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Dear Joanna

Mitigating network charging volatility arising from the price control settlement

We welcome the opportunity to provide a response on the 'mitigating network charging volatility arising from the price control settlement' consultation. This response is provided on behalf of National Grid, both as National Grid Gas plc (NGG) in its role as owner and operator of the gas transmission system in Great Britain and also National Grid Electricity Transmission plc (NGET). NGET owns the electricity transmission system in England and Wales and is the National Electricity Transmission System Operator (NETSO). In our role as NETSO we collect allowed revenue associated with the cost of providing transmission assets on behalf of all Transmission Owners (TOs) through Transmission Network Use of System (TNUoS) charges.

In the main body of this response we present both general thoughts on the subject of network charging volatility following engagement with stakeholders, and also provide high level views on the options presented in the consultation. A full National Grid response to the questions raised in the consultation is provided in Annex 1 of this response.

National Grid has discussed with stakeholders the subject of charging volatility and, in particular, the impact of RIIO-T1 on volatility, both through our RIIO-T1 stakeholder engagement and also via the Transmission Charging Methodologies Forum. Our findings are similar to those expressed in the consultation document, in that this is an important issue for suppliers, and ultimately energy consumers.

We agree that predictability of charge changes is a key issue for stakeholders. This is not only limited to the provision of forecast information to users, but should also consider the tools and assistance customers need to make their own forecasts of future charges. As noted in the consultation document, we have already taken steps to improve the predictability of charges in the presentation of the Condition 5 material of our electricity transmission charging forecasts[1] and in the accompanying initial view of tariffs for 2013/14. NGG already make available the transportation model, revenue forecast information spanning a number of future years, and a quarterly information provision detailing the inputs used to set indicative and future charges.

In addition to the predictability of charges, we also believe that stability and transparency of charges are valued by our customers. It is important that the interaction between all these elements is fully understood. For example, feedback from our stakeholder engagement recognised that predictability and stability of charges do not mean the same thing. Charges can be stable for a period especially

[1] NGET Condition 5 – Long Term Tariff Publication:
http://www.nationalgrid.com/uk/Electricity/Charges/gbchargingapprovalconditions/5/

with a limited ability to change (e.g. by setting for a year or longer), but this can often be followed by a greater change in charges to correct to a new stable position. Generally, stakeholders have told us that predictability of Network Operator (NWO) charges is of greater importance to them than stability.

Different NWO charges have varying impacts on overall energy bills[2], and differences in methodologies and industry arrangements exist. As such one solution may not fit all and looking at individual charges or categories in relation to the options suggested is likely to deliver a more efficient solution for the benefit of the end consumer.

The consultation focuses on the charges raised by NWOs that will be subject to the RIIO form of regulation. Whilst in gas this approach covers all NWOs, there are important differences in electricity that National Grid believes should be taken into account. Specifically, National Grid in its role as NETSO is the sole party responsible for setting customer-facing electricity transmission charges. These charges recover the allowed revenues of onshore TOs that are subject to RIIO-T1 and offshore TOs that are not. Against this background, many of the provisions being consulted upon for option 1 (Information Provision) and option 2 (Frequency of change) are equally applicable to offshore TOs and indeed are necessary to deliver all the benefits identified in the consultation, particularly given the expected growth of revenues associated with offshore transmission.

We agree that changes to the actual methodologies should sit outside the scope of this consultation. We also recognise that this consultation does not directly deal with SO external costs and therefore we do not comment on the Balancing Services Use of System charges (BSUoS) that National Grid sets for electricity transmission customers.

We note that Ofgem has developed five potential options and provided an initial assessment of these options. We provide a view on each of these options in the following paragraphs. Further consideration will be required by industry ahead of any implementation of these options, to fully understand the impact of such proposals. In general, it is vital that proper account is taken of financing costs to ensure that the affected NWO is neutral to any change in timing.

In relation to option 1, National Grid agrees that improving information provision could help reduce volatility risk and would generally promote competition. Providing additional information should allow greater transparency of charges without introducing additional risk to the NWO. Indeed this is the reason why we have already taken steps to address concerns in this year's Condition 5 material of our electricity transmission charging forecasts.

We agree that there are benefits associated with the restriction of the frequency of intra-year charge changes as suggested in option 2. However, these need to be carefully considered against the increased reliance on business forecast data and we note that in the consultation Ofgem express concerns regarding charge setting errors. We do not believe that, given the rarity of transmission charge setting errors, the case has been made for the introduction of an additional licence condition to penalise an NWO for a charge calculation error.

Option 3 proposes a lag to the recovery of incentive rewards / payments. We believe that there may be benefit to industry as a whole through considered application of such mechanisms. We agree that a period of two years is an appropriate gap between the year in which an NWO's performance is assessed and the resultant change in charges to customers. However the introduction of such lags

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[2] In Ofgem's 'Updated household energy bills explained Factsheet 97 31.05.12', the transmission element currently forms 2% of an average household gas bill and 5% of an average household electricity bill, whereas the respective distribution elements are 19% and 18% respectively.

needs to be considered on a case by case basis to understand the implications of the lag on each affected party.

We agree that option 4, proposing a lag on adjustments to allowed revenues from uncertainty mechanisms, increases risk for NWOs. Such a proposal will significantly affect a NWO's cash flow, and put at risk the financeability of major capital works. This is particularly the case for NGG, where funding for future incremental capacity signals over the RIIO-T1 period will be provided via the incremental entry and exit capacity uncertainty mechanisms. We therefore do not believe that such proposals are beneficial to the industry as a whole except in certain targeted cases. Further analysis is required and understanding of all consequences for industry would need to be established before any such mechanisms were put in place.

Option 5 proposes the imposition of a cap and collar on changes to NWO's allowed revenues. We agree with Ofgem's assessment that implementation of such a proposal is unlikely to be of benefit to industry or the end consumer, in causing increased financing and cash flow risk for only limited benefit to other industry participants.

If you wish to discuss any of these issues or comments further, or have any other queries regarding this response, please contact either myself or Andy Wainwright on 01926 655944.

Yours sincerely

[By e-mail]

Pauline McCracken
RIIO-T1 - Price Review Manager

Annex 1 – National Grid Transmission Detailed Responses to Questions Raised in Consultation

Chapter 2 – Network Charging Volatility

Question 2.1: Have we correctly characterised the scope of the problems we are trying to address?

National Grid Electricity Transmission, as NETSO, is responsible for collecting revenues on behalf of all GB transmission owners. This includes not only NGET as a TO, but also the other onshore TOs (SPT and SHETL) and offshore transmission owners (OFTOs). Whilst the consultation acknowledges the existence of SPT and SHETL, it does not explicitly cover the OFTO regime nor NGET's revenue collection role. OFTO revenue provisions currently sit outside of a RIIO framework, however they do present a level of uncertainty to customers' overall electricity transmission charges. This situation is exacerbated through the emerging nature of this regime which presents a significant element of uncertainty both relating to the magnitude and timing of OFTO revenue requirements. An illustration of the increasing relevance of OFTO revenues is provided in NGET's 2012 Condition 5 report[3] which forecasts by 2016 that 14% of TNUoS revenue will be driven by OFTO requirements.

Question 2.2: Are there certain market segments or groups of customers that are particularly affected by charging volatility?

As part of our RIIO-T1 stakeholder engagement, National Grid has received feedback from a number of customers indicating their concerns regarding the volatility of transmission charges and, in particular, the potential increase in price volatility. However we do not believe that, thus far, a greater concern has been demonstrated for a particular market segment or group of customers. It is worth noting that gas transmission is approximately 2% of an average household gas bill and electricity transmission is approximately 5% of an average household electricity bill.[4]

Question 2.3: Do you agree with the assessment criteria? Are there additional criteria that we should adopt for our final assessment?

National Grid broadly agrees with the assessment criteria suggested, however we have comments on some of the associated detail.

We agree that options should be assessed in terms of their ability to lead to a more efficient allocation of risk with regards to charging volatility, as ultimately this will result in the lowest cost to the end consumer. It therefore needs to be remembered that, as NETSO, NGET collects revenues on behalf of all onshore and offshore electricity transmission owners, and therefore any assessment of risk should also consider whether the risk can be more efficiently managed by the NETSO or individual transmission owners.

Our stakeholder engagement on charging volatility has indicated that users value charges which are transparent and predictable. The transparency of revenue inputs forms an important part of these criteria and therefore we agree that care needs to be taken not to introduce any undue complexity into the setting of allowed revenues. However it should be noted that predictability is not the same as stability of charges and, if stakeholders do value predictability then they may be more tolerant of less stable charges. Both of these potentially competing requirements need to be balanced against each other.

[3] NGET Interim Information Paper: A Discussion of Possible TNUoS Tariff Scenarios Under Project TransmiT: http://www.nationalgrid.com/NR/rdonlyres/C9BF215A-2616-49C6-B40F-D1E895F58189/53212/ADiscussionofPossiblePTTariffScenariosv10.pdf

[4] As detailed in Ofgem's 'Updated household energy bill explained Factsheet 97 31.05.12'

In regards to the other assessment criteria suggested, we broadly agree that there needs to be a strong link between the performance of a NWO and its financial indicators. We also agree that consideration needs to be given to other ongoing policies and objectives. Such consideration should be extended not just to Ofgem policies, but ongoing industry proposals in related areas. For example, one of the CUSC modification proposals raised in March by Haven Power (CMP206[5]) seeks to establish additional reporting requirements on NGET in relation to forecast TNUoS charges. This proposal is currently being discussed by an industry workgroup, and has significant overlap with option 1 of this consultation. There is also scope for overlap with the work being undertaken to develop SO incentives. Information provision to improve charging transparency is one of the potential outputs raised by our stakeholders during our engagement under RIIO-T1 for potential development as an SO incentive in gas transmission.

Consideration should also be given to interaction between different options in the consultation. For example, there may be a level of interaction between the provision of information under option 1, and the potential for penalties under option 2 for performance against target revenues, in regards to the forecast information published and used to determine the target revenue.

Chapter 3 – Options to mitigate volatility in network charges

Question 3.1: Do you have any further suggestions of what could be done to mitigate network charging volatility arising from the price control settlement?

Revenue volatility for TOs arising from the price control settlement provides only one source of network charging volatility. Other areas of potential volatility include charging model input and data assumptions, and revenue requirements for TOs that are separate to any price control settlement. Users are concerned with the overall volatility of a network charge, rather than a particular source of volatility. As such, National Grid will continue to work with the respective industries to consider and develop ways to improve both the methodologies for network charge derivation, and also the provision of relevant information to customers to assist in the management of charging volatility.

Question 3.2: Do you agree with our initial assessment of each option?

National Grid agrees with Ofgem's initial assessment of options 1 and 2, and believes that, with certain caveats as detailed below, overall implementation of these options is likely to provide benefits to end consumers.

We can see potential areas of benefit associated with option 3 in certain targeted cases, but it is important that the outcome results in the affected TO being kept whole.

We have more significant concerns regarding option 4, particularly in relation to NGG and the impact of revenue delays to the financeability of its capital plan under the proposed RIIO-T1 regime. This is due to the need to receive funds at the time of spend associated with incremental entry and exit capacity, which is a particular concern given NGG's low ex-ante baseline funding arrangements in comparison with the potential level of incremental entry and exit capacity spend forecast over the RIIO-T1 period. Any proposal affecting the timing of allowed revenue from uncertainty mechanisms needs to be considered as part of the financeability package for the affected TO.

We strongly agree with Ofgem's view that option 5 is unlikely to be beneficial to industry as a whole.

[5] CMP206 - Requirement for National Grid Electricity Transmission to provide and update year ahead TNUoS: http://www.nationalgrid.com/NR/rdonlyres/85360322-FA6D-4918-9C1E-3E14AB0D7D44/52998/CMP206TNUoSForecasts1.pdf

Specific questions in relation to option 1:

Question 3.3: Do code and licence charge notification differences in each network sector create problems in managing charge changes?

National Grid is not aware of any problems created by differing charge notification requirements in each network sector, however this may be an issue of more significance for users of energy networks.

Whilst not strictly an existing alignment issue, it should be noted that appendix 3 of the consultation document fails to mention the information provision requirements for external transmission owners under the provisions of the System Operator –Transmission Owner Code (STC) as stated in STCP 14-1 (Issue 006 Data Exchange for Charge Setting), Part 3.4[6]. This requires a best forecast of revenue items by 1st November for the following financial year, and a final forecast by 25th January. There is currently no codified requirement for any additional forecast information to be provided to the NETSO. Improvements to this data exchange would allow for improved TNUoS revenue forecasting by NGET in its role as NETSO. We have discussed this limitation and potential improvements with other electricity TOs within the Charging User Group (CHUG).

Question 3.4: What information would you like the network operators to provide, that they currently do not, in order to help improve predictability of network charges for different customer groups? This should include:

a) what information you would like to see in their business plan submissions, and

b) what information you would like to see provided on an ongoing basis.

National Grid has engaged extensively with stakeholders as part of our RIIO-T1 price control process to understand and incorporate, where possible accounting for commercial confidentiality, information customers would like to see in our business plan submissions. We would welcome any further engagement and suggestions from our stakeholders that would facilitate debate in this regard.

Feedback from stakeholders from this engagement has suggested they value transparency of charges to allow informed forecasts of future charges to be made. We have therefore considered a number of ways that we could improve the level of forecast revenue information to our customers. From an NGET perspective, this includes making available more forecast revenue information as part of our Condition 5 report, including a greater granularity of forecast. In this year's interim report[7] we have already forecast TNUoS revenues down to TO level for the next five years. We have also started to produce a fuller forecast of TNUoS charges including more detail on the future trends for the residual element. From an NGG perspective we have provided initial forecasts on the impact that RIIO may have on NTS Capacity charges. NGG already make available the transportation model, revenue forecast information spanning a number of future years, and a quarterly information provision detailing the inputs used to set indicative and future charges.

Any information that is provided however, should not introduce confusion. It should be information that is of use to users and therefore it will be worth understanding stakeholder requirements further and, if required, modifying the provisions in the licences and industry codes accordingly. In addition to ensuring that only relevant information is made available, we need to be mindful that any information provided does not cause any confidentiality issues but we are supportive of additional / improved information sharing that would also allow customers to improve their own charging modelling.

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[6] STCP 14-1 (Issue 006 Data Exchange for Charge Setting) - http://www.nationalgrid.com/NR/rdonlyres/194108E0-7791-4513-A568-048497F15739/36728/STCP141DataExchangeforAnnualChargeSetting_InclOffs.pdf

[7] NGET Interim Information Paper: A Discussion of Possible TNUoS Tariff Scenarios Under Project TransmiT: http://www.nationalgrid.com/NR/rdonlyres/C9BF215A-2616-49C6-B40F-D1E895F58189/53212/ADiscussionofPossiblePTTariffScenariosv10.pdf

We also believe that it is important that users have access to tools and assistance to enable them to make their own forecasts of future charges. In electricity transmission we are currently developing an improved front end to the TNUoS transport and tariff model to make it easier for use to understand how changes to input parameters such as revenues can affect their charges. Similarly, increased flexibility of base data within the gas transportation model would allow more informed user forecasting. Such changes would require UNC modifications, in a similar manner to the current proposed Mod 423. NGG also make the Transportation Charging model available to Users to enable them to forecast charges.

Question 3.5: What information do you think we could provide, that the network operators cannot, that would benefit you in terms of improving predictability of network charges?

National Grid welcomes Ofgem's open request for industry participants to consider ways in which the Regulator could assist information provision relating to NWO charges. We consider that there are two particular areas that Ofgem should consider with a view to potential improvements.

Firstly, we agree that the RIIO financial model can provide a useful tool to enable stakeholders to better understand the reasons for transmission revenue changes. Making the RIIO financial model available to all parties would provide greater transparency on the reasons for revenue changes. In gas transmission, when transportation charges are updated such information is already provided as to the causes of such change and this would seem a natural extension to this process. However, the RIIO financial model will cover adjustments to the base revenue term only and so will not provide any visibility of changes caused by pass through costs and most incentive mechanisms.

Secondly, whilst not strictly a price control settlement issue, we believe that more information could be provided in relation to OFTO revenue forecasts and, in particular, forecasts relating to future OFTOs both in terms of timing and likely magnitude. Whilst we accept that there are some commercial sensitivities around this data, it does present an increasing source of revenue uncertainty to users going forwards.

Specific questions in relation to option 2:

Question 3.6 – In the last 5 years how frequently have networks introduced intra-year changes? What were the main reasons for these?

In the case of electricity transmission, National Grid typically sets transmission network use of system (TNUoS) charges once a year in April providing two month's notice of the changes. The exception to this was in 2010/11, where National Grid took the unprecedented step to update tariffs a second time during the year, where again two month's notice of the change was provided. The decision to do this was not taken lightly and was undertaken to implement the offshore transmission regime, and to pass-through mid-year changes that both other onshore TOs had notified to National Grid.

National Grid also sets offshore TNUoS charges[8] mid-year following the appointment of the OFTO, as this process is dependent on information the OFTO provides to National Grid following asset transfer and is not known accurately before this time.

In the case of gas transmission, National Grid sets both capacity and commodity charges. National Grid routinely updates commodity charges twice a year in April and October, in each case providing two month's notice of the change. This is to ensure that National Grid remains compliant with its

[8] a component of an offshore generator's total transmission charge

licence obligations. If these restrictions were relaxed then potentially charge changes could be less frequent.

These routine changes also recognise the availability of accurate information to set charges, for example, the outcomes of entry capacity auctions and exit capacity booking processes; and uncertainty in some of the underlying costs, in particular external system operator costs such as shrinkage costs. In two instances National Grid has updated the SO commodity charge a third time, typically in February, in response to volatility in wholesale gas prices that would otherwise have led to significant over-recoveries. In 2006/07 a third price change was also necessary to manage the consequences that the reconciliation of meter errors have on revenue recovery. Entry and exit capacity charges are set at various times throughout the year for a 12 month period starting on 1st October, each with at least two month's notice of the change. Entry capacity prices are set in January for the QSEC auction held in March and prices for monthly entry capacity updated in July and August. Exit capacity prices are set in May.

Question 3.7 Are there any business processes that would mean only allowing one change per year on 1 April would not be feasible?

As noted in the consultation, the ability to set charges at other times than 1st April enables National Grid to reduce the likelihood and magnitude of any over and under recoveries.

It should be noted that the processes to purchase entry and exit capacity are aligned to a capacity year running for a 12 month period from 1st October (a Gas Year). This means that were capacity prices set for a 12 month period starting from 1st April, two prices would apply to a Gas Year, and there may be an information disjoint between the prices and capacity booked.

There are a number of business and industry-wide processes that whilst these would not prohibit setting charges only on 1st April, there would be much greater reliance on business forecasts, such as recoverable costs and SO incentive performance, and the use of older data sets that might be potentially less accurate. Greater reliance on forecasts can also cause financeability issues for NWOs. Availability of information after the November financial model iteration would mean a delay in reflecting this information in charges, and hence revenue collection. Even so, NWOs would be expected to make the required network investments.

Some detailed issues relating specifically to gas and electricity transmission are provided below.

Gas transmission

In gas transmission greater reliance on forecasting would be required in the following areas:

- the outcomes of processes to purchase entry and exit capacity;
- arrangements to reconcile meter errors that emerge;
- external system operation costs;
- demand estimation affecting the charging bases; and

– information to populate charging models.

The industry processes for **purchasing entry or exit capacity** operate throughout the year (primarily for entry auctions but exit bookings can take place through the year under the ad-hoc process). The outcomes from these processes determine the revenue that National Grid recovers from entry and exit capacity charges and affect the level at which the various commodity charges need to be set in order to collect the correct total revenue for each control (e.g. approximately 60% of TO entry target revenue is now collected through a commodity charge). National Grid uses the October update of commodity charges to take account of updated information on the outcomes of these processes which would not be possible if charge changes were limited to 1st April (with two month's notice). For example, the outcome of the AMSEC auction held in February would not be known at the time charges were set.

Further to this, the industry process to **reconcile meter errors** can result in large changes to the SO revenues (and therefore charges) once concluded. However, the duration and outcome of the process is often unknown, since it depends on access to sites to undertake fieldwork (often when gas flows are at a specific level); the preparation of independent expert reports; and industry agreement. This means that where forecasts are made about the eventual outcome and timing of the meter error reconciliation, large under or over recoveries may emerge if these prove to be wrong. Based on recent meter errors that have been identified, the magnitude of the over / under recovery can be significant, and in the order of several tens of millions.

External **system operation costs**, in particular, shrinkage costs that can represent around 40% of the costs and revenues recovered through the SO commodity charge, can be challenging to predict. This is often because the cost is set by external markets. In recent years, there has been considerable volatility in wholesale gas costs that means that the SO commodity charge may over or under recover shrinkage costs if these change after charges have been set.

Annual **demand forecast information,** which is used to prepare capacity and commodity prices, is prepared in May each year as a pre-cursor to the Transporting Britain's Energy processes. Were updates to gas transmission charges to be restricted to 1st April, then alternative longer-term forecasts and / or greater reliance on previous (potentially less accurate) forecasts might be required.

To illustrate the combined effect of these factors, the following table shows the under / over recovery that occurred in a number of previous years and in each case how it would be different had the TO and SO commodity charges only been set once for 1st April. The table illustrates that restricting charging changes to once a year would have resulted in larger inter year corrections which are less cost reflective.

	NGG updates to commodity charges during year	Over / (Under) Recovery (£m)		
		2009/10	2010/11	2011/12
TO	Multiple times (status quo)	10	7	(9)
	April only (proposed)	(67)	18	(25)
SO	Multiple times (status quo)	(35)	(18)	9
	April only (proposed)	(66)	35	(53)

In addition to the factors outlined above, National Grid uses a range of data to populate its **charging models** that generate capacity prices. If entry capacity prices were set for 1st April and at least two month's notice of the changes provided, the capacity prices currently set in July and August would no longer take account of the demand data that is updated in May each year. Whilst this would not affect revenue collection, it would delay the impact of demand changes on the locational signals provided through capacity prices. There may also be a similar impact of QSEC prices that are currently set for the QSEC held during March each year.

Electricity transmission

National Grid currently sets the onshore component of TNUoS charges once a year in April and the supporting business processes are aligned to support this. As noted above, an exception to this are offshore TNUoS charges, which tend to affect a limited number of generators, and can only be accurately set once the process to appoint an OFTO has been completed. This means that the offshore component of TNUoS charges may be set at different times throughout the year, as and when the tender process completes for that particular offshore generator / project.

Having set onshore and offshore charges for transmission customers, National Grid (as NETSO) is charged each month by TOs, so that each can recover its allowed revenue for a given year. Against this background, were restrictions on mid-year updates to charges applied to certain TOs only, National Grid would be unable to pass-through any mid-year change that one or more "un-restricted" TOs might make during the year. This would have a number of undesirable affects:

- the incentives in place for National Grid to not over / under recover may be distorted and potentially weakened through the actions of a third party; and

- risk may be transferred to National Grid over which it has no control and would have no ability to mitigate this, this risk would need to reflected in the rate of return.

Question 3.8: Do you think that there should be exemptions that would allow for changes due to specific events? Do you think these events should include the occurrence of errors when calculating charges or changes to the charging methodologies? Are there any other events that should potentially be exempt?

National Grid believes it would be pragmatic, mainly from a process perspective, to include exemptions to the restriction on frequency of changes to provide flexibility in limited, defined circumstances and / or with the approval of the Authority. To the extent that the wider commercial framework does not allow for errors to be corrected (as opposed to genuine data changes that can be expected during the year), it would be appropriate to include changes due to errors to ensure that these are rectified as quickly as possible. Against this background, provisions already exist in the electricity transmission charging arrangements to correct "manifest charging errors" during the annual reconciliation processes for customers that are materially affected.
In addition to the exclusions included in the consultation, it may be appropriate to also include provisions for:

- wider regulatory changes or framework changes, other than the charging methodology itself, that could impact the cash flows of network companies. Such impacts might arise when changes are made to network access arrangements, which sit outside the charging methodology.

- handling large meter error reconciliations that have a low likelihood but when they do occur, the timing and magnitude of the reconciliation can be difficult to predict and can have a large impact of revenue collection / recovery.

- directions made by the Secretary of State related to special administration arrangements and fuel security provisions.

- European and primary legislation coming into effect.

Question 3.9: Do you agree with our proposed change to the penalty for over or under recoveries were this option to be implemented?

National Grid agrees that it would be appropriate to change the penalties for not collecting the allowed revenue should changes to charges be limited to once per year in April. Such changes should to take into account the specific circumstances of each licensee and form of control, since the likelihood and magnitude of an over / under-recovery may vary between licensees. For example, in gas transmission there are more externalities that can be volatile and unpredictable which affect the SO over / under recovery compared to the TO (see table above); and in electricity transmission only National Grid's revenue recovery is affected by changes in generation and demand, whereas for other onshore (and offshore) TOs this is not the case. Differentiation in the penalties could be in the form of greater dead bands before the application of penal interest charges or the rate of penal interest.

The consultation suggests that performance over a number of years should be taken into account to apply a penalty where there is a persistent (or systematic) over or under recovery. The consultation notes that such provisions already exist for gas transmission and distribution. In the case of electricity transmission, Special Condition D6 in NGET's licence already provides for this. Therefore National Grid does not believe any further changes would be needed to the gas or electricity transmission licences, over and above any broadening (or otherwise) the penalty thresholds themselves, to take into account any new restrictions on the frequency of tariff changes. Any other proposals should be developed through consideration of the overall financeability of the individual NWO affected.

Question 3.10: Do you agree with our initial view that there should be a two year lag on adjustments due to the over or under recovery of revenue through the correction factor?

A delay of recovering any over / under recovery would increase the predictability of changes in charges due to over / under recovery, which would (all other things being equal) reduce the uncertainty faced by customers. It should be noted that the correction itself may be larger than those historically seen, which might be perceived as reduced stability. If a delay were introduced for the correction of any over / under recovery that might emerge, National Grid believes this should take proper account of the time value of money to ensure that, in the absence of a penalty being made, the adjustment to the network company's allowed revenue is as if the over / under recovery had not occurred i.e. the network company is neutral to the timing.

Question 3.11: Are you aware of any errors that have been made when calculating network charges in sectors other than electricity distribution?

National Grid is not aware of any errors that have been made when setting gas or electricity transmission charges in the previous 5 years.

Prior to then there was a "manifest" error in 2005/06 in the electricity transmission charges set in the first year of BETTA. The error was caused by a data error in the network information National Grid received from one of the Scottish TOs. Following consultation with all industry participants, National Grid corrected this error at the earliest opportunity and introduced manifest charging error correction arrangements.

Question 3.12: Do you think that introducing an additional licence condition to penalise NWOs when they make charge calculation errors is warranted?

National Grid believes the case for introducing a new licence condition to penalise for network companies when they make charge calculation errors has yet to me made, particularly given the very low error rate within transmission charging. This is because the existing incentives around over / under recovery, coupled with proposed RIIO incentives to enhance customer service, already drive the correct behaviour by network companies.

Notwithstanding these points, as highlighted in the example above, were such a penalty introduced, National Grid believes that errors caused by inaccuracies in data provided by third parties, for example, other onshore and offshore TOs over which National Grid has no control, should be excluded for any such mechanism. In addition, further consideration would be needed about how such a mechanism would work in practice, not least to ensure that genuine forecast inaccuracies are not considered to be an error, and to clarify the scope of the mechanism, such as whether it applies to the tariff (the unit rate) calculation or the charge calculation, which may be more easily remedied within year with the individual customer.

Specific questions in relation to option 3:

Question 3.13: What do you consider to be an appropriate notice period for changes to allowed revenues?

We agree with the conclusion that in the majority of cases, a two year lag on adjustments would be beneficial to enable it to be based on actual outturn data.

Question 3.14: Do you consider there to be any potential exemptions to our proposal to lag all incentive adjustments?

No.

Specific questions in relation to option 4:

Question 3.15: Do you agree or disagree with our initial assessment of whether a lag should be applied to the following uncertainty mechanisms? Please explain your reasoning.

a) indexation

We agree that since these annual changes are based on publicly available information and therefore predictable, lagging is not warranted.

b) pass through costs

NWOs have a number of different costs that are subject to pass through. The ability of the NWO to predict these costs ahead of the year varies on a case by case basis. Generally these can be predicted at the year ahead stage. However, there are times when externalities reduce the accuracy of these forecasts, for example, business rate revaluations that occur every five years; and one-off regulatory / government costs that feed through to licence fees.

In the case of NGET specifically, the allowed revenues of onshore and offshore TOs are treated as a pass through item for NGET (as NETSO). In this case, it would be inappropriate to introduce a delay between the payments NGET makes to other TOs and the revenue recovered from transmission users.

c) revenue drivers

We agree that lagging adjustments are not appropriate for revenue driver funding.

In gas transmission, where there is a single mechanism for incremental entry and exit capacity and a baseline of zero incremental capacity, a two-year lag would have consequences for our proposed financial package which has been based on income being provided to match expenditure in the year of spend.

In electricity transmission, where projects with a very high cost receive a separate treatment (within-period determination) and volume-drivers adjust allowances up or down from a base scenario, a two-year lag may be more appropriate. However this appropriateness would be affected should the baseline for electricity transmission be reduced significantly, and an increased reliance be placed on revenue drivers.

d) within period determinations

We agree that any delay would have consequences for our financial package. The process for strategic wider works in electricity transmission envisages additional regulatory scrutiny and a consultation with stakeholders in advance of any expenditure. Given this, and the significant lead-time associated with these large projects, it is likely that the impact on future revenue should be known with sufficient notice for most years of project expenditure.

e) reopeners

As with within-period determinations, we agree that there should not be a lag for this type of revenue change as in general there would already be a delay in funding being provided. As these will have received due and proper consultation, the effect of such revenue adjustments should already be known and therefore predictable.

It is worth noting that the proposed materiality threshold of one per cent of revenues net of the totex incentive (i.e. two per cent of revenues with the application of an efficiency incentive rate of 50%) represents a very high value that may essentially make the re-openers redundant. We have proposed alternative thresholds as part of our March business plan submission.

f) innovation funding

We agree that there is no need to delay this allowance as it is unlikely to have a material effect on the volatility of charges.

Specific questions in relation to option 5:

Question 3.16: Do you agree or disagree with our initial assessment that the benefits of introducing one of the three options for a cap and collar do not outweigh the drawbacks?

We agree with your initial assessment that a cap and collar is not appropriate as the benefits do not outweigh the drawbacks.

Question 3.17: Do you consider there are any other options for the design of a cap and collar mechanism that we have not considered?

While there may be other approaches that could be adopted, they are all likely to suffer the same drawbacks as the options that have been assessed and therefore we do not consider any form of cap and collar should be introduced.

Question 3.18: Do you have any views on whether a cap and collar, if implemented, should be symmetric or asymmetric?

See answers to 3.16 and 3.17.

Timing of implementation:

Question 3.19: Do you agree that if changes are needed in the gas distribution or transmission sectors that they should be implemented on 1 April 2013, the start of the next price control period?

Implementation timescales for any option which would have the potential to alter users' charges should be carefully considered to avoid any additional volatility to the network charge the option intends to assist.

Some of the options suggested may require further industry consultation and consideration prior to implementation, and it is vital that the duration of such a process is accounted for in the implementation date.

Question 3.20: When should we apply any changes to the electricity distribution sector?

As this annex provides a response from National Grid as a gas and electricity transmission company, we are neutral to the nature and timing of the application of any changes within the electricity distribution sector.