 'planning permission' where required), would result in the user(s) being able to provide a formal incremental capacity signal.

3-5 National Grid has developed a generic timeline, which has been shared with the industry, to illustrate its understanding of the process steps leading up to a submission to the Planning Inspectorate and how the proposed PCA process overlays these process steps.

[22] For clarity, within this document where reference is made to an NTS User, this may be a Shipper, a Distribution Network Operator or a Developer



3-6 Part of this proposal is the introduction of a two stage revenue driver. The Stage 1 Revenue Driver funds the pre-construction activities that NGG is required to undertake prior to the receipt of a formal capacity signal. The Stage 2 Revenue Driver funds physical asset build and/or commercial/contracting activity (as applicable) to support the delivery of the requested incremental capacity.

3-7 Signature of the PCA would trigger the calculation and application of the Stage 1 Revenue Driver.

3-8 The Stage 2 Revenue Driver will be triggered when NGG accepts an incremental capacity obligation. An incremental capacity obligation arises when:

(a) one or more NTS User(s) signal a requirement for new or additional capacity rights at a new or existing NTS entry or exit point, which would result in capacity holdings in excess of the baseline obligated capacity levels that National Grid Gas (NGG) is obliged to provide;

(b) the NTS User(s) have progressed through the Pre Capacity Agreement (PCA) contract process to the appropriate point[23]; and

(c) the signal results in a capacity bid/application that passes the relevant user commitment test, such that release of this capacity is viewed as economic, and is not met through capacity substitution.

3-9 Upon receipt of a valid incremental capacity signal, NGG's allowed revenue increases by the level determined by the revenue driver.

3-10 The Stage 1 Revenue Driver will be based on a simplistic calculation using the existing NTS Charging Transportation Model, which is accessible by all NTS Users and stakeholders[24]. The Transportation Model estimates marginal costs based upon a pipe model of the NTS, a supply and demand forecast comprising individual exit point and Aggregate System Entry Point (ASEP) flows, and an expansion constant representing the capital cost of adding transportation capability to the system. It is proposed that a proportion (17% over a four year period) of this value will be triggered as an approximation to

[23] Either successful granting of a Development Consent Order (or equivalent local planning consent) in cases where a physical build option is being progressed and planning consent is required or equivalent agreed trigger point within the PCA process in cases where commercial / non-planning consent solution(s) are the chosen option(s).

[24] Users can obtain a copy of the Transportation Charging Model by following the instructions with the document "How to obtain the NTS Transportation Model" which can be downloaded from the National Grid website at the following address: http://www.nationalgrid.com/uk/Gas/Charges/Tools/

fund necessary pre-construction (including seeking planning consent) activities.

3-11 The Stage 2 Revenue Driver will be calculated from this generic methodology as soon as sufficient data is available during stage 2 of the PCA process[25]. It will be based on an estimation of the cost of the physical build required on the Network to provide the required incremental capacity. This will be calculated by Network Analysis (as described further below) but with regard to likely real-world construction options (such as specific potential route corridors) to enable an appropriate build cost to be calculated by the application of an agreed library of unit costs. This calculation will be informed by information gathered from the optioneering and enhanced consultation (required under the Planning Act) at the time the revenue driver is calculated.

3-12 The Stage 2 Revenue Driver triggers:

(a) Funding for NGG to undertake construction activities (in cases where construction is required)

(b) Funding for NGG to implement a contracting solution (where contracting is seen as a more economic option to construction)

(c) An adjustment to the SO Constraint Management Target to reflect the resulting net change in the level of risk on the Network[26]

(d) A combination of any or all of the above three options as appropriate.

3-13 Whilst calculated during stage 2 of the PCA process, the Stage 2 Revenue Driver would trigger an adjustment to the allowed revenue only upon allocation of the associated incremental capacity following receipt of a valid formal capacity signal.

3-14 The Stage 2 Revenue Driver will be set as early in stage 2 of the PCA process as soon as sufficient information is available. It is necessary to undertake this calculation sufficiently early in the PCA process to be able to provide a basis against which to assess non-build options and to incentivise efficient solution delivery, and yet late enough to ensure that the appropriate level of information necessary for the calculation is available.

3-15 When calculating a revenue driver, NGG must take account of existing obligated levels of capacity at system entry/exit points which interact with the proposed incremental capacity system entry/exit point. Obligated levels of capacity are, in aggregate, far beyond current NTS capability. Therefore, when calculating an appropriate revenue driver, NGG will first need to assess the inherent level of risk on the Network i.e. the pre-existing difference between obligated levels of capacity and actual Network capability.

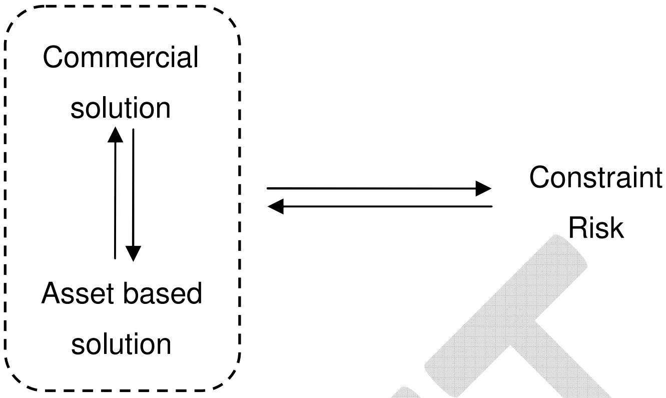
3-16 The revenue driver calculation will then take account of both the reinforcement (or requirement for commercial service) identified to accommodate the incremental capacity, and the resulting change in residual risk on the Network. This calculation will also identify an investment cost against which other (non-investment) solutions can be assessed.

[25] Stage 2 of the PCA process covers 'Outline Routing and Siting' and will result in the identification of a preferred route corridor

[26] Note that the resultant level of risk on the Network may increase or decrease hence the adjustment to the constraint management target may be positive or negative

Objective of Methodology

3-17 When releasing incremental capacity on the Network, NGG will look to achieve the optimum balance between physical build, commercial solutions and constraint risk on the network.



3-18 Asset and commercial solutions both alter (directly or indirectly) system capability, and this adjustment needs to be considered against the change in constraint risk[27]. For example, simplistically, where the capability provided by a new asset is less than the amount of incremental capacity released, the overall constraint risk on the system may reasonably be expected to increase; conversely where the added capability is greater than the amount of incremental capacity released, the overall constraint risk may be expected to decrease.

3-19 The objective of this generic revenue driver methodology is to identify the investment cost associated with making available incremental capacity over and above the prevailing obligated levels. This value can equally be considered to reflect the costs that would be avoided if a commercial / contractual solution were to be possible and hence allows the relative merits of these two options to be considered. In the case of a commercial / contractual solution being the most economic and efficient investment solution, a 20% downward adjustment to the Stage 2 Revenue Driver will be applied[28].

3-20 This analysis will also allow NGG to undertake risk analysis on the Network to determine how either/both options (physical build and commercial solution) change the inherent level of risk on the Network. The result of this optimisation may be:

(a) A requirement for physical asset build to increase system capability

(b) Procurement of commercial services to redistribute system capability

(c) A change (increase or decrease) in the residual level of risk on the Network (increase of decrease) triggering a change (increase or decrease) in the SO constraint management target

[27] For clarity, a contractual / commercial solution does not create additional system capability, rather it facilitates the re-distribution of existing capability

[28] This was the approach taken by Ofgem during TPCR4 and was intended to provide an incentive to investigate potential scope for contracting solutions to the delivery of incremental capacity

(d) A combination of any two or more of the above.

3-21 Treatment of the costs and associated revenue streams is important to ensure there is no cross-subsidy between forms of control (TO/SO), and that costs are recovered from the appropriate user base:

(a) Direct provision of increased network capability through the provision of an asset solution is defined as a TO activity, with costs incurred by the TO and revenues received through addition of the calculated revenue driver to the TO totex allowance. The totex incentive mechanism (TIM) will capture any under or overspend on delivery against the allowed revenue[29].

(b) Re-distribution of network capability through a commercial solution should be considered a TO activity as it is a direct alternative to physical investment. Revenues will be received by the TO (through the addition of 80% of the calculated revenue driver to the TO totex allowance), however it must be recognised that it is the SO who bears the risk resulting from the absence of the physical investment. It is therefore appropriate that the TO compensates the SO by the sum equal to 80% of the calculated revenue driver, and the SO use this compensation to put in place any necessary commercial arrangements. The full revenue allowance will feed into the TO totex allowance (regardless of the actual initial spend) to reflect the fact that the contracting costs will be ongoing and individual contracts are likely to be of relatively short duration.

(c) The acceptance of a different level of inherent network risk is defined as an SO activity, with the costs of any constraint management action feeding into the SO constraint management incentive arrangements.

<u>Worked example</u>

A signal for 100 units of incremental capacity is received. The optimised solution is for 60 to be delivered by physical investment, 30 by commercial solution and 10 will be accepted as increased inherent network risk. The calculated revenue driver for both physical delivery and commercial arrangement in this case is £1m/unit capacity. This example assumes that the actual TO spend is £60m and hence this full amount feeds into the TO totex allowance.

[29] We understand that the efficiency rate is proposed to be between 40% and 50%

	Capacity	TO		SO
		TO receives into totex allowance	TO pays to SO annually	SO receives
Physical delivery	*60*	*(60 units * £1m/unit) = £60m*	-	-
Commercial arrangement	*30*	*(0.8 * 30 units * £1m/unit) = £24m*	*Revenue from £24m in TO totex allowance*	*Revenue from £24m in TO totex allowance*
Inherent risk increase	*10*	-	-	*Reflected in Constraint Management target*

3-22 Once a Stage 2 Revenue Driver has been determined and a valid formal incremental capacity signal received and allocated[30], NGG will determine the most economic and efficient solution to facilitate the release of that incremental capacity through the optimisation of the three factors above.

Network Analysis Methodology

3-23 The following generic methodology is proposed for calculating Entry and Exit Capacity Stage 2 Revenue Drivers:

<u>Network Model and Supply / Demand Forecast Assumptions</u>

3-24 The gas year to be used in the network analysis to calculate a revenue driver will be the gas year that the Shipper/Developer has specified that incremental capacity will be required or a later year where incremental capacity has already been signalled and is to be released at the relevant system point, or in an interacting zone/ASEP.

3-25 A network model of the NTS will be used for the analysis consistent with the gas year identified for analysis, in line with NGG's Transmission Planning Code.

3-26 NGG's supply and demand forecasts for the relevant gas year will be used as a basis for the analysis. Levels of Entry/Exit Capacity will be considered depending on the type of NTS System Point being considered for the release of Incremental capacity (see Appendix B). For further information on NGG's supply and demand forecasts, see NGG's Transporting Britain's Energy (TBE) Documentation, Future Energy Scenarios (FES) publication and Ten Year Statement (TYS).

3-27 Network reinforcement projects which are currently planned for completion in readiness for the gas year in question (including potential contractual arrangements between NGG and NTS Users which are applicable to the year/demand level to be considered) will be included in order to provide a

[30] Excluding by substitution

best view of the topology of the NTS in that year. For further information on planned infrastructure, see NGG's Ten Year Statement.

3-28 All analysis will be conducted using Transient (Dynamic) Analysis, taking into account changes in system conditions over the course of the gas day, using NTS Flex Capacity / Distribution Network (DN) Diurnal Storage levels consistent with the assumed demand level. DN exit point profile shapes, as provided by Distribution Network Operators, will be used. For further information on the types of analysis undertaken by NGG, see Section 9 of NGG's Transmission Planning Code.

3-29 Analysis will be completed using an appropriate Design Margin incorporating a Flow Margin and Pressure Cover at system extremities. For further information on Design Margins, see Section 9.5 of NGG's Transmission Planning Code.

3-30 All NTS operating limits such as Assured Offtake Pressures (for Distribution Network Exit Points) which are applicable to the demand level assumed, Anticipated Normal Operating Pressures (for Directly Connected Exit Points) and Maximum Operating Pressures will be adhered to throughout the analysis.

3-31 All NTS plant will be assumed to be operational, other than where plant is providing standby capability, and compressor performance will be determined from the ambient air temperature for the relevant demand level, in line with NGG's Transmission Planning Code.

Determining the Demand Scenario for Analysis

3-32 An appropriate demand scenario for the Incremental Capacity Type and Type of NTS System Point being considered will be selected as per table 1 from Appendix B.

Determining the Supply Scenario for Analysis

3-33 An appropriate supply pattern for the Incremental Capacity Type and Type of NTS System Point being considered will be selected as per table 2 from Appendix B.

Reinforcement for Incremental Capacity

3-34 The incremental supply/demand for the ASEP/exit point being considered will then be added. A supply/demand balance will be maintained using the same assumptions as those previously used (as described in tables 1 and 2).

3-35 For Entry Capacity Revenue Driver Analysis, the reinforcement projects considered will be those required to increase system entry capability for ASEPs set at obligated Entry Capacity levels **but not** those required to increase system exit capability should the reduction in supply at balancing ASEPs lead to low pressure constraints. If low pressure constraints are triggered by insufficient levels of supply at a balancing ASEP then supply levels at the ASEP will be increased to alleviate the constraint and the next balancing ASEP as defined in Table 4 will be used.

3-36 For Exit Capacity Revenue Driver Analysis, the reinforcement projects considered will be those required to increase system exit capability for Exit Points set at obligated Exit Capacity levels **but not** those required to increase system Entry capability should the increase in supply at balancing ASEPs lead to a high pressure constraints. If high pressure constraints are triggered by excess supplies at a balancing ASEP then supply levels at the ASEP will be reduced to alleviate the constraint and the next balancing ASEP as defined in Table 5 will be used.

3-37 Only those reinforcement projects that directly affect the NTS' capability to accommodate the supply and demand conditions being considered will be identified. Investment / costs to mitigate constraints incurred as a result of plant being unavailable through construction / commissioning activities will not be included in revenue driver calculations as these will be included in the Constraint Management Incentive.

3-38 The required reinforcement projects (if any) will be recorded and a cost estimate determined. The cost estimates will be calculated using the unit cost assumptions from the agreed Unit Cost Library as detailed below.

Calculation of Stage 2 Revenue Driver

3-39 Following signature of a PCA NGG will determine, using the methodology described above, the investment that would be required to deliver the requested incremental capacity. The Stage 2 Revenue Driver will be calculated from this proposed build solution and a unit cost library agreed at the start of the RIIO-T1 period.

3-40 The precise point in time at which sufficient information is available to undertake this calculation will vary from case to case. For example, where stage 1 of the PCA process clearly indicates that a commercial solution is the favoured option, the Stage 2 Revenue Driver calculation can take place at the start of stage 2 of the PCA process. Conversely, in the opposite situation where stage 1 of the PCA process indicates a requirement for significant physical asset build, it is likely to be towards the end of stage 2 of the PCA process before sufficient information is available to calculate the Stage 2 Revenue Driver.

3-41 To apply unit costs to set the Stage 2 Revenue Driver it is necessary to take account of the key factors which drive costs in investment projects.

Pipelines

3-42 For pipeline construction, there are a number of major cost drivers over and above pipe diameter and overall length including:

(a) proportion of the pipeline length through hilly/urban terrain

(b) density of road/river/rail crossings (i.e. use of non open-cut pipe-laying techniques)

(c) proportion of the pipeline length requiring use of heavy-wall pipeline

3-43 We will use an agreed methodology which scores the complexity of any given project against these factors and maps the total complexity score against a library of unit costs. This approach derives an appropriate unit cost for any project under consideration based on its expected complexity.

Construction through sensitive areas

3-44 Construction through sensitive areas (including Areas of Outstanding Natural Beauty (AONB), Sites of Special Scientific interest (SSSI), National Parks and Archaeologically significant areas) introduces particular challenges in addition to those a construction project through non-sensitive areas would normally face, such as:

(a) Requirement for material environmental protection measures

(b) Significant risk of exceptional protestor action

(c) Significant risk of co-ordinated landowner action

3-45 Planning consent conditions can also have a material impact on project costs, for example:

(a) Replacement of large lengths of dry stone walls

(b) Ten year aftercare arrangements

3-46 Our experience demonstrates that construction projects through sensitive areas (as defined above) attract additional requirements.

3-47 Options available to us to manage the impact of construction in these areas include re-routing the pipeline or facing more onerous planning consent conditions (for example use of a greater degree of non-open cut pipe-laying techniques or the need for extended environmental aftercare). As the revenue driver will be calculated during the pre-planning application process, we will have information relating to the likely options available to us. If re-routing is the preferred option, this will be captured in the inputs to the revenue driver calculation (i.e. through a revised pipeline length). Conversely, if accepting more onerous planning consent conditions is favoured, this will require the application of an additional targeted complexity factor.

3-48 Construction in certain areas also attracts a heightened potential for increased compensation payments, as well as significant protestor action (which can introduce delay and security costs). At the time of calculation we will be engaging with local communities and other stakeholders on potential route corridors, and should have a view (with supporting evidence) as to the likely level of enhanced costs which will apply. Given this information, we will be able to estimate the cost impact of potential enhanced requirements and this will trigger an agreed adjustment to the calculated project cost which will be applied within the Stage 2 Revenue Driver calculation.

Other pipeline-related activity unit costs

3-49 There are a number of other construction activities which may be required in the provision of incremental capacity, these are listed below and are subject to separate unit costs in addition to the pipeline unit cost.

(a) High Flow Modifications

(b) Multi-junction Modifications

(c) Pipeline Up-rating

(d) Flow Control Valves

Exceptional items

3-50 There is the potential for future projects to require exceptional items that are outside the scope of this complexity of approach (an example of such an item could be a requirement for a major tunnel for a significant river crossing or the requirement for a major Pressure Reduction Installation rather than a more typical AGI). We have not included the potential costs for such high impact, low probability requirements in our unit costing methodology. In the event such an item is required, we will open discussions with Ofgem regarding funding arrangements.

Compression projects

3-51 Where compression projects are required to support the delivery of incremental capacity (either as stand alone projects or as part of a wider network reinforcement project), we will use an agreed unit cost model based on the required power and fuel type of the station.

3-52 For commercial sensitivity reasons, we do not intend to publish any of our unit cost assumptions, as to do so would significantly weaken our position in future procurement negotiations.

3-53 In the case of a commercial / contractual solution being the most economic and efficient investment option, NGG / Ofgem will apply a 20% downward adjustment to the Stage 2 Revenue Driver.

3-54 Where accepting a change in risk on the network is the most economic and efficient option (or where there is a change in residual network risk allowing for the effects of physical investment and/or commercial/contractual solutions) the appropriate SO constraint management target will be adjusted to reflect the changed level of risk on the Network.

3-55 Prior to the receipt of a formal capacity signal and under the terms of the PCA, NGG will have determined the most economic and efficient investment solution to increase NTS capability to accommodate the increase in supply or demand.

3-56 NGG may have previously received funding (either in part or in full) for a reinforcement project identified in this analysis. In this case, cost estimates equivalent to the received funding for that project will not be included in the total costs however the details of the project will be included in the reporting tables for completeness.

3-57 It is important to note that whilst NGG may have previously received funding for a reinforcement project it may be necessary to include further costs if the scope/capability/requirements of the funded reinforcement project are insufficient for this analysis. For example, if National Grid NTS had previously received funding for a new 8MW (+8MW standby) compressor station at a defined location and, during this analysis, it was identified that a 12MW (+12MW standby) compressor station was required, then costs included in the revenue driver will be cost of the 12MW (+12MW standby) compressor station minus the funding already received for the 8MW (+8MW standby) compressor station. Note that this only applies in cases where the initially identified reinforcement has not yet been built (or NGG has not yet committed to contract for build). Where the initial reinforcement has proceeded beyond the point of contract award, it will be necessary to separately address and fully fund any additional incremental requirement identified as a result of a subsequent signal.

Commercial/Contractual Solutions

3-58 The generic revenue driver methodology is a defined process for identifying the investment (and hence not the contractual alternatives) to meet an incremental capacity signal.

3-59 When assessing potential capacity related investments, National Grid considers multiple supply and demand scenarios based on forecast demand, and considers combinations of various alternative commercial/contractual solutions and incremental buy-back risk.

Residual Network Risk

3-60 NGG uses a probabilistic model and associated methodology to forecast capacity constraint volumes and costs on the NTS. This model and associated methodology are referred to as the entry and exit capacity constraint forecasting model / methodology (the "EECC forecasting model / methodology").

3-61 The EECC forecasting model and associated methodology provides a probabilistic forecast (a range of potential outcomes along with their likelihoods) of expected constraint volumes and associated costs for a period. This model exemplifies the hypothesis that entry and exit constraints are interlinked e.g. solving an exit constraint can generate an entry constraint and vice versa.

3-62 The model and methodology have been developed to automatically determine if the NTS has sufficient capability to cope with a wide range of supply and demand patterns. A constraint is identified when network analysis indicates that the forecast supply / demand pattern would result in either pressures at entry points exceeding pre-determined limits (e.g. operational / safety limits) or pressures at exit points being lower than pre-determined limits (e.g. assured / agreed limits).

3-63 The EECC forecasting model is built around an Access database and the Simone Network Analysis software used by NGG. The EECC forecasting model methodology is based on the premise that network analysis provides the best view of forecasting network capability and that previous network analysis studies can be used to analyse new networks with similar supply / demand patterns.

3-64 The model can assess approximately 120 scenarios per hour and so analysing the entire population of annual supply / demand patterns is not practical. To overcome this, a representative sample of supply / demand patterns is tested and the results from this sample are used to forecast the constraint volumes for the population as a whole.

3-65 The probability distributions representing the likelihood of a constraint are used in conjunction with Monte Carlo techniques to build an appropriate model. The model works at a daily resolution using probability functions to determine the supply, demand and capability on any given day in the period being considered.

3-66 The probability functions of supply, demand and capability are used to forecast constraint events, constraint shortfalls (supply minus capability) and constraint volumes (baseline minus capability).

3-67 The output data is combined to form monthly summary statistics of event risk, volume and costs. These are in turn used to determine distributions of potential constraint events and the associated volumes and costs.

3-68 Using the EECC model & methodology NGG will evaluate the level of risk on the Network prior to the release of the requested incremental capacity. The model / methodology will then be applied again with the inclusion of the requested incremental capacity and the proposed physical system reinforcement and/or commercial/contracting solution(s) as appropriate.

3-69 The difference between these two iterations of the model will indicate the net change in the residual network risk. This change in network risk will then be reflected in the SO Constraint Management Target.

(a) Where the residual risk on the Network has increased, the SO Constraint management target will be increased by an appropriate amount from the incremental capacity release date onwards.

(b) Where the residual risk on the Network has decreased, the SO Constraint management target will be decreased by an appropriate amount from the incremental capacity release date onwards.

Addendum 3: Appendix A

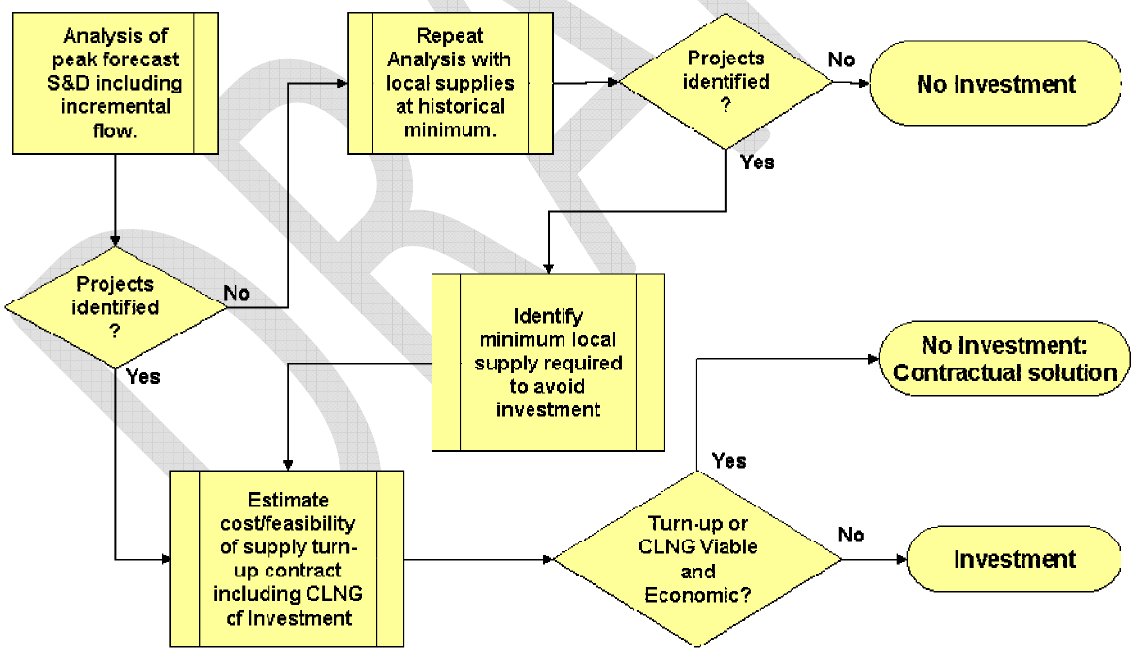
3-B-1 Examples of the high level processes for considering the appropriate solution for the provision of incremental entry and exit capacity.

Exit capacity

3-B-2 The main driver for exit capacity investment is the 1-in-20 obligation. The Safety Case and 1-in-20 obligation require the system to be designed to meet demand up to the 1-in-20 level taking into account demand reduction rights. Analysis is carried out at high/peak demand levels with forecast entry flows to identify investment and constrained LNG requirements. If no investment is identified at these demand levels, further analysis for minimum local supplies is carried out, and further investment may be identified as being required. Where investment has been identified, the potential for contractual solutions will be identified.

3-B-3 In regard to the provision of exit capacity, the investment verses contractual solutions/buy-back risk issue must be considered in relation to our wider security of supply obligations including the 1-in-20 obligation and the gas safety case. The 1-in-20 obligation requires us to consider the commercial arrangements in place and our contractual rights to curtail demand at the time of making exit capacity driven investment decisions rather than closer to real time gas flows. The 1-in-20 obligation limits our scope for taking exit buy-back risk. The 1-in-20 obligation does not apply to entry and hence there is more scope to consider accepting buy-back risk compared to contractual solutions.

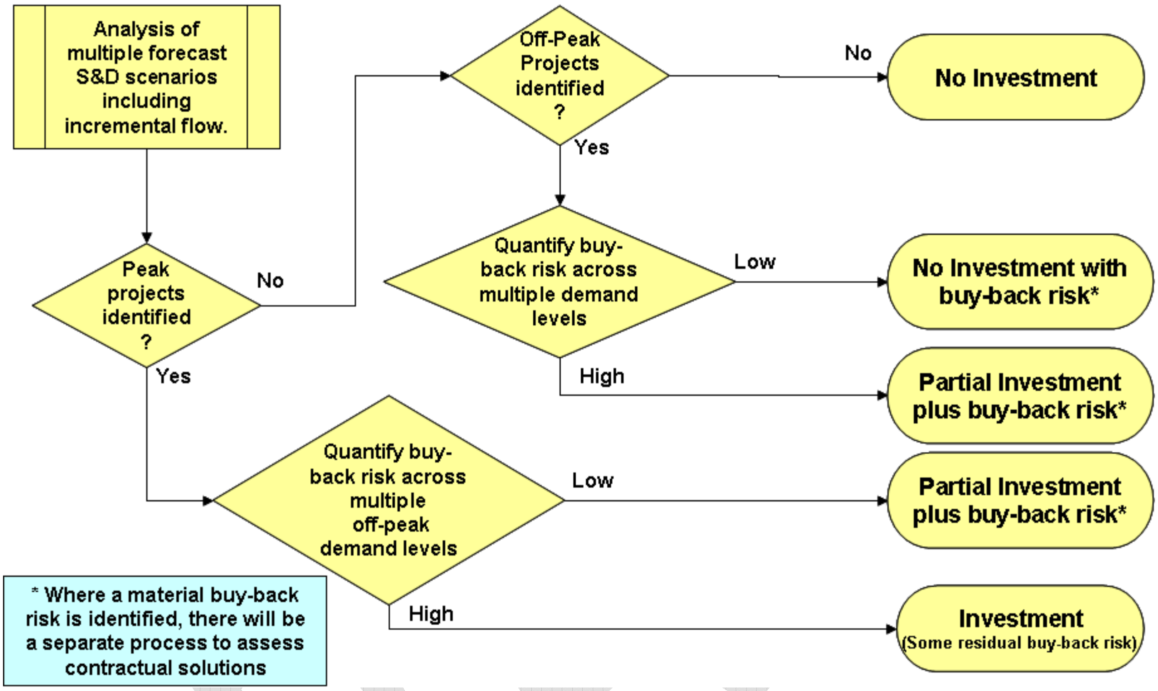
3-B-4 The following diagram outlines the high level process for considering investment versus contractual solutions in relation to exit capacity.



Entry capacity

3-B-5 The main driver for entry capacity investment is analysis at high demand levels based on forecast Supply scenarios. Further analysis for off-peak demand and supply sensitivity scenarios is carried out, and investment may be identified as being required under either of these conditions. Where investment has been identified, the potential for contractual solutions will be identified.

3-B-6 The following diagram outlines the high level process for considering investment verses contractual solutions in relation to entry capacity.



Addendum 3: Appendix B - DRAFT – to be agreed during TPC consultation

3-B-1 This appendix is indicative of the information that will be included in the Transmission Planning Code (TPC) to support the calculation of revenue drivers.

Determining the Demand Scenario for Analysis

3-B-2 An appropriate demand scenario for the Incremental Capacity Type and Type of NTS System Point being considered will be selected as per the tables below:

Incremental Capacity Type	Type of NTS System Point	Demand Conditions
Incremental Entry Capacity	All Supply points	Forecast levels of demand for Distribution Networks (DN), Directly Connected Loads (DC) and Interconnector Exit Points for Day 30 of National Grid NTS' Average Load Duration Curve (Diversified). NTS Flex Capacity / DN Diurnal Storage utilisation consistent with this demand level Power Station within-day profiling based upon operational experience
Incremental Exit Capacity	Distribution Network / Directly Connected Load (e.g. power station / industrial facility)	Combinations of Sold and forecast demands capped at the obligated capacity level depending on type and location. (1) Sold Exit Capacity levels at all DN Exit Points (2) Peak day undiversified forecast demand levels at all DC Exit Points including NTS Storage Sites and Interconnectors NTS Flex Capacity / DN Diurnal Storage utilisation consistent with this demand level Power Station within-day profiling based upon operational experience
	Interconnector with uni-directional physical flow (e.g. Moffat)	
	NTS Storage Site	(1) Forecast levels of demand for DN Exit Points (across entire NTS) for an appropriate day (or days) of National Grid NTS' Average Load Duration Curve (Diversified). (2) Forecast levels of demand for all DC Exit Points, including NTS Storage Sites and Interconnectors, from an appropriate day (or days) of National Grid NTS' Average Load Duration Curve (Diversified) NTS Flex Capacity / DN Diurnal Storage utilisation consistent with this demand level Power Station within-day profiling based upon operational experience
	Interconnector with bi-directional physical flow (e.g. IUK)	

Table 1

Determining the Supply Scenario for Analysis

3-B-3 An appropriate supply pattern for the Incremental Capacity Type and Type of NTS System Point being considered will be selected as per the tables below:

Incremental Capacity Type	**Type of NTS System point**	**Supply Pattern**
Incremental Entry Capacity	All Supply points	Supplies at all ASEPs in the entry zone (see **Table 3** below) of the incremental capacity ASEP, plus a single ASEP, deemed to be that of highest interaction with the incremental ASEP zone, as defined in **Table 4** below will be increased to maximum forecast supply levels A supply/demand balance (the demand level as determined from **Table 1** will be maintained by reducing supplies, as appropriate, at ASEPs of lowest interaction with the Incremental capacity ASEP, as also defined in **Table 4** below. The balancing ASEPs will be reduced to an appropriate minimum as defined in **Table 3** until a supply and demand balance is created. If there is insufficient supply at all balancing ASEPs, then the ASEP of highest interaction with the incremental ASEP zone, which had previously been increased to maximum forecast supply, will be reduced until a supply and demand balance can be achieved. Profiled supplies will not be assumed.
Incremental Exit Capacity	All Exit points	ASEPs of highest interaction to the LDZ/Zone where the incremental capacity exit point is located, as defined in **Table 5**, will be reduced to an appropriate minimum level, as defined in **Table 3**. A supply/demand balance will be maintained by increasing supplies, as appropriate, at ASEPs of lowest interaction with the LDZ/Zone where the incremental capacity exit point is located, as defined in **Table 5**. Supplies at balancing ASEPs will not be increased beyond current obligated entry capacity levels. Profiled supplies will not be assumed.

Table 2

Entry Zone	ASEPs	Appropriate Minimum Supply Level (mcm/d)
Easington Area	Easington	5th Percentile of the range of historical supplies at the ASEP on days of aggregate national demand of 400mcm/d or above, from at least the last two complete gas years
	Hornsea	
	Garton / Aldbrough	
	Hatfield Moor	
	Burton Agnes (Caythorpe)	
South East	Bacton	
	Grain LNG	
	Tatsfield	
	Albury	
	Palmers Wood	
North West	Fleetwood	
	Partington	
	Burton Point	
	Hole House Farm	
	Cheshire	
Theddlethorpe Area	Theddlethorpe	
	Blyborough (Welton)	
Northern Triangle	Barrow	
	Teesside	
	St Fergus	Forecast minimum supply level for the gas year and demand level being considered
	Glenmavis	5th Percentile of the range of historical supplies at the ASEP on days of aggregate national demand of 400mcm/d or above, from at least the last two complete gas years
	Canonbie	
West UK	Milford Haven	
	Dynevor Arms	
South West UK	Barton Stacey (Humbly Grove)	
	Avonmouth	
	Wytch Farm	
	Portland	

Table 3

Zone of Incremental ASEP	ASEP of highest interaction with the incremental ASEP	ASEPs of lowest interaction with the incremental ASEP
Easington Area	Bacton	Determined by pipeline distance from the incremental ASEP, with the farthest considered first.
Theddlethorpe	Easington	
South East	Easington	
Northern Triangle	Easington	
North West	Milford Haven	
West UK	Bacton	
South West	Milford Haven	

Table 4

LDZ / Zone of the Incremental Exit Point	ASEPs of highest interaction with the LDZ / Zone of the Incremental Exit Point	ASEPs of Lowest interaction with the LDZ / Zone of the Incremental Exit Point
Scotland	St Fergus, Teesside, Barrow, Glenmavis, Canonbie	Determined by pipeline distance from the incremental exit point, with the farthest considered first.
Northern	Teesside, Barrow, Easington, Hornsea, Garton / Aldbrough, Hatfield Moor, Burton Agnes (Caythorpe)	
North East	Teesside, Easington, Hornsea, Garton / Aldbrough, Hatfield Moor, Burton Agnes (Caythorpe)	
North West	Barrow, Fleetwood, Partington, Burton Point, Hole House Farm, Cheshire, Milford Haven	
West Midlands	Fleetwood, Partington, Burton Point, Hole House Farm, Cheshire, Milford Haven	
East Midlands	Easington, Hornsea Garton / Aldbrough, Hatfield Moor, Burton Agnes (Caythorpe), Theddlethorpe, Blyborough (Welton)	
East Anglia	Theddlethorpe, Bacton, Grain LNG, Tatsfield, Albury, Palmers Wood	
North Thames	Bacton, Grain LNG, Tatsfield, Albury, Palmers Wood	
South East	Bacton, Grain LNG, Tatsfield, Albury, Palmers Wood	
South	Milford Haven, Dynevor Arms, Barton Stacey (Humbly Grove), Avonmouth Wytch Farm, Portland, Grain LNG, Tatsfield, Albury, Palmers Wood?	
South West	Milford Haven, Dynevor Arms, Barton Stacey (Humbly Grove), Avonmouth Wytch Farm, Portland	
Wales North	Barrow, Fleetwood, Partington, Burton Point, Hole House Farm, Cheshire, Milford Haven	
Wales South	Milford Haven, Dynevor Arms, Barton Stacey (Humbly Grove), Avonmouth Wytch Farm, Portland	

Table 5

Addendum 4: March 2012 RIIO-T1 business plan submission

Please note the numbering in this addendum has been kept the same as that in the March 2012 RIIO-T1 business plan in order to preserve cross references.

Summary

B1. Our plan is based on the Gone Green electricity generation and demand scenario along with a set of assumptions for incremental capacity requirements, driven by anticipated new customer connections during the RIIO-T1 period. Due to the uncertainty surrounding the timing and likelihood of many of these new connections, we are proposing that incremental capacity is funded on an ‘as and when required’ basis in order to avoid the potential for windfall gains and losses if we were to agree funding at the start of the price control period.

B2. We have not requested that we are allocated funding at the start of the price control period to deliver incremental capacity; this will be triggered by our proposed incremental entry and exit capacity uncertainty mechanism as discussed in our ‘Managing risk and uncertainty’ annex. The uncertainty mechanism is a development of the existing revenue driver mechanisms and also takes account of changes to the level of risk on the system as a result of construction and commissioning activities.

B3. Our stakeholders have clearly stated that the price control framework should not dictate commercial change and we agree that the delivery of commercial changes should be driven forward by the established Transmission Workgroup[31] which discusses issues relating to the UNC. We must be mindful however that there is a clear linkage between the regulatory and commercial frameworks and that the regulatory framework is part of an overall package. We have proposed, in this document, a number of changes to the regulatory framework and the subsequent changes to the commercial framework which we believe are necessary to enable the regulatory changes to function correctly. In proposing these changes to the commercial framework, we have taken stakeholders’ views into account and will continue to engage with stakeholders on these topics going forwards.

B4. There are two significant factors associated with the delivery of incremental capacity that require changes to the regulatory framework:

(a) The scale of investment we are likely to undertake in delivering these new connections and associated capacity requires changes to the way we need to recover our allowed revenue in order for us to be able to finance our business

(b) The introduction of The Planning Act (2008) (“the Planning Act”) into UK legislation will result in a re-profiling and increase in costs and timescale to deliver incremental capacity.

B5. We are also proposing changes to our obligated lead times and incentives on delivery in order that these two elements of the current regulatory framework

[31] This workgroup meets monthly to discuss issues relating to the industry contract; the Uniform Network Code (“UNC”).

continue to interact with the revenue driver mechanisms as originally intended to drive and incentivise the correct behaviour on all parties involved.

B6. In addition to the drivers identified above, customers have requested that the connections and capacity processes are better aligned to make them simpler to understand and navigate.

"There must be a smooth process from building the physical connection, linking through to capacity provision."
Stakeholder comment, stage two workshop, 5th April 2011

B7. We have already started discussions with the Transmission Workgroup about these developments and have reflected these early discussions in the high level process we have outlined as a potential way forward below. We recognise that there is further work required until these discussions are ready to inform a UNC Modification Proposal which the industry may or may not support and that we must also engage non-UNC signatories on the proposals. If the commercial changes do not progress in a timely manner or diverge from our high level proposal, we would need to revisit our proposals through discussions with Ofgem on the appropriateness of the risk/reward balance of the regulatory settlement.

B8. Capacity triggered prior to 1st April 2013 will continue to be dealt with via the current regulatory process under the TPCR4 arrangements and we will provide Ofgem with a table of the current revenue driver funding which has already been triggered during TPCR3 and TPCR4 following the March 2012 QSEC auction[32].

B9. We recognise that there are a number of projects that already have planning consent that could participate in an auction or application window at any point, triggering network reinforcement and a requirement for us to seek planning consent – so called transitional projects. We are talking to these customers on an ongoing basis with a view to entering into bi-lateral arrangements, but we propose that if this situation does arise and incremental capacity is triggered, an appropriate adjustment should be made to our allowed revenue (either via a suitable revenue driver or our operational buyback allowance).

B10. We envisage that the formal connections offer process included within UNC Modification 0373[33] can be integrated with our high level proposals below to deliver a better aligned connections and capacity process. Charging arrangements would remain separate for connections, as the cost relating to a physical connection to the network is currently recovered as a cost pass through item direct from the customer.

B11. This document assumes that the principles of UNC Modification 0373 are formally implemented and/or adopted.

B12. When considering a customer's request for incremental capacity we will consider all commercial options (rules), operational arrangements (tools) and physical investment (assets) that are available to us in order to determine the most efficient overall solution. This appendix talks primarily about the arrangements that are required where assets are the most efficient solution – as these are the situations where the implications of the Planning Act and the need to finance our business have the biggest impact.

[32] We envisage that this will be further updated following the receipt of any incremental signals through the July exit capacity application window

[33] UNC Modification 373 proposes that defined steps and timescales in relation to connection offers be introduced into the UNC.

Drivers for change

B13 The drivers for regulatory change are:

(a) The need to adjust the revenue driver mechanisms so that we are able to fund our business by receiving income in time for our capital intensive activities

(b) The introduction of the Planning Act.

B14 The drivers for commercial change are:

(a) The need for the regulatory and commercial frameworks to be compatible so that they work as a package

(b) Customer requests that the connections and capacity processes be better aligned

(c) The introduction of the Planning Act.

Funding our business

B15 If the existing TPCR4 arrangements were to continue into the RIIO-T1 period, we would not receive funding until the point of incremental capacity delivery. With the level of capital expenditure we are forecasting is likely to be required for the business plan period, we would be unable to finance our business if we did not receive the associated allowed revenue in time to fund the capital intensive expenditure. In addition, the Planning Act drives higher costs into the process and re-profiles the expenditure so that more cost is incurred earlier; funding for these activities is therefore also required at an earlier stage.

The Planning Act

B16 The Planning Act brings into effect a new development consent regime. Under the Planning Act a Development Consent Order is required for development where it is, or forms part of, a Nationally Significant Infrastructure Project (NSIP).

B17 The construction of a gas transmission pipeline is considered to be a NSIP when each of the conditions below are met:

(a) The pipeline must be wholly or partly in England and either:

(i) the pipeline must be more than 800 millimetres in diameter and more than 40 kilometres in length, or

(ii) the construction of the pipeline must be likely to have a significant effect on the environment; and

(b) The pipeline must have a design operating pressure of more than 7 bar gauge; and

(c) The pipeline must convey gas for supply (directly or indirectly) to at least 50,000 customers, or potential customers, or one or more gas suppliers.

B18 Gas transmission pipelines (including new pipelines and diversions) that are less than 800 mm in diameter and 40 km in length are only considered NSIP developments if the construction is likely to have a significant effect on the environment. The Infrastructure Planning (Environmental Impact Assessment)

Regulations 2009 provide a mechanism to establish whether the proposed works are likely to have a significant effect on the environment.

B19 The Planning Act will require a more resource intensive pre-application phase with a greater level of earlier engineering design activity and a wider consultation process than previous requirements. This increases the time required to complete the overall process but means that stakeholders' views are included in the process earlier, improving certainty of the outcome.

B20 Whilst we welcome the increased certainty associated with the Planning Act, the process will increase the time taken from project inception to commissioning for new gas pipeline infrastructure, which must be considered along with the associated cost challenges of delivering the requisite infrastructure on time and efficiently, whilst minimising the impact on the surrounding environment.

B21 The Planning Act does not apply to gas transmission pipelines in Wales (or indeed Scotland where the Planning Act itself does not apply). These are installed under permitted development rights by virtue of the Gas Act 1995 (as amended). Planning associated with Above Ground Installations (AGIs) in Wales and Scotland continues to be determined by local planning authorities. We expect however that statutory bodies, other stakeholders and society in general in Wales and Scotland (and England in relation to pipelines to which the Planning Act does not apply) will expect to be consulted during the development of projects similar to the processes set out in the Planning Act, as this will be considered best practice.

Impact of the Planning Act

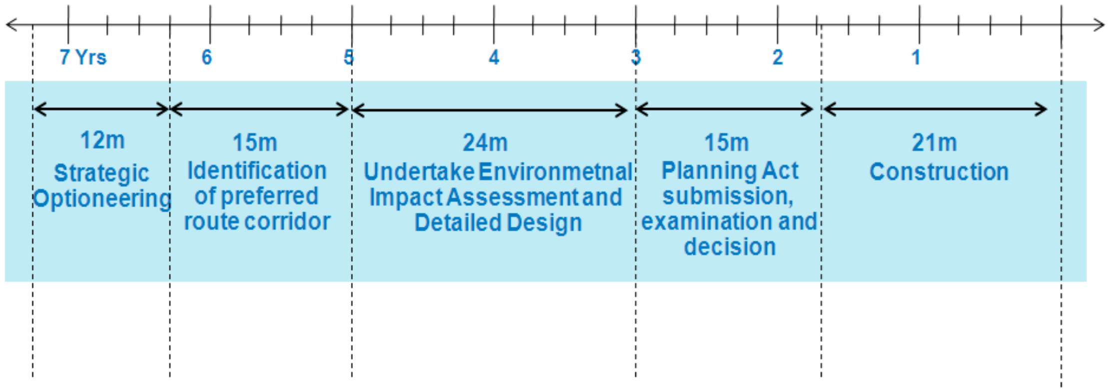
B22 The establishment of a single consenting regime streamlines the planning system to provide greater certainty, efficiency and consistency for all whilst ensuring the quality of decision-making, including appropriate community and stakeholder engagement, is improved. The increase in stakeholder engagement, along with definitive consultation timescales, should provide greater certainty for delivery of nationally significant energy projects.

B23 We have been engaging with organisations that have projects progressing through the Planning Act process and have been able to take a view of the implications of the Planning Act on our major projects. We will, however, continue to learn how to navigate the legal requirements as these become more certain and we gain experience of the process ourselves. What is clear is that the earlier engineering and wider consultation processes will drive more cost upfront into the early stages of the process and increase the level of expenditure, which will be a step change to the profiles of past major projects and those in countries with different planning requirements.

B24 The Planning Act does not affect the actual build time to deliver new infrastructure, which will remain largely unchanged (subject to consent conditions, terrain and weather). The project front end process, however, has lengthened and we will manage this carefully to ensure we have considered and justified all reasonable planning options in full.

B25 Under the current regulatory regime, we would not be able to meet the customer's requirements in a timely manner or deliver the incremental capacity in the standard obligated timescales, where a Development Consent Order is required, exposing both the end consumer and ourselves to material capacity buyback costs for an extended duration.

B26 We have developed a timeline, which has been shared with the industry, to illustrate our understanding of the process steps leading up to, and the submission of, a Planning Act submission. This has been tested against the experiences of National Grid Electricity Transmission and previous gas infrastructure projects. This has later been reinforced through shared learning with RWE npower, who are the first company to take a gas pipeline[34] through the Planning Act process. This is a generic timeline and will in reality vary from project to project, however it is largely consistent with the experiences of others to date. The timeline does not take account of the other factors that interact with this process such as revenue drivers, customer charges, capacity auctions and applications amongst others.



B27 National Grid Electricity Transmission has been engaging with stakeholders in relation to the Hinkley Point C Connection since autumn 2009. The formal planning application is expected to be made in 2013, with a decision expected in 2014. This timeline of five years to reach the application decision point is consistent with our projected timeline above. EdF, the developers of the Hinkley Point C Power Station, have recently submitted their planning application to the Infrastructure Planning Commission following three years of extensive stakeholder engagement. This timeline is slightly shorter than our generic timeline presented above – but this is to be expected with a project at a single location, which therefore has fewer stakeholders to consult.

B28 We have also engaged with RWE npower and will continue to do so on an ongoing basis with regard to their new connection for the proposed pipeline to supply natural gas to the consented Willington Power Station. As part of this ongoing engagement, RWE npower have shared their project timeline with us which shows that they started their exploratory work in 2008 and expect to submit an application in 2012, with approval one year later; five years from the start of their work relating to this project.

B29 We presented our generic timeline to stakeholders through our Talking Networks stakeholder engagement activities. We proposed that the current connections and capacity processes need to be developed to take account of the longer timescales associated with attaining planning permission and the fact that higher costs will be incurred earlier in the processes than currently due to increased consultation requirements.

“” *Many stakeholders expressed deep concerns about the significantly increased timelines that are likely to result from the Act. A concerted effort is required across the industry to ensure that the connections and capacity processes can operate as smoothly as possible and minimise lead times in the future.*
Stage three workshop Brunswick report, 9th November 2011

[34] To supply gas to their already consented Willington Power Station

B30 Some stakeholders were sceptical about the timeline presented.

A number of stakeholders argued that the 7 year timeframe is a worst case scenario.
Stage three workshop Brunswick report, 9th November 2011

B31 Stakeholders representing organisations that had been through this process themselves, however, thought the timescales looked realistic.

"We broadly agree with National Grid's estimate of 7 years."
RWE npower, November 2011 consultation response

B32 Some stakeholders questioned our timeline, asking whether certain elements could be run concurrently rather than end to end, such as the optioneering and routeing processes. We stated that as we currently understand the requirements, the stages must run end to end to ensure full and proper engagement with all stakeholders. There is the possibility, however, that the process will become more streamlined as greater experience is gained. Stakeholders noted that any developments to the connections and capacity processes would need to be flexible enough to cope with any future efficiencies or innovations.

Interactions between the commercial and regulatory frameworks

B33 The purpose of this document is to put forward our proposals for the regulatory framework to apply from April 2013 onwards. There will be a degree of consequential commercial change that would need to be undertaken in order to ensure that the two regimes are compatible. Commercial change must be progressed through UNC governance – and we have started these discussions already. We propose below a number of high level proposals which take on board the initial feedback received from industry discussions. If commercial developments do not progress in a timely manner, or move away from our high level proposals below, we will need to re-visit the package to ensure the risk/reward balance remains appropriate.

Customer requirements

B34 We have discussed the connections and capacity processes throughout our stakeholder engagement activities. Stakeholders have told us that the current connections process is cumbersome and understood by very few. It is further complicated by the need to apply for capacity separately, with stakeholders expressing uncertainty about how the interactions between the two processes are managed. There was support for the two processes to be simplified and further aligned.

"There must be a smooth process from building the physical connection, linking through to capacity provision. Ideally the contracts for both parts should be started up front, classifying one as enabling works."
Stakeholder comment, stage two workshop, 5th April 2011

B35 Many stakeholders expressed views about how the processes could be developed, citing the possibility of a 'connect and manage' regime for gas or giving a small user commitment at the start of the process to underwrite the initial costs, highlighting that there will be pros and cons to any way forward.

There is clearly a tension between the need to signal early in the process and increasing the risk of a stranded asset.
Stage three workshop Brunswick report, 9th November 2011

B36 Many stakeholders felt that the Transmission Workgroup should play a prominent role as a forum for future discussions. We therefore discussed this topic further through the Transmission Workgroup in January 2012. At this meeting we presented five initial options that had been developed with the request to align the processes and the implications of the Planning Act in mind:

(a) Do nothing – retain the status quo, which could result in constraint costs being allocated to the industry if the Planning Act timescales resulted in the late delivery of capacity. This option does not address stakeholder requests to align the connections and capacity processes.

(b) Connect and manage – our default lead times would remain as they are under TPCR4. We would allow the connecting party to flow gas as soon as the physical connection is ready and would manage any resulting constraints. This may involve constraint costs being incurred, or it could be managed by the introduction of a product that allows users to book interruptible (i.e. non firm) capacity, or a combination of both. This would not address stakeholder requests to align the connections and capacity processes.

(c) Anticipatory investment – we would undertake zonal reinforcement based on commercial intelligence rather than specific customer signals. This could address the implications of the Planning Act. The implications on the connections and capacity processes would need to be carefully considered, there could, however, be some resulting benefits in terms of simplification. This would be a considerable change to the user commitment principle of the current regime.[35]

(d) Extend lead times – extend our obligated lead times to better align with the Planning Act timelines (estimated at 72 months from 38 months and 42 months for exit and entry capacity respectively). This addresses the Planning Act timelines and could be developed to align the connections and capacity processes.

(e) Contractual alignment of timescales – a form of user commitment is provided earlier than under the current auction timescale that would underwrite the initial work required before a formal capacity application is received. A process would need to be developed to address all of the interactions, such as revenue drivers, which would provide an opportunity to align the connections and capacity components of that process.

B37 We told stakeholders that our current preference based on our initial view of the pros and cons would be the last option above, i.e. contractual alignment of timescales.

[35] Additionally, before considering such an option, we would need to be confident of the regulatory framework under which any such investment would be made, such that investment would be deemed economic and efficient based on the information available at the time of deciding to invest

Stakeholders were able to immediately rule out the 'do nothing' and 'extend lead times' approaches as being options they would not be willing to consider. They thought, however, that there were elements of all three remaining options that it would be beneficial to develop further, with stakeholders individually favouring different elements. Stakeholders noted that some of the options were variants of the others

B38 We will continue to develop our thinking and will return to the Transmission Workgroup in April 2012 with a more detailed view. Our plan is based at a high level around contractually aligning our timescales with those of our customers and gives an indication of how this process interacts with the changes we are proposing to the price control framework.

Proposed changes

B39 We are proposing a number of changes to the regulatory framework:

(a) An initial allowance to fund pre-planning activities will be triggered on receipt of a user commitment from a customer resulting from the signature of a bi-lateral contract

(b) Revenue drivers are removed from our licence and are calculated as and when they are required, and published, in accordance with an agreed methodology

(c) Our obligated lead times are reduced to 24 months[36], from an October capacity allocation (which equates to Y+2[37] and covers two build seasons), with appropriate incentives to encourage innovation and efficiency in our capacity delivery activities

(d) We have a reasonable endeavours obligation placed on us to encourage efficiency in the pre-planning stage.

B40 Industry discussion is required in order to develop the detail of the commercial arrangements. We are proposing some high level elements, however, that will be required to ensure the regulatory and commercial frameworks are compatible:

(a) The entry capacity auctions and exit capacity application methods are changed so that baseline (including substituted baseline) and incremental capacity are made available through separate processes

(b) All customers wishing to apply for incremental capacity will be required to enter into a bi-lateral contract, consisting of generic terms and conditions, project specific timelines and user commitment points

(c) The trigger for the capacity process, defined below, is aligned with the trigger for the connections process, introduced by UNC Modification 0373.

---

[36] This option is dependant on the necessary commercial changes being implemented, such as alterations to the existing long term capacity application/auction methods

[37] Where Y equals a capacity year which runs from 1st October to 30th September

Detail of changes

Process trigger

B41 UNC Modification 0373 specifies that if a party wishes to connect to the NTS, or wishes to modify an existing NTS connection, it shall complete and submit the relevant application form as published on our website.

B42 We propose that this application form is also filled in by any party wishing to signal incremental capacity and upon acceptance of the application form the connections process, as envisaged by UNC Modification 0373, and the incremental capacity process will run concurrently, where both are required.

B43 Any information submitted via this application form will be treated as commercially confidential. An applicant can be a UNC-signatory or any other third party, but by signing the contract they will be agreeing to be bound by the relevant terms of the UNC[38].

Bi-lateral contract

B44 The application form, once accepted by National Grid, would trigger the start of the incremental capacity process and the issue of a bi-lateral contract. Every party wanting to signal incremental[39] capacity would be required to sign a bi-lateral contract.

B45 We envisage that the contract would build upon and expand the bi-lateral contract that has been discussed under UNC Modification 0373[40]. The new bi-lateral contract would be called a Pre-Capacity Agreement ("PCA") and would consist of a generic set of terms and conditions, that would be available on our website, and would cover a number of elements:

(a) A series of user commitment points, forming a phased user commitment profile; each phase would underwrite the next stage of the incremental capacity process

(b) The date by which a programme of delivery for the connection and capacity will be delivered

(c) Break out clauses and associated ramifications

(d) Dates by which any baseline capacity must be booked and substitution quantities reserved in order not to affect the overall timeline

(e) Demonstration dates specifying the deliverables required by National Grid and the customer

(f) Obligations with respect to when formal capacity signals must be made by a UNC signatory, subject to other activities being completed

(g) Trigger points for key activities such as the calculation of revenue drivers or submission of a Development Consent Order planning consent application.

[38] For example, under the generic Advanced Reservation of Capacity Agreement (ARCA) in existence in the exit regime, non-UNC signatories, by signing the ARCA, are agreeing to be bound by certain principles of Section B3 of the Uniform Network Code

[39] Incremental capacity is anything above our existing obligated level

[40] Bi-lateral contracts are not specifically included in the modification proposal but the concept of a contract that would allow the customer to underwrite planning activities has been discussed through the industry meetings

B46 It could be the case that there is unsold baseline capacity available or an option to substitute baseline capacity from elsewhere that would meet part or all of the customer's overall requirements. There would be a critical point in the process where we must be certain what proportion of an applicant's capacity requirements are met by baseline, substituted or incremental capacity in order that planning consent, our internal activities or any commercial negotiations, can progress. We have identified two options to deal with this:

(a) the baseline and/or substituted capacity is reserved at the point the applicant signs the PCA contract; or

(b) there is a requirement placed on the customer to purchase the baseline and/or substituted capacity by a certain date.

B47 There are pros and cons to both solutions, for example option (i) provides certainty earlier on but also potentially sterilises capacity. Further thought and discussion is required in conjunction with the industry in relation to these options.

Incremental capacity applications

B48 After the PCA conditions and processes have been completed, and planning consent received where required, then the user will be required to formally signal for the incremental capacity in an agreed timeframe.

B49 The existing Quarterly System Entry Capacity ("QSEC")[41] auction in March and the exit application window in July would sell baseline and non-obligated capacity only. Separate incremental application method(s) would be utilised to sell obligated incremental entry and exit capacity.

B50 It must be a UNC signatory that participates in all of the formal capacity application processes.

B51 Projects that require incremental capacity would be required to submit a formal capacity signal through an application window held by September each year.

B52 Following the formal signal, as with the entry regime today, we would submit a proposal to Ofgem by the end of September detailing the request(s) we have received, when the capacity will be delivered by, how it will be delivered, taking into account the trade offs available to us, and our intention to allocate that capacity. Ofgem would have 28 days to respond, such that a response would be received by the end of October. If they do not veto the proposal, we would allocate the capacity and would be obliged to release it in 24 months from that October (which equates to Y+2 and covers two build seasons).

B53 In order for the incremental capacity application method to be held by September and construction, where applicable, to begin the April following Ofgem's non-veto of our proposal to release incremental capacity, a Development Consent Order (where required) would need to have been submitted 17 months prior to the capacity application window to allow for the statutory 15 months of consideration and the set up of the incremental capacity application window to take place.

B54 Further thought needs to be given to the mechanics of the incremental capacity application. This requires discussion through the Transmission Workgroup.

[41] The auction that currently provides the method for signalling incremental entry capacity

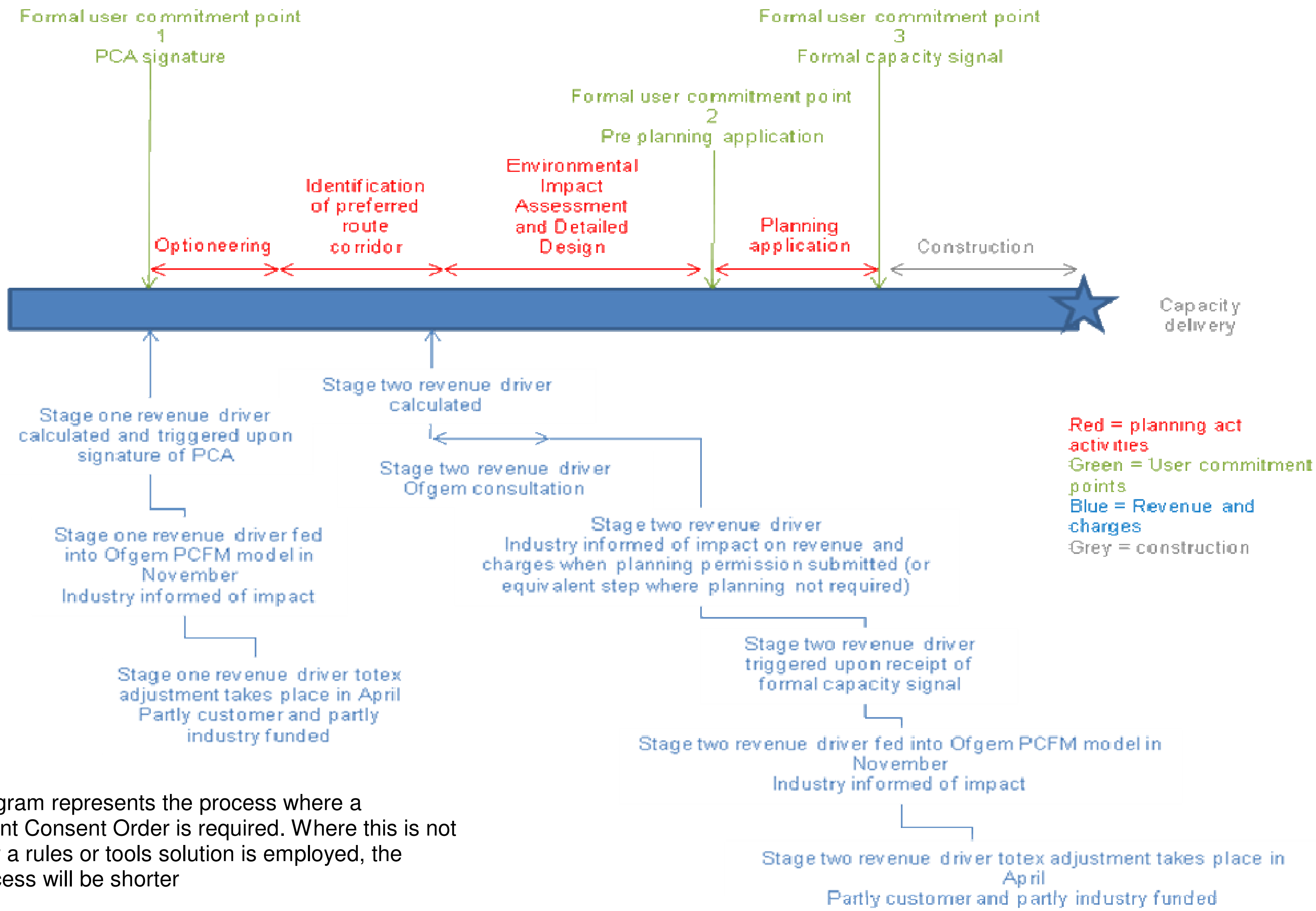
Revenue drivers

B55 When contemplating the financing options available to us, we considered asking for an ex ante allowance in our price control settlement to cover our activities in this area. We consider, however, that given the uncertainty surrounding requirements for incremental capacity within the business plan period is out of our control, this creates a potential for windfall gains and losses and it would therefore be more appropriate for funding to be triggered as and when a signal for incremental capacity is received from a customer. We have also considered the appropriate proportion of the costs that should be funded by the customer. We believe that the customer funding all of the works could present a barrier to entry and therefore believe it should be partially funded by the wider industry, however, we recognise that this is a debate which needs to be taken forward with the industry via an appropriate forum such as the NTS Charging Methodology Forum.

B56 The level of capital expenditure we forecast to be required to deliver customer connections and capacity results in a need to receive income in time for us to undertake those activities, in order for us to be able to finance our business.

B57 In our July 2011 submission we proposed that our revenue should have a capitalisation rate of 72% - which meant that 28% of our allowed revenue would be recovered as 'fast' money in the year of expenditure. The other 72% would be recovered as 'slow' money and depreciated through the Regulatory Asset Value (RAV) over 45 years from the year of expenditure. Engagement with our stakeholders through our Talking Networks workshops, one-to-one meetings and the UNC-governed Charging Methodology Forum revealed that stakeholders dislike volatility in their charges and would like charges to be predictable and transparent. The 72% capitalisation rate that we proposed would increase volatility, compared to a smaller amount being recovered as 'fast' money. We have therefore updated this for our March 2012 business plan and propose that in relation to incremental capacity, a capitalisation rate of 90% will apply. This results in a smaller amount being recovered in the year of expenditure, which reduces volatility as incremental projects are triggered throughout the period. As part of our proposals in this document we will also clarify at which points we will release information to the industry in relation to when and by how much charges will be affected.

B58 We propose that there are two revenue driver mechanisms that will adjust revenue in relation to incremental capacity; the stage one revenue driver would be triggered upon the signature of a PCA and the stage two revenue driver would be triggered upon receipt of a formal capacity signal. Both would be subject to the aforementioned 90% capitalisation rate and any over- or under- spend will be subject to the overarching totex efficiency rate. The following schematic shows the steps that will be needed to deliver incremental capacity where a Development Consent Order is required.



NB this diagram represents the process where a Development Consent Order is required. Where this is not required, or a rules or tools solution is employed, the overall process will be shorter

Note there may be other non formal user commitment points identified in the PCA

Stage one revenue driver

B59 For the stage one revenue driver, we considered a number of potential options:

(a) A fixed amount, which would be set at the start of the price control period and would be applied to every project regardless of size and requirements. We do not think this is appropriate as setting a fixed amount at the start of the period introduces the potential for windfall gains and losses

(b) A revenue driver that is triggered and calculated automatically, based on an agreed methodology. This would have the benefit of calculating a more cost-reflective amount, without placing the revenue driver calculation on the critical path of the project.

(c) A revenue driver that is set following individual discussions with Ofgem. This approach affords the benefit of calculating a project specific amount and so is a more accurate representation of potential costs. It does, however, place the Ofgem discussions on the critical path of the project, placing a disproportionate burden on the regulator and us, and could potentially delay the project whilst these discussions take place

B60 We believe that option (b) is the most appropriate method. In order that this is a transparent process, we propose that it could be based around the existing NTS Charging Transportation Model[42], which is accessible by all stakeholders. The Transportation Model estimates marginal costs based on a pipe model of the NTS, a supply and demand forecast comprising individual offtake and Aggregate System Entry Point flows, and an expansion constant representing the capital cost of adding transportation capacity to the system in terms of £/GWhkm. The Transportation Model marginal costs are already used to set the project costs used within the Incremental Entry Capacity Release (IECR) Methodology to determine the level of incremental NTS entry capacity revenue which must be met prior to incremental capacity being released.

B61 If this approach was adopted, the location and size of the new project would be entered into the Transportation Model, along with the network model and supply and demand data consistent with the year and scenario, which would be used to determine the revenue driver. An expansion constant of £4,344/GWh/km[43] would be used to calculate the pre-application marginal cost. This pre-application expansion cost has been based on the unit costs and project phasing used for the business plan.

B62 The funding released by the revenue driver will be phased so as to be consistent with the phasing used in the business plan. The phasing associated with delivering a pipeline, that has been assumed in our business plan, is shown below, where 'T' is the year of capacity delivery. This shows a six year lead time for delivery of capacity as the initial activities in year T-6 would be very small (financially) in comparison and so have been included in the year T-5 value.

[42] Which is used to calculate transportation charges and is publicly available via our website

[43] This is an updated expansion constant, compared to today, and has been calculated utilising our proposed unit cost library, as discussed in our 'Detailed plan' annex

Years funded by stage one revenue driver				Years funded by stage two revenue driver		
T-5	T-4	T-3	T-2	T-1	T	T+1
2%	5%	5%	5%	35%	46%	2%

B63 The stage one revenue driver would recover the T-5 to T-2 phasing in accordance with the values above. Note that the funding for years T-1 to T+1 will be calculated separately by the stage two revenue driver (detailed later in this document) and recovered according to that methodology.

Worked example

The location and size of a new customer project is entered into the Transportation Model, which calculates a total project cost of £100m. This is phased as below:

T-5	T-4	T-3	T-2	T-1	T	T+1
£2m	£5m	£5m	£5m	£35m	£46m	£2m

Years T-5 to T-2 would be used to calculate the allowed revenue amount that will be triggered by the stage one revenue driver and the consequent adjustment to our allowed revenue. The amount to be recovered would be as follows:

Year 1	Year 2	Year 3	Year 4
£2m	£5m	£5m	£5m

The incremental capitalisation rate would be applied which would result in the following revenue recovery profile:

Year 1	Year 2	Year 2	Year 4	
£200,000	£500,000	£500,000	£500,000	'Fast' money in year of spend
£1.8m				'Slow' money depreciated in the RAV over 45 years
	£4.5m			
		£4.5m		
			£4.5m	

B64 Our proposed process and approach in relation to triggering the stage one revenue driver is as follows:

(a) A PCA is signed

(b) We calculate the stage one revenue driver according to the agreed methodology

(c) We provide a copy of the signed PCA to Ofgem, along with the revenue driver calculations

(d) Ofgem take account of this in their annual review of the Price Control Financial Model (PCFM) in November which adjusts our allowed revenue by the agreed amount from the following April

(e) Each November we would inform the industry how many PCAs have been signed and consequently what the impact is on the following year's revenue

(f) This publication would not mention project details so as to maintain commercial confidentiality.

B65 For the initial pre planning activities we considered whether it is appropriate for the customer to fund the entire cost. We believe, however, that this could form a barrier to entry and so instead propose that the customer funds 50%, with the wider community paying the other 50% (through transportation charges). The customer would securitise 100% and if they were to default we would draw down the security and refund the relevant transportation charges which the wider community has paid.

Stage two revenue driver

B66 In order to fund our activities from capacity signal to capacity delivery, which is generally where our capital intensive expenditure (such as construction) occurs where an asset solution is required, we propose that a revenue driver approach is adopted.

B67 A methodology statement and unit cost library will be agreed at the start of the price control period with defined governance arrangements. We propose that the revenue driver would be calculated on an as required basis with reference to a library of unit costs (as agreed with Ofgem at the time the RIIO-T1 price control is set[44]).

B68 We considered a number of options in relation to the point within the process at which we should calculate the revenue driver:

(a) In TPCR4, revenue drivers were calculated for all entry points at the start of the price control period. We do not think this is an appropriate approach for RIIO-T1 because of the time it would take to calculate revenue drivers for each point (which in a lot of cases would be for no purpose as there are a considerable proportion of system points where we do not expect to receive an incremental signal) and the chance that this results in inaccurate project costs being calculated (particularly for those that appear towards the end of the eight year period)

(b) Calculating the revenue driver immediately prior to the capacity signal being received would result in a more accurate project cost but would place the revenue driver calculation on the critical path of the process, with the potential of delaying it (as is the case with the revenue driver process

[44] The details of our proposed unit cost library is covered in our 'Detailed plan'

in the current exit regime) and leaves little room for us to be incentivised to be efficient and innovative in trying to beat the revenue driver amount

(c) We therefore believe the best approach is to use a mid point in the process which is early enough so it removes the revenue driver from the critical path and incentivises us to strive to beat the calculated value, but is late enough for us to have a more detailed understanding of customer requirements and allow us to take into account any other incremental capacity signals already received.

B69 Our proposed methodology and process for triggering the stage two revenue driver funding is as follows:

(a) The revenue driver calculation would commence in relation to a trigger point specified in the PCA.

(b) We would provide Ofgem with our revenue driver calculations based on the agreed methodology. Ofgem would have 28 days to respond and raise queries. Ofgem would then have 6 months to consult on the revenue driver.

(c) At the point where a Development Consent Order application is made, or an equivalent position specified in the PCA for projects where this is not required, we would write to Ofgem and the wider industry explaining that we expect to receive a formal capacity signal, stating the date we expect to receive the signal, when the change to our allowed revenue should take place (subject to a formal signal being received) and what the impact will be.

(d) This information would be fed into the annual review of the Price Control Financial Model (PCFM) in November which would give an indication of the adjustment that will be made to our totex allowed revenue in the relevant year once planning consent has been sought.

(e) Once the Development Consent Order has been received (where required), the customer would have to provide a formal signal for incremental capacity by September in any year.

(f) Following the receipt of a formal incremental capacity signal, a submission would be made to Ofgem notifying them of the application, how we intend to deliver that capacity, when that capacity will be delivered, our intention to allocate that capacity and by which date. Ofgem would have 28 days to agree to our proposal, such that a decision would be received by the end of October.

(g) If Ofgem do not veto our proposal, the results would be fed into the annual review of the Price Control Financial Model (PCFM) in November which would feed through to an adjustment of totex allowed revenue in the following April.

(h) If a Development Consent Order is not granted, changes will not be made to our allowed revenue through the phase two revenue driver and customers will be informed.

(i) The allowed revenue adjustment would be based on the agreed revenue driver methodology. We propose that the following network modelling assumptions are specified in the said methodology statement:

(i) The year in which capacity is first required is the year that would be used for modelling purposes unless incremental capacity has already been triggered at the relevant point or points in the locality in a later year

(ii) The base network used would represent the existing network along with any additional assets planned for completion by the relevant year included, and any assets planned for removal by the relevant year removed

(iii) Base flow network assumptions are used which include the use of modelling of obligated levels limited by capability at entry and obligated levels with reinforcements where capability is a limit at exit

(iv) Network assumptions including gas supply scenarios for the relevant year are selected in accordance with the Transmission Planning Code[45]

(v) Gas demand is forecast consistent with our 1 in 20 peak demand obligations in accordance with the UNC, Licence and Transmission Planning Code

(vi) Supply and demand balancing is based on least helpful supply with supplies ranked in terms of efficiency in accordance with the Transmission Planning Code

(vii) The quantity of incremental capacity modelled will be led by the customer's requirements

(viii) Modelling is carried out both on a steady state end of day basis and transiently to take account of within day profiles

(ix) All costs necessary to support incremental capacity will be attributed to the revenue driver cost, taking account of the Transmission Planning Code planning standards

(x) Gas Telemetry and Gas Analysis equipment costs will be included

(xi) Compressor standby ability will be maintained to cover the loss of the single largest operational unit

(xii) Any constraint management costs associated with the connection and commissioning of new infrastructure would be factored into the calculation of the revenue driver.

(j) Contractual solutions will always be considered as an alternative to investment and where we believe there is any possibility of utilising contractual solutions, we will test the market to determine availability. We would expect a factor of 0.8 (based on previous precedent) to be applied to the revenue driver calculation if we believe that contractual solutions are a viable option, at the point of calculation of the revenue driver.

(k) Unit cost assumptions will be made in line with the unit cost library developed at the start of the price control period.

(l) The mechanics of how the adjustment to allowed revenue is collected from customers must be considered. The current arrangements, that are different for entry and exit, could continue, although the appropriate balance between socialisation and targeting of costs must be considered. Our current thoughts, taking into account the ability of the new customer to pick up a large proportion of charges versus the appropriate apportionment

[45] http://www.nationalgrid.com/uk/Gas/TYS/TPC

of targeted and socialised costs, is that the most appropriate solution would be for the community to fund 50% through transportation charges and the other 50% to be funded by the customer. This topic requires further discussion through the NTS Charging Methodology Forum.

B70 The allowed revenue adjustment that is calculated by the stage two revenue driver would be recovered in line with the overall project phasing utilised in our business plan. The phasing that has been assumed is as follows:

Years funded by stage one revenue driver				Years funded by stage two revenue driver		
T-5	T-4	T-3	T-2	T-1	T	T+1
2%	5%	5%	5%	35%	46%	2%

When looking at the stage two revenue driver in isolation, this equates to a phasing of	35/83	46/83	2/83
Which equates to a phasing percentage of	42%	55%	3%

Worked example

If the stage two revenue driver calculated according to the agreed methodology, calculates a total allowed revenue adjustment of £750m, the amount to be recovered would be as follows:

Year 1	Year 2	Year 3
42%	55%	3%
£315m	£412.5m	£22.5m

The incremental capitalisation rate would be applied which would result in the following revenue recovery profile:

Year 1	Year 2	Year 2	
£31.5m	£41.25m	£2.25m	'Fast' money in year of spend
£283.5m			'Slow' money depreciated in the RAV over 45 years
	£371.25m		
		£20.25m	

Capacity/constraint management

B71 The details of the buyback risk that we envisage over the RIIO-T1 period and associated arrangements are discussed in our 'Managing risk and uncertainty' annex. This covers those risks that are inherent in our system (operational buybacks) and those that are driven by the delivery of incremental capacity, network flexibility and emission-related investment (investment buybacks).

B72 As the system access requirement increases in the future to deliver investment linked to Asset Health, environmental legislation and customer connections, this is likely to drive higher constraints through more frequent requirements for system access and we therefore propose that the risk of investment related buyback is assessed as part of the revenue driver process for inclusion in the constraint management target. We propose that the revenue driver methodology includes the calculation of the incremental revenue required in relation to capacity buybacks resulting from delivering and commissioning new capacity. We propose that the target for incremental investment constraint management at the start of the period is zero and this is then adjusted in accordance with the level of incremental capacity released. We propose that the parameters around this target are included within our external SO incentives May 2012 submission.

B73 As discussed in paragraphs B78-B80 we anticipate that a transitional solution needs to be found for those projects that already have their own planning consents and thus could apply for incremental capacity at any time. If reinforcement is required to support the incremental capacity it is unlikely that we would be able to deliver this in line within our current obligated lead times due to the need to progress through the Planning Act process. Our stakeholders have requested that we investigate the development of a long term interruptible product for use in this circumstance. Another option would be the specification of a buyback fund specifically to deal with constraints emerging as a result of these in flight projects connecting before reinforcement is delivered. In this situation we would propose that a target is set based on the volume of incremental capacity required.

Incentive on delivery

B74 At this stage, our process timeline reflects our understanding of the Planning Act implications along with the relevant interaction with our funding arrangements. As we gain experience of the Planning Act, it may be possible to further optimise and refine our activities. We propose that a reasonable endeavours obligation is placed upon us to be innovative and efficient in delivery of the process steps with a view to optimising the timelines.

B75 We also propose that our current obligated lead times from receipt of a formal customer signal (38 months for exit capacity and 42 months for entry capacity) are shortened to 24 months from an October allocation of incremental capacity (which is equivalent to Y+2, to cover two build seasons). We believe that where the customer would value delivery of capacity in timescales shorter than this, we should be incentivised to deliver this capacity early. Conversely, where we expect that the capacity delivery will take longer than two build seasons, there should be a mechanism in place to manage this. We have considered a number of options that could be utilised:

(a) No direct incentives. We could be exposed to buybacks for the late delivery of capacity with no incentive for delivering capacity early. Given that delivering capacity early would generally involve us picking up some level of increased cost and / or risk, the lack of an incentive is unlikely to make the risk/reward balance of delivering capacity early attractive.

(b) Retain the permit schemes that are currently in place. This has the advantage of both incentivising early delivery and having a set scheme in place for the late delivery of capacity.

(c) Hardcode an incentive for early delivery of capacity in the licence and be exposed to buybacks or permits for late delivery. This has the advantage of incentivising early delivery whilst having a set scheme in place for late delivery of capacity. The incentives around early and late delivery, however, would not be symmetrical between the two schemes.

(d) A scheme where both a target related to the late delivery of capacity and incentive for early delivery are calculated utilising our buyback modelling assumptions with reference to the value that the customer places on that capacity. This has the advantage of being symmetrical for both the early and late delivery of capacity.

B76 At this stage our preference is option (d) as this retains the principle of the current permit scheme, whereby there are defined mechanisms in place, whilst simplifying the regime by removing the permit mechanism and using pre-determined modelling assumptions. Option (d) also has the benefit over option (b) of recognising locational sensitivities. Utilising an incentive scheme that is based around buyback parameters also has the benefit of increasing the interaction between the TO and SO. Within the 'Managing risk and uncertainty' annex we have detailed how the incremental entry and exit capacity uncertainty mechanism will take account of any buyback costs likely to arise from system access associated with construction and commissioning and also changes in the inherent level of risk on the system. Initial modelling has been undertaken in relation to the level of risk we will face over the RIIO-T1 period and we will carry out further modelling to inform our external SO incentives submission in May 2012, where we will detail the mechanics and parameters for our proposed buyback scheme. Given that option (d) above is dependant on this modelling and the buyback scheme parameters, we intend to make detailed proposals for this scheme in our external SO incentive submission in May 2012.

B77 It should be noted that in order to facilitate shortened obligated lead times, we would need to order long lead time items before the customer formally signals for incremental capacity. Funding arrangements for this would need to be considered.

Transitional issues

B78 The long term changes we are proposing will take some time to develop. We recognise that there are a number of projects that currently have planning consent, that have not yet applied for capacity, which may require network reinforcement and thus planning consent. We are talking to these customers on an ongoing basis and will seek to enter bi-lateral agreements to ensure the customer is connected in a timely manner.

B79 There may also be product developments that can be pursued, as discussed with stakeholders at the January 2012 Transmission Workgroup meeting. The introduction of a non-firm product that allows capacity to be scaled back when there are constraints forecast could be utilised until reinforcement is delivered or as an alternative to reinforcement.

B80 Another option could be to introduce an agreed and specifically targeted buyback incentive to manage constraints if capacity is made available before reinforcements are delivered. The benefit of this approach is that any party could relinquish capacity, not just the new ones triggering the incremental capacity. These options require further discussions with the affected parties and the industry as a whole.

Equitable trade offs

B81 When considering a customer's request for incremental capacity we will consider all commercial options (rules), operational arrangements (tools) and physical investments (assets) that are available to us in order to determine the most efficient overall solution.

B82 Our unique position as both TO and SO gives us the opportunity to make holistic decisions between the two distinct areas. Through undertaking both roles we are incentivised to make decisions which balance the costs and risks of both forms of control. As such we consider the impact of decisions across our business and also look for opportunities to minimise costs through this joint role.

B83 There are two main interactions in this area that are considered:

(a) Cost and risk balance between TO capital investments and the costs of SO actions

(b) TO capital investments versus development of the commercial framework.

B84 There are four options we consider to meet customers' signalled incremental needs. These are not mutually exclusive, with it being possible for a combination of these being used to meet an individual capacity signal:

(a) Do nothing – this is a valid option if analysis shows the risk introduced by the incremental capacity is acceptable and can be managed operationally (including through buybacks) or there is existing physical capability

(b) Seek a contractual solution

(c) Invest to provide additional physical capability

(d) Capacity substitution.

B85 When we have sufficient confidence that an auction or capacity signal will be received from our customers, or that our analysis shows a need to enhance capability for new flow patterns to maintain the existing levels of service, we assess the most efficient means of meeting the requirements. Where we consider these are unlikely to be met through operational or short-term commercial options, we will assess the likelihood of a successful enduring contractual solution against the potential investment requirement. This could be many years ahead of receiving a formal auction or capacity signal.

B86 Our stakeholders have told us that it may be more efficient to enter into commercial agreements ahead of time to deliver the changes in flows required to safely manage the NTS:

"Commercial contract discussions ahead of time would be better than Force Majeure suddenly being needed. Short term pain sharing is better than being switched off."
Stakeholder comment, stage two workshop, 5th April 2011

B87 Potential contract forms fall into three categories:

(a) **Turn up:** a customer agrees to increase supply (or demand) at a specified location

(b) **Turn down:** a customer agrees to reduce supply (or demand) or to reduce their capacity holding at a specified location

(c) **Flow swap:** a customer agrees to increase supply (or demand) at one location and reduce it by an equivalent amount at a different (non-interacting) location.

B88 It is likely that contracts will include an element of (fixed) option cost and (variable) exercise cost. Evaluation of their economic value will therefore be dependent on the forecast distribution of frequency of use.

B89 Experience from previous contract tenders for 'options' and 'forwards'[46] and other bilateral discussions suggest that customers could place a high price on these contracts as they may restrict their operational flexibility on the day. Long lead times to exercise will also lead customers to include an element of risk premium in their pricing. Discussions with potential contract providers will identify key drivers of their perceived risk and we will work with the customer to mitigate these risks (for example through limitations on exercise and price indexation) that will enable more economic pricing.

B90 Where system constraints are forecast to occur infrequently or are not expected to be enduring in nature, there is potential for commercial alternatives to provide a more economic solution than physical investment:

(a) Investment in physical assets has a long lead time, large fixed costs and long remuneration periods

(b) On the day actions, in comparison, can have much shorter lead times and higher (unpredictable) marginal costs

(c) Contracts for commercial actions will lie somewhere between the two, although it is likely they would have relatively low fixed costs (compared to physical investment) and higher marginal costs, although these are likely to be set in advance and therefore mitigate some of the price and availability risks in the non-contract scenario.

B91 Physical assets, by comparison, will have lower marginal costs, and hence the total cost will be known with greater confidence. The asset will be 'always available' and may help to resolve constraints not previously anticipated. There is, however, the converse risk that constraints are less frequent than anticipated and where a contract could be terminated or reduced in scope to reduce costs, an asset cannot.

B92 Through our engagement with stakeholders we will review the costs of investment against the expected cost of commercial actions and will test such contractual options with the market for appropriateness.

B93 Our engagement with industry to demonstrate contestability in Operating Margins (OM) services highlighted a number of new providers who have joined the market or have considered the principle of entering into contracts to adjust their flows on or off the NTS. Although the nature of OM is different, due to the short notice period and

[46] As provided for in the UNC

expectation of infrequent exercise, this demonstrates a willingness from some parties in the industry to participate in these sorts of arrangements, and may provide some context in terms of the value that users may wish to place on contracts.

B94 To further develop the potential for contractual alternatives, a number of areas need to be addressed, including:

(a) Increasing customers' familiarisation with the commercial regime

(b) Understanding customers' commercial drivers and the appetite they place on commercially firm capacity rights being physically firm in practice

(c) Understanding factors which influence customers' pricing, such as exercise lead times and limits on exercise

(d) Identifying ways to mitigate customers' risks associated with lead times, such as price indexation

(e) Ensuring a sufficient volume can be contracted for us to deliver the required level of response.

B95 Regarding point (e) above, the number of shippers at a location, the distribution of their capacity holdings and the size of the required response will be important factors. For example there are currently in excess of 20 shippers with firm capacity holdings at St Fergus, most of whom have relatively small holdings and in order to guarantee a response when required, a number of parties would need to be contracted with.

Interactions

B96 We have detailed above our proposals for changes to the regulatory framework and our initial thoughts on how the commercial regime could be developed. The commercial elements require further discussion with industry to ensure that any developments do not lead to unintended consequences. Additionally, it should be noted that if the resultant commercial framework is not as envisaged within this business plan, we will need to revisit the appropriate regulatory arrangements within the licence.

B97 There are a number of other interactions that must be considered within these discussions. Both the existing substitution methodologies and incremental capacity methodologies link to the areas of the licence that our proposals would change – consequential changes to these methodology statements must be considered.

B98 There is also a requirement for consideration to be given to the most appropriate charging arrangements, such as which elements should be targeted and which should be socialised. This requires further discussion through the Transmission Charging Methodology Forum.

B99 Although our initial thoughts have sought to retain as much of the existing commercial arrangements as possible, some change is considered inevitable and any impacts on IT systems such as Gemini must be investigated and understood. There is no funding for changes to systems such as Gemini for the facilitation of this process included in our baseline plan, we have, however, proposed a GB and EU market facilitation uncertainty mechanism which would be triggered if any required changes were financially significant (i.e. above the relevant materiality threshold as proposed within the uncertainty mechanism).

B100 The interactions with Europe must also be considered. European Network Codes and other developments are still being worked on, and experience shows that proposals can change substantially in a short space of time. In light of the uncertainty over the European CAM (Capacity Allocation Mechanism) and CMP (Congestion Management Principles) codes, our high level thoughts largely retain the current principles of the long term entry auction and exit application processes to ensure, when compared to the current regime, the magnitude of European impacts are as manageable as they are under the current regime. As the European position becomes clearer it will be easier to understand and assess the interactions.

B101 The interactions between the TO and SO must be considered. Under the TPCR4 arrangements, funding associated with incremental capacity is allocated to the SO for five years before transferring to the TO. We propose that under these new arrangements, for simplicity, all incremental capacity is provided for through the TO form of control (unless we decide to take a buyback risk). This should make the funding arrangements more straightforward but raises a question about how funding should be treated if build is not the most efficient option and consequently the TO retains the benefit of the revenue driver but the SO inherits the risk. We will address this further as part of our submission of the business plans for the SO price control at the end of May 2012.

B102 It should be noted that none of these proposals affect the charging arrangements for the delivery of the physical minimum connections to the NTS which are done on a cost pass through basis.

Next steps

B103 We will continue to discuss these proposals with the Transmission Workgroup and Transmission Charging Methodology Forum in order that the commercial developments can progress alongside the regulatory framework changes.

Worked example

B104 The following page contains a schematic to demonstrate how all the different elements discussed in this appendix fit together.

Process steps where a Development Consent Order is required