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Dear Rachel,

Response to "Consultation on strategy for the next gas distribution price control –RIIO GD1"

Wales and West Utilities Limited (WWU) is a licensed Gas Distribution Network (GDN) providing Gas Transportation services for all major shippers in the UK. We cover $^{1}/_{6}{}^{th}$ of the UK land mass and deliver to over 2.4 million supply points. WWU is one of only two Licence Operators that focus solely on Gas Distribution in the UK.

We welcome the opportunity to formally respond to this first consultation which gives an indication of Ofgem's initial thoughts on the detailed application of the RIIO[1] principles within the next price control period.

This response builds on the feedback we gave in response to the "Review of the regulatory regime"[2] and this executive summary is structured to provide a summary of our key issues on the strategy recommendations contained within the consultation.

The executive summary is supported by six appendices which provide responses to the questions raised within each of the consultation documents. An index of appendices is provided at the end of this executive summary.

We hope this response, and all future feedback, help shape Ofgem's next strategy consultation in March and ultimately, a price control package currently proposed to 2021 that is appropriate for consumers, networks and investors.

Context

The next price control period to 2021 is likely to be a critical period for the UK energy sector and we think everyone fully recognises that sustainable networks are central to the significant energy challenges ahead. Therefore, a successful application of the RIIO principles is vitally important if the UK is to deliver the challenges we face.

The WWU philosophy from day one has been to deliver value for money services with full justification for the money we spend. We have undertaken significant stakeholder engagement from the outset and the RIIO principles, if implemented sensibly, should further support our philosophy.

We understand the importance of effective asset management and have been constantly seeking to improve the robustness of our asset management processes. Notwithstanding the evolution of our processes, safety of consumers remains at the heart of our business. We

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1 RIIO: Revenue = Incentives + Innovation + Outputs
2 WWU response to Ofgem headed "WWU response to RPI-X@20" dated 06/09/2010

welcome the ten year review of the "Iron Mains 30/30 programme" and we are fully supporting the HSE/Ofgem review process and providing them with all the information at our disposal.

WWU is already at the heart of all the industry Output workgroups and our aim is to play a full role in developing an "Outputs" led framework with appropriate incentives to deliver long term value for money services for stakeholders.

As part of the RIIO GD1 process we will be submitting our "well justified" business plan to you later this year which will have regard to stakeholder views and incorporate our plans to deliver value for money outputs and investments to current and future consumers.

We think it is fundamental to have a regulatory framework with core concepts that promote:

- Enhanced engagement with stakeholders,
- Network companies playing a full role within a sustainable energy sector,
- A focus on long term value for money, and
- Linking network revenues to the efficient delivery of Outputs.

The Scope of the Review

The first detailed application of the RIIO principles will provide new process challenges but it is important that all the material key issues are covered within scope the review.

Unlike electricity distribution, the gas distribution licence still contains an obligation to be a "Meter Provider of last resort" (MPOLR) and we note it is recommended to omit the obligation; and the review of the price caps from the review.

It is our view that:

- The obligation is redundant as metering has been a competitive activity within the UK for a number of years, and
- The price caps are not reflective of the costs incurred.

We think it is appropriate to include this onerous obligation within the scope of the review and would hope to update the licence obligation to reflect the competitive nature of metering. We have, so far, stopped short of requesting derogation in this area but the cost impact on WWU is significant and a continuation of the existing regime will place a non compensated cost to; and hence additional risk to our business.

Stakeholder engagement

We fully support enhanced engagement with all our stakeholders and will ensure our business plan submission has regard to their views. Delivering for our customers is nothing new for WWU and customer delivery has been a key business priority from day one. We have led the ground breaking shipper forum to enhance transparency of our charges and we meet regularly with our major users. We also have daily interaction and feedback from the emergency, connection and replacement services we provide. Our strong current performance on existing customer standards is a product of significant focus from day 1 and we aim to strive for further improvements into the future.

We therefore look forward to further engagement with our stakeholders during and beyond this price control period.

Early indications from our stakeholder events are:

- Recognition of our role as part of the critical energy infrastructure,
- Customer standards and WWU performance appear appropriate,

- Extending the network is a priority for non gas communities,
- Safety, security and reliability are key issues - and in many respects are taken for granted,
- Stakeholders are not generally aware of the iron mains risk - but identified it as a key priority when they better understood it, and
- There is general support for anything networks can do to facilitate carbon reduction

We look forward to including their updated views back to you as part of our well justified business plan.

Outputs and incentives

We support the principle of providing stronger links between the delivery of well justified Outputs and revenues. Early evidence suggests that stakeholders value the additional transparency of network services. Well defined outputs should assist a greater understanding of the value gained by consumers from the Gas Distribution Network (GDN) portion of the average domestic bill of circa £10 per month.

To avoid uncertainty and unintended consequences, it is vital that we "test" the introduction of any outputs against a common sense set of characteristics. Example characteristics should include, but may not be limited to:

- Material
- Controllable
- Auditable
- Measurable
- Comparable between networks
- Not likely to result in unintended behaviours

We are supportive of a regime that includes appropriate incentivisation and we are currently working within all the output workgroups to identify and develop appropriate incentives for the future. The rewards for outperformance against incentives should reflect the desired outcomes for consumers but they should not be a substitute for the return required by equity to invest in the sector.

Within the consultation there is only a limited number of objectively measurable incentives that give networks the ability earn additional revenues through out performance. We think there is further work to be progressed in this area.

It is highly likely that the major incentive to be applied to networks will continue to be the Information Quality Incentive (IQI). With the application over a longer price control period it is vitally important that the cost assessment process is robust.

To drive the right behaviours, the incentive regime must promote those behaviours valued by stakeholders and provide a real opportunity for networks to outperform. We also think the incentives should be symmetrical with clear and transparent reward mechanisms. If discretionary panels are used in isolation we have concerns that real, continual performance may not be recognised and rewarded.

Finally, we think the incentive regime must promote "improving" behaviour within a sector. If relative incentivisation is used, there is a danger that improved performance is penalised and overall sector performance is not improved. It may therefore be appropriate to apply absolute targets to reward any network that achieves incentives which are calibrated through the consultation process.

We aim to include our view of outputs and incentives within our well justified business plan.

Review of the Replacement 30/30 programme

As stated in the context section above, safety of our stakeholders is at the heart of our business and we welcome the scheduled HSE/Ofgem review of the Iron Mains 30:30 replacement programme. The current programme, which was initiated by the Health and Safety Executive, is there to replace deteriorating Iron Mains within thirty metres of properties over a thirty year period with plastic. Iron Mains have a propensity to fracture and release gas into buildings which then gives rise to potential gas explosions.

We are committed to working with HSE, Ofgem and the other networks and our evidence suggests:

- Total WWU fracture numbers remaining steady - despite the current pace of replacement
- Fractures as a percentage of remaining iron population are actually increasing
- Proximity to iron pipes increases risk
- We also believe that modelling *all* the relevant factors involved actually gives a strong case for increasing the speed of the replacement programme.

It is our intention to continue to remove this risk to consumers at a rate to meet our societal risk obligations.

As part of our stakeholder engagement it is clear that consumers are not fully aware of this risk but there is early recognition from them to address this risk as a priority.

Financeability

The financeability package is a key enabler for all the other RIIO principles and will be under intense scrutiny from current network owners, future potential investors, banks and credit rating agencies.

The financeability package must appropriately fund an efficient network and it is also the key to securing current and future investment. The detailed financeability package must be applied with these thoughts in mind.

If the detailed application of the RIIO financeability package is insufficient to fund networks; sustain current investment; and attract new investment throughout the current decade and into the next, RIIO will not succeed and many of the key UK energy sector deliverables will be put at risk.

We are currently working closely with Ofgem in this area and intend to play full part during the ongoing discussions that will inform the detailed application of the principles.

We acknowledge we are required to propose our own financing arrangements within our business plan submission but we think it is appropriate to clearly set out our early concerns with the consultation recommendations.

During the review of RPI-X@20 on financeability the networks provided significant feedback on the recommended principles. This consultation period now presents an early opportunity to fully explore the implications of the principles. We hope that Ofgem incorporate the feedback from the parties who will be most affected by their implementation.

The combined effect of key components within the financeability proposals would result in an uncompensated risk to equity which may undermine future investment to support a sustainable energy sector. A summary of our key issues are outlined below

- WACC estimates are inconsistent with the need to secure funding against competing equity investment opportunities in the UK and globally over the price control period and beyond - particularly if Ofgem are looking to equity to manage apparently short to medium term cash flow issues.
- Cost of equity range of 4% to 7.2% is below current 7.25% and does not reflect the increased risk inherent in detailed application of RIIO principles. Our analysis suggests this range results in a significant challenge to meet financeability tests. Additionally, a cost of equity at Ofgem's low to mid range results in an insufficient premium compared to the cost of debt.

  The financial market crisis since 2008 has resulted in change in underlying rates and significant volatility compared with the market prior to the crisis. Arguably, even the pre-crisis market was exhibiting behaviours that were not sustainable over the long term. RIIO GD1 requires the appropriate Cost of Equity to be set for the 8 year period to 2021. It would not be in the interests of stakeholders to set a cost of equity based on an assessment of recent market rates which is too low to provide sustainable funding to networks into the next decade.
- Cost of Debt indexation is likely to increase cost of debt as companies try to match index - and increases equity risk as opposed to reducing it. It also ignores networks liquidity requirements, the other costs associated with raising or maintaining debt and the debt maturity profile requirements of the rating agencies. Consequently, it will result in less flexibility for networks to manage their financing in the most efficient manner.
- Financeability needs to be assessed in the context of financeability specifically throughout the price control period - not just the medium and long term
- The current allocation of 50% of repex into RAV remains the appropriate balance to reflect the timing of the benefit of the activity to stakeholders
- Due to the significant detrimental cashflow effect on equity, any change in RAV capitalisation policy should be implemented over a transition period equal to price control period
- The depreciation profile should be set based on an assessment of when the stakeholder benefits of expenditure accrue – safety and environmental benefit could justify something other than "simple" straight line, but it seems premature to justify accelerated depreciation on grounds of economic useful life of gas as all credible scenarios show gas networks being in use for at least the next 40 years. There will be more clarity regarding industry developments in 2021
- The outputs and incentive regime should encourage and reward good performance, but should not be seen as compensation for otherwise inadequate allowed returns to debt and equity

As stated above, we think it is critical to the Price Control Review process, the future of RIIO and the future energy challenges ahead to ensure we give due regard to this key policy area. Our initial analysis suggests that the combination of factors highlighted above will place an uncompensated risk on the equity investors with the real potential of investors choosing to invest outside of UK energy networks.

Tools for cost assessment

Given the likely lengthening of the price control period and the likely reliance on the Information Quality Incentive (IQI), it is critical that we use the appropriate tools for cost assessment. We must get cost allowances right as the consequence of getting them wrong clearly increases over a longer price period**.**

The Current regime clearly provides strong incentives to reduce costs**.** The Opex 100% incentive drives networks to reduce costs to an efficient level and WWU have driven hard and made significant cost reductions to achieve this. It is our view that the current incentive has delivered the savings expected as a result of network sales fully within this current price control for WWU.

The cost impact of different company structures and operating environments needs proper assessment:

- Simple regression comparisons are questionable - and do not reflect all appropriate cost drivers
- Economies of scale associated with different group structures need to be fully taken into consideration

We fully support a wider review of costs - with appropriate recognition given to quality of network business plans along with past performance

One of the key issues that we must address through RIIO GD1 is the funding of the emergency service. The emergency service is a core service provided by all networks and some networks have succeeded in maintaining competitive metering work within a highly competitive environment since network sales. We should maintain a meter tipping adjustment mechanism. We think the benefits to the recipients of the regulated service coupled with a relatively simple adjustment mechanism are a reasonable solution to this activity. We welcome further discussions with you in this area and will provide our proposals within our business plan submission later this year.

Greater role for third parties in delivery within Gas Distribution

As you state within the consultation documents, there is already a significant role played by third parties within the sector, for example Independent Gas Transporters (IGTs). There is also comparative regulation and many of the networks market test key activities and major contracts. It is not only difficult to see significant consumer benefit but it is quite easy to visualise additional safety risks and costs to consumers with the introduction of further mechanisms.

A key feature of RIIO is the provision of a well justified business plans, engaging with stakeholders and defining outputs that will shape investment decisions. One would hope this regime plus many additional controls deliver an appropriate outcome for consumers.

Innovation Stimulus

Within the RIIO principles, there is a clear desire to develop a framework that will promote innovation to support sustainable networks whilst achieving regulatory standards. We welcome the continued focus on innovation and hope to be part of an industry where innovation continues to add value.

At this early stage we offer some principles on which an Innovation stimulus should be provided. We will continue to play a full role within the Innovation Stimulus workgroup and also provide feedback at every opportunity.

- There are opportunities for Gas Distribution to play a full role within a Low Carbon sustainable future and it is important innovation is promoted in sustainable gas related technologies.
- Any innovation stimulus should not be limited to low carbon technologies. Innovation is needed in all areas such as Safety, Commercial arrangements and customer services and may be just as important to UK plc.
- The networks have different group structures and different corporate footprints. Therefore the framework should be flexible to include large scale and small scale innovations as recognised within the documents.
- The networks are regulated entities and the Regulated Allowed Revenues are the only source of income to fund regulated activities. Therefore the costs of innovation should be included within the cost base and any increase in non funded costs may be a barrier to participation
- There are opportunities for networks to work with partners but the introduction of complex mechanisms to fund potential partners in competition against networks could deter smaller networks from participating in discretionary schemes

Uncertainty mechanisms

Within the consultation documents[3] there is recognition that over a longer price control period there are greater uncertainties of the outputs required and greater potential uncertainties of the costs to achieve these Outputs. We welcome the early discussion on potential uncertainty mechanisms and recognise that we will have an opportunity to propose our views of the uncertainty mechanisms within our well justified business plan.

Our early view is that the proposed uncertainty mechanisms broadly reflect the uncertainty mechanisms that we have in place currently. Therefore to maintain the current risk profile to networks there needs to be recognition through increased returns to equity of the greater uncertainty the longer period introduces.

We broadly support the criteria that should be used to assess the introduction of uncertainty mechanisms and in addition to the detailed feedback we provide through the detailed answers to the specific questions we would like to make some specific comments within this executive summary.

- The introduction of a debt index based on a long trailing average. The networks will be required to raise debt finance at certain points in the future and there is no evidence to suggest that the that the trailing average will be reflective of the market conditions at the time as the historical index could be influenced by material historical dips – e.g.: a prolonged recession. There is also a concern that the uncertainty mechanism makes no allowance for potentially significant other costs associated with raising or maintaining debt. In summary, the current format of this uncertainty

[3] Overview section of the Uncertainty mechanism appendix

mechanism could actually introduce a level of increased risk to networks and perhaps a better approach would be to look at forecast cost of debt, aligned to the current arrangements.

- National Transmission System (NTS) dependency. You will fully appreciate the unique dependence our system has on the availability and cost of NTS products and services. We are pleased to be working within the capacity outputs workgroup with the NTS and Ofgem to fully explore the potential improvements we can make as an industry. Despite this, Ofgem must recognise that relatively minor changes to NTS products could have profound impacts for networks. The NTS products include Flat Capacity, Flex Capacity and System Pressures. There could be significant influences on the NTS during the period to 2021 outside of our control which could have significant, as yet unknown implications for the delivery outputs and costs within our business. Therefore we think it is appropriate to consider a broad, flexible re-opener to reflect the unique potential uncertainties.

- Funding an efficient emergency service – the Meter Tipping Point Adjustment. The emergency service is a core service provided by all networks and some networks have succeeded in maintaining competitive metering work within a highly competitive environment since network sales.

  It appears appropriate to maintain a meter tipping adjustment mechanism. We think the benefits to the recipients of the regulated service coupled with a relatively simple adjustment mechanism are a reasonable solution to a complex issue. We welcome further discussions with you in this area and will provide our proposals within our business plan submission later this year.

This early, initial strategy consultation is helpful and we hope to have a continuing dialogue with you to review the points we raise. Many of the RIIO principles are welcome and very well aligned to our existing business philosophy within Wales & West Utilities. That said, we must ensure there is an appropriate risk and financeability regime to support the customer facing RIIO principles. Attached to this executive summary are the responses to the detailed questions. We look forward to further discussions throughout the process with you.

Attached to this executive summary are six appendices:

- Appendix 1: WWU response to RIIO GD1 Overview paper
- Appendix 2: WWU response to RIIO GD1 Outputs and Incentives Supplementary Annex
- Appendix 3: WWU response to RIIO GD1 Tools for cost assessment Supplementary Annex
- Appendix 4: WWU response to RIIO-T1 and GD1 Business plans, innovation and efficiency incentives Supplementary Annex
- Appendix 5: WWU response to RIIO-T1 and GD1 Uncertainty mechanisms Supplementary Annex
- Appendix 6: WWU response to RIIO-T1 and GD1 Financial issues Supplementary Annex

Yours sincerely

Steve Edwards

Head of Commercial and Regulation

Wales & West Utilities

APPENDIX 1: WWU response to RIIO GD1 overview paper

CHAPTER: One

Question 1: Do you have any comments on the proposed process and timetable for the review?

We welcome the early engagement on the next price control review which does not take effect until April 2013. This is the first opportunity to test and implement the RIIO principles and we are already heavily engaged in various work streams to try to deliver an initial, well justified business plan to Ofgem by July of this year.

The process is challenging as we are developing a significantly different regulatory regime which consists of many new elements. As a summary we are currently:

- Involved in six output workgroups to develop a new outputs led regime;
- Participating in the HSE review of the Iron Mains Replacement 30/30 programme;
- Consulting with stakeholders to support a well justified business plan;
- Developing the detailed application of the RIIO principles into practical policies for the first time ; and
- Developing a well justified business plan for July this year.

As stated earlier we are fully supportive of many of the principles but it is clear this first application of the principles is very resource intensive for the networks.

In summary, our early experience of RIIO is that there is a requirement for Networks to support several key work streams very early in the process to allow the remaining timetable to be achieved.

CHAPTER: Two

Question 1: Do you agree that we have identified the key challenges facing the gas sector, and our approach to accommodating these challenges within the price review?

We agree the gas networks face a number of important challenges. A key enabler is the financeability package which must be sufficiently attractive for investors to participate. We feedback our detail response to the financeability package in our responses to the questions raised in chapter 8 and the financial issues consultation paper.

Most of the key challenges are identified within the scope of the review but unlike electricity distribution, the gas distribution licence still contains an obligation to be a “Meter Provider of last resort” (MPOLR) and we note it is proposed to omit the obligation; and the review of the price caps from the review.

It is our view that:

- The obligation is redundant as metering has been a competitive activity within the UK for a number of years and
- The price caps are not reflective of the costs incurred.

We think it is appropriate to include this onerous obligation within the scope of the review and would hope to update the licence obligation to reflect the competitive nature of metering. We have, so far, stopped short of requesting derogation in this area but the cost impact on WWU is significant and a continuation of the existing regime will place a non compensated cost to; and hence additional risk to our business.

CHAPTER: Three

Question 1: Do you have any comments of the overall approach to stakeholder engagement?

We fully support enhanced engagement with all our stakeholders and will ensure our business plan submission has regard to their views. Delivering for our customers is nothing new for WWU and customer delivery has been a key business priority from day one. We have led the ground breaking shipper forum to enhance transparency of our charges and we meet regularly with our major users. We also have daily interaction and feedback from the emergency, connection and replacement services we provide. Our strong current performance on existing customer standards is a product of significant focus from day 1 and we aim to strive for further improvements into the future.

We therefore look forward to further engagement with our stakeholders during and beyond this price control period.

Early indications from our stakeholder events are:

- Recognition of our role as part of the critical energy infrastructure
- Customer standards and WWU performance appear appropriate
- Extending the network is a priority for non gas communities
- Safety, security and reliability are key issues - and in many respects are taken for granted
- Stakeholders are not generally aware of the iron mains risk - but identified it as a key priority when they better understood it
- There is general support for anything networks can do to facilitate carbon reduction

We look forward to including their more comprehensive views back to you as part of our well justified business plan.

Question 2: Do you have any views on how our engagement process and that of the network companies could be made more effective?

We participate in the Ofgem led "Price control review forum" (PCRF) and we have found that forum useful to be able to discuss issues and receive feedback in addition to our stakeholder forums. We also support the involvement of stakeholders within the output workgroups. It would be helpful for our stakeholder process if Ofgem made the feedback that it receives from stakeholders more readily available to networks.

CHAPTER: Four

Question 1: Do you consider that the proposed outputs and associated incentive mechanisms, taken together with other elements of the price control, will ensure that companies deliver value-for-money for consumers, and play their role in delivering a sustainable energy sector?

A detailed response to the Outputs and associated incentive mechanisms is attached as a separate appendix "RIIO GD1 Outputs and Incentives" but we provide our summary responses below.

In summary, we support the principle of providing stronger links between the delivery of well justified outputs and revenues. Early evidence suggests that stakeholders value the additional transparency of network services. Well defined outputs should assist a greater understanding of the value gained by consumers from the Gas Distribution Network (GDN) portion of the average domestic bill of circa £10 per month.

We are generally supportive of a regime that includes appropriate incentivisation and we are currently working within all the output workgroups to identify and develop appropriate incentives for the future.

Question 2: Do you consider that the proposed outputs and incentive arrangements are proportionate (e.g. do we have too many or too few)?

Generally, the output workgroups appear to be developing a sensible number of outputs. We are working within all output workgroups to ensure the outputs that we ultimately implement are appropriate to the services we provide and those valued by stakeholders. We do not want to implement a suite of outputs that add no value for stakeholders or networks.

Within the consultation there is only a limited number of objectively measurable incentives that give networks the ability earn additional revenues through outperformance. We think there is further work to be progressed in this area

Question 3: Do you have any views on the proposed outputs or incentive mechanisms?

To avoid uncertainty and unintended consequences, it is vital that we "test" the introduction of any outputs against a common sense set of characteristics. Example characteristics should include, but may not be limited to:

- Material
- Controllable
- Auditable
- Measurable
- Comparable between networks
- Not likely to result in unintended behaviours

We are supportive of a regime that includes appropriate incentivisation and we are currently working within all the output workgroups to identify and develop appropriate incentives for the future.

The rewards for outperformance against incentives should reflect the desired outcomes for consumers but they should not be a substitute for the return required by equity to invest in the sector.

It is highly likely that the major incentive to be applied to networks will continue to be the Information Quality Incentive (IQI). With the application over a longer price control period it is vitally important that the cost assessment process is robust.

To drive the right behaviours, the incentive regime must promote those behaviours valued by stakeholders and provide a real opportunity for networks to outperform. We also think the incentives should be symmetrical with clear and transparent reward mechanisms. If discretionary panels are used in isolation we have concerns that real, continual performance may not be recognised and rewarded.

Finally, we think the incentive regime must promote "improving" behaviour within a sector. If relative incentivisation is used, there is a danger that improved performance is penalised and overall sector performance is not improved. It may therefore be appropriate to apply absolute targets to reward any network that achieves incentives which are calibrated through the consultation process.

We aim to include our view of outputs and incentives within our well justified business plan.

CHAPTER: Five

Question 1: Is our proposed approach to cost assessment appropriate?

We have provided a detailed response to the cost assessment approach within appendix "RIIO GD1 Tools for cost assessment". Therefore there are no responses to this chapter. An overview of our points is contained within our executive summary.

CHAPTER: Six

Question 1: Do you have any views on the uncertainty mechanisms identified?

We have provided a detailed response to the proposed uncertainty mechanisms within appendix "RIIO GD1 Uncertainty mechanisms". Therefore there are no responses to this chapter.

CHAPTER: Seven

Question 1: Do you have any views on the role of innovation in RIIO-TI?

We assume the question was actually meant to refer to the role of innovation in RIIO GD1 and will therefore answer the question on this basis.

Within the RIIO principles, there is a clear desire to develop a framework that will promote innovation to support sustainable networks. We welcome the continued focus on innovation and hope to be part of an industry where innovation continues to add value.

At this early stage we offer some principles on which an Innovation stimulus should be provided. We will continue to play a full role within the Innovation Stimulus workgroup and also provide feedback at every opportunity.

- There are opportunities for Gas Distribution to play a full role within a Low Carbon sustainable future and it is important innovation is promoted in sustainable gas related technologies.
- Any innovation stimulus should not be limited to low carbon technologies. Innovation is needed in all areas such as Safety, Commercial arrangements and customer services and may be just as important to UK plc.

- The networks have different group structures and different corporate footprints. Therefore the framework should be flexible to include large scale and small scale innovations as recognised within the documents.
- The networks are regulated entities and the Regulated Allowed Revenues are the only source of income to fund regulated activities. Therefore the costs of innovation should be included within the cost base and any increase in non funded costs may be a barrier to participation
- There are opportunities for networks to work with partners but the introduction of complex mechanisms to fund potential partners in competition against networks could deter smaller networks from participating in discretionary schemes

Question 2: Do you have any views on the time limited innovation stimulus?

We generally support the continuation of the existing “Innovation Funding Incentive” (IFI) as a % adjustment to Allowed Revenues, in addition to the time limited stimulus. If the innovation stimulus is constrained to partially funded “large major bids” there is a real danger that smaller but equally important innovations will be lost within the sector.

We also support the proposal to widen the scope beyond “Low Carbon” technologies within gas distribution. Innovation is needed in all areas such as Safety, Commercial arrangements and customer services and may be just as important to UK plc.

Appropriate funding arrangements will be an important element of the innovation stimulus and given the future uncertainties, we think there is merit in maintaining as much flexibility within the funding profile as possible. We think that maintaining a constant maximum annual level of funding is preferable to a front loaded funding option. As the expenditure is incurred on a fast basis we think the costs should be funded as “fast money”. If the desire is to promote expenditure on innovation then funding on a slow basis may deter smaller networks from participating.

CHAPTER: Eight

Question 1: Do you consider that our proposed package of financial measures will enable required network expenditure to be effectively financed?

WACC estimates are inconsistent with the need to secure funding against competing equity investment opportunities both in the UK and globally over the Price Control Period to 31 March 2021 and beyond - particularly if Ofgem are looking to equity to manage apparently short to medium term cash flow issues.

Cost of equity range of 4% to 7.2% is below current 7.25% (GDPCR1) and does not reflect the increased risk inherent in detailed application of RIIO principles. Significant changes to the regulatory regime (even with transitional arrangements) increase uncertainties over a network cashflows and hence the risk to equity. As a consequence, investors should require a higher rate of return to compensate. Further, a cost of equity at Ofgem’s lower to mid range is a materially insufficient premium as compared to the cost of debt. At the proposed levels there is a significant risk that investors will prefer to invest in senior and high yield debt.

Cost of Debt indexation is likely to increase cost of debt as companies try to match index - and increases equity risk as opposed to reducing it. It also ignores networks liquidity requirements, the other costs associated with raising or maintaining debt and the debt maturity profile requirements of the rating agencies. Consequently, it will result in less flexibility for networks to manage their financing in the most efficient manner.

Financeability needs to be assessed in the context of financeability specifically throughout the price control period - not just the “medium” and “long” term which has been interpreted as focusing only on subsequent rather than the immediate Price Control periods.

The initial range of WACC, when input into the 2008-13 GDPCR Finance Model indicates a significant financeability challenge – failing to meet Post Maintenance Interest Cover Ratios consistent with “comfortable investment grade” credit rating metrics.

Question 2: Do you have any views on our proposed approach to capitalisation and depreciation policies?

The current allocation of 50% of repex into RAV remains the appropriate balance to reflect the timing of the benefit of the activity to stakeholders. Any proposal to depart from the well established and accepted 50% repex methodology must be based on solid evidence.

For accounting and tax purposes, the repex programme has been treated as having no future economic benefit as the network is not enhanced (in its ability to carry out key activity of transporting gas) by this expenditure, but we do recognise safety, environmental and some operating costs benefits to stakeholders from repex.

Question 3: Do you have any views on our proposed approach to implementing any transitional arrangements required to address cash-flow affects from a change in our repex capitalisation policy?

Regulatory Certainty is an important concept highly valued by investors. Changes in Regulatory Treatment reduce regulatory certainty and will result in Networks experiencing a higher cost of debt and equity. We do not concur that a change is required, but any change in RAV capitalisation policy has a significant detrimental impact on equity cash returns and should only be implemented over a transition period equal to at least a price control period.

We have not yet seen a credible rationale for a front-loaded depreciation profile. However, if applied we believe this should be for new investment only and to continue to depreciate existing gas distribution assets on a straight-line basis.

Additionally, an increase in proportion of expenditure capitalised into RAV increases the size of “capital” and other finance facilities required by a network.

Question 4: Do you have any views on our preferred approach to assessing the cost of debt?

We believe that rather than reduce uncertainty, introduction of debt indexation has two potential adverse consequences, being:

1. The cost of debt of energy networks, and consequently the cost of debt funded by consumers, has the potential to rise due to demand concentration as energy networks seek to avoid the risk of underperformance against a variable cost of debt allowance by matching their debt profile to the index which drives the allowance (and consequently will not necessarily result in networks and consumers paying an efficient cost of debt), and
2. The cost of equity will increase due to a transfer of risk (the uncertainty as to whether the network will be able to raise debt funding no more costly than the debt index over the price control period) and the uncertainty over WACC over the price control period and hence revenues and returns.

In addition, there are significant practical difficulties to overcome in arriving at a realistic index-based cost of debt allowance that reflects energy networks funding costs which are excluded from an observable index. All of the factors below should be reflected in the "efficient" cost of debt that Ofgem believes that consumers should fund.

- transaction costs
- the impact of new issue premia on bond coupons
- Credit Rating Agency fees
- commitment commission and other 'costs of carry' associated with prudent pre-funding of capital and replacement expenditure programmes.
- the higher margins and arrangement fees associated with bank debt and other liquidity facilities.

We note comments in the consultation that the historic value difference between "corporate" and "utility" index can be seen as a long term allowance for debt issuance costs. This comment does not reflect the uncertainty that this relationship is merely historic accident and will not continue in the future – particularly if future events adversely impact utility yields

Licensee mitigation to exposure to underperformance against an Ofgem debt index would be to restructure existing and future debt to track the debt index.

1. Licensees' debt is currently structured to be consistent with the long term nature of the business and be compliant with key Credit Rating Agency and common debt covenant criteria:

   - Bonds already issued are of long duration
   - Banks are reluctant to lend for periods in excess of 3, or possibly 5, years which means that a network could only track the proposed debt index through bond debt
   - Debt covenants normally require no more than 40% of debt/RAV to fall due for refinance within any 5 year Price Control period.

   Debt restructure to match debt index will be expensive, (due to restructuring/transaction costs and market premia as networks "chase" the index) and may be precluded or adversely impact Credit Rating due to Rating Agency criteria

2. Bond market participants have identified bond investor's preference for a mix of tenors for bond issuance. Pension funds in particular are most focussed on long dated (20 year plus) maturities, particularly in respect of index-linked debt. Bond market participants have concerns that investors would react to both the concentration of energy network debt issuance around the debt index tenor, and issuance in amounts below that seen as "liquid" (circa £200-£300m) by increasing the premium required by issuers to fill the bond order book, were issuers to "chase the index". Networks with RAV value below £3.2bn will not be able to issue bonds sized as "liquid" without exposing themselves to variation from the 10 year trailing average index, assuming notional gearing of 62.5%.

Consequently, adoption of the debt index is likely to both increase networks actual cost of debt by incentivising them to re-structure existing debt to mitigate the risk of under-performance against the index, and also have potential to increase the cost of debt incurred by networks tracking the index in the future. Whether this will either result in consumers paying a higher cost of debt to networks, or equity suffering the excess cost of actual debt compared to the index will depend on specific debt index mechanics; but neither outcome appears to meet "Better Regulation" criteria.

The proposed mechanism results in a transfer of risk to equity. Towards the end of the Price Control process, Licensees assess the Final Proposals "in the round" – including:

1. a comparison of existing and expected future cost of debt with cost of debt allowance and WACC proposed for the Price Control Period and
2. an assessment of financeability.

If Final Proposals are not accepted then this can result in referral to the Competition Commission.

Currently, networks can compare the current cost of embedded debt and an assessment of the future cost of new debt required to fund expected expenditure during the Price Control period. Future cost of debt can be hedged in the financial markets through debt issuance or entering into an interest swap financial derivative at the time this assessment is made. This is the practical assessment by the networks of whether Ofgem has met its duties regarding financeability.

When future cost of debt allowance is based upon an index that will change over time this assessment cannot be done with precision. When considering the Final Proposals, networks will need to assess the risk of underperforming against the index, which changes the balance of risk to equity and consequently increases the Cost of Equity.

It is also more difficult for the network to assess whether Ofgem has met its duties regarding financeability, as it cannot be assumed that a cost of debt allowance based on historic trailing averages will match the cost of debt that a network will need to pay to raise finance when required during the future Price Control period.

There are significant practical issues around debt indexation design. Under the proposals, Consumers will effectively fund cost of debt at Index values. Consequently the index should seek to reflect the efficient cost of debt. We note that the initial analysis done by Ofgem's identifies potential index structures which currently give "headroom" over spot rates, but we have not seen any analysis which demonstrates that the proposed debt index is an "efficient" debt profile over a future or successive Price Control periods, or will meet the cost of debt that a network will need to pay to raise finance when required during the future Price Control period.

We also have significant concerns in respect of the proposal to use an average of the Bloomberg indices, in particular:

- From discussions with several leading banks, these indices are not widely used in the capital markets
- The A rated index only commenced in 2003 and therefore there are concerns as to the robustness of any data prior to that date
- The A rated index does not include structured finance transactions and hence the bonds issued by WWU in 2010 are excluded from the index. The A index only includes 14 bonds with a significant bias to certain organisations (for example 5 are RWE and one bond within ithe index was issued by the State of Israel) and hence cannot be regarded as representative
- The A rated index contains bonds with maturities between 2014 and 2039 – consequently does not reflect the credit charge for 10 year debt that Ofgem seem to be seeking. Adding this spread to the 10 year gilt yield is not likely therefore to result in a true reflection of the costs of raising 10 year debt.
- Additionally, index-linked bonds have historically been issued at a premia to nominal bonds, which will not be reflected in the index.

- The BBB index is reporting a lower credit charge than BBB debt as it contains bonds that additionally have 1 or 2 A ratings.
- The index includes insurance protected “wrapped” bonds but will not include the costs associated with the ‘wrap’ protection. The wrapped bonds will therefore reflect tighter spreads pre 2007, which could not be replicated in the current market.

Further, a mechanistic index would not appropriately reflect any immediate ‘shock’ on bond pricing that could arise (e.g. as a result of another financial crisis, or Solvency II requirements having an adverse impact on long term corporate bond spreads)

We have spoken to several banks who have said that it will not be possible for them to offer financial derivatives to networks which achieve a hedge against the network’s interest rate exposure under the proposed debt index. This contrasts with current financial markets, where networks are able to fix their real cost of debt and hedge cashflow exposure between an RPI adjusted real debt allowance and interest costs through issuance of index linked bonds or swaps.

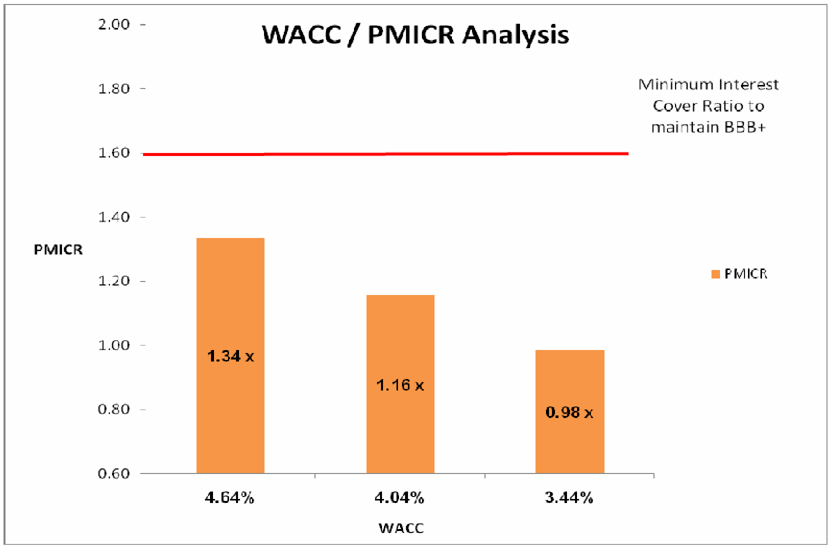
We believe that Ofgem should continue with its previous approach of settling a fixed real cost of debt for the Price Control Period to 2021 that meets the expected real cost of debt finance for networks for that period.

Oxera have carried out initial work which indicates a risk free rate of 1.50 – 2.00%. The credit charge on A/BBB debt over the last decade has been averaging around 1.3%. Allowance for debt issuance costs and costs of finance such as maintaining a credit rating means that networks will require a cost of debt allowance throughout the price control period, at 62.5% gearing similar to the GDPCR1 allowance of 3.55% real.

Question 5: Do you have any views on our proposed approach to assessing the cost of equity and the associated range of 4.0-7.2 per cent (real post-tax)?

The range of cost of equity proposed in the consultation document:

- Does not reflect the deferral of cashflows and transfer of risk to equity inherent in RIIO-GD1 proposals;
- Indicates significant financeability challenges;
- Is at a materially insufficient premium compared to the cost of debt.



Assumptions

- Tool : 2008-13 Ofgem Finance Model
- Gearing initially 62.5%
- Replacement expenditure 50% RAV
- No incentives or out-performance
- High, Low and "mid" case WACC - December Consultation

	High	Low
Cost of debt	3.1	3.1
Cost of equity	7.2	4.0
Post tax Vanilla WACC	**4.64**	**3.44**

Adopting Ofgem's proposed WACC range to their 2008-13 GDPCR financial model indicates that there is an annual funds from operations shortfall of £13m at High case and £31m in Low case (approximately 4% and 11% allowed revenue respectively).

"Mid" case WACC requires gearing to reduce to 50% Debt/RAV to achieve PMICR of 1.6x . For WWU this equates to an equity increase of approximately £225m. We do not consider that WWU will easily achieve access to this amount of equity funding through offering a "mid case" equity return of 5.6% real post tax.

It is important that incentives are not used as a 'plug' to compensate networks for an insufficient allowed cost of equity. Rating agencies have traditionally discounted income earned from incentives when considering the strength of the regulatory deal available to networks.

The Energy Networks Association have submitted an independent initial assessment of Cost of Equity by Oxera. Their report describes an estimated initial range of 5.1 to 7.5% real post tax. We believe that due to:

- The transfer of risk to equity inherent in RIIO-GD1
- The need to ensure financeability of networks

- The absolute need for the UK to ensure that significant infrastructure investment requirements
- Regulatory Certainty – equity investors currently receive an allowance of 7.25%, and 7.5% in the 2002-7 and 2008-9 Price Control Periods

the correct Cost of Equity for the Networks is at the high end of this range – 7.5%.

Question 6: Do you have any views on the other elements of our financeability proposals?

A key equity metric that has not been included in the proposals is dividend yield.

We reiterate our concern that "RORE" calculations should be used as an indicator of potential returns to investors, but should not be used to confirm financeability of the network throughout the Price Control period. RORE assessments could include potential returns for performance under discretionary incentive mechanisms that would not be recognised under credit rating agency methodology.

APPENDIX 2: WWU response to RIIO GD1 outputs and incentives supplementary annex

Chapter 1 – Overview of Outputs and incentives

Question 1: We would welcome respondents' views on the approach we have taken to develop the outputs framework.

We support the principle of providing stronger links between the delivery of well justified Outputs and revenues. Early evidence suggests that stakeholders value the additional transparency of network services. Well defined outputs should assist a greater understanding of the value gained by consumers from the Gas Distribution Network (GDN) portion of the average domestic bill of circa £10 per month.

WWU is already at the heart of all the industry Output workgroups and our aim is to play a full role in developing an "Outputs" led framework with appropriate incentives to deliver long term value for money services for stakeholders. We think the establishment of industry work groups with stakeholder involvement is a positive feature of the process but they are resource intensive.

The output workgroups are evolving at different speeds and overall progress is being made but there is still a lot of work to be done to get us to a point where we have well defined outputs and incentives.

Within the consultation there are a limited number of objectively measurable incentives that give networks the ability earn additional revenues through out performance and we think there is further work to be progressed in this area

We aim to include our view of outputs and incentives within our well justified business plan.

Question 2: Do any of our proposed output measures present potential difficulties in ensuring the submission of accurate and comparable data?

To avoid uncertainty and unintended consequences, it is vital that we "test" the introduction of any outputs against a common sense set of characteristics. Example characteristics should include, but may not be limited to:

- Material
- Controllable
- Auditable
- Measurable
- Comparable between networks

Early indications are that many of the desired outputs will require networks to develop additional processes, support tools and reporting capability. The introduction of new output measures will clearly bring new comparability issues. The Rune report highlights many issues with current cost comparisons and it is likely that much work will be needed in relation to Outputs to avoid similar issues. We are committed to working towards the desired outcomes but we recognise this will be an ongoing issue. The consistency issue is particularly pertinent to the development of Asset Health indicators and possible safety and reliability support monitors.

We have also identified that system changes would be required to capture and report revised outputs such as complaints resolved in D+31 or revised connections standards within the "Customer Outputs".

Question 3: Are there any aspects of our proposed outputs framework where the reporting requirements are likely to lead to disproportionate regulatory costs?

We are fully engaged within all the output workgroups and whilst some initial outputs are being identified, much of the detail is still yet to be worked through. It is likely that there will be significant additional reporting required by the networks but it is unclear at this stage whether or not this will be disproportionate in any particular area. We should be in a better position to answer this question following the March consultation document.

Question 4: Should we introduce an independent examiner for all companies to improve regulatory reporting?

We agree that there is the potential for inconsistent reporting in relation to Outputs and the risks of inconsistency increase with the increased reporting requirements. However, we think this risk is better mitigated by well defined Outputs with clear and transparent guidance documents. The introduction of an independent examiner may help. Regulatory returns are subject to internal and external audit and Ofgem already has powers at its disposal to request an independent examiner should it wish to do so. In summary, existing governance and well defined Outputs should be the best solution to possible inconsistencies but an independent examiner could also help.

Question 5: Do you have any views on our proposed approach to revising outputs?

The RIIO principles suggest our business plans should be Outputs led with our Allowed costs and Allowed revenues clearly linked to the delivery of Outputs. The final package that we accept will be built on delivery of agreed outputs with the agreed costs. Therefore any change to Outputs could have material implications for the whole settlement and risk profile to the network. Therefore we caution against change to outputs but recognise change may be necessary if new legislation / government policy is developed. Any change would therefore need full consultation and appropriate lead times before it could be applied.

Chapter 2 – Environmental impacts

Question 1: Do you agree with our proposal to require GDNs to report the capacity of bio-methane connected as a broad measure of environmental impact but not to adopt an associated financial reward/penalty?

Early stakeholder feedback appears to support our view that we should promote biomethane connections to the network. We would not have an issue with reporting the capacity of bio-methane connected. The amount of bio-methane connected is likely to be driven by producers, and by economic factors outside of network control. Therefore it would be inappropriate to apply an incentive on networks at this time. We recognise that there is merit in encouraging bio-methane connections so requiring networks to report connections and enquiries would raise the profile of this important issue.

Question 2: Is there any other measure of environmental impact which you believe could be financially incentivised, bearing in mind the need for an output to be measurable and controllable by the GDNs?

The use of recycling facilities which currently are not sufficiently incentivised via taxation to be viable.

Question 3: We would welcome respondents' views on the expected take-up of biomethane following the introduction of the Renewable Heat Incentive (RHI).

This is difficult for WWU as a network to predict. It will clearly be dependant on the views of producer's and the relative attractiveness to them. The value of the RHI is still to be determined but what ever level is decided it is important that bio-methane is encouraged and therefore it is our view that the network regulatory regime should encourage potential producers.

Question 4: Are there any wider-network benefits associated with bio-methane which might imply that we need to change the current connection charging boundary?

Significant volumes of Biomethane injected into the network could increase the overall supply of gas and result in lower gas Prices. This could feed through to lower energy bills for consumers. The cost of the gas is a significant proportion of the end user bill and therefore fuel poverty could be addressed by significant volumes of Biomethane entering the gas networks.

Our early evidence also suggests that the substitution of natural gas with biomethane would result in a significant reduction in CO_2. Indicatively, a 10% substitution could result in a reduction of circa 300,000 tonnes of CO_2.

In addition, there will be security of supply benefits and potential reduction in local reinforcement once a mature industry develops**.** In as much as customers use gas rather than some other fuel because bio-methane is part of the gas they receive then they are sharing the fixed cost of the network and therefore all other customers benefit from the larger customer base.

Currently networks use the Economic Test for exit connections and this results in a "relatively shallow" exit connections charging regime in which the exit customer pays for their own service pipe and related facilities and pay for some upstream specific reinforcement (if applicable) depending on the results of the Economic Test. Currently entry customers will pay for all the costs of the connection including reinforcement and Entry Facilities. Conceptually the Economic Test could be used for entry connections if there was transportation revenue to offset the costs. The size of the revenue stream would determine the deepness or shallowness of the entry connection charging boundary.

Question 5: We would welcome respondents' views on our proposed approach not to recover connection and downstream asset costs through general network charges. In particular, we would like to hear views on the potential rationale for socialising the costs of connecting bio-methane plant, and how we might be able to do this within our vires.

We have early concerns that the proposed approach will not encourage the use of a renewable source of energy. We acknowledge that Biomethane entry into the gas network is in its infancy and there appears to be value in further work to ensure that learning progresses collectively. We have a concern that there is some confusion over terminology and a lack of understanding that could impact the options going forward. We actually think there is a quite a strong case for socialising some of the costs and we also think Ofgem has existing powers to socialise the costs. We split our response to this question into two sections.

The rationale for socialising the costs

To give some support to our argument we provide an analysis of the existing funding arrangements for gas entry into the distribution network from an NTS offtake. For these offtakes both the capital and operating costs of the offtake are recovered from the generality of customers. We suggest that the following split of costs between the entrant and the DN is appropriate. (The terms Delivery Facility and Entry Facility are Uniform Network Code terms for the Entrant assets and the DN assets).

Delivery Facility assets (designed, built, funded, owned, operated by DN entrant) include:

- Production plant
- Gas sourcing plant
- Propane enrichment (to FWACV)
- Compression to put gas into system
- Connection to DN pipeline including design work

Connection pipe between Delivery Facility and Entry Facility Assets include:

- DN reinforcement (subject to economic test)
- DN compression costs to move gas up pressure tiers (subject to economic test)
- Blending facilities if required and possible

Entry Facility assets (designed, built, funded, owned, operated by DN) and included in RAV, operating costs funded in price control include:

- Connection pipe between existing DN main and Entry Facility Assets (funded by DN entrant
- Gas quality monitoring
- Pressure/flow control
- Metering
- Odorant and odourisation plant
- Remotely operable valve
- Telemetry and control equipment

The model above also has the additional benefit of supporting competition because it allows a third party to:

- Construct and own the gas network within the Delivery Facility
- Construct and own lay the pipe work from the Delivery Facility to the Entry Facility
- Construct and pass to the Transporter for adoption the pipe work from the Entry Facility to the existing Transporter main.

Ofgem Powers to agree the socialising of costs

Section 4AA of the Gas Act defines Ofgem's principle duty as protecting the interest of current and future consumers in relation to gas conveyed in pipes.

The interests of existing and future customers is defined as their interests taken as a whole including

- Their interests in the reduction of gas-supply emissions of targeted greenhouse gases: and
- Their interests in the security of the supply of gas to them

The section defining the interests of existing and future customers was added by the Energy Act 2010 and we believe that this provides Ofgem with the powers to agree to socialise some of the costs of connecting bio-methane plant.

As described above our stakeholder engagement showed support for bio-methane connections to our network. We would argue that achieving the government's target for greenhouse gas emissions is both within customers' general interests as UK citizens as well as reflecting their more directly expressed interests as evidenced by our stakeholder engagement.

Bio-methane will also increase security of supply, once a mature industry develops. Currently gas comes from the NTS, however having additional entry points that independent of the NTS will by definition add to security of supply and as the number of bio-methane connections grows it will start to have an appreciable impact.

While bio-methane plants cannot guarantee supply 24/7 they will not suffer from the intermittency associated with some other renewable technologies such as wind. Wind farms do not generate when there is no wind. Peak electricity demand tends to occur at times of extremely cold weather associated with high pressure systems where there is often little wind. Therefore at times of peak demand bio-methane plants are more likely to be producing gas than wind farms generating electricity.

It should be noted that this security of supply justification applies to all forms of entry into the network not just bio-methane connections, therefore this argument also applies to gas from other renewable sources (such as landfill gas) and to gas from non-renewable sources such as LNG and coal bed methane.

In summary, we therefore believe that Ofgem has the powers to agree to the socialising of costs of bio-methane entry

Question 6: Do you agree with our proposed approach of logging-up costs associated with bio-methane connections in the event that the connection boundary changes?

While the arrangements are being developed it is sensible to record these costs in some detail to enable legacy arrangements to be unravelled in the event of changes. We are aware that this was an issue for electricity distributors and we are keen to learn from their experience. While all spend is subject to an efficiency test it is important to recognise that there is a cost of learning and that until sufficient expertise has been developed costs are likely to be higher for early schemes.

Question 7: Are there other issues we should be considering for the price control in relation to distributed gas (predominately bio-methane)?

Although bio-methane is currently the most likely source of gas from renewable source, landfill gas is also renewable and although there are more quality issues associated with it, we are hopeful that these will be overcome in time. Therefore it would be helpful if it was made clear that references to bio-methane also refer to other gas from renewable sources

Consideration should also be given to the funding of entry costs for gas from non renewable sources. We recognise that in this case the green house gas reduction benefits are not present but we believe that the security of supply benefits are still present and their value should be recognised and that there is a case for socialising the costs of these Entry Facilities. Wales & West Utilities has received some enquiries from coal bed methane producers and also from companies seeking to build LNG entry points on the local transmission system.

Question 8: What information would distribute gas users find useful to help them connect?

Last year, Wales & West Utilities and all other gas networks provided the input for the industry leaflet generated by the Department of Energy and Climate Change (DECC) for potential biomethane producers who wish to connect to a network.

Locally, Wales & West Utilities offers the following process which, as far as possible, follows the existing exit connections process

- General network information (where all the most likely points of connection are (more importantly, where they are not). Entry connection customers can also have access to CD maps of the WWU network in the same way as exit customers
- Land enquiry type request – simple information on likely flow rates and pressure requirements (as for exit connections)
- Detailed chargeable network analysis (new service for entry connections)
- Budget estimate (as for sufficiently complex jobs for exit connections)

Detailed feasibility and/or design study and quote which follows the process for sufficiently complex jobs

Question 9: Do you agree with our proposal to broadly continue with the shrinkage allowance mechanism and Environmental Emissions Incentive (EEI) adopted at GDPCR1?

Gas leakage accounts for well over 90% of network emissions and shrinkage gas costs are material costs for stakeholders. The early stakeholder feedback we have received appears to support a continuation of the shrinkage allowance and the current environmental emissions incentive. There is recognition from our stakeholders that we should focus our efforts on lost gas and hence improve our impact on the environment.

Question 10: Do you agree with our proposed change to the valuation of carbon for the EEI to bring it in line with DECC's recommended approach?

Given the value to stakeholders of this Output, it would appear there is support to align the value of the incentive to something tangible as measured by DECC. An increase in the value of lost gas would be a clear incentive for networks to provide additional focus in this area.

Question 11: Should we retain a cap and collar on the EEI and at what level should any cap and collar be set? Should we introduce a cap and collar on the shrinkage incentive mechanism, and if so, at what level should any cap and collar be set?

There needs to be appropriate risk sharing between Networks and stakeholders but there appears to be some logic to incentivise networks to continue to reduce emissions and not deter further improvements by applying an artificial cap. The current incentive has been running for a period of time and it may be the right time to widen the boundary for this particular incentive.

Question 12: Do you agree with our proposal not to adopt a rolling-incentive mechanism for the EEI mechanism?

We generally support your proposal not to adopt a rolling incentive.

Question 13: Do you agree with our proposal to require GDNs to report actual shrinkage data when the relevant data becomes available, with the intention that we will use actual shrinkage as the basis for the shrinkage allowance and EEI at future reviews?

When the relevant data becomes available and the reporting of actual shrinkage clearly improves on the existing basis of shrinkage gas reporting, we would support a move to using actual data. Until smart metering has been fully rolled out, it is highly unlikely that any practicable solution will better the current reporting process. Leakage is less than 1% of throughput and a method to support that level of accuracy is probably some time away. We have an existing licence obligation to test this principle each year already. When we actually to get to point where we can measure actual gas lost we must ensure that we review the desired outcomes as other factors such as shipper-less sites and theft of gas will impact the volumes measured and lost.

Question 14: Do you agree with our proposals to require GDNs to establish a code of practice outlining how they will identify and process unregistered sites? Do you agree with our proposals to require GDNs to report annually on the number of unregistered sites they have processed?

Our understanding is that there is already a national working group looking at this issue. At this point in time it is not clear what obligations a code of practice would place on networks. We think this area is better addressed through a specific industry workgroup.

Question 15: Do you agree with our proposal to publish companies' business carbon footprint (BCF) as a league table to provide reputational incentives but not to provide an associated financial penalty/reward?

WWU would welcome incentives (to fund investment) to reduce its BCF where it is currently not financially viable to do so, yet would provide GHG emissions benefit hence contributing to a low carbon economy. The DECC abatement rates would seem appropriate.

Question 16: Do you agree with our proposals to publish other emissions and resource use but not to apply financial rewards/penalties?

See Q2. WWU support measurement but recognise the difficulty of accurate measurement of some areas such as excavated material to landfill where many sites do not have weighbridges. We would welcome incentives (to fund investment) in plant/processes/resources and behaviours to reduce other emissions.

Chapter 3: Customer service

Question 1: Are there any aspects of customer service provided by the GDNs not captured by the proposed broad measure?

The Customer Service Work Group (CSIWG) recommended changes to the customer satisfaction questionnaire to capture site tidiness and the quality of reinstatement and to modify the questions on the Connections survey to clarify the time taken to give a plan date and complete the works. These changes have not been included or referred to within the consultation document.

Question 2: Other than those specified, are there any other customer-GDN contact experiences that should be captured in the customer satisfaction survey?

Whilst we support engagement with Shipper, Suppliers, IGTs and ICPs it should not be through the satisfaction questionnaires.

WWU do not support the use of advocacy question alone - it should form part of the overall score. It should reflect the overall satisfaction with the service and could be weighted differently to reflect its importance

Question 3: Do you agree with our approach to introduce a financial incentive linked to the successful resolution of complaints?

The proposals give no incentive, only penalties for the poorer performers. However, we agree with the approach to basing this on effective and efficient complaint resolution rather than volumes.

Question 4: Do you agree with our proposal to introduce a measure associated with resolving complaints alongside the existing guaranteed standards?

Whilst we agree with the sentiment we believe the Guaranteed Standards (GS) and output measures should be consistent (20 working days v 31 calendar days) and that only one measure should exist. The GS ensures payment is made to individual customers whereas the output measures would not.

The current GS and Complaint Handing Regulations are inconsistent and we previously submitted documents to demonstrate this. The financial implications require all GDNs to work to clear guidelines and in a consistent manner. E.g. clear definitions of what is a resolved complaint, what should be logged as a complaint, what is a repeat complaint vs an escalation. At the latest CSIWG, WWU agreed to facilitate a workshop with the other DN's to develop these guidelines.

Question 5: Should we retain the discretionary reward scheme (DRS), given our proposed stakeholder engagement mechanism as part of the broad measure?

The current DRS topics will be captured by the wider Stakeholder engagement process and subsequent actions and innovations. The DRS scheme currently only addresses two key output categories, environment and social obligations. The stakeholder feedback and innovations would cover all six areas.

Question 6: What interest groups should be considered when designing the customer satisfaction surveys and approach to assessing stakeholder engagement activities?

Refer to our stakeholder engagement process.

Question 7: Do you agree with the proposed size and structure of the financial reward/penalty associated with each element of the broad measure?

WWU are generally happy with the reward and penalty mechanism.

The complaints and customer satisfaction measures are supported by large volumes of auditable data.

The financial rewards for the stakeholder engagement element of up to 0.5% of turnover equates to £1.6m per annum. It is not felt appropriate that this should be measured solely on a short summary paper and a presentation to an independent panel, but should also be supported by a visit to the network where a more detailed discussion could be held.

Question 8: Will the fact that we will not be consulting on the size of the dead band before the end of 2011 prove to be a significant issue for companies/showstopper for fast track agreements?

WWU believe that sufficient detail already exists for complaints and customer satisfaction surveys and that the benchmarking and dead-band can be established for discussion now.

Chapter 4 - Xoserve

Question 1: Do you agree with the scope and the timing of the review?

We agree that the scope of the industry review of xoserve services is appropriate and, even with the transition to a smart metering regime, we still need a fully funded, efficient service provider to support key industry processes. There are many changes on the horizon that still need to be implemented to support an efficient service provision over the medium term. The output from the industry workgroup will provide valuable inputs to the wider review of future funding arrangements for xoserve. The future scope of xoserve services is uncertain and there is key dependency on the future industry processes that are being designed to support a smart metering world. We are fully engaged within the review and the Smart Meter Implementation Programme.

Question 2: Are there any issues with xoserve that we have not considered that you think are relevant to a review?

The User Pays regime created the concept of 'Non-Code Services'. This was envisaged to be the mechanism for Users to obtain new services from xoserve outside of the Uniform Network Code (UNC) arena. Due to competing industry priorities this work has not moved forward but is likely to be covered within the industry review workgroup. Our view is that they are not required as existing non-code services could be migrated back in to the UNC and new services outside of the UNC can still be requested on a bilateral / commercial basis.

Xoserve will be working with the new DCC and developing systems and processes to support DCC activities. We are unclear regarding how the cost of this activity which is to benefit of consumers will be funded, and would welcome confirmation that operating cost allowances for this additional activity wil be made available.

Question 3: Do you think xoserve will be able to deliver the requirements for the smart metering programme and Project Nexus?

There are significant challenges ahead but xoserve has been working closely with Ofgem/DECC and the Smart Meter Implementation Project (SMIP). Subgroups meet weekly and xoserve has provided detailed responses to consultations and information requests which include costs and timescales of the changes that would be required to meet the future challenges. Work is ongoing.

Outside of the smart metering programme we must not forget some of the existing challenges that xoserve and networks need to address over the next ten years. The list includes but is not limited to:

- The maintenance of essential central systems (Supply Point Register, settlement systems, Gemini etc) regardless of the scope of the DCC
- AMR / I&C requirements that are being scoped as part of Project Nexus
- SMIP changes required to facilitate the creation of the DCC
- Migration of any additional services from the to the DCC (via the Smart Energy Code (SEC))

In summary, transporters/xoserve will need to ensure that any investment made for this change horizon is economic & efficient. Support for each stage is therefore required by the industry (& Ofgem) to ensure these can be achieved.

Chapter 5 – Social Obligations

Question 1: Is the fuel poor network extension scheme still the most appropriate way to assist the fuel poor?

The current scheme has only been in place for just over one year. The uptake and initial feedback from our stakeholders appears to support a continuation of the scheme, largely in its current form. The scheme, with the requirement to work with partners, appears to deliver significant benefit to those most vulnerable and who are close to the existing network without penalising existing gas customers. However, the limited value of the "voucher" does not assist the fuel poor who are some distance from the Gas network. We will give some further thought on how to assist those in fuel poverty who are further from the network. There may be the opportunity to improve the communications between suppliers, Government and community funding programmes to try to attract funds to this worthwhile initiative.

Question 2: Which is the best mechanism for delivering fuel poor network extensions?

As stated above the gas distribution fuel poor scheme is helping fuel poverty for those close to the gas mains. There are a couple of further options that we have discussed with Ofgem at the Outputs workshops:

- The option to use the current Uniform Network Code (UNC) ability to charge a higher transportation rate to those customers benefiting from a network extension which could allow for higher investment and therefore more projects to proceed.
- The use of an enhanced Economic test model that not only takes account of the NPV of future transportation income but also the carbon cost savings and fuel costs savings seen by the property.
- Partnerships with other third parties to use funding such as the funding from the Welsh Assembly Government to fund our infrastructure costs as well as other Home Efficiency measures.

We will explore and expand upon these options through the business plan process.

Question 3: Are there other incentives or mechanisms we could put in place to play a role in delivering non-gas solutions?

There are entities that are better placed than ourselves to help develop some of the options and we would be happy to explore our role within future partnership arrangements. We acknowledge that a balanced energy mix will be required and we will play an appropriate role within industry to encourage the right solutions for the different circumstances.

Question 4: Is it appropriate to fund GDNs through the price control for their activities in relation to reducing risks of CO poisoning?

Carbon Monoxide (CO) poisoning is a major issue for the energy sector as a whole. Early feedback from our stakeholders is that we should play a role in partnership with others but stakeholders acknowledged reducing the risks associated with CO was not our sole responsibility.

Many occurrences of suspect or actual CO spillage are associated with non gas appliances. Our evidence suggests there are some key causes of CO poisoning, and there are actions that the various industry participants such as manufacturers, suppliers, Government and Ofgem can take. We already provide significant awareness services and are currently reviewing how best to deploy future network resources to address the CO risk. Our early view is that awareness, partnerships and targeting those most at risk could have the biggest impact. We will continue to develop our thinking in this important area but we believe that a "national" joined up network approach would beneficial. We also believe that it is appropriate to provide firm funding for Networks to provide services that reduce risks of CO poisoning, i.e. we do not believe that activities should be subject to the vagaries and uncertainties of a DRS type approach.

Question 5: Are there any identifiable output targets that could be associated with reducing CO poisoning risks?

The causes of CO poisoning and CO incidents are largely outside of the control of networks and whilst we acknowledge we can contribute to risk reductions we are not supportive of identifiable targets to be applied to networks. That said, we record data on CO incidents

Question 6: Are there any other social issues for which we should be setting outputs?

There are no other issues that our stakeholders have identified at this stage. We will continue to explore any options.

Chapter 6 – Connections

Question 1: Are the current arrangements for charging margins in gas connections appropriate? Is there a need to introduce regulated margins for potentially contestable market segments for the gas connections market (as we did for electricity at DPCR5)?

For Statutory Connections (Gas Act section10) Wales & West Utilities are only allowed to pass on the estimated gross costs less any applicable allowances to the customer. For Non Statutory Connections (Gas Act Section 9), we apply the same charging methodology although a contingency is built in dependent on risk. We do not add a margin to connections charges. We understand that there may be differences between networks.

Wales & West Utilities' view is that all connections work is contestable even though competition has not developed in some market segments. This is primarily the case where the GDNs give a Domestic Load Connections Allowance (DLCA) but also single connections and small developments.

We believe it is appropriate to add a separate regulatory margin for the provision of connections services in respect of contestable Non Statutory Connections.

Question 2: Are there market segments where competition works sufficiently well, where we should consider excluding these market segments from the guaranteed standards regime?

Competition is well established in the larger new development market and mainly due to different regulatory regimes for Independent Gas Transporters (IGTs) and Gas Distribution Networks we are generally unable to compete with the IGTs on price. These jobs are currently classed as exempt from Guaranteed Standards (GS) and we believe this should continue.

Question 3: What, if any, new standards do you consider are required to ensure that gas connections customers receive a good standard of service?

Our early stakeholder engagement suggests the current standards are appropriate. We will continue to review this position subject to future stakeholder feedback.

Question 4: Should we extend existing standards to distributed gas customers? We would also welcome views on whether any new service standards should be introduced for distributed gas, and whether we should revisit this issue during the price review (once the market has developed)?

Our licence requires a formal response to enquiries to be given with 180 days. This work is in its infancy and each scheme will present its own challenges (network locations, pressure tier LP to HP, gas quality). We would support the review of the approach and whether a standard of service is required once the market has developed.

Question 5: Should we change any of the existing standards' timescales, penalties, or caps on the penalties (for example, to bring them into line with the guaranteed standards in electricity)?

It is generally acknowledged that competition in gas connections is well established with high levels of performance and low penalty payments. We always strive to improve our performance for customers and the current regime does incentivise the drive for improvement. We have made significant improvements under the existing regime and our performance clearly demonstrates that customer service is at the heart of our business and a key part of our philosophy. We do not think there is a requirement to make any significant change to the existing regime. The initial feedback from our stakeholders appears to support this position.

Chapter 7 – Safety

Question 1: Do you have any views on the primary output and secondary deliverables for gas distribution safety (Emergency) including whether:

(1) These are the appropriate areas to focus on?

Yes- the GDN's are a major accident hazard industry, and due recognition has been taken of lessons learnt from previous major accident hazards, such as Piper Alpha and Texas City. WWU has been fully engaged within the safety and reliability workgroup. We think the group output is progressing well we generally think the initial safety outputs are the appropriate areas to focus on. Response times and Performance are key safety indicators.

One area of concern is that it may not be feasible to undertake a direct comparison across all GDN's repair performance; this is not due to a scaling issue but due to some fundamental process differences. We will however continue to review the feasibility of solutions that achieve the objective of a cross GDN comparative measure.

(2) There are any other areas that should be included?

No, albeit HSE's HSG254 (Process Safety Indicators) was considered in full, but a number of measures were not considered to be appropriate e.g. leadership and competence, due to the difficulty in objective measurement).

(3) The performance of the GDNs in undertaking their maintenance programmes should be used as a secondary deliverable for reliability?

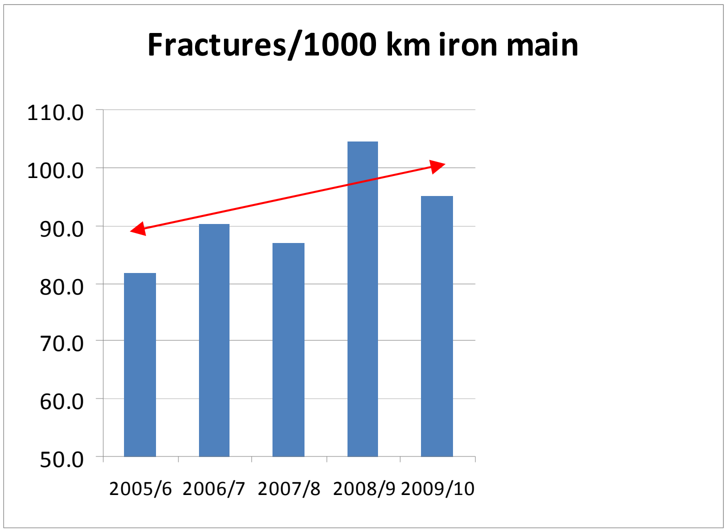
Yes, the maintenance programme is a key cost driver for approx 25% of expenditure and the inspection & maintenance of the most safety critical assets. In addition, HSG254, HSE guide to measuring Process Safety, recommends its use.

(**4) You agree with our approach to changing the revenue driver for repex from length of main decommissioned to a volume driver of risk removed?**

Safety of our stakeholders is at the centre of our business and we welcome the scheduled HSE/Ofgem review of the Iron Mains 30:30 replacement programme. The current programme, which was initiated by the Health and Safety Executive, is there to replace, deteriorating Iron Mains within thirty metres of properties over a thirty year period with plastic. Iron Mains have a propensity to fracture and release gas into buildings which then give rise to potential gas explosions.

We are committed to working with HSE, Ofgem and the other networks and our evidence suggests:

- Total WWU fracture numbers remaining steady despite the current pace of replacement
- Fractures as a percentage of remaining iron population are actually increasing
- Proximity to iron pipes increases risk
- We also believe that modelling *all* the relevant factors involved actually gives a strong case for increasing the speed of the replacement programme.
- The graphic below illustrates the increasing fracture rate of the remaining iron mains population.



It is our intention to continue to remove this risk to consumers at a rate to meet our societal risk obligations.

As part of our stakeholder engagement it is clear that consumers are generally unaware of this risk but there is early recognition from them to address this risk as a priority. The safety of our stakeholders is central to our business. The replacement of the Iron Mains within the 30/.30 programme provides key safety benefits for stakeholders. We are fully engaged within the HSE review of the Iron Mains Programme.

A move to change the revenue driver from length of main decommissioned to a volume driver based on risk could lead to gaming and non optimised approach to asset investment, e.g. splitting mains units (PONs) and only addressing part of the pipe. Other benefits of the programme, such as reduced repairs, public disruption repairing escapes, GHG emission reductions, etc. etc. would be compromised.

We therefore believe a move from a revenue driver based on Mains Decommissioned to one based on risk should only be progressed after a full review of the potential impact. It is unclear at this moment in time how risk can be translated into revenue without tangible workloads. We will continue to work with the industry workgroup in this area.

Question 2: Do you agree with the proposed approach of not imposing further incentives relating to safety?

We support the proposal not to impose further incentives relating to safety. We already have sufficiently strong incentives through our obligations to the Health and Safety executive (HSE) and through our Licence. Further incentives could result in unintended consequences and drive the wrong behaviours.

Chapter 8 – Reliability

Question 1: Do you have any views on the primary output and secondary deliverables for gas distribution reliability including:

(1) Whether these are appropriate areas to focus on?

WWU has been fully engaged within the safety and reliability workgroup. We think the group output is progressing well we generally think the initial reliability outputs are the appropriate areas to focus on.

(2) Whether any other areas should be included?

We think the initial workgroup output is appropriate and at this time we have not identified any other areas to be included.

(3a) Whether it is appropriate to remove the cap on the guaranteed standard for supply restoration and change the level of payments?

The existing penalty is already severe and improving performance is not within the control of the gas distribution network. HSE (Gas Safety Management Regulations (GSMR)) requirements currently prevent quicker restoration and the requirement to use qualified work-force (GS(I&U)R) limit the usable resource.

(3b) The appropriate form of secondary deliverable on the time taken to address network faults?

A 'number of faults multiplied by duration' measure incentivises both the reduction in number of faults and the timely rectification. This is a key leading indicator for the prevention of supply failure and a key cost driver, both in reacting to faults and future investment to prevent them.

(4) Whether there should be a secondary deliverable associated with offtake meter errors?

There is a question whether this meets the requirements of an output measure i.e. material and controllable. We note that, whilst offtake meter errors should be avoided, the gas settlement system is designed so that shippers and suppliers ultimately pay for the gas used by their customers as recorded at the meter at point of use, and not the offtake meter.

(5) Ofgem request views on appropriate risk metrics for large interruption risk and threshold for reporting (8.8) (extra question not referenced)

Risk metrics are difficult as these events are very low frequency, generally uncontrollable and very high consequence. Developing risk metrics for such events is inherently unreliable and has not been achieved in any high hazard sector, including the nuclear industry. A more qualitative approach is usually used in such circumstances, such as the evaluation of the risk management system deployed; a risk vs. investment analysis; and an understanding of what the controls are, how strong they are, how to test them and how to mitigate/react to an unfolding event.

Work presented by WWU to Ofgem indicated the threshold/classification for a large event is 250 consumers.

Question 2: Do you agree with the proposed approach to reliability incentives?

We support the proposals not to apply a financial incentive to the "Customer Minutes Lost/Customer Interruptions" (CML/CI) outputs. There is further work to progress in relation to new capacity incentives and Offtake Mater errors.

Question 3: We would welcome respondents' views on our proposal to require GDNs to develop their approach to valuing interruptible capacity to include a real option value, and views on how to achieve this.

The general principle to try to equalise incentive rates across different types of capacity expenditure is sensible. We are currently engaged in the capacity outputs workgroup and broadly support the retention of exit and interruption incentives. We are not in a position at this time to comment on the fine detail of the incentives but will address the consultation points through the workgroup.

Chapter 9 – Broader approach to asset risk management

Question 1: Do you have any views on our proposed approach to the development of asset health and risk metrics including:

(1) the approach to the assessment of asset health

We understand the importance of effective asset management - and have been constantly seeking to improve and evolve the robustness of our asset management processes. Notwithstanding the evolution of our processes, safety of consumers remains at the heart of our business.

WWU is already at the heart of all the industry Output workgroups and we are playing a full role in developing an "Outputs" led framework with appropriate incentives to deliver long term value for money services for stakeholders.

Within the safety, reliability and environment work groups we have shared with the industry participants the developments we are making within asset management. We are continually evolving our decision support tools to try to ensure better asset management decisions with regard to the longer term. We are currently not only looking at health indices but also "condition based risk models" (CBRMs) that take into account risk reduction and consequence of failure. We acknowledge that networks may be in different places in regard to the development of their own decision support tools but we will work to try to implement a workable solution that will clearly evolve over the next decade.

(2) the number and definition of primary asset categories

WWU do not consider the development of CBRM models is relevant for all asset classes. For example, the time and difficulty of development for HP storage or LP Holders would be disproportionate to the number of assets and the nature of their operation. WWU only have three HP sites and six LP sites. However, appropriate decision support tools will be needed and the following table illustrates our current thinking:

Asset Group	Current Risk Model	Future Risk Model	Timescale
NTS Offtakes	Condition Based Assessment	CBRM	1- 5 Years
> 7 bar Pressure Regulators	Condition Based Assessment	CBRM	1 Year
< 7 bar Pressure Regulators (District Governors)	DST	CBRM	1 Year
> 7 bar Mains	Condition Based Assessment	CBRM	1 – 5 Years
Special Fittings, Supports & Crossings	DST	CBRM	1 Year
< 7 bar Mains	MRDST	MRPS and MRP GAS	In Place
< 7 bar Storage	Holder DST	Holder DST	In Place
> 7 bar Storage	Manual Assessment	Manual Assessment	In Place
LPG	Manual Assessment	Manual DST	In Place
< 7 bar Pressure Regulators (Service Governors)	Risk Matrix	Risk Matrix	5 Years +
Services	Postcode analysis of service leakage	Postcode analysis of service leakage	In Place

DST = Decision Support Tool

MRDST = Mains Replacement Decision Support Tool

(3) the assessment of criticality or consequences of failure

WWU support the use of criticality or consequence in the build up of risk models. WWU's experience is that defining the criticality is complex and currently utilise the following factors:

- Security of supply;
- Safety;
- Financial;
- Environmental

WWU have not utilised reputation as a consequence factor.

It should be noted that WWU would expect to utilise risk models to justify the main elements of investment and will model the affect on outputs of that investment. We would draw your attention to table 9.1 which confirms that we should have suitable data for the areas listed above.

(4) the development of replacement priorities/risk metrics

We are currently working through the development of Risk priorities and matrices and will continue to work through the detail within the output workgroup.

We note the proposed definitions and development of “Health and criticality” indices. We suggest the models illustrated appear over simplistic and WWU’s experience is that this will cause difficulty in assessing investment priorities across asset groups. We note the reference to the National Grid Gas – National Transmission System (NGG-NTS) risk indices, but feel this will not enable the comparison we aspire to.

WWU also note in table 9.5 a weighting against low probability, high consequence events. This does not appear to meet the requirements of a high hazard industry and would conflict with previous experience and recommendations relating to incidents such as the Piper Alpha explosion or Maryhill LPG incident.

In addition, WWU does not consider that the principle of risk trade off between asset groups would satisfy the current civil and criminal legislative regime. HSE view in this regard was recently clarified:

‘However, we have made it clear to Ofgem that HSE's legislation necessitates that the requirement of each and every regulation is addressed to achieve compliance to a standard of 'so far as is reasonably practicable' or 'so far as is practicable' depending on the regulation. So, whilst a 'holistic' asset risk register should allow the GDNs to better identify and address the key issues present (and emerging) on their networks it will not, in our view, justify a cherry-picking approach that addresses only the highest asset risks whilst leaving lower or emerging asset risks unattended.’

Jim Stancliffe (HM Principal Inspector, HSE), 11 January 2011.

We will provide a more detailed update on our thoughts, progress and challenges when we respond to Stuart Cook’s letter[4].

Question 2: Do you have any views our proposed approach for the revenue driver associated with repex?

The current programme, which was initiated by the Health and Safety Executive, is there to replace, deteriorating Iron Mains within thirty metres of properties over a thirty year period with polyethylene pipes. Iron Mains have a propensity to fracture and release gas into buildings which then give rise to potential gas explosions.

We are committed to working with HSE, Ofgem and the other networks and our evidence suggests:

- Total WWU fracture numbers remaining steady – despite the current pace of replacement
- Fractures as a percentage of remaining iron population are actually increasing
- Proximity to iron pipes increases risk
- We also believe that modelling all the relevant factors involved actually gives a strong case for increasing the speed of the replacement programme.

[4] Gas Networks have received a request from Ofgem on their current Asset Management modelling capability to support RIIO. Responses are due back to Ofgem 14th February 2011

It is our intention to continue to remove this risk to consumers at the most reasonably practicable level.

As part of our stakeholder engagement it is clear that consumers are not fully aware of this risk but there is early recognition from them to address this risk as a priority.

We believe a move from a revenue driver based on Mains Decommissioned to one based on risk should only be progressed after a full review of the potential impact. It is unclear at this moment in time how risk can be translated into revenue without tangible workloads. We will continue to work with the industry workgroup in this area.

In addition, the move to a risk based revenue driver may lead to undesirable behaviour which would fail to gain the full benefits of the programme and lead to short term decisions which will disadvantage consumers over the long run.

Question 3: Do you have any views on our proposed uncertainty mechanisms associated with the repex review?

We are fully engaged with the HSE /Ofgem review of the Iron mains 30/30 programme. If there are significant changes to the programme we would need to review our business plan. The business plan is outputs led which drives the investment proposed. The replacement of the Iron Mains has material impacts on several output workgroups and change would require a significant review of the business plan investment, costs and revenues. Therefore we agree a significant change could alter the RIIO GD1 timelines. Due to material impact of the Iron Mains programme any mid point review would also require significant consultation.

APPENDIX 3: WWU response to RIIO GD1 Tools for cost assessment supplementary annex

We set out our response to the December Consultation Document Supplementary Annex "RIIO-GD1 Tools for cost assessment" ("the cost assessment paper") as below, broken out into three sections.

Firstly our general comments on the cost assessment paper, secondly our comments on the Rune report published with the December Consultation Document and thirdly our responses to the specific questions asked in the cost assessment paper.

A. WWU's general observations on the cost assessment paper are:-

1. The use of regression analysis

We note that Ofgem has concentrated on using regression as a tool for comparing the costs of certain activities between GDNs. We remain concerned that due to the limited number of independent data points (eight GDNs in four ownership groups) the results of the regression analysis may have limited benefit.

We also note that the regression analysis undertaken by Ofgem as part of GDPCR1 resulted in a significantly different result to the top down analysis which they also undertook. This lead to Ofgem increasing Opex allowances to compensate.

The regression undertaken so far on the results reported by the GDNs for 2008/9 and 2009/10 has produced mixed results, with some of the regression analysis undertaken giving low R^2 results. We also question the functional form estimated and the fact that some of the residuals in the regression show patterns that suggest that the equation may be mis-specified. This calls into question the regression drivers being used and the consistency of the data submissions between GDNs. Whilst the GDNs and Ofgem are currently striving to improve the consistency of data submissions, the question of the appropriateness of the regression drivers remains.

We note that the regressions take logs of both dependent and independent variables and question whether this is the correct approach and whether consideration should be given to alternative functional forms.

We also note that Ofgem has not adjusted the base data included within the emergency and total regression tables for the non-labour regional factors awarded to four of the eight GDNs at the setting of the current price control. Ofgem has however adjusted for the labour regional factors in arriving at these regression tables. Accordingly we believe that the regression analysis, as presented, is misleading.

Whilst we acknowledge that regression analysis is a useful tool, we would consider that it should be used only once the data has been validated, adjusted for regional factors and the correct "drivers" applied.

2. Consistency of GDN data submission

Whilst significant progress has been made in ensuring consistency of data submission between the GDNs there are still areas where the guidance notes for completing the Regulatory Reporting Packs ("RRPs") each year are open to interpretation. The GDNs and Ofgem are striving to improve consistency and have met on a regular basis over the period since the 2008/9 and 2009/10 RRP visits to improve consistency. However, these meetings and the current results produced by Ofgem demonstrate that there is still a degree of inconsistency which is impacting on the regression analysis being undertaken by Ofgem.

3. Totex and regression drivers

Ofgem is intending to benchmark Totex. Totex is intended to be the sum of Operating expenditure + Replacement expenditure and Capital expenditure. We have significant concerns that achieving appropriate regression analysis/benchmarking of Totex will be very difficult, especially given the issues currently being experienced with performing regression analysis over individual areas of spend. We are concerned that the appropriate regression drivers for Totex may not be properly identified and that such drivers will not adequately take account of differences between networks, such as geographic spread/separation and sparcity. We are also concerned with how Totex is derived; the current intention is to sum Opex, Repex and Capex. However, the "lumpy" nature of Repex and Capex spend has the ability to significantly distort any analysis work.

4. GDN obligation to maintain the network

GDNs have an absolute duty to maintain the network and are obliged under their respective licences to ensure that this happens. Accordingly the GDNs and Ofgem should ensure that they are resourced to achieve this. Consequently, annual movements in the level of activity undertaken by the GDNs are unlikely to significantly impact on the costs incurred by the GDNs.

An example would be the Emergency service, where, irrespective of the level of activity, the GDNs are obligated to ensure that they attend escapes within guaranteed standards (either one or two hour) in 97% of cases. Thus, First Call Operatives are required to be on standby to achieve these standards irrespective of how frequently they are actually "called out".

Obviously in extreme circumstances, such as the last two winters, the level of cost is likely to increase, with additional costs (such as overtime and the use of reservists) being incurred to deal with such high peaks in activity.

5. Asset health

A significant amount of Capex spend is aimed at maintaining the current condition, or asset health of the gas distribution network, rather than dealing with growth of that network. This spend therefore prevents future increases in Opex (especially maintenance) as a result of deterioration of the network. It is therefore not expected to reduce current Opex levels; indeed the requirements from manufacturers to maintain these new assets in order to comply with guarantees and warranties may result in increased Opex in the short to medium term.

6. Indirect costs

Irrespective of the industry within which a business operates, there is a minimal back office cost of being in business. This covers the cost of the base level of operation. Where a company operates in more than one geography the cost of supporting those geographically diverse operations is incremental, rather than being a straight multiplier of the cost of operating in one geography. Therefore the cost of operating multiple GDNs should be an incremental increase to the cost of operating one GDN. In your review of business support costs, Ofgem will need to consider this impact in your proposed approach of benchmarking by ownership group rather than licensee.

We note that you intend appointing consultants to review Property Management costs. Ofgem need to be clear that GDN costs are likely to be different dependant on the own/rent decisions which those GDN's have made historically, thus the "Totex" cost of property needs to be considered, rather than just the Opex cost as part of the consultants work.

7. Efficiency improvements

We are concerned that Ofgem may be attempting to benchmark GDNs against an efficiency target as derived from their regression analysis and then to apply an additional efficiency challenge by looking at efficiency improvements achieved in other sectors of the economy (section 3.11). It is important to ensure that such an approach doesn't result in a "doubling" of any efficiency challenge and consequently result in insufficient allowances for cost being given.

We are also concerned that Ofgem are expecting future benefits of sale to exist in RIIO-GD1, which are in addition to the "normal" efficiency improvements (section 3.13). WWU is strongly of the opinion that such benefits are already being realised within GDPCR1.

8. Loss of meterwork incentive

WWU is committed to finding in-fill work which its Emergency First Call Operatives are able to undertake whilst on call but not attending a gas escape. To this end, WWU has recently retained its non-formula metering work with National Grid metering under both the domestic and commercial/industrial contracts.

However, it is likely that domestic work volumes will reduce over the life of the contract partly as the result of the introduction of smart metering. Whilst WWU will take the appropriate steps to ensure that the resultant cost increase to the regulated emergency business is minimised, there is expected to be an increase. This is because, due to the large geographic area and the requirement to respond to a PRE within one hour, a level of resource is required regardless of the amount of work undertaken, so the reduced meterwork does not link to equivalent reduced manpower as non-productive waiting time will increase. Therefore it will be necessary for the loss of meterwork incentive to continue into the next price control.

9. Repex costs

We understand that WWU has a different delivery model to the other GDNs for Repex work. This delivery model is based on WWU paying the actual cost (not a "schedule of rates") for that work compared to a target discounted matrix value.

Charges received by a GDN under a "schedule of rates" approach perpetuates any current incorrect allocation of allowances by diameter band within the matrix as such historic schedules of rates are unlikely to accurately reflect the underlying costs of performing the work at each diameter band currently.

WWU also consider that splitting repex costs between mains & services is artificial as the work is generally done by same teams and any split is an allocation, rather than an accurate costing.

We note that Ofgem are considering rewarding Repex activity under the condition and policy programme by reference to the amount of risk removed from the network rather than the length of mains decommissioned (and associated number of services relayed or transferred) as under the current price control. We are not confident that this approach is appropriate as risk is dynamic throughout the control period and the amount of risk removed by different networks may be different dependant on where each are on their risk curve and the slope of that curve. Whilst we have reservations with this approach, we are working with Ofgem to identify if it is appropriate.

Errors in the cost assessment paper

We have identified a number of possible errors in the paper. These are set out below:-

- 5.41, WWU's understanding at the time of accepting GDPCR1 was that the TMA reopener introduced as part of that price control is applied in respect of increases in NRSWA and TMA Costs through the life of GDPCR1, not just the increase in TMA Costs. This is because the introduction of TMA has led to Section 74 legislation, overrun charges, being enforced in Wales, which previous to TMA had not been enforced. Therefore WWU is suffering increased NRSWA Costs as a result of the introduction of TMA which should be considered as part of the TMA reopener.
- 8.12 is wrong:- Purge & relight is an incidental activity to mains & services replacement activity. This activity is allowed as part of the matrix services work or as part of the fixed allowance for service relays following escape or meter work.
- 8.17 ~ 8.20 Ofgem state that where allowances were given in GDPCR1 for LTS Repex projects that have subsequently been identified as not required during the life of GDPCR1, that allowances will not be given in future price controls if those projects are subsequently completed. This is incorrect. Whilst allowances for these projects have been given under GDPCR1, the true up of RAV at the end of GDPCR1, would mean that underspend from the deferral of such projects would be removed from RAV. Whilst the GDNs would benefit from the IQI benefit of such underspend, the consumer would also benefit from RAV being lower than it would otherwise be at the start of the next price control review period.

B. <u>WWU's general observations on the Rune report are:-</u>

We welcomed the publication of the Rune report and welcome the opportunity to provide feedback.

In its Executive Summary, Rune note that SGN and NGG are of the view that spend in some areas of Capex and Repex in excess of the allowance can be offset by spend in other areas below the allowance when looking at overall RAV additions. WWU is also of this view and that this was a fundamental part of the basis upon which the GDPCR1 Final Proposals were accepted.

Whilst Rune has provided a table on page 6 of its December report setting out its subjective view on the quality & clarity of the various GDNs submissions, responses and presentations as part of the 2008/9 and 2009/10 RRP process it has not indicated what the perceived deficiencies were or how it would see these being improved. As Ofgem & Rune are the only parties to have attended all the RRP visits, it is not possible for the GDNs to identify how they can improve their submissions to Ofgem and their consultants.

On page 8 of their report, Rune identify the variability in work management costs. Given the reported inconsistency in data for work management and the low R^2 (0.4 in 2007/8, 0.7 in 2008/9 and 0.8 in 2009/10) achieved by the regression analysis in this area it is clearly difficult to assess relative performance between GDNs.

On Page 9 of their report, Rune state that in Emergency "performance has deteriorated in 2009/10". We argue that performance has not deteriorated, guaranteed standards were once again achieved and WWU consistently achieves top or top quartile positions in customer surveys. The current regression analysis would indicate the WWU's costs have increased relative to some other GDNs, however the GDN/Ofgem regression review work undertaken as part of the costs and outputs group has identified that there is inconsistency in the way GDNs are reporting the underlying Emergency workload. It is therefore currently not possible to state performance has deteriorated without regard to the outputs achieved.

WALES&WEST UTILITIES

In section 6.4.3.1, Rune make reference to the increased costs of governors between 2008/9 and 2009/10. We discussed this during the October 2010 RRP visit by Ofgem and their consultant and also made clear in the commentary submitted with the RRP in July 2010 the reasons for the increase.

<u>Detailed responses to the questions in the cost assessment paper</u>

<u>Chapter 2: Overall approach to cost assessment</u>

Question 1: Do you agree with our approach for assessing companies' business plans?

We refer you to our comments in section A above.

The results of the regression analysis should be treated with caution given the statistically limited number of available data points (four ownership groups of a total of eight GDNs) and the large variations in resultant R^2. With limited data points even regression analysis which results in a high R^2 could be questionable.

It is worth noting that inconsistencies in reporting of historic actual results between GDNs are likely to be replicated in their business plan submissions. This inconsistency, may result in errors in the regression analysis undertaken by Ofgem and their consultants.

We note that in some cases, to achieve the efficiency frontier, GDNs are required to remove in excess of 30% of their costs in that area. This would appear to be an indicator that the regression results are incorrect rather than the GDN is "inefficient" to that degree.

Whilst regression is not perfect, provided it is used only as a "directional tool" with other techniques (including a top down view) then it is appropriate to consider the results it provides. A Top down approach also required.

Ofgem and their consultants need to consider the "cost of being in the game" the base cost of operating a GDN and then the incremental costs for operating additional GDNs in the same ownership group.

Question 2: Have we proposed the optimum range of techniques (A) Are there better techniques that we have not included? (B) Are we applying the appropriate techniques in the appropriate areas?

See our response to question 1 above.

WWU is aware of the limited suit of appropriate techniques available to Ofgem and their consultants. However, given the difficulties involved with this type of modelling and the advantages & disadvantages that different approaches have, we consider the use of a broad a "tool kit" to cost assessment is appropriate. Approaches should not be discounted until they have been populated with real data and their limitations tested. Focusing from the start on an ordinary least square approach does not achieve this.

Chapter 3: Input price inflation and ongoing efficiency

Question 1: Are there any additional analytical techniques that we should consider beyond those that we have used at past price control reviews to assess these factors?

Please see our response to Q2 of Chapter 2 above.

WWU is strongly of the view that efficiency from network sale has been achieved during GDPCR1, and that the lemon is squeezed, with no future benefits from network sale being achievable.

Question 2: Are there any additional data sources that we should be aware of to assist with our analysis in these areas? In particular, are there specialist labour indices that would be relevant for the gas distribution sector?

Ofgem should be considering real price factors for:-

- Labour costs (direct and contractor),
- Reinstatement (aggregate & macadam),
- Materials (steel and PE),
- Fuel
- Utility bills
- Use Baxter index for Labour & materials

The impact of TMA on NRSWA, especially in Wales needs to be built into the allowances, or remain within the uncertainty mechanisms. The impact of TMA likely to still be uncertain for RIIO-GD1, thus a re-opener/uncertainty mechanism is required.

Question 3: Of the data sources presented in this chapter, are there some that you think we should rely more on than others?

WWU would consider that those indexes which are closely relate to the utility sector are more appropriate than those that are less related, and those that are UK related are more appropriate than overseas sources.

Chapter 4: Totex

Question 1: Do you agree with our approach for assessing companies' business plans?

We are concerned that given the difficulty in identifying the appropriate regression drivers for individual areas of spend, identifying the regression drivers for Totex may prove impossible.

Question 2: Are our tools and techniques adequate for assessing the GDNs expenditure plans?

Please refer to our comments above on regression.

Chapter 5: Direct Opex

Question 1: Do you agree with our approach for assessing opex in the companies' business plans?

Please refer to our comments above. It is our view that we should continue with GDPCR1 approach of setting allowances off the second best performer

Question 2: Are our tools and techniques adequate for assessing the GDNs opex expenditure plans?

Please refer to our comments above and in section "A.1-The use of regression analysis".

Chapter 6: Indirect opex/business support costs

Question 1: Are there any comments on the proposed assessment for business support costs?

Please refer to our comments above.

Question 2: Are the cost drivers proposed the most appropriate ones?

See comments above

Chapter 7: Capital expenditure

Question 1: Do you agree with our approach for assessing capex in the companies' business plans?

We will evidence the cost required to deliver the Outputs we include in our business plan submission. We are supportive of a regime that takes into account the longer term and one where there is a more "holistic review" of costs. As stated earlier we think the use of regressions should be limited, especially where Capital spend is by very nature is irregular.

Question 2: Are our tools and techniques adequate for assessing the GDNs' capex expenditure plans?

It may be appropriate to link LTS & storage growth capex to demand forecasting but this would mean identifying the incremental demand increase that leads to the requirement to invest, which is likely to be different between networks.

Chapter 8: Replacement expenditure

Question 1: Do you agree with our approach for assessing repex in the companies' business plans?

See our comments in section A. There is difficulty in accurately separating the real mains & services costs. Is it therefore more appropriate to give a combined allowance per meter laid or abandoned?

Cost is based on mains laid not abandoned so moving to an allowance based on lay should better match cost. However, Ofgem are looking to link the incentive to the risk removed from the network, which is unlikely to have a linear relationship to the cost of achieving that risk reduction. In addition, the risk reduction and therefore the resultant allowances by network may be significantly different.

The allowances for Service relay following Emergency & Meterwork are both too low in current control, this requires addressing in next control.

LTS spend deferral ~ Disallowing spend in next control that has been allowed in current control is not the right approach. Price controls are accepted in the round with GDNs expecting to outperform in some areas and under perform in others. Part of the outperformance is finding alternative solutions, inc work deferral where justified, the resultant underspend offset overspends elsewhere. But if further expenditure is required in subsequent controls, then this should be allowed for in those controls ~ otherwise there is asymmetric treatment and this defeats the idea of the IQI.

Question 2: Are our tools and techniques adequate for assessing the GDNs repex expenditure plans?

See our comments in section A. We need to ensure consistency of reporting to improve benchmarking.

Question 3: In light of our proposals, do you agree with our selection of risk removed as the primary output of the mains replacement programme?

See our comments in section A. Each GDN will be at a different point on the risk curve, so it may be difficult to reconcile this.

Risk is dynamic & will change through the life of RIIO-GD1 based on asset performance. This will lead to difficulty in setting output measures on risk resolution at the start of the price control period.

It is expected that the cost of risk removed will be different depending on the pipe size, location etc. We do not currently understand how will this be addressed.

WWU are committed to discussing with Ofgem their detailed proposals in this area and how they can be applied in practice.

APPENDIX 4: WWU response to RIIO T1 and GD1 business plans, innovation and efficiency incentives supplementary annex

CHAPTER: Two

Question 1: Do you have comments on the description of the form and structure of the price control?

We welcome the early engagement on the next price control review which does not take effect until April 2013. This is the first opportunity to test and implement the RIIO principles and we are already heavily engaged in various work streams to try to deliver an initial, well justified business plan back to Ofgem by July of this year. It is already clear that the timescales are achievable but tight to deliver a well justified business plan back to Ofgem by July this year.

The process is challenging as we are developing a significantly different regulatory regime which consists of many new elements. As a summary we are currently:

- Involved in six output workgroups to develop a new outputs led regime;
- Participating in the HSE review of the Iron Mains Replacement 30/30 programme;
- Consulting with stakeholders to support a well justified business plan;
- Developing the detailed application of the RIIO principles into practical policies for the first time; and
- Developing a well justified business plan for July this year.

As stated earlier we are fully supportive of many of the principles but it is clear this first application of the principles is very resource intensive for the networks.

In summary, our early experience of RIIO is that there is a requirement for Networks to support several key work streams very early in the process to allow the remaining timetable to be achieved.

Question 2: Is the scope of the price control including the range of services excluded appropriate?

Most of the key challenges are identified within the scope of the review but unlike electricity distribution, the gas distribution licence still contains an obligation to be a "Meter Provider of last resort" (MPOLR) and we note it is recommended to omit the obligation; and the review of the price caps from the review.

It is our view that:

- The obligation is redundant as metering has been a competitive activity within the UK for a number of years and
- The price caps are not reflective of the costs incurred.

We think it is appropriate to include this onerous obligation within the scope of the review and would hope to update the licence obligation to reflect the competitive nature of metering. We have, so far, stopped short of requesting derogation in this area but the cost impact on WWU is significant and a continuation of the existing regime will place a non compensated cost to; and hence additional risk to our business.

Question 3: What are the appropriate criteria for assessing whether a proposed change to the revenue profiling is appropriate?

We generally support the principle of setting base revenues each year consistent with the expected path of expenditure requirements. A change in revenue profiling may arise if there an unacceptable funding gap for networks or a potential significant, material "spike" impact to consumers. Therefore the criteria should have regard to these two factors. If revenue profiling is required, there should also be a review of risk faced by networks and consequently a potential change to the equity return.

CHAPTER: Three

Question 1: Are you content with the degree of guidance we are providing on a well-justified business plan? Is there additional guidance you would value?

This is the first time that a well justified business plan is delivered but we think there has been adequate guidance through the RPI-X@20 review process, the recent Ofgem open letter and this consultation. It would be helpful to have early visibility of the cost templates and financial model required in support of the well justified business plan.

Question 2: Do you have comments on the use of ten years as the basis for forecast data? What level of detail should additional five years data to place this forecast into context be? Where might a longer period be appropriate? Are there cases where ten years would be problematic? If so what alternative approach might we follow?

The network has key obligations to deliver a wide range of services and outputs over the short, medium and long term. Some outputs require investment in long term assets and others have little reliance on long term asset investment (the emergency service). Therefore the level of detail and the appropriate period for appraisal will vary dependant on the output in question. Forecasting beyond ten years could be of little value as beyond this period there is so much political, economical and technological uncertainty that the robustness would be questionable. Therefore a ten year forecast would appear appropriate.

Question 3: Do you support the basis of our initial sweep assessment?

The networks will provide well justified business plans back to Ofgem during July this year. We think the four stage process outlined, with an initial sweep between July and December, is reasonable.

Question 4: What should be included in our assessment of past performance at these first reviews?

We would hope that Ofgem takes into account all relevant performance for networks; this may not be limited to but include:

- Safety record
- Customer performance
- Track record in meeting licence obligations
- Performance against standards
- Information gained through the annual RRP visits
- Track record of reducing costs

Question 5: Do you have comments on the proportionate treatment process?

We are generally supportive of the proposals to utilise a proportionate approach. We have not been through the process yet but the principle is reasonable and could reduce some unnecessary administration.

Question 6: Do you have comments on our assessment criteria?

As stated in our response to the "tools for cost assessment" we are supportive of a more holistic approach to assessment. We are generally supportive of the criteria outlined within the documentation to assess the business plans.

Question 7: Do you support the way we propose to apply fast-tracking?

We are supportive of the fast track process and we hope to demonstrate the characteristics of a fast track company. It would be very important to ensure that a fast tracked company is penalised in the light of new information. Therefore we would support the option to allow adjustments after a fast track settlement during the period February 2012 to December 2012.

Question 8: For RIIO-GD1, do you have views on the additional reward reflecting their relative superiority over comparators. Which of the options for implementing the reward do you prefer and why?

The principle of rewarding a fast tracked company is appealing but the practicality may be a little more complex. The option to reward a fast tracked company by giving that company an extra cash allowance based on a percentage of saving generated through benchmarking analysis does not appeal to us. We have clearly identified many issues with the use of benchmarking for cost comparisons and by extending the use of benchmarking for this purpose to reward some networks would not stand up to robust external scrutiny. A simpler cash award would be easier to implement but the level of materiality would be key.

CHAPTER: Four

Question 1: Do you agree with our view that the case to develop the framework to enable third parties to compete to develop and own elements of the electricity transmission network is significant, and that we should work to develop this option as a priority? Do you foresee any areas of significant benefit or concern?

As a gas distribution network we do not have a view.

Question 2: Do you consider there is a case for introducing competition for development and ownership of gas transmission assets? What form this should take? Do you foresee any significant barriers to the development of a competitive regime? When would be the appropriate time to develop this option?

As a gas distribution network we do not have a view.

Question 3: In light of the role competition already plays in *gas distribution* do you feel there is a case for making further provisions to enable new entrants to develop and own parts of the network? If so, what form do you think these provisions should take?

As you state within the consultation documents, there is already a significant role played by third parties within the sector, for example Independent Gas Transporters (IGTs). There is also comparative regulation and many of the networks market test key activities and major contracts. It is not only difficult to see significant consumer benefit but it is quite easy to visualise additional safety risks and costs to consumers with the introduction of further mechanisms.

A key feature of RIIO is the provision of a well justified business plans, engaging with stakeholders and defining outputs that will shape investment decisions. One would hope this regime plus many additional controls deliver an appropriate outcome for consumers.

CHAPTER: Five

Question 1: Should the scope of the innovation stimulus be confined to projects which help deliver a low carbon future, or should the scope be wider to include long term network sustainability? Should there be a different scope to the innovation stimulus that applies to electricity and to gas?

We think innovation takes many forms and there is value in widening the scope in all sectors. Safety, reliability and commercial developments are as equally important to stakeholders as low carbon technologies and we think all innovation should be encouraged.

Question 2: Do you agree that the level of funding available under the innovation stimulus for each of electricity transmission and gas distribution and transmission should be within the ranges identified? Are there further arguments for different funding levels which we have not considered?

The arguments that support the level of indicative funding within the consultation are reasonable and at this time we no better information to provide a different range. Our only concern with a shared Gas Transmission and Distribution fund is that Transmission projects are generally bigger by nature and the fund may be swallowed up by Transmission at the expense of distribution. It may be appropriate to clearly define a split of the Gas stimulus between Transmission and Distribution.

Question 3: How should network companies be required to meet the costs of the innovation stimulus? Should this be through fast cash, slow cash or the standard expenditure capitalisation ratio?

As a relatively small Gas Distribution network to encourage use of the innovation fund we support your recommendations to meet the costs as they fall due on a fast basis. A mismatch of the funding to the expenditure will simply add risks for potential participants.

Question 4: Do you agree that we should provide a limited innovation allowance directly to each company? If so, do you have views on the form and scope and of this allowance, and on which mechanism would best incentivise efficient investment in innovation?

We generally support the continuation of the existing "Innovation Funding Incentive" (IFI) as a % adjustment to Allowed Revenues, in addition to the time limited stimulus. If the innovation stimulus is constrained to partially funded “large major bids” there is a real danger that smaller but equally important innovations will be lost within the sector.

Question 5: Do you agree that there should be a revenue adjustment mechanism to encourage innovation roll-out within the price control period? If so, do you agree with our views on the criteria for such an adjustment and how frequently should we allow companies to apply for this adjustment?

We generally support the continuation of the existing “Innovation Funding Incentive” (IFI) as a % adjustment to Allowed Revenues, in addition to the time limited stimulus. If the innovation stimulus is constrained to partially funded “large major bids” there is a real danger that smaller but equally important innovations will be lost within the sector.

Appropriate funding arrangements will be an important element of the innovation stimulus and given the future uncertainties, we think there is merit in maintaining as much flexibility within the funding profile as possible and companies should be able to apply for funding at least annually. We think that maintaining a constant maximum annual level of funding is preferable to a front loaded funding option

CHAPTER: Six

Question 1: Do you agree with our proposed approach to the implementation of the efficiency incentive rate? Do you have views on the intergenerational impact?

Regulatory certainty is a highly valued component to investors and the commitment to (a) a fixed symmetrical efficiency incentive rate and (b) not to making retrospective adjustments is welcomed.

The proposal to apply annual adjustments (with a two year lag) could introduce price volatility for shippers and consumers but we also recognise this mechanism could avoid large adjustments at the end/start of a new price control period.

Question 2: Do you agree with our proposed range for the efficiency incentive rate?

We would hope that the range applied reflects the current risk sharing between networks and consumers. The current risk sharing is within the 40% to 60% range.

Question 3: Do you agree with our proposed approach to the calibration of the IQI?

Calibration will not be a simple mechanistic activity for non fast tracked companies. The business plan costs are clearly linked to the defined outputs within the business plan. Therefore it may not be appropriate to refer a “first” forecast from the network against an Ofgem “last” forecast as the costs may be supporting different outputs. It is also unclear how a “lighter” touch company would be assessed. Is it impossible for a lighter touch company to have the maximum incentive rate?

Question 4: Do you agree with our proposals for the application of the RIIO approach to efficiency incentives to the areas of gas transmission expenditure that are currently covered by the suite of separate incentive schemes set at TPCR4?

We are not in a position to answer this question as a Gas Distribution network.

Question 5: Specifically, do you agree with our proposals to apply the same efficiency incentive rate, and to have no caps and collars? Do you have any views on the potential downsides and risks to consumers?

We are not in a position to answer this question as a Gas Distribution network.

Question 6: Do you have views on the scope for alignment between the TO and SO incentive schemes, including greater alignment than we have proposed?

We are not in a position to answer this question as a Gas Distribution network.

APPENDIX 5: WWU response to RIIO T1 and GD1 Uncertainty Mechanisms supplementary annex

CHAPTER: Two

Question 1: Are there any additional criteria that we should take into account to guide the appropriate use of uncertainty mechanisms?

We generally support the overarching principle of using uncertainty mechanisms and we also accept there is a level of operational risk that networks should manage. The level of risk that networks are exposed to should be reflected through the rate of equity return.

Question 2: Do you agree with the information requirements that we set out to support the justification of additional uncertainty mechanisms? If not, what changes should we make to these requirements?

The information requirements as set out appear reasonable and we do not have additional comments at this time.

CHAPTER: Three

Question 1: Do you think there should be a change to a 12-month average approach to RPI indexation of allowed revenues? If there were a change to a 12-month average approach, would there need to be any transitional adjustments?

We don't have a strong opinion on whether there should be a change to a twelve month average approach but we would prefer the use of a January to December period as opposed to an April to March period to allow a sufficient period to include actual data within transportation pricing notifications.

Question 2: Do you have any views on the design of the reopener for the introduction of Traffic Management Act permitting schemes? In particular, is the timing of the reopener window appropriate and what approach should we adopt to set the materiality threshold before it can be triggered? Do you agree with our proposal that the reopener would only apply in gas distribution?

There are future significant unknown costs associated with the Traffic Management Act. We think there is a strong case to ensure there is a broad re-opener. The impact and detail impacts are unknown and in our view the re-opener needs to have flexibility to reflect the high degree of uncertainty and not be constrained by detail definitions that may be non reflective of the actual impacts.

We think we should be able to access the re-opener during any year of the review period and not be constrained to a one off application at the mid period review. The impact over an eight year period could be significant to networks and if there was an exposure for any length of time, this should be reflected within the cost of equity.

Question 3: Do you have any views on the design of the mechanism for changes in the requirements required by the Centre for the Protection of National Infrastructure? As above, is the timing of the reopener window appropriate and what approach should we adopt to set the materiality threshold before it can be triggered?

If we have an indication from the Centre for Protection of National infrastructure of the sites in good time to allow inclusion before any final proposals, we would suggest that funding should be treated as any other potential investment. It should be funded on an ex ante basis. If there is no clear indication, then we would support a Re-opener mechanism but would not want to limit an application to a one off application at the mid point review. We have little indication of the materiality at this moment but any non-funding of material costs for a significant length of time should be reflected through the equity rate.

Question 4: Are there any additional mechanisms that we should be considering? If so, how should these be designed?

You will fully appreciate the unique dependence our system has on the availability and cost of National Transmission System (NTS) products and services. We are pleased to be working within the capacity outputs workgroup with the NTS and Ofgem to fully explore the potential improvements we can make as an industry.

Despite this, Ofgem must recognise that relatively minor changes to NTS products could have profound impacts for networks. The NTS products include Flat Capacity, Flex Capacity and System Pressures. There could be significant influences on the NTS during the period to 2021 outside of our control which could have significant, as yet unknown implications for the delivery outputs and costs within our business. As an indication if network "Flex" was removed there would be investment implication of over £50m. Therefore we think it is appropriate to consider a broad, flexible re-opener to reflect the unique potential uncertainties.

We would suggest a broad NTS re-opener that networks could access during any year of the price control period period.

Question 5: Do you agree with our proposal to leave the disapplication arrangements unchanged?

At this time, we have no additional information that would support a change to the existing regime.

Question 6: Do you have any views on the other mechanisms discussed in this chapter?

No other comments.

CHAPTER: Four

Question 1: Do you have any views on our proposed approach to managing uncertainty around connections volumes?

We aim to justify our volume forecasts within our business plan and therefore do not anticipate the requirement for a volume driver. Any changes from forecasts can be addressed through the IQI mechanism.

We would like to remind Ofgem that we have an obligation to provide a quotation service and regardless of the number of actual connections there is a level of fixed costs that requires funding.

Question 2: Do you agree with our proposal to remove the loss of meter work revenue driver? If not, why do you think retaining the mechanism is in the consumer interest?

No, we do not agree that we should remove the loss of meter work revenue driver. The emergency service is a core service provided by all networks and some networks have succeeded in maintaining competitive metering work within a highly competitive environment since network sales. Where networks have retained metering contracts, gas consumers benefit from the existing regime as they are not exposed to the costs of a standalone emergency service. The imminent start to the supplier led smart meter programme will increase the likelihood of meterwork reductions for networks at some point during the next price control review and it therefore appears appropriate to maintain a meter tipping adjustment mechanism. We think the benefits to the recipients of the regulated service coupled with a relatively simple adjustment mechanism are a reasonable solution. We welcome further discussions with you in this area and will provide our proposals within our business plan submission later this year.

Question 3: Are there any additional mechanisms that we should be considering? If so, how should these be designed?

You will fully appreciate the unique dependence our system has on the availability and cost of National Transmission System (NTS) products and services. We are pleased to be working within the capacity outputs workgroup with the NTS and Ofgem to fully explore the potential improvements we can make as an industry.

Despite this, Ofgem must recognise that relatively minor changes to NTS products could have profound impacts for networks. The NTS products include Flat Capacity, Flex Capacity and System Pressures. There could be significant influences on the NTS during the period to 2021 outside of our control which could have significant, as yet unknown implications for the delivery outputs and costs within our business. As an indication if network "Flex" was removed there would be investment implication of over £50m. Therefore we think it is appropriate to consider a broad, flexible re-opener to reflect the unique potential uncertainties.

We would suggest a broad NTS re-opener that networks could access during any year of the price control period.

Question 4: Do you agree with our proposal to leave the disapplication arrangements unchanged?

At this time, we have no additional information that would support a change to the existing regime.

Question 5: Do you have any views on the other mechanisms discussed in this chapter?

The other mechanisms discussed are:

- The mains replacement incentive and repex policy
- Reopener for change in the connection charging boundary

The mains replacement incentive and repex policy

Safety of our stakeholders is at the centre of our business and we welcome the scheduled HSE/Ofgem review of the Iron Mains 30:30 replacement programme. It is unclear at this moment in time how risk can be translated into revenue without tangible workloads. The current incentive is valued by stakeholders, measurable, controllable, auditable and comparable. We need to promote and retain incentives with these properties.

If there are significant changes proposed from the joint HSE /Ofgem review we would need to significantly review our business plan submission. If the timing results in changes during the price control review then there may be the requirement for transitional arrangements and a re-opener to address the significant impact.

Reopener for change in the connection charging boundary

We agree that if there is a material change in the charging boundary as a result of a change in Govt policy or some other external factor there should be a mechanism to pass through the efficient additional costs incurred by the networks. A re-opener mechanism could also achieve the same aim.

CHAPTER: Five

We have no comments on the Gas Transmission uncertainty mechanisms covered in chapter 5.

CHAPTER: Six

We have no comments on the electricity distribution uncertainty mechanisms covered in chapter 6

CHAPTER: Seven

Question 1: Do you agree with the scope of the mid-period review? If not, what changes to the scope are needed?

We agree that there is the potential for increased uncertainty under a longer price control period and hope this is recognised through the return on equity rate.

Whilst we understand the desire to keep the scope tight for a mid point review, in practice this may be difficult to achieve. A key principle of RIIO is the delivery of outputs that stakeholders value. Our business plan costs, revenues and risk profile of the settlement will be driven from the outputs and incentives we agree at the start of the price control period. A change to the outputs at a mid point review could have significant implications for network costs and risk profile. Therefore we are very cautious about a mid point review and we have concerns that a tightly scoped review –in practice will be possible.

Question 2: Do you agree with the indicative process and timetable? If not, how could the process and timetable be improved?

The timeline indicated by figure 7.1 outlines a 15 month review process. We think this represents a significant period of uncertainty for all stakeholders. The alternative to this is to retain a shorter price control review period.

Question 3: Do you have views on when we should make licence changes as a result of any actions taken at the mid-period review? If a threshold to make a licence change is seen as appropriate, what should this be?

We have stated above that a mid point review introduces significant uncertainty into the price control period. Ofgem outline two options to address potential licence changes. We would strongly support that option to draft the licence so that any changes that Ofgem wish to make at the mid point review would require a licence modification. (Option1). To draft the licence now to allow future changes at the mid point review will add significant risk to networks.

The assessment of a threshold will be difficult to calibrate because the impact of the change may not be completely transparent at the time and there may be differences in opinion between parties over the materiality of the actual impacts.

APPENDIX 6: WWU response to RIIO T1 and GD1 Financial Issues supplementary annex

Chapter: Two

Question 1: Do you agree with our proposed economic asset lives for gas and electricity transmission and gas distribution?

We recognise that there is some uncertainty regarding the ultimate economic life of gas asset but note that all credible forecast models currently anticipate significant use of gas until 2050 so agree that the current assumption of a weighted average economic life of 45 years should continue. Maintaining this approach supports Regulatory Certainty.

Question 2: Do you agree with our proposals for the depreciation profile?

The depreciation profile should be set based on an assessment of when the stakeholder benefits of expenditure accrue – safety and environmental benefit could justify something other than "simple" straight line, but it seems premature to justify accelerated depreciation on grounds of economic useful life of gas as all credible scenarios show gas networks being in use for at least the next 40 years. There will be more clarity regarding industry developments in 2021.

Question 3: We invite views on our proposed approach to transition.

We agree that the depreciation profile or economic asset life should not change for assets currently in RAV, as a change is not justified and reduces Regulatory Certainty. If it were concluded that depreciation profile should change then transition arrangements should be sufficient to assure all stakeholders that Regulatory Certainty is not reduced.

There is clearly a need to assess the impact on financeability impact of any change in depreciation profile. We note that the Post Maintenance Interest Cover Ratio (PMICR), a key financeability metric utilised by Credit Rating Agencies and incorporated into the debt covenants of many networks, is unaffected by changes in depreciation profile. PMICR is primarily affected by gearing, the actual cost of debt compared with that assumed in WACC, and the assumed cost of equity. A failure in financeability tests is most likely due to underestimate of cost of equity for a given notional gearing.

CHAPTER: Three

Question 1: Is our approach for setting the allowed return appropriate, particularly in the context of an eight-year price control?

This is the first time that Ofgem have attempted to implement the RIIO principles and stated that they will be informed by each Network's business plan in considering the appropriate allowed return. It is currently unclear how this fundamental change in methodology will work in practice.

A key consideration is that without absolute clarity regarding the components of allowed income throughout the whole of the Price Control period, including the potential for adjustments at Year 4, it will be difficult for Network management to assess the acceptability of the Final Proposals.

We comment on Cost of Equity, Cost of Debt and Gearing elsewhere. We do not believe that an 8 year price control has demonstrated to be "better regulation", but it is clear that an 8 year control requires appropriate uncertainty mechanisms which are still being developed.

There is a need for clarity regarding the scope and possible outcomes of the 4 year review – both to prevent the Price control degenerating into two 4 year Price Controls and provide Regulatory Certainty regarding the risk to networks of an asymmetric approach.

Incentives should be designed to be just that; not mechanisms to compensate otherwise inadequate allowed return.

We continue to be concerned that RORE will be used as a mechanism for setting WACC, particularly Ke, rather than a tool to assess the overall "fairness" of the settlement. We believe it is possible that discretionary incentives which investors and credit rating agencies cannot have assurance will be earned will be used to justify otherwise un-financeable proposals.

Question 2: What impact do our proposals for RIIO-T1 and GD1 have on the companies' cashflow risk, and does this have a material impact on how the allowed return should be set?

The themes of the consultation document; deferral of cashflows, lengthening of price control with as yet undefined uncertainty mechanisms and a greater role for incentives to reward and penalise companies relative to outputs that can change at a 4 year interim review all indicate increased cash flow risk.

Areas where RIIO-G1 increases equity risk include:

- 8 year control, which requires a more accurate assessment of "efficient" cost targets
- uncertainty mechanisms only under defined criteria
- Change in financeability tests – looking at medium and long term and requiring equity to manage issues that arise
- Debt indexation
- Deferral of cash flows (eg Repex100% into RAV) which is not NPV neutral
- More emphasis on an Outputs and incentive regime
- Pensions costs – ongoing costs subject to benchmarking and consequently possibly not funded by consumers
- Removal of IQI "upside" for forecast "accuracy"
- Real Price Effect assumptions included in efficiency assessments (RPEs are not controllable and not a measure of efficiency)

We are concerned that this increased risk is inconsistent with Ofgem's proposals for the range of cost of equity, where the higher end of the range is lower than the current cost of Equity for the 2008-13 Price Control.

Deferral of cashflows, through treating replacement expenditure as a 100% RAV'able expense, increases Cost of Equity due to an increase in investor's perception of Regulatory Risk. This "real life" effect is supported by academic analysis performed by Oxera which draws on the work of Brennan & Xia and others.

The Outputs and incentives regime must be properly calibrated to ensure appropriate sharing of risk and incentives between consumers and providers of debt and equity. We continue to believe that incentive mechanisms should be based upon outputs that have the following key characteristics;

1. Controllable
2. Measurable

3. Recognised by stakeholders as valuable
4. Demonstrable relationship between cost of delivery and societal benefit of output

The major incentive will continue to be the IQI - so over a longer price control period it is even more important that the cost assessment process is robust, and delivers appropriate incentive targets.

It is in the interests of all stakeholders for there to be real opportunity to outperform. Incentives should reward improved performance - and not penalise improving performance (absolute vs relative).

The incentives regime should be:

- symmetrical
- reward improved performance - and not penalise absolute improving performance that falls short of peers
- not be biased towards penalties rather than reward

We are concerned that the low number of incentives that meet these criteria and the ability of companies to significantly out-perform under related incentive payment mechanisms will mean that Ofgem's stated intention of enabling "good" companies to achieve high RORE will not be achieved.

Question 3: What considerations do we need to take into account when setting the notional gearing level?

Notional gearing, and allowed income arising from the notional gearing assumption should be tested against credit rating agency Debt/RAV and interest cover ratio metrics such that "comfortable investment grade" (A/BBB+) can be met throughout the price control period when "downside" sensitivities, including the absence of incentive income, are applied.

Question 4: Is our proposed approach to setting the notional equity wedge appropriate?

The approach to setting the equity wedge appears undeveloped. It seems the equity wedge will primarily be a function of the gearing assumption.

WACC calculations need to allow for cost of equity to rise under CAPM as gearing increases.

Question 5: Is our proposed mechanism for indexing the cost of debt assumption appropriate?

There are a significant number of practical issues that will need to be addressed in designing an index which reflects funding costs incurred by networks that are not part of an observable index, and also the "basis" differences between any observable nominal index and the real cost of debt for a notionally geared network which currently forms a basis for network's WACC.

We note that there are significant issues in respect of the chosen Bloomberg index, which we have outlined in our response to question 4 in chapter 8.

As noted above several leading banks have told us that it will not be possible to hedge through financial derivatives against the debt index currently proposed. The only way to attempt to match the index is to issue debt in accordance with the index profile (ie 1/10th of debt requirements each year). This is inconsistent with prudent treasury practice, credit rating agency expectations, and debt covenant requirements to pre-fund anticipated expenditure through debt or bank facilities.

Question 6: How should we account for the costs of issuing debt?

All costs of raising and maintaining debt should be recognised in assessing overall cost of debt. ENA have engaged third parties to report objectively on the cost of debt raising and maintenance.

We note comments in the consultation that the historic value difference between "corporate" and "utility" index can be seen as a long term allowance for debt issuance costs. This comment does not reflect the uncertainty that this relationship is merely historic accident and will not continue in the future – particularly if future events adversely impact utility yields. We have given further detail on the type of costs to be considered, which are discussed in our response to question 4 in chapter 8.

Question 7: Is our range for the equity beta appropriate for the network companies? What factors might mean that we should use different equity betas for the different sectors and/or companies within a sector?

Equity betas are extremely difficult to estimate given the small number (2) of quoted network companies. Even these companies have other significant operations which mean that they are not comparable to a "pure-play" network. The key test as to whether equity Betas are appropriate is the financeability test over throughout the Price Control period discussed above. A failure to meet this financeability test would indicate that WACC and possibly Beta's have been incorrectly estimated.

Question 8: Does our overall range for the cost of equity correctly capture probable risk for RIIO-T1 and GD1?

Cost of equity estimates do not reflect risk inherent in detailed application of RIIO principles. Returns to equity should be sufficient to ensure financeability, augmented by an incentive regime that appropriately rewards equity for delivery of outputs. We are concerned that Ofgem as currently structured will not have the ability to ensure that this is the case over a full (4 year plus 4 year) price control period and consequently would need to carefully assess the mechanisms for agreeing any adjustments to the control at year 4 this when deciding whether to accept the Final Proposals or to seek referral to the Competition Commission.

Detailed application of the RIIO principles have the potential to increase equity risk compared with GDPCR1.

- Changing the financeability test
- Deferring cash flows
- Extending price control period with unproven, and potentially inadequate uncertainty mechanisms
- Introducing cost of debt indexation
- Risk of asymmetric incentive mechanisms
- Increasing risk on changes in ongoing defined benefit pension costs

Consequently, it is difficult to understand why the high end of Cost of Equity range currently proposed by Ofgem is below that applied for GDPCR1. The range is inconsistent with the need to attract and retain equity funding of key UK infrastructure.

Question 9: Is the ex ante approach to the cost of raising equity, with a true-up at the next price control review appropriate for RIIO-T1 and GD1?

A "true up" aims for the cost of raising equity to be a "pass through" to consumers. We would like to understand the benefits of consumers bearing this risk, rather than continue the previous approach where it has been considered more appropriate for the risk to lie with investors (subject to appropriate allowances).

CHAPTER: Five

Question 1: Do you agree with modelling tax based on the proposals in the June 2010 Budget?

Modelling should be based on the most recent tax legislation outlined in the most recent budget. The June 2010 budget will have been superseded by the time it is expected Final Proposals will be published. If one or more networks are "fast-tracked" then mechanisms should be put in place to ensure that these networks are not disadvantaged by changes in tax methodologies prior to Final Proposals.

Question 2: Do you agree with modelling tax under UK GAAP pending adoption of IFRS reporting with any changes to be subject to the tax trigger?

We agree, provided

1. the "dead band" is small, as all parties agree that this assumption is extremely unlikely to be applicable for the duration of the Price Control Period.
2. Financeability is assessed by reference to credit rating agency metrics calculated under IFRS reporting, as it is extremely unlikely that credit rating agencies will assess a business that is reporting under IFRS using obsolete GAAP.

Question 3: Views are invited on the size of the dead-band?

As above, the dead-band should be no more than 1% effective tax rate. Any tax effect of a change to IFRS accounting for replacement expenditure should be recognised in full (i.e. not be subject to a dead-band).

Question 4: Do you agree that clawback of the tax benefit of excess gearing in TPCR4 and GDPCR1 should be spread over the 8 years of the RIIO price control? If not, which alternative option do you prefer?

For reasons of regulatory consistency the period should be five years.

Question 5: Do you agree that clawback of the tax benefit of excess gearing should be updated every three years during the price control period?

Further clarification is needed to understand why 3 years is an appropriate period to consider the tax benefit of excess gearing in context of an 8 year price control with a 4 year interim reset? This proposal appears to introduce unnecessary complexity when 3 years is not a specific recognised tax period.

Question 6: Do you agree that the tax treatment of incentives should be calculated using vanilla WACC?

The retained element of incentives should be of sufficient strength to incentivise the desired behaviour. Reducing the net retained incentive by applying notional taxation should result in an increase in the strength of the gross incentive to compensate.

CHAPTER: Six

Question 1: Do you agree that the timing of true up adjustments for existing controls should be spread over the eight years of the RIIO price control? If not, which alternative option do you prefer?

There was an implicit understanding when GDPCR1 was accepted that the true up adjustments would be spread over the following 5 years as a change in Price Control Period was not contemplated. Consequently should maintain 5 years on grounds of regulatory certainty.

Question 2: Do you agree that updated valuations for non-fast tracked companies should be the same as fast tracked companies, ie 31 March 2011 unless no network company is fast-tracked, in which case updated as at September 2012 in time for final proposals?

The financeability issue for pensions deficit recovery payments is matching, to the greatest extent possible, cash payments to pensions schemes with allowed revenues. The uncertainty mechanism for pension schemes where allowed revenues are adjusted to reflect interim 3 year actuarial valuations appears to be attempting this. Consequently, initial allowed revenues should be based on the most recent actuarial valuation against which the sponsoring employer's schedule of contributions was agreed. This could be 31 March 2012.

Question 3: Do you agree that the deficit funding rate of return should be derived from the range of benchmarked pre-retirement real discount rates? If not, which alternative option do you prefer?

Yes. We believe that the funding rate of return should be derived from the range of net pre-retirement discount rates used by Network Operators for their most recent actuarial valuations. We would also note that the Pensions Regulator also publishes summarised valuation assumptions (including the net pre-retirement discount) which could also be considered in deriving the appropriate deficit funding rate of return.

Question 4: Do you agree that same rate should apply to the calculation of the net present value of the ex post true up adjustments?

No – should use Post Tax Vanilla WACC as this adjustment reflects compensation to investors for cash-flow timing differences.

Question 5: Do you agree that ex ante deficit funding allowances and the true up to date in a RIIO price control period should be every three years rather than truing up at the next eight-year price control?

Yes –provided appropriate mechanisms to achieve matching of cashflows between consumers and pension schemes are in place.

Question 6: Do you agree that PPF levies should be part of benchmarked total costs? If not, which should be the alternative option?

PPF levies should not be part of benchmarked total costs as they are not controllable but are dependent on the actions of the Pension Protection Fund ("PPF") in response to their anticipated costs in providing underwriting protection to over 7,000 UK pension schemes. The PPF has revised its charging methodology several times since inception, resulting in significant changes in charges to Networks.

PPF levy should be recoverable provided GDN can demonstrate it has not been negligent in challenging the cost.

Question 7: We invite views on whether the revised guidance to our pension principles is comprehensive and adequate for licensees and stakeholders to understand how the principles will be applied in RIIO controls and for network companies to prepare their business plan?

We are keen to see the results of the initial efficiency assessment commissioned by Ofgem and being performed by the Government Actuary Department.

The Energy Networks Association intend to respond to Ofgem regarding Ernst & Young's proposals regarding identifying and compensating established pension deficits in early 2011.

CHAPTER: Seven

Question 1: How should we calculate the percentage of totex allowed into RAV?

Analysis should consider

1. Underlying nature of company's expenditure being compensated by consumers – short or long life?
2. The impact on financeability of changes to the current percentage based on current RAV treatment
    a. Increase to cost of equity resulting from any deferral of cash flows
    b. Requirement for additional investment by debt and equity if there is deferral
    c. Credit rating agency metrics

The principle of Regulatory Certainty suggests that absent demonstrable benefit in changing, the proportion of "fast"/"slow" money identified in the next price control should be similar to that currently allowed for in this price control.

Question 2: The proposed totex approach includes repex, business support costs and non-operational capex as part of totex.

We invite views on whether totex should include:

a) Repex

b) Business support costs

c) Non Operational capex

Yes – to do otherwise will have potential to distort the IQI based incentive regime. However, Totex should exclude shrinkage gas costs recovered from consumers under the current market price based mechanism and pass through costs.

Question 3: Should the definition of related parties include captive insurance companies?

Yes. All transactions with related parties should be examined during the price control to identify the "arms length" cost of services provided by such organisations.

Question 4: In GDPCR1 GDNs were allowed to retain the proceeds of asset disposals in RAV for five years to incentivise GDNs to dispose of assets at competitive prices. We invite views on whether this treatment should continue.

This treatment should continue; otherwise GDN's might be indifferent to maximising RAV disposal proceeds, which would result in a higher RAV which does not benefit consumers in the long run.