Price Control for Northern Ireland's Gas Distribution Networks GD17

Final Determination – Annex 13

Draft Determination Consultation Report

15 September 2016



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1 Executive Summary

1.1 As part of the GD17 price control process, we undertook a consultation on the GD17 draft determination which was published on 16 March 2016. The consultation period closed on 31 May 2016.

1.2 The purpose of the consultation was to seek feedback on the proposals set out in our draft determination to inform and shape the final determination.

1.3 This annex to the GD17 final determination provides a summary of the feedback given in response to the consultation.

1.4 The remainder of this report in structured in two chapters:

- Chapter 2 provides an introduction to the responses received
- Chapter 3 summarises the key issues raised and our response

1.5 We have grouped the key issues raised by respondent and topic.

1.6 Where appropriate, we have addressed specific technical issues in detail directly in the GD17 final determination document and/or in technical annexes to same. In this case, rather than repeating the information detailed there, this report only includes a high level summary with a reference to the relevant section of the final determination. Where this is not the case, we have responded to the issue raised directly in this draft determination consultation report.

2 Introduction

2.1 Detailed responses to the assessments and proposals which were set out in the GD17 draft determination were received from all three GDNs:

- firmus energy (Distribution) Limited (FE)
- Phoenix Natural Gas Ltd (PNGL)
- SGN Natural Gas Limited (SGN)

2.2 Furthermore we received one confidential response and responses from seven other parties as follows:

- Consumer Council for Northern Ireland (CCNI)
- Manufacturing Northern Ireland (Manufacturing NI)
- National Energy Action Northern Ireland (NEA)
- NI Natural Gas Association (Ninga)
- Fermanagh and Omagh District Council
- SSE Airtricity Gas Supply Northern Ireland (ASGNI)
- Major Energy Users' Council (MEUC)

2.3 In our draft determination we noted that we would publish all consultation responses unless respondents requested otherwise. We have followed-up on this statement and published the responses received, except where specifically marked as confidential. Appendix 1 provides a listing of the links to the relevant documents. We note that we have also taken into account the confidential response, but have not reproduced it (and our response to it) here in order to maintain the requested confidentiality.

3 Responses

Overview

3.1 In this chapter we summarise the key issues raised in response to the GD17 draft determination consultation and indicate how we have addressed the issue in the final determination.

3.2 We have not responded to feedback which broadly supported our approach and determination or that touches on the roles and responsibilities of the respondents themselves. Nor have we provided commentary on wider policy issues which are not directly influenced by the outcome of the final determination.

3.3 We note that our GD17 decisions (including but not limited to the uncertainty mechanism and related adjustments at the time of the next price control) are set out in the GD17 final determination document, subject to either confirmation or change following a consultation conducted under Article 14(2) of the Gas (Northern Ireland) Order 1996. This responses report should therefore not be read as constituting a Utility Regulator decision.

FE Response

3.4 The FE responses and our high level views are summarised in Table 1: Responses on Comments from FE. More detailed information to address specific issues is included in the GD17 final determination document and/or in technical annexes to same where appropriate.

No	Ref.	Section & Topic	Comment	Our Response
1	Section 2 Para 2.1	Volumes	FE states the load loss of Michelin and Gallaher should be reflected in UR's volume projections. The combined impact of Michelin and Gallahers is 11% reduction to overall volumes. FE acknowledges and agree with UR's volume forecasts for the domestic and SME sectors and would ask that the load loss be updated to the I&C volume forecast and be incorporated accordingly.	The loads included in the draft determination for I&C are taken directly from the FE business plan. The DD volumes included Michelin but excluded Gallahers from 2018. The final determination takes account of the closure of Michelin and the load has been excluded from 2018 to take account of this.
2	Section 2.3.1	Owner Occupied Connections Target -	The Utility Regulator's modelling does not appear to reflect the reduced network growth	The increased connection target for GD17 reflects the planned extension of the network.

No	Ref.	Section & Topic	Comment	Our Response
		Penetration Rate	rate projected beyond the GD17 horizon. No explanation is provided for the very significant increase from the 45% penetration assumption set out in the Utility Regulator's revised GD14 final determination modelling. Benchmarking against other utility networks demonstrates that the annual growth rate is likely to be less than 5% (i.e. c.3%) in the post GD17 period when the majority of networks rollout is complete. Modelling by the Utility Regulator on the basis of an arbitrary 85% penetration figure is therefore unsupported, as is its application to backcast connection rates for the GD17 period. This has resulted in a connections target that FE does not believe is achievable, particularly with the proposed funding available.	The connection targets are commensurate with the increase in the number of properties passed but not connected. The 5% connection rate (of properties passed and not yet connected) is supported by an analysis of historical connection rates in both the firmus area and PNGL areas and reflects local experience. The 85% figure quoted is an assumption that 15% of owner occupied properties passed will not opt to connect in the long term and is not a penetration rate. Based on the planned development of the network in GD17 and the OO connection targets, we estimate an OO penetration rate at the end of GD17 of 24% of properties passed.
3	Section 2.4.1.1	Connection Incentive - Underperformance / Outperformance Mechanism	In the context of the Utility Regulator's substantially increased GD17 owner occupied connection targets there is a significant difficulty with the asymmetric risk presented by the proposed Connection Incentive underperformance / outperformance mechanism	We consider that we have dealt with this issue by removing the cap from the OO connection incentive for GD17 which is detailed in Chapter 6 of the final determination.
4	Section 2.4.1.3	Connection Incentive: Non-additionality	As part of our September 2015 Business Plan submission to the Utility Regulator FE acknowledged that there are indeed some customers who will connect without incentivisation, but that the number is closer to 5%. FE has not received any substantiation from the Utility Regulator regarding its estimate of 25% and would welcome any supporting analysis which might be available. Our 5% proposal for non-additionality recognises the extent to which firmus energy's network development plans are into new infill areas (as opposed to infill of our existing network).	We consider that a significant amount of customers are aware of the benefits of gas and are willing to switch without the need for marketing and sales teams. This is increasingly the case when gas is the dominant fuel and neighbours and families use the fuel. Therefore we find that keeping the 25% figure, as used in GD14, reasonable. We have introduced an additional allowance for New Areas to deal with the issues raised.
5	Section	Re-allocation of fixed	FE has stated that 'in conjunction with a	We have employed the same overall approach

No	Ref.	Section & Topic	Comment	Our Response
	2.4.1.4	costs to the Connection Incentive	reduction to the Connection Incentive for the GD17 period the Utility Regulator has determined that significant additional fixed costs be reallocated to fund the Connection Incentive. The removal of these cost lines from the Opex allowances, reduces FE's overall Opex cost allowance very substantially, by £139k p.a. or £834k over the GD17 period. In some cases the reallocation has been simply applied incorrectly, for example, salary costs for our Director of Sales, Marketing & Customer Services have been removed from a cost line that never encompassed those costs to begin with. In other instances, the proposed reallocation is simply not reflective of the percentage of company resources utilised for owner occupied connections'.	to the reallocation of corporate O'H costs to be recovered under the incentive mechanism as we used in GD14. In relation to relevant staff costs we have reviewed the allocations and have made changes to allowances to reflect alignment with GD14 allocations. This is covered in Chapter 6 of the final determination.
6	Section 3.2.2.	Manpower – The Utility Regulator's analysis	FE has stated that 'the Utility Regulator's approach fails to take account of the FTE's required to realise firmus energy's challenging network growth plans but also fails to recognise the appropriate salaries required during this period of development. There are three fundamental issues with the Utility Regulator's analysis and use of 2014 actuals ie (1) the FTE's assumed by the Utility Regulator is understated by 1.4 FTE's due to the average number of positions open, or furloughs caused by staff turnover, during 2014. This would re-base actual FTE's in 2014 to 5.1 (2) this approach fails to take account of the uplift required to move 2014's actual costs to December 2014 prices, and (3) the analysis does not take account for the additional uplift of 2 FTE's allowed by the Utility Regulator in 2015 for system control as a result of market opening.	We consider that that we have allowed a sufficient increase in FTE's in the final determination for FE in the GD17 period, which recognises the envisaged growth in the FE network. The 2014 FTE's we used for our analysis are not understated since they reflect the FTE's recorded by FE in its 2014 ACRT. We agree that an uplift in 2014 costs is required for the GD17 final determination since FE did not apply the correct RPI figure within its 2014 ACRT submission. The analysis of FTE's undertaken within GD14 does not cover the GD17 period and therefore it should not be assumed that allowances allowed in the GD14 automatically transfer into the GD17 period. However we have amended the FTE's to take account of the FE requested FTE's for system control as covered in Chapter 6 of the final determination.
7	Section	Manpower – The Utility	FE have stated that 'in addition to the re-	The re-basing of FE costs has been

No	Ref.	Section & Topic	Comment	Our Response
	3.2.2	Regulator's analysis	basing of firmus energy's FTE numbers and costs to 2014, the Utility Regulator has applied further efficiencies to manpower costs (i.e. RPE's). This constitutes a double counting of efficiencies'.	undertaken via a triangulated process of bottom-up benchmarking, using FE's own run rates and unit costs, compared to an efficient company's forecast of costs, using FE's own cost drivers. Both analyses use actual or historical data and cost drivers so the estimate of efficient costs is centred on 2014, the base year. This is commonly termed catch-up efficiencies. As is normal in regulation, we have applied frontier shift to the determination costs to account for our view on the extent of continuing productivity improvement we assume across time and the GD17 price control period. Including catch-up and frontier shift efficiencies therefore do not represent "double counting".
8	Section 3.2.2.1 and Section 3.9	HR and Non-operational training	FE included professional and legal fees of £67k per annum to cover recruitment and HR consultancy and legal advice. Together with a reduction of 0.6 FTEs under this activity, the Draft Determination has proposed reducing the allowance for these professional and legal fees to £28k per annum (a 57% reduction). The fees have been reduced to their 2014 level. HR consultancy and legal advice can fluctuate year and to year, depending on employee relationship issues, and to use a single year does not provide a true representation of average costs. This is borne out by the fact that HR professional and legal fees in 2013 were £71k. Upon review of the Utility Regulator's analysis, FE notes that costs have not been provided for all of the determined FTEs	As we set out in the draft determination we consider that using the 2014 year as a base year for analysing costs is appropriate as we found that it was not possible to use historic opex prior to 2013 as the historic opex costs provided by FE in its GD17 Business Plan template were not consistent with previous submissions provided by FE. We have for the final determination corrected staff costs for HR and Non-operational training to reflect the determined number of FTE's set out in the draft determination.

No	Ref.	Section & Topic	Comment	Our Response
			(56.5), specifically 0.6 FTEs under HR and Non-Operational.	
9	Section 3.2.2.1	Procurement	Firmus energy included professional and legal fees of £18k per annum to cover ongoing consultancy and legal advice. As a regulated utility, firmus energy is governed by the EU Utilities Directive with regard to how it awards contracts. As such, FE continuously reviews procurement policies and procedures, as well as collating and evaluating tender documents for new and existing contracts. The Draft Determination has reduced the allowance for these professional and legal fees to£11k per annum (a 38% reduction). The fees have been reduced to their 2014 level, thus reducing FE's opportunity to market test cost categories or to drive Opex savings. Upon review of the Utility Regulator's analysis, FE notes that costs have not been provided for all of the determined FTEs (56.5), specifically 0.1 FTEs under Procurement.	See our response to number 8 which covers the reasoning for use of 2014 as a base year and updated FTEs.
10	Section 3.2.2.2	Customer Management	Forecasts indicate a doubling of connection numbers across the GD17 period. Based on this connection growth FE believes an uplift of 0.4FTE's in addition to the 8.92 FTE's already in place is reasonable to provide the additional customer support that will be required.	We consider that as the business expands, additional resources will be required to manage the business. We therefore have allowed additional resources to reflect this issue.
11	Section 3.2.2.2	Trainees and Apprentices	FE had included 2 FTE's (agency staff) for trainees and apprentices to provide engineering assistance, whilst also fulfilling their licence obligations and firmus energy values to promote training and development. The Draft Determination allows for only 1 trainee but FE would welcome the opportunity to train and develop an additional trainee to	We consider that 1 FTE is sufficient and is consistent with the actual number of trainee's and apprentices utilised by FE in 2014. We have allowed however for the final determination for trainings costs in relation to trainee's and apprentices in line with 2014 actual spend.

No	Ref.	Section & Topic	Comment	Our Response
			support the growth of the industry in Northern Ireland.	
12	Section 3.2.2.2	IT and Comms	The growth in all activities of FE has placed significant strain on the IT and Telecoms function. FE's Business Plan forecast the requirement for an extra 1.2 FTE's within this area to support the original FTE count of 0.75 FTE's. FE would contend that headcount of 2 FTEs is not unreasonable for managing, developing and administering the IT and Telecoms function within firmus energy.	This area has been more difficult to access, due to FE change of ownership which has resulted in higher costs in the 2014 base year. We have set the allowance based on business as usual (after removing the cost associated with change of ownership) and we consider this is appropriate based on size and scale of the operation.
13	Section 3.3 & Appendix 3	Maintenance	Subsequent to bottom-up analysis the UR undertook a benchmarking exercise the result of which proposes a 25% cut to FE's variable costs in the GD17 period. FE concludes that this cut results from flawed analysis which does not account for special factors. The more sparsely populated the area is, the more expensive it is for a company to maintain its network on a per-customer basis and resource staff to attend to emergency calls. FE would request that UR recognises the impact of low customer density in relation to maintenance allowances and engages with FE post draft determination to look in detail at the proposed maintenance activities, the special factors, benchmarking, and opportunities for synergies. Given the generic nature UR's proposed disallowances and notwithstanding consideration of the benchmarking weaknesses outlined in the daft determination response, FE considers it incumbent upon the UR to review our proposals in light of legislative and safety case requirements for FE.	We have reviewed the analysis taking account of more detailed information provided by FE on the allocation of costs and revised our analysis. We have also taken account of a correction to the allowances for PNGL which we have used to benchmark FE's costs. This has resulted in an increased allowance for metering and maintenance but the final determination remains 15% lower than FE requested. FE has disagreed with the use of benchmarking to inform our determination of costs in an area where new activities will materially increase costs, asking us to accept its bottom up estimates instead. We have concluded that benchmarking is essential to protect consumers and have continued to apply it in our final determination. As part of its response to our benchmarking, FE asked us to consider the impact of sparsity. We have noted that Ofgem has considered sparsity in its assessment of costs but concluded that this should only be applied to emergency call out costs to reflect the standby time inherent in this work. In view of this precedent, we have not applied a sparsity adjustment to our benchmark costs for FE.

No	Ref.	Section & Topic	Comment	Our Response
14	Section 3.4	Insurance	The Draft Determination proposes a reduced allowance for these costs by applying the GD14 driver of 1.04% of turnover. Applying this metric leads to a reduction in costs in 2017 of £103k (39%) and £0.5 million over the GD17 period. FE would challenge the Utility Regulator's approach in this regard. A material weakness in application of this calculation is consideration of firmus energy's revenues when accounting for profile adjustment. Failure to account for profile adjustment results in an artificially low calculation of insurance requirements. Further, as revenue is a function of items including Opex, Capex and WACC and the draft determination proposes reductions to each, there is a material impact upon any allowance calculated as a function of revenue. FE has also stated that UR's approach to setting its insurance allowance is inconsistent with the approach taken to setting PNGL's insurance allowance.	We have taken into consideration a benchmarking report provided by FE in setting insurance allowances for FE in the GD17 final determination Chapter 6. We note that in some areas the report explains that FE has options to lower its insurance premiums and our insurance allowances for FE take into account these comments. We have set the FE GD17 final determination allowances based mainly on the FE 2015 actual insurance. We note that the 2015 FE actual insurance was lower than that forecast in the FE GD17 BP submission and that shown in the insurance benchmarking report provided by FE. We also note that the benchmarking report provided by FE covers the period July 2015 to June 2016.
15	Section 3.5	Governance	FE has stated that the Opex overspend of 2014 cost allowances (by £0.4m) was entirely a result of having to uplift our marketing spend to support our challenging connection targets. It was not a consequence of our change in ownership. Furthermore, whilst individual Opex cost lines may reflect the new structure of ownership (i.e. costs detailed within individual Opex items, as opposed to a rolled up parental charge), again firmus energy has not requested any additional allowances associated with a change in ownership. Of note, in GD14 the Utility Regulator allowance for parental recharge (from our previous owners) was over £0.5m	We note that the commentary provided by FE here appears to contradict the commentary provided by FE in section 3.1.1 of its draft determination response which states 'Firmus energy's Business Plan clearly articulated the three principal reasons for the difference between the GD14 determined spend and the firmus energy actual spend for 2014; connection related activities, additional GD17 consultancy costs and IT transition costs.

No	Ref.	Section & Topic	Comment	Our Response
			per annum. For GD17, these costs are now included within specific Opex line items.	
16	Section 3.6	Audit, Finance and Regulation	Firmus energy included professional and legal fees of £85k per annum to cover financial and regulatory consultancy and legal advice, audit and taxation fees and professional subscriptions. Together with a reduction of 1.1FTEs under this activity, the Draft Determination has reduced the allowance for these professional and legal fees to £20k per annum (a 77% reduction) from the figure in 2014. Whilst the professional and legal fees have been produced to their 2014 level, the stationary communications and billing costs of £11k per annum have been accepted as presented (by the Utility Regulator) and not uplifted to the 2014 cost of £27k. The Utility Regulator's approach is therefore inconsistent. The Utility Regulator has also allocated 15% of staff time (and cost) within this area to owner occupied connections, which equates to £62k per annum. Only a small proportion of time (<5%) for staff in Finance and Regulation is spent on owner occupied Advertising and Market Development. We therefore believe the Utility Regulator's assessment to be overstated (by a minimum of £40k per annum) and do not believe the proposal of £62k per annum is justified. FE also note an error in figures under this activity within the draft determination, in that table 39 shows figures for Utility Regulator draft determination before re-allocation. This error is £34.2k per annum, or £205k for the	We consider that the FTE's that we have allowed for under Audit, Finance and Regulation, which is based on the 2014 actuals is appropriate. Overall we have provided for an increase in FTEs as set out in section 6 of the FD For the final determination we have used the 2014 costs for stationary, communications and billing. We consider the allocation and proportion of staff time (and costs) to be recovered under the OO incentive mechanism is appropriate. The 15% represents the overhead costs that are associated with supporting other parts of the business. This was the approach used in GD14. Table 39 has been corrected for in the final determination.

No	Ref.	Section & Topic	Comment	Our Response
			GD17 period.	
17	Section 3.6.1	Price Control Consultancy Costs	In formulating some of these responses FE required consultancy support. As a result of the level of detail required these professional and legal fees were higher than the costs allowed within the GD14 price control determination. Looking forward to the next price control period, we note the impact of price control related consultancy costs has not been acknowledged by the Utility Regulator in the Draft Determination.	We recognise that in using 2014 as a base year there may be some costs which are higher or lower in other years. However we have not seen evidence that suggests these changes would not be appropriate over the duration of the control period, as these costs tend to average out.
18	Section 3.8	Asset Management	FE included professional and legal fees of £12k per annum to cover Asset Management consultancy and legal advice. UR has recognised and appears to allow these costs in UR's detailed calculations. Unfortunately, however, these costs do not appear to flow through to the final total allowed under Asset Management in the draft determination.	These costs have been included in the allowances for the final determination.
19	Section 3.11	Emergency Costs	FE has requested, but is yet to receive the UR's modelling of emergency calls.	The model requested was issued to FE on 22/04/16 in advance of the company issuing its consultation response on 31/05/16. The response issued to FE included a description of how the model outputs were derived and used to project call numbers. FE confirmed receipt of this information on 05/05/16, advising that it would consider it and contact us to arrange a further meeting if required. No further meetings were requested so it was assumed that FE was content with the response provided.
20	Section 3.11	Emergency Costs	Any disallowances in proposed, efficiently incurred forecasted costs are of particular importance. FE's comments are made in this context, and FE would welcome further engagement with the UR in this regard.	We met with FE on 15/07/16 to explain the modelling and approach used for assessing call numbers and the allowances for emergency costs. At this meeting we explained why we considered the approach to be reasonable and any changes likely to be adopted for the final determination and their potential impact.

No	Ref.	Section & Topic	Comment	Our Response
21	Section 3.11.1	First Response Activities	The UR has revised the methodology of modelled call numbers. The call number modelling is now based on mild (below average temperature) for the winter for years 2012, 2013 and 2014. FE believes the actual average temperatures were: 2012; 9.17°C, 2013; 9.61°C, 2014; 10.09°C. The seasonal norm temperature for 2013 was 9.22°C and for 2014 was 9.38°C. This provides an artificially low basis for deriving the UR's assumptions.	We have considered FE's comments but have not made any adjustments in this regard for the following reasons: • Regional climate information on the Met Office web site states that the mean annual temperature at low altitudes in Northern Ireland varies from about 8.5°C to 10.0°C decreasing by approximately 0.5°C per 100m elevation. Given the range quoted and the sensitivity to elevation we judge that 2012-14 data lies broadly within the 'normal' range. • The allowances are intended to be for an average year and while costs in any year may be higher or lower, we would expect this to balance out over the price control period. • We note that call centre contract allows for a 15% increase above base level call volumes across the year before any additional costs are incurred. This helps mitigate against any potential call centre cost increases associated with an increase in activity.
22	Section 3.11.1	First Response Activities	The revised model makes a material change to the assumed mix of calls emanating from existing customers as compared to those emanating from new customers. This is of particular concern to FE and FE would ask the UR to reinstate the assumptions applied as part of the GD14 review, particularly given the significant growth targets. FE believes the UR's change in mix is not commensurate with FE's network/customer profile. FE believes the UR's proposals should be revisited.	We have reviewed the assessment and increased projected connection numbers to align with those used elsewhere in the final determination. This has reduced the scale of the call centre disallowance. Further details can be found in Annex 8 – Emergency Costs. We have considered FE's request for us to revert to the GD14 assumptions for calls per 10,000 connection but do not believe that this would be appropriate for the following reasons: • The GD14 assessment was based on 2010, 2011 and 2012 data. During this period the relative proportion of new

No	Ref.	Section & Topic	Comment	Our Response
				connections to existing connections was higher than it will be in GD17. This is particularly the case for FE where this was in the order of 30% in the 2010-12 period compared to projections of around 10% in GD17. The use of outputs based on 2012-14 data is therefore more reflective of the customer mix in the GD17 period and the increasing familiarity of the growing proportion of existing customers with their gas installations. The type of movement in the model output data evident since GD14 would be expected as a consequence of such changes starting to take effect. • The application of the 'calls per 10,000 connection' figures generated by the model to the actual connection numbers generates the total number of calls estimated for each company in the modelled years. The model outputs should therefore reflect actual customer behaviour within each supply area.
23	Section 3.11.1 and Section 3.11.2	First Response Activities and Emergency Response Efficiencies	The UR has proposed a significant reduction in the first response allowance, notwithstanding a significant increase in connections to the network FE would ask the UR to review the scale of disallowance with regard to Emergency Response Efficiencies.	We have reviewed the assessment and increased projected connection numbers to align with those used elsewhere in the final determination. This has reduced the scale of the first response disallowance. We have also reviewed the fixed cost element of providing this service and as a result of clarification received in discussions with FE, have allowed additional costs for cover provided to large meter rigs and pressure reduction stations and for enhanced cover over the winter months. All fixed costs identified by FE are now included in the allowance and so we believe this is now fully reflective of FE's fixed cost for maintaining 24

No	Ref.	Section & Topic	Comment	Our Response
				hour emergency first response cover. This has reduced the scale of the first response disallowance further. Further details can be found in Annex 8 – Emergency Costs.
24	Section 4	Capex	FE has indicated concern about how some potential customers may be disadvantaged by UR's proposed re-profiling of the network build to front load those projects delivering the highest economic return. FE also notes some of the allowances in the Basket of Works are lower than in the GD14 period and lower than the fixed rates in their period contract.	We acknowledge FE concerns surrounding the re-profiling of the network build and have engaged with FE in order to better understand the estimated burns of various property types used in our economic assessment. We have concluded that it is appropriate for FE to build out their network as proposed in GD17. We agree that some allowances are lower than the fixed rates in FE period contract and also note that equally some allowances are higher. The basket of works consists of actual costs from several groups of similar activities completed by NI GDN's. We expect that over time natural efficiencies occur in any activity and the benefits of these should be passed onto consumers in due course.
25	Section 4.4	Benchmarking - Basket of Works Approach	The allowances for domestic services and meters are much less favourable than GD14 despite the GD17 period being focused on domestic growth. For example the reduction in domestic services allowances could require FE to ask customers to contribute towards this element of the cost of a (domestic services) connection. FE would therefore request that in the final determination the UR reflects, as far as possible, the reality that FE will be working to a fixed period contract. The proposed (BoW) rates have been derived based upon FE's historic costs from 2011 to 2014. This date range somewhat predates the current period contract.	We have updated the basket of works unit rate for domestic services in the final determination for FE to reflect historical costs incurred by FE in 2011 to 2014.
26	Section	Other Capex - Foyle	FE would urge the UR to progress the	We have received further submissions from

No	Ref.	Section & Topic	Comment	Our Response
	4.5	River Crossing & Telemetry	approval process for the Foyle River crossing with themselves as a matter of urgency. Pending the outcome of discussions with the UR with regard to the telemetry proposals FE did not include these costs within the GD17 Business Plan Template. FE would welcome consideration by the UR of the provision of allowances for these installations of new telemetry across the network, the cost for which is forecast as £191k over the GD17 period.	FE for the Foyle River crossing and have responded to FE with our initial assessment. We include an allowance for the preliminary works in 2016 and an additional ring fenced allowance for the remainder of the works in 2017. This will be trued up via the uncertainty mechanism. We have included £75k for telemetry over the GD17 period. This allowance is to continue upgrading daily metered supply points and to monitor 18 sites where low pressure may be a risk.
27	Section 4.6	IT Capex	FE has a requirement to replace obsolete IT systems, costs for which were not allowed in the draft determination. This investment is essential. FE is seeking an appropriate allowance for essential investment in replacing obsolete IT systems. UR has confused this with other issues around change of ownership but it is a straightforward necessary replacement to drive productivity across the business with excellent payback.	We have included the allowance as requested by FE to replace their existing aged bespoke IT system. Further details of our assessment can be found at Chapter 7 of the final determination.
28	Section 5.6	WACC	FE expresses concern that the allowed rate of return of 4.3% is too low	See below.
29	Section 5.6	WACC – comparison to the GB GDNs	FE states that the UR's DD provided for a cost of equity that is significantly below the GB GDNs' allowed cost of equity on a like-for-like basis.	The GB GDNs' allowed cost of equity was fixed by Ofgem in December 2012. Since this time, there has been a move down in regulators' cost of capital estimates, due mainly to a lowering of estimates of the generic CAPM parameters (e.g. the expected return on the market portfolio). The UR does not consider that it is required in this review to align FE's allowed return to a calculation made four years ago. Rather, its task is to set a return that is sufficient to cover FE's forward-looking opportunity cost of capital in today's market conditions. If this condition is met, FE ought be capable of

No	Ref.	Section & Topic	Comment	Our Response
				attracting equity investment.
30	Section 5.6	WACC – comparison to other regulated networks	FE claims that it was misleading for the UR to present a comparison of cost of equity calculations using a common gearing assumption and to state in its DD that FE's allowed cost of equity sits above the returns allowed by Ofgem and Ofwat in their most recent decisions, on a like-for-like basis, given that FE cannot increase its gearing to match the debt-equity ratios selected by other networks.	There is no suggestion on the UR's part that FE needs to alter its gearing ratio. The comparison in table 178 of the DD document simply shows that the UR's assessment of FE's cost of equity contributes to a slightly higher rate of return than has been allowed in other recent reviews, once one allows for the fact that a higher proportion of FE's overall WACC is weighted to the cost of equity (and holding all other things equal).
31	Section 5.6	Cost of equity – generic CAPM parameters	FE states that the UR has relied on a snapshot of recent market evidence, thus giving FE a lower allowed cost of equity than Ofgem gave to the GDNs in 2012.	It is incorrect to state that the UR has relied on a 'snapshot' of recent market evidence. The lower values for the generic CAPM parameters reflect a broad consensus among regulators that previous figures were set too high. This is explained clearly in the 2014 Competition Commission (CC) NIE inquiry report.
32	Section 5.6	Cost of equity – tax	FE argues that the tax wedge adjustment in the DD WACC is too simplistic, and calls once again for the UR to adopt the alternative methodology put forward by Oxera in its July 2015 cost of capital submission.	The UR acknowledges that regulatory practice in this area is not uniform, with some regulators (e.g. the CAA and the CC) applying the simple tax wedge adjustment used in the DD and other regulators (e.g. Ofcom) applying the adjustment that FE is now proposing. The lack of consensus is perhaps best exemplified by the fact that Oxera sometimes uses the former approach (e.g. in its cost of capital advice to SGN in the recent Gas to the West competition years 1-5) and sometimes uses the latter approach (e.g. in its advice to FE). The UR's reluctance to depart from its usual practice of making a simple tax wedge adjustment stems from the sheer number of

No	Ref.	Section & Topic	Comment	Our Response
				factors that can cause a company to pay more or less tax in any one year than the simple gross up of the real cost of equity would appear to provide for. These factors include: - the capitalisation of a proportion of the nominal return on equity within the TRV, and subsequent run down of the TRV value - the availability of nominal interest tax shields, over and above the real cost of debt factored into the WACC calculation - the availability of accelerated tax capital allowances Oxera's proposed methodology addresses the first of these issues, but does nothing about the second and third. As a matter of principle, the best way of capturing a company's actual tax-paying position is to provide for a vanilla WACC and a separate, modelled allowance for tax. The UR notes that Oxera has not recommended this approach. Our own analysis suggests that if we were to go down this path, FE will only begin paying tax during the GD17 period and, hence, allowed revenues would fall below the level provided for in the FD. In these circumstances, where FE is already being over-compensated for the tax that is payable within the confines of this price control period, the UR is reluctant to increase FE's GD17 tax allowance still further. We are especially reluctant to adopt a methodology which builds in one of the factors that is overlooked in a simple tax wedge adjustment (and which happens to have a favourable impact on revenues) but ignore other equally

No	Ref.	Section & Topic	Comment	Our Response
				important factors (which go the opposite way).
33	Section 5.6	Cost of equity – beta	FE notes that the UR said in its DD that it had sought to position FE's beta at the top of the range that regulators have judged appropriate for steady-state utilities, but argues that the UR ignored recent moves up in listed companies' asset betas.	The UR acknowledges that empirical estimates of equity betas have been increasing in recent months. In line with the position taken by the CC/CMA in recent reports, the UR considers that it should not be overly swayed by short-term movements in share price data, but should instead seek to look at empirical estimates of beta over a longer time horizon. The UR notes that equity betas of listed companies averaged over, say, five years lie below the 0.38 asset beta estimate that the UR has ascribed to a 'standard' network utility, especially after SSE is removed from the comparator set, as a company that makes approximately half of its profits from riskier generation and retail activities.
34	Section 5.6	Cost of equity – beta	FE states that it does not in any event accept the view that it is of equivalent riskiness to steady state networks. FE states that the UR was wrong to disregard FE's arguments about 'immaturity' on the grounds that FE could not quantify what immaturity means in numerical terms. FE states that the UR was also wrong to overlook arguments about the effect that deferral of revenues has on risk, noting that some of the deferral can be said to relate to return and opex and that there is no other setting in which a companies' prices using a long-term Profiling Adjustment (PA). This is exemplified by the fact that revenues that were modelled in GD14 as accruing to FE after 2017 will not now be recoverable due to the UR's decision to reduce the allowed	The UR did not disregard FE's arguments about immaturity because FE could not offer a quantified analysis. The UR instead carried out its own quantitative analysis which showed that it is extremely difficult to construct scenarios in which FE is unable to recover the full value of its TRV through charges to customers. We note that when presented with this analysis, neither FE – nor PNGL, who made similar arguments about immaturity – have sought to disagree with either the arithmetic or the conclusions that the UR drew. The UR does not consider that it is valid to attribute deferred revenues to individual price control building blocks. The PA term is unusual, but serves a clear purpose – i.e. to give stability to prices and bring about a more

No	Ref.	Section & Topic	Comment	Our Response
			WACC.	equitable sharing of costs across customers over the life of built assets. So long as this profiling of revenues does not create an undue burden on future customers, it does not increase the risk around cost recovery. The fact that GD17 revenues are lower than the post-2017 revenues modelled in GD14 should not be taken as an indication that the PA term exposes FE to additional risk. The UR was very clear in its GD14 documents that the GD14 model contained a placeholder "modelling assumption" for the post-2017 WACC and that the UR would be assessing the appropriate value for the allowed rate of return during GD17. The GD17 DD and FD are the culmination of that process. Investors will have understood that the "modelling assumption" was not a guaranteed rate of return and that it was more important to pay attention to the overarching principle that returns from 2017 onwards would be aligned to a forward-looking estimate of FE's cost of capital, as made during 2016. Furthermore, the UKRN peer review supported the view that the PA term should not increase beta risk.
35	Section 5.6	Cost of equity – beta	FE argues that by allowing for a debt beta of 0.1 the UR has accepted that FE is a higher risk company in comparison to other regulated networks. FE also states that it is counter-intuitive for the UR to allow a high debt beta and a top-end asset beta (0.40), but arrive at an equity beta (0.77) that is lower than most other regulated networks.	The UR does not agree that 0.1 is a high debt beta. The same debt beta assumption can be found in Ofgem's RIIO-GD1 calculation of the WACC for the GB GDNs. The calculated equity beta is a function of the UR's gearing assumption (55%). Insofar as higher leverage makes equity returns more risky, the selection of higher gearing figures by the likes of Ofgem and Ofwat (i.e. in the range 60% to 65%) means that other networks'

No	Ref.	Section & Topic	Comment	Our Response
				equity betas naturally come out higher than the equity beta that the UR has allowed FE.
36	Section 5.6	WACC – incentives	FE states that because the UR has not included any meaningful incentives in its DD, the UR has removed the possibility that FE might increase equity returns above the allowed cost of equity. FE argues that this reduces the business's resilience to risks that might crystallise in the GD17 period.	The UR considers the connections incentive to be meaningful and notes the outperformance GDNs have made in some previous years, However we do not accept the implication that fewer incentives require a higher WACC. Indeed it would seem that increased use of symmetric incentives could add to GDN risk.
37	Oxera report	Cost of debt	Oxera argues that the UR was wrong to depart from the methodology it used when estimating SONI's cost of debt earlier this year.	Our approach follows that which was used in RP5 and PC15 and we consider it appropriate.
38	Oxera report	Cost of debt – inflation assumption	Oxera states that the UR erred by not using a short-term (i.e. 2017-19) forecast of RPI inflation in its calculation of embedded debt costs, resulting in an under-estimate of the real cost of embedded debt.	The approach in the draft determination was to apply the same average GD17 annual inflation rate to both embedded (i.e. pre-2017) and new (i.e. post-2017) debt. Oxera's alternative approach of applying a short-term inflation forecast for embedded debt is valid, except that Oxera fails to recognise the need for an accompanying adjustment to the inflation assumption used in the calculation of new debt. That is to say that if Oxera's split approach requires a 2017-19 RPI forecast for embedded debt, it should apply a 2020-22 RPI forecast to new debt, not the full 2017-22 average RPI inflation rate. This issue then becomes no more than a matter of presentation. Mathematically, the overall cost of debt remains the same regardless of whether the UR applies the GD17 annual inflation rate or (correctly) applies a split approach.
39	Oxera report	Cost of debt – fees	Oxera suggests that there was an error in the UR's DD calculation of debt fees.	The UR accepts Oxera's proposed calculation and updated figures are included in Chapter 10 of the final determination.

No	Ref.	Section & Topic	Comment	Our Response
40	Oxera report	Cost of debt – allowance for higher debt premium	Oxera recommends that the UR should allow an additional debt premium, in recognition of the likelihood that FE will have to raise debt with a BB rating.	As explained in the section on financeability, the UR does not accept that FE will not be able to achieve a BBB rating. FE is able to choose its mix of debt and equity finance, and the selection of a prudent capital structure will enable FE to achieve a BBB rating.
41	Section 5.3	Financeability	FE argues that the UR's DD analysis of financeability was flawed because: - the inputs into the UR's modelling were set to mirror the assumptions feeding into the determination - FE's network business was not modelled on a stand-alone basis - the UR modelled only two financial ratios, and did not take account of other ratios that are considered important by lenders - the UR did not account for the profile of its GD17 interest payments - the UR did not produce downside sensitivity analysis FE finds that when these shortcomings are fixed, GD17 produces a package of ratios which is not financeable. FE suggests three possible remedies: - deferral of capex from the GD17 period to later years - removal of reduction of the Profile Adjustment - an increase in the allowed WACC	The UR took a conventional approach in its analysis of financeability and modelled the ratios that a company would exhibit if it performed in line with the DD assumptions about costs and volumes because it wanted to understand the financeability of an efficient company. The UR accepts that some of the assumptions feeding into the model were not constructed on a stand-alone basis as it did not have this information. Since this information has now been provided it has rectified this in the final determination FD. The UR has modelled a broader range of financial ratios as part of this FD, including FFO interest cover, FFO to net debt and Retained Cash Flow / Capex, although these do not alter the UR's conclusions. The UR has considered FE concerns on the profile of interest rates, however we have continued to apply an average interest rate for interest calculations during the GD17 period. Our analysis is focused on the overall picture and not individual years. The cost of debt will be subject to adjustment within the Rate of Return adjustment mechanism with a true up via TRV adjustment at GD23. The UR has conducted downside sensitivity scenarios in this FD, involving increases in

No	Ref.	Section & Topic	Comment	Our Response
				opex and capex of 15% and ignoring risk sharing. Unsurprisingly, these scenarios show a deterioration in ratios compared to the central case presented in Chapter 10. While these scenarios depict some of the possible out-turns that FE may encounter, the UR considers them to be of limited interest from a financeability point of view because they assume that all under-performance is financed through debt issuance. The UR does not consider that this is necessarily the correct assumption. The risks here are risks that equity holders are being paid to bear via the allowed return on equity and it is just as reasonable to assume that equity rather than debt will flex to accommodate downside scenarios. If one holds debt constant in the scenarios we have constructed, key financial ratios remain broadly unchanged. The UR has considered the alternative financeability remedies that FE has proposed, as well as some other suggestions made in later correspondence, but does not consider that it is right to flex the regulatory framework in response to a financeability problem. As noted in the DD, and again in the FD, financial ratios are a function of two main factors: i) the revenues that FE earns under its price control and ii) the amount of debt that FE chooses to take on. The UR considers that weak financial ratios are first and foremost a consequence of FE attempting to take on too much debt. It follows that the appropriate response to the issues that FE has highlighted is for the company to adopt a more suitable capital structure for the GD17 period, taking account of the revenues and cashflows available.
42	Section	Under-Recoveries	FE notes that UR’s proposed treatment of	As set out in Chapter 11 of the FD, we

No	Ref.	Section & Topic	Comment	Our Response
	6.1		underrecoveries is in FE's view entirely inconsistent with the reasonable expectations of investors as well as the terms of the FE licence. FE also considers that there is no justification for allowing differentiated returns on different elements of its capital structure. FE accepts the lower rate of return for future under-recoveries post 2017 but strongly opposes to any change that is retrospective in application. In particular, FE considers that any proposal to reduce the rate of return on pre-existing under-recovered revenues to a level below its allowed WACC would be entirely arbitrary, disproportionate, retrospective in effect, and not backed by principles of good economic regulation.	considered in GD14 whether to modify the FE licence at that time but concluded that it would be more appropriate to delay this and send a clear signal that modification would be addressed in GD17. The approach we have taken is consistent with that in the previous PNGL and current SGN licences. The change to the rate of return will only apply from 2017 and will not be retrospective. FE will keep all of the return it has built up over the years. As above the proposal has been clearly flagged and follows a number of GDN precedents.
43	Section 6.2	Utility Regulator's top-down benchmarking approach	FE has made various comments on the Utility Regulator's top-down benchmarking analysis. FE submitted a paper from Oxera outlining specific comments on the benchmarking analysis carried out by the Utility Regulator at draft determination.	We have detailed our final determination benchmarking methodology within our GD17 Annex 5 - Top-Down Benchmarking.
44	Section 6.3	Materiality Threshold	FE believe that the proposed increase of the materiality threshold to £150k is arbitrary and an example of the "downside bias prevalent throughout the GD17 DD". FE outline that this increase has the potential to offer no adequate funding for significant projects that could occur that would be of benefit to the industry and customers.	We note FE's concerns and have taken the decision to reduce the materiality threshold to a £100k level
45	Section	Stakeholder	FE emphasises they have already evidenced	We shall build on the strong focus on

No	Ref.	Section & Topic	Comment	Our Response
	6.4	engagement	positive feedback from stakeholder interaction and welcomed the opportunity to further scope the impact on consumers from a number of Draft Determination proposals i.e. reduction of the Connections Incentive and re-profiling of network, with stakeholders such as the Consumer Council.	customer service already built up by the GDNs and consider these responses further as we progress the GD17 development objective for improved customer services, specifically continuous consumer and stakeholder engagement throughout GD17.
46	Section 6.5	Consumer research	FE recognises the opportunity for further alignment of consumer research between GDNs to improve customer service standards and welcomes the GD17 customer service development objective (including new customer service metrics, satisfaction surveys and enhanced GDN partnership working). Firmus also recognises the opportunity to learn from local water / electricity sectors but cautions that a balance of focus on existing and new consumers (not already connected to the network) is required.	We shall build on the strong focus on customer service already built up by the GDNs and consider these responses further as we progress the GD17 development objective for improved customer services, specifically the re-convening of the Consumer Engagement Working Group and agreement of a collaborative research programme.
47	Section 6.6	Innovation	FE notes the statement in paragraph 8.19 of the GD17 DD that UR do not intend to incentivise innovation projects stating: *"To be clear, by saying this we do not mean that GDNs should not pursue innovation. On the contrary, we welcome innovation initiatives where reasonable and economically efficient. However, we consider that at this stage it is not appropriate to provide further incentives to further innovation."* FE views this as an opportunity missed. FE considers that by failing to provide any incentive for innovation of any type UR is restricting the prospect of innovative measures to address problems specific to Northern Ireland's unique network areas.	We note the point. However, we disagree with the view that not providing further incentives to innovation is an opportunity missed as it restricts the prospect of innovation measures to address problems specific to Northern Ireland's unique network area. We have set out, in section 8 that we may provide funding of innovation projects through specific innovation allowances and increased prices, provided certain conditions are fulfilled. We note that this does not exclude or restrict GDNs progressing innovation measures. All GDNs are incentivised to innovate in order to meet and outperform on its costs, connections and other targets.
48	Section 6.6	Innovation	FE is concerned that UR's repeated statements outlining UR's intention to set high hurdles for any allowances for innovation projects (such as the biomethane injection	As above we encourage innovation. We are conscious that robust assessment criteria for funding of innovation projects may impact on the time and resource GDNs need to invest if

No	Ref.	Section & Topic	Comment	Our Response
			proposal submitted by FE) could have the effect of discouraging innovation from the outset.	they wish to request funding. However, we consider that this is appropriate, proportionate and necessary to provide protection to consumers who would bear risk and cost of such innovation projects.
49	Section 6.7	Supplier of last resort	FE considers that rather than interim tariff adjustments or the use of an uncertainty mechanism at the time of the next price control, robust and transparent cost recovery arrangements should be clearly set out in the relevant licences to ensure robust governance exists. In particular, cost recovery through inclusion of a specific and limited special review within GDNs' licences would prevent any potential detrimental cost impact on development of the network. FE considers that the development of an appropriate licence modification is the only satisfactory option available and, given the licence modifications already proposed in order to implement the GD17 price control, not an unwarranted request.	As detailed in Chapter 11, we have included in the uncertainty mechanism a ring-fenced allowance for a SoLR event. The SGN licence in its current form already references the uncertainty mechanism. Our initial intention was to use these as a basis for introducing corresponding uncertainty mechanism arrangements in the FE and PNGL licences. As part of our engagement with the GDNs on this matter, and our related analysis, it became clear that there were a number of shortfalls regarding the uncertainty mechanism arrangements in the SGN licence, in particular with respect to clarity and accuracy of the related drafting. In light of these findings, we propose to revise the uncertainty mechanism arrangements in the SGN conveyance licence to address these issues, and introduce equivalent arrangements, accounting for these revisions, in the FE and PNGL licences. We consider that these arrangements for costs associated with SoLR events are pragmatic, appropriate and proportionate while providing assurance that efficiently incurred costs relating to a SoLR event can be recovered in due course. They avoid the administrative burden associated with special reviews whilst providing a buffer to prevent the potential for financing issues arising as a result of a SoLR event.
50	Section 7	Proposed licence	FE considers that the full effect of the	We note that we had indicated in the GD14

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		modifications	proposed change from price cap to revenue cap, extension of forecasting horizon, treatment of under-recoveries and future treatment of profile adjustment has not been adequately considered ahead of the proposed licence modifications, which include the designated parameter changes to bring the price control into effect.	final determination[1] our intention to change FE from a price cap to a revenue cap form of control, to review the treatment of under-recoveries and the use of profile adjustments, thus giving plenty of notice for consideration of the related effects. Also, we had issued a separate consultation[2] and outcome paper[3] with respect to the change from a price cap to a revenue cap form of control. The extension of the forecasting horizon was proposed by FE in its business plan submission. We note furthermore that in preparation of the GD17 final determination, we have further engaged with FE. This has included provision of advance view of our drafting of the proposed licence modifications with related reasons and effects as well as consideration of FE's views on these.
51	Section 7.1	Proposed licence modifications – Parameter changes	FE notes that the designated parameters to apply to the first formula year and subsequent formula years must be amended for the GD17 price control to take effect. FE notes it is important these changes are designated as a licence modification so that FE have recourse to the Competition Markets Authority (CMA) in the event of dispute.	The GD17 FD is accompanied by associated licence modifications including to designated parameters.
52	Section 7.1	Proposed licence modifications – Parameter changes	FE sets out, in the response to the GD17 draft determination, its proposed values for the designated parameters, compared to the GD17 draft determination. In particular, FE considers that the rate of return r_t should be 0.055 rather than 0.043 and that $x_{u,t}$, the rate	Our views on WACC and under recoveries are set out mainly in sections 10 and 11.

[1] Utility Regulator: GD14 Price Control for Northern Ireland's Gas Distribution Networks for 2014-2016, Final Determination, 20 December 2013.
[2] Utility Regulator: Consultation on modifications to the Price Control conditions of the firmus Energy (Distribution) Limited Licence, 18 June 2015.
[3] Utility Regulator: firmus energy (Distribution) Limited Licence, Outcome of Consultation paper on moving to a revenue cap regime, 16 September 2015.

No	Ref.	Section & Topic	Comment	Our Response
			of return adjustment which may be used to encourage or discourage accumulated under-recoveries, should be set to 0.	
53	Section 7.2	Proposed licence modifications: GDNs working together – common branding	FE requests that the Utility Regulator provides detailed clarification regarding the practical outworking of the requirement to work together in the area of common branding. This should then enable subsequent drafting of the licence condition to clearly set out the obligations on the GDNs.	We note that the proposed new licence condition clearly outlines the scope of the common branding approach. It is our view that it is not our role to prescribe what the actual approach should, or needs to, be or entail, and therefore the proposed condition does not include such detail. Rather, this is essentially what the licensees need to work together and agree upon. Once the common branding approach has been developed, it will be for each licensee to implement it and comply with it, in line with the provisions contained in the common branding approach. We consider that this is appropriately reflected in the proposed licence drafting. We note that in the case of non-compliance with the proposed new licence condition, we could consider enforcement action. However, any such enforcement action could only be taken against those licence holders holding up the development of the approach and/or failing to implement the common branding approach and comply with it, and not against those licence holders duly co-operating on common branding.
54	Section 7.3.2	Proposed licence modifications: Regulatory Instructions and Guidance	FE suggests that the Utility Regulator should undertake a deeper analysis of the relevant Ofgem templates to see whether the proposed modification is fit for purpose in a Northern Irish context. FE notes that it supports benchmarking in principle, but considers that the significant scale differential	We have developed the NI annual/cost reporting templates, based on the Ofgem template, but with due consideration of the specifics of NI GDNs. In preparation of the templates with associated Regulatory Instructions and Guidance (RIGs), we sought feedback from the GDNs and gave it due

No	Ref.	Section & Topic	Comment	Our Response
			between FE and the comparators (particularly GB GDNs), particularly with respect to manpower, places a reporting and compliance burden on the FE business that has not been adequately acknowledged.	consideration. We are of the view that the annual/cost reporting templates with associated RIGs are fit for purpose in an NI context. That said, when we consult – in line with the proposed new licence Condition 1.26 – on any revisions to the annual/cost reporting template and RIGs for the reporting years 2015 and onwards, there will be an opportunity to highlight any areas and proposed amendments the GDNs (or any other interested parties) consider necessary to ensure the templates are fit for purpose.
55	Section 7.3.2	Proposed licence modifications: Regulatory Instructions and Guidance	FE notes that, despite its September 2015 Business Plan outlining the significantly greater level of workload resulting from price controls, RIGs and Retail Energy Market Monitoring framework (REMM) reporting, the draft determination disallows the proposal for an additional 0.5 FTE staff member to assist with the collation and regulatory reporting of information.	We note FE's comments. However, we consider that compliance with regulatory reporting requirements forms part of the business as usual activities of a GDN and that our manpower allowances, determined based on trend analysis and consideration of business needs, appropriately account for such business as usual activities. Also, we expect a prudent operator to have high quality data collation and recording arrangements in place to support such reporting requirements.
56	Section 7.3.4	Proposed licence modifications: connection charges and obligation to permit a connection	FE suggests that the proposed wording for the licence modification is revised to provide more clarity on frequency and timescales for the submission of the accuracy review scheme.	The proposed licence modification no longer forms part of the licence changes pursuant to the GD17 final determination and other regulatory decisions but is now being addressed as part of a separate licence modification initiative. The comments made by FE and PNGL in response to the GD17 draft determination will be considered as part of that initiative.

Table 1: Responses on Comments from FE

PNGL Response

3.5 The PNGL responses and our high level views are summarised in Table 2: Responses on Comments from PNGL. More detailed information to address specific issues is included in the GD17 final determination document and/or in technical annexes to same where appropriate.

No	Ref.	Section & Topic	Comment	Our Response
57	Section 2.4 & Section 3.4	Infill Mains	PNGL is proposing to make natural gas available to a further c.5,700 properties in line with the practice for standard infill projects established over the last 20 years where consumers are not required to pay an upfront cost to PNGL for making natural gas available to their property. UR has concluded, via what PNGL believes to be a flawed economic test, that PNGL's proposal to make natural gas available to a further c.5,700 properties is unwarranted. PNGL would therefore urge the UR to review the basis of UR's current analysis and to reconsider the message that UR's proposal to ignore the long-term average cost of passing a property will have on the development of the natural gas network and on consumers. In reality this means that those consumers who have not been provided access to the natural gas network to date will have to pay. PNGL does not understand why UR has used an economic test to determine the average allowance for an average street and then disallowed PNGL's proposal on the basis that the marginal cost for a street during GD17 is higher. This is a fundamental misinterpretation by the UR of its own economic test.	We have considered PNGL's case to extend the existing network past a further 5,700 properties. We are not minded to change our position for GD17, but will consider further representations for GD23 if PNGL can provide further evidence as to why these properties should be connected. PNGL correctly, does not propose to connect every property in its network area because PNGL judges that some properties are uneconomic and their connection would increase tariffs for all customers. We therefore agree in principle that it is uneconomic to connect some properties; it is just the quantum that we disagree on.
58	Section 2.5.2	Real wage adjustment and top-down benchmarking	PNGL engaged NERA to review UR's regional wage adjustment and the implications for the top-down benchmarking. NERA concluded that there were a number of areas where UR does not follow sound	Our approach to the regional wage adjustment and other aspects of the top-down benchmarking methodology is detailed within our GD17 Annex 5 - Top-Down Benchmarking. This fully deals with

No	Ref.	Section & Topic	Comment	Our Response
			economic principles, and established regulatory practice, and as a consequence, UR overstated the required adjustment for differences in real wages in NI relative to GB. PNGL submitted a paper from NERA detailing specific comments on the regional wage adjustment.	responses.
59	Section 3.1	Rate of Return	PNGL expresses concerns with the UR's proposed rate of return and tables a supporting paper by Frontier Economics and NERA containing a critique of the DD weighted average cost of capital (WACC) calculation. PNGL's updated view is that the real pre-tax WACC falls in the range of 5.3%-5.6% (see table 9 on p.35 of PNGL's response document).	See below.
60	Section 3.1.2	Cost of equity – beta	PNGL considers that the UR has not positioned PNGL's beta at the top end of regulatory precedent, as it set out to do, because it made incorrect interpretations of other regulator's determinations. In particular, PNGL argues that the UR failed to control for differences in regulators' debt beta assumptions.	The UR accepts that there is no single right way of reading across from the values of beta that are identified in other regulators' published price control documents. The approach that the UR took in the DD, which built on the approach that First Economics took in its report, involved taking quoted asset betas at face value – i.e. as the regulators' estimates of the beta that a firm would have if it were financed entirely by equity. In this way of looking at things, it falls to the UR to assess, independently as a separate and stand-alone task, how firms' betas then change in response to higher gearing. We can nevertheless acknowledge that there is an alternative way of utilising other regulators' analysis, in which quoted asset

No	Ref.	Section & Topic	Comment	Our Response
				betas have to be looked at in the context of the detailed computation methodology that each regulator used to derive the asset beta estimate. Under this approach, an asset value of x is only x because the regulator used a debt beta of y; using a different value for debt beta would mean that the asset beta value takes on a value of z. It follows that if the UR is not using a debt beta of y in its calculations, it might need to adjust the asset betas quoted in regulators' published documents before reading across to PNGL and FE. In practice, however, the UR does not consider that this matter had any effect on its draft determination. The estimates of asset beta that the UR placed most weight on were: - Ofgem, RIIO-GD1 = 0.38 - SGN Gas to the West, years 6-10 = 0.43 - CC, NIE RP5 = 0.40 There is no issue with the first two points of reference in this list, because the UR, Ofgem and SGN all use the same debt beta of 0.1. The read-across from the CC's estimate of NIE's asset beta is less straight-forward, but the UR notes that the CC's final NIE inquiry report contains a calculation of the equity beta that NIE would have if its gearing were 65%, in which the CC gears up a 0.4 asset beta using a debt beta of 0.1.* The UR's DD effectively replicated this computation, but for gearing of 55%. The UR is content, therefore, that it used the regulators' beta estimates in the three above-mentioned reviews appropriately and that the

No	Ref.	Section & Topic	Comment	Our Response
				draft determination positions PNGL's beta logically relative to other, comparable regulatory determinations, having regard to the intrinsic riskiness of the businesses. *See table 13.13 of the CC's final NIE inquiry report.
61	Section 3.1.2	Cost of equity – beta	PNGL considers that the UR and its consultant provided very little justification for its debt beta assumption of 0.1.	The UR's 0.1 debt beta aligns to debt beta assumptions in the Ofgem RIIO-ED1, SGN and CC beta analysis, as noted above. More generally, it is important that the UR captures an appropriate relationship between gearing and WACC when it transforms an asset beta into an equity beta. Using a debt beta of 0, as PNGL recommends, would have the effect that PNGL's pre-tax WACC increases quite significantly as gearing increases, which runs contrary to mainstream views on the effect that one would expect to observe.
62	Section 3.1.2	Cost of equity – beta	PNGL notes that equity betas for the UK's listed regulated companies have been increasing in recent months. PNGL argues that the UR should have factored these increases into its analysis.	The UR acknowledges that empirical estimates of equity betas have been increasing recently. In line with the position taken by the CC/CMA in recent reports, the UR considers that it should not be overly swayed by short-term movements in share price data, but should instead seek to look at empirical estimates of beta over a longer time horizon. The UR notes that equity betas of listed network companies averaged over, say, five years lie within the 0.3--0.40 asset beta range that the UR has ascribed to a 'standard' network utility, especially after SSE is removed from the comparator set, as a company that makes approximately half of its profits from riskier

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				generation and retail activities.
63	Section 3.1.2	Cost of equity – tax	PNGL argues that the tax wedge adjustment in the DD WACC is too simplistic, and calls once again for the UR to adopt an alternative methodology that is used by Ofcom.	The UR acknowledges that regulatory practice in this area is not uniform, with some regulators (e.g. the CAA and the CC) applying the simple tax wedge adjustment used in the DD and other regulators (e.g. Ofcom) applying the adjustment that PNGL is now proposing. The lack of consensus is perhaps best exemplified in the way that PNGL and its consultants were content to use the former approach in its July 2015 cost of capital submission but are now advocating the latter approach in its response to the DD. The UR's reluctance to depart from its usual practice of making a simple tax wedge adjustment stems from the sheer number of factors that can cause a company to pay or more less tax in any one year than the simple gross up of the real cost of equity would appear to provide for. These factors include: - the capitalisation of a proportion of the nominal return on equity within the TRV, and subsequent run down of the TRV value - the availability of nominal interest tax shields, over and above the real cost of debt factored into the WACC calculation - the availability of accelerated tax capital allowances PNGL's proposed methodology addresses the first of these issues, but does nothing about the second and third. As a matter of principle, the best way of capturing a company's actual tax-paying position is to provide for a vanilla WACC and a separate, modelled allowance for tax. The UR notes that PNGL has not recommended this

No	Ref.	Section & Topic	Comment	Our Response
				approach. Our own analysis suggests that if we were to go down this path, PNGL will only begin paying tax during the GD17 period and, hence, allowed revenues would fall below the level provided for in the FD. In these circumstances, where PNGL is already being over-compensated for the tax that is payable within the confines of this price control period, the UR is reluctant to increase PNGL's GD17 tax allowance still further. We are especially reluctant to adopt a methodology which builds in one of the factors that is overlooked in a simple tax wedge adjustment (and which happens to have a favourable impact on revenues) but ignore other equally important factors (which go the opposite way).
64	Section 3.1.3	Cost of debt – inflation assumption	PNGL suggests that the UR over-estimated the rate of RPI inflation, principally because it drew on OBR inflation forecasts rather than inflation readings from the gilt market	The UR accepts that all inflation forecasts come with a margin of error. It placed reliance on OBR forecasts in recognition of the OBR's pre-eminent role as the provider of macroeconomic forecasts to the public sector. The UR notes that had it looked instead to other economic forecasters, the estimates of future RPI inflation would not have been materially different. We compare below the forecasts in the OBR's November 2015 release and the average forecast in HM Treasury's November 2015 round-up of independent forecasts. <u>OBR</u> 2017 = 2.9% 2018 = 3.2% 2019 = 3.2% 2020 = 3.2%

No	Ref.	Section & Topic	Comment	Our Response
				Long term = 3.0% <u>Average independent forecast</u> 2017 = 3.1% 2018 = 3.3% 2019 = 3.3% 2020 = not given Long term = not given PNGL's alternative RPI forecast of 2.2% per annum inflation over the GD17 period differs from the OBR forecast not because the OBR forecast is an outlier, but because PNGL is employing a fundamentally different methodology. We question first of all whether it is credible to think that RPI inflation will come out so close to the government's 2.0% CPI inflation target, given historical evidence of a substantial wedge between the RPI and CPI inflation measures. We also question whether reliable forecasts of inflation can be taken from the gilt market, and note that commentators have expressed concerns about such readings in the light of certain distortions that impact on gilt prices.* Taking these things together, the UR does not accept that there was any fault in its DD RPI forecast or that PNGL's approach gives a more reliable forecast of RPI inflation. * See, for example, Hughes (2009), Understanding and addressing the pension liabilities of regulated utilities – a paper for the Regulatory Policy Institute.
65	Section 3.1.3	Cost of debt – inflation assumption	PNGL states that the UR erred by not using a short-term (i.e. calendar year 2017) forecast	The approach in the draft determination was to apply the same average GD17 annual inflation

No	Ref.	Section & Topic	Comment	Our Response
			of inflation in its calculation of embedded, resulting in an under-estimate of the real cost of embedded debt.	rate to both embedded (i.e. pre-2017) and new (i.e. post-2017) debt. PNGL's alternative approach of applying a short-term inflation forecast for embedded debt is valid, except that PNGL fails to recognise the need for an accompanying adjustment to the inflation assumption used in the calculation of new debt. That is to say that if PNGL's split approach requires a calendar year 2017 RPI forecast for embedded debt, it should apply a 2018-22 RPI forecast to new debt, not the full 2017-22 average RPI inflation rate. This issue then becomes no more than a matter of presentation. Mathematically, the overall cost of debt remains the same regardless of whether the UR applies the GD17 annual inflation rate or (correctly) applies a split approach.
66	Section 3.1.3	Cost of debt – forward rate adjustment	PNGL states that the forward-rate adjustment should allow for increases in interest rates that may occur after the refinancing of its bond in mid-2017 up to the expiry of its bank facilities in late 2018.	Insofar as PNGL expects to refinance itself in two tranches, the UR accepts that the forward rate adjustment should extend beyond mid-2017 to the end of 2017 (as roughly the mid-point between the redemption of its bonds and the expiry of its bank facilities).
67	Section 3.1.3	Cost of debt – illiquidity premium	PNGL argues that the UR under-estimated the illiquidity premium that is apparent in price of its bond in the secondary market because the UR did not allow for a 'tapering' of the premium that occurs as the date of redemption draws nearer. PNGL's consultant, NERA puts forward a methodology which it says corrects for this effect.	The UR considers that is plausible that there will be a 'tapering effect'. However, the UR is not persuaded that it needs to correct its calculation of the illiquidity premium, or that it should adopt the methodology proposed by NERA. This is for the following reasons: - the UR's estimate of the illiquidity premium

No	Ref.	Section & Topic	Comment	Our Response
				was based on observations of bond yields since late 2012, and not only at the end of 2015 as stated by NERA. It is not clear that the tapering effect will have a material effect on yields 4-5 years out from redemption; and - NERA attributes the premium on PNGL's bond to credit risk, whereas the UR considers that the premium is more likely to be due to illiquidity. If illiquidity is the key issue, the scale of the tapering effect cannot so easily be assessed with reference to the shape of the yield curve. Instead, it may be reasonable to assume that the illiquidity premium is a constant that applies to debt of all maturities. The UR recognises that it is difficult to estimate the premium that PNGL might have to pay on new debt with any accuracy. It was for this reason that the UR originally proposed wrapping the illiquidity premium into the cost of debt adjustment mechanism. Insofar as PNGL has argued against this approach, the UR considers that it should be quite cautious when dealing with conjecture that PNGL will have to price its debt at a materially different level to other issuers with a BBB/Baa category rating.
68	Section 3.1.3	Cost of debt – fees	PNGL argues that the UR made no allowance for the bank fees that it will have to pay for financing facilities outside of new bond issues	The UR accepts that allowance should be made for the cost of arranging and maintaining these facilities. The FD allowance for fees has been increased accordingly.
69	Section 3.1.3	Cost of debt – nominal-real transformation	PNGL states that the UR should not have deflated the whole of the calculated cost of debt by RPI inflation.	The UR does not accept that there is any material error in this aspect of its methodology. Having established what the

No	Ref.	Section & Topic	Comment	Our Response
				total cost of debt would be in nominal terms, it was appropriate to partition this overall figure between the RPI indexation of PNGL's TRV and a residual in-year cost of debt allowance. There is no reason why the nominal-real transformation should be applied to only a sub-total within the build-up of the coupon that PNGL will pay on its debt. The UR accepts that it is arguable whether the small allowance for fees should be added before or after the nominal-real transformation, but notes that there is no material impact on the cost of debt allowance.
70	Section 3.1.3	Cost of debt – adjustment mechanism	PNGL makes a number of suggestions about the design of the cost adjustment mechanism	These suggestions are considered in the discussion of the final design of the mechanism, in chapter … of the UR's FD document.
71	Section 3.1.1	Financeability	PNGL argues that the UR's DD analysis of financeability was flawed because: - the UR modelled financial ratios at a level of gearing (55%) that was set below 'efficient gearing' - the UR targeted a lower credit rating (BBB/Baa) than has been deemed sufficient in most other regulatory reviews - the UR modelled only two financial ratios, and did not take account of other ratios that are considered important by lenders - the UR did not produce downside sensitivity analysis PNGL notes that it has been placed on negative watch/outlook following the publication of the DD and argues that this	The UR made a conscious decision to model the financial ratios for a notional company with a notional gearing. The UR notes that PNGL has previously selected a higher gearing level, but considers that this is a matter for the company alone and should not influence a regulator's calculation of allowed revenues or the assessment of a business's innate ability to finance its activities. PNGL's contention that the efficient gearing ratio lies in excess of 55% does not withstand scrutiny. The rating agency guidelines it cites identify the maximum level of indebtedness that the rating agencies would consider to be compatible with particular credit ratings. These limits cannot be looked at in isolation. Other factors may mean that it is efficient for a

No	Ref.	Section & Topic	Comment	Our Response
			demonstrates that the UR is jeopardising PNGL's financeability	company to take on less debt. In PNGL's case, the Profiling Adjustment and the combination of a real rate of return and nominal interest payments serve to reduce cashflows in the short term and put pressure on interest cover ratios. In these circumstances, the UR judges that it is likely to be efficient – from the perspective of both the company and its customers – for a company to select a gearing ratio that lies some way below the maximum permissible limit. The selection of a BBB/Baa credit rating mirrors the judgment that PNGL has hitherto made about the optimal credit rating. Unless PNGL is proposing to target a different rating in the GD17 period, the UR does not consider that it has reason to target a different rating in its financeability analysis. The UR has modelled a broader range of financial ratios as part of this FD, including FFO interest cover, FFO to net debt and Retained Cash Flow / Capex, although these do not alter the UR's conclusions. The UR has conducted downside sensitivity scenarios in this FD, involving increases in opex and capex of 15% and ignoring risk sharing. Unsurprisingly, these scenarios show a deterioration in ratios compared to the central case presented in Chapter 10. While these scenarios depict some of the possible out-turns that PNGL may encounter, the UR considers them to be of limited interest from a financeability point of view because they assume that all under-performance is financed through debt issuance. The UR does not consider that this is necessarily the correct

No	Ref.	Section & Topic	Comment	Our Response
				assumption. The risks here are risks that equity holders are being paid to bear via the allowed return on equity and it is just as reasonable to assume that equity rather than debt will flex to accommodate downside scenarios. If one holds debt constant in the scenarios we have constructed, key financial ratios remain broadly unchanged. If, ultimately, PNGL is downgraded, the UR would take this to mean that PNGL has attempted to take on too much debt and needs to de-gear to a more efficient capital structure.
72	3.2.2.1	Connection Targets	UR's proposed target for OO connections for the GD17 period is too high. Overall UR's target is 25% higher than PNGL's forecast.	We have reconsidered the current connection targets and have revised them downwards, based on the evidence as provided. Further detail in contained in Section 6 on this area.
73	3.2.3.5	Connection Incentive: The reduction of allowances through the concept of 'non-additionality'	Reducing the value of allowances available to PNGL per connection (i.e. from £789 in PNGL to £570 in GD14 and to £420 in 2022) whilst also increasing the volume of 'non-additional' connections is arbitrary penalising PNGL. The application of 'non-additionality' to a price control period that PNGL anticipates to be more challenging than in recent past to obtain OO connections, is particularly punitive. UR's proposal that no allowance be given for the first 33% of OO connections serves only to magnify the downside risk loaded onto PNGL. The concept of 'non-additionality' should be removed in its entirety from the GD17 determination.	In GD14 next steps, we considered that cutting the overall allowance by 50% would be appropriate, which reflects that gas has now moved to being the fuel of choice in Greater Belfast. However, having considered the arguments from PNGL on the potential impact of such a change we propose that 33% "non - additional" represents a reasonable figure which recognises that the awareness of gas has increased since 2014 in the existing PNGL area while still facilitating a substantial amount of resources to be available for continuing the growth of the industry
74	3.2.3.6	Connections Incentive: Cap and Collar	PNGL proposes that the mechanism utilised to reward outperformance and penalise for under performance is amended to be symmetric i.e. that it is only the connections from outperformance or underperformance that are subject to the increased / lower	We consider that we have dealt with this issue by removing the cap from the OO connection incentive for GD17 which is detailed in Chapter 6 of the final determination.

No	Ref.	Section & Topic	Comment	Our Response
			allowance. Furthermore, UR should consider adjusting the cap and collar included in the mechanism from a percentage of connection allowances to set monetary values with a minimum connection target.	
75	3.2.3	Connections Incentive Allowances	It is imperative that the mechanism that sets the allowances available for AMD to encourage OO connections in GD17 generates sufficient allowances to cover the costs required to generate the targeted level of OO connections. The current mechanism proposed by the UR does not do this. PNGL suggests UR gives consideration to simplifying the proposed incentive mechanism. A simplified mechanism gives clearer signals to the company about what the Regulator is trying to achieve, simplifies trade-offs, and is more likely to avoid unintended consequences.	We have amended the connection incentive mechanism in 2 main ways for the final determination. First, In addition to the incentive allowance set out in the draft determination we have provided and an additional 'new area' allowance for each of the GDNs in recognition of the challenges in promoting gas as the fuel of choice in areas and therefore potential customers who are unfamiliar with natural gas. Second, we have simplified the mechanism by removing the cap and adjusting the collar. We believe this regime ensures the GDNs have sufficient incentive to connect as many OO properties as possible.
76	3.3	Manpower: Operations	As part of its GD17 submission, PNGL requested 1 additional FTE within Operations as a direct consequence of the forecast growth of customer numbers in the GD17 period. The maintenance activities proposed to be performed by the additional FTE are directly related to the volume of connected properties. UR proposes to disallow this additional FTE even though the proposed increase in FTEs amounts to only 9% within Operations compared to a forecast increase of c54k connections (or 24%) over the GD17 period. UR's proposal that the end-of-life replacement for larger Industrial and Commercial meters is extended beyond the industry standard of 20 years will also impact on the resources required within Operations. UR's determination should include the additional requested FTE for GD17.	We have accepted the points made by PNGL and allowed for an additional FTE in the GD17 period for Operations Management.

No	Ref.	Section & Topic	Comment	Our Response
77	3.3	Manpower: Customer Management	PNGL welcomes UR's small increase in Customer Management FTEs '*given the expected increase in customer connections in GD17*'. However, the proposed increases in FTEs for Customer Management is not sufficient as: • PNGL's 2014 average FTEs for Customer Management were understated due to the high levels of staff turnover experienced in 2014 and 2015. The actual FTEs currently employed are 37.5 FTEs • The proposed increase is not sufficient when compared with the increase in connections forecast during the GD17 period. UR's determination should include sufficient increase in FTEs within Customer Management to appropriately account for the forecast growth in connections.	As noted by PNGL we provided for additional FTE in the draft determination and maintained this for the final determination.
78	Section 3.3.1 Section 3.3.1.2 and Section 3.3.1.3	Asset Management Manpower	UR's proposal to base PNGL's GD17 allowances for manpower on 2014 FTE actuals as the starting point is inappropriate as PNGL's actual number of FTEs for 2014 did not include the FTE required to prepare for the introduction and the ongoing operation of a formalised asset management system. UR provided PNGL with an allowance for 1 additional FTE in 2014 and 2015 to facilitate the introduction of the new asset management system, which will ultimately be accredited to the new ISO Asset Management Standard – ISO55001. However, this FTE was employed during 2015 and not 2014 as forecast by PNGL at the time of its GD14 submission. At the time of the GD14 price control	We consider that we allowed appropriate FTE's to allow PNGL to implement its Asset Management system in 2014. We consider that over time, the existing resources as used in this area, will manage the assets going forward.

No	Ref.	Section & Topic	Comment	Our Response
			submission, PNGL estimated that 1 additional asset management FTE would be sufficient to develop and introduce an ISO55001 complaint asset management system. However, at the time PNGL did not fully comprehend the significant volume of new activities required in order to ensure ongoing compliance with the standard. The additional FTE now requested by PNGL for the 2017 period reflects the actual resource required to administer and manage an asset management system that remains complaint with ISO55001 each year.	
79	3.3.3	Manpower Costs	UR's proposal to base PNGL's GD17 allowances for manpower using 2014 FTEs as a baseline is inappropriate due to the significantly higher than normal levels of staff turnover experienced at that time. In addition, UR's proposal is inappropriate as it excludes the additional 1 FTE allowed by UR in its GD14 determination and employed by PNGL in 2015 to facilitate the introduction of the new asset management system, ISO 55001. A more appropriate baseline, which should be used by UR in its final determination, is the latest actual number of FTEs employed by PNGL i.e. 124.3 FTEs in Q1 2016. These FTEs are in line with the FTEs granted by UR under its GD14 determination. UR's proposal to only allow a minor increase in FTEs over the GD17 period does not fully reflect the growth of the customer base forecast for GD17 and the future needs of the business. PNGL requests that UR	We consider it is appropriate to use actual numbers rather than projections as a baseline in determining appropriate FTE's and manpower cost allowances and this information is more robust than projections which would be subject to change. We regard use of a baseline based on the most recent actual figures as best practice. We note that the limited data we have seen in relation to PNGL 2015 actual headcount suggests that the FTE numbers are less than projected by PNGL in its business plan submission. In addition we have provided additional allowances to reflect a growing network consistent with previous growth rates.

No	Ref.	Section & Topic	Comment	Our Response
			reconsiders its proposed number of FTEs for GD17 as part of its final determination. UR's proposed allowance for the PNGL Management Team is based on outdated analysis performed in 2011 and results in allowances c.42% less than PNGL's forecast costs and potentially c.52% less once you take into account the impact of the allocation methodology employed as part of the connection incentive mechanism. PNGL would therefore urge UR to reconsider its current proposal as it is entirely inconsistent with actual costs incurred as dictated by market conditions.	 We consider that the Benchmark used for the PNGL Management team is appropriate, based on no significant change in market conditions
80	4.1.1 and 4.1.2	Apprenticeship Levy and National Living Wage	From 6 April 2017 all employers in the UK with a pay bill in excess of £3m per annum will be required to pay an Apprenticeship Levy to HMRC. The Apprenticeship Levy is set at 0.5% of an employer's gross total employee earnings. Employers paying the Apprenticeship levy will be eligible to an allowance of £15,000 to spend on Apprenticeship training. However, there is currently no guarantee PNGL will receive this allowance as the NI Executive is yet to communicate on how it will use the new income from the Apprenticeship Levy. PNGL requests that UR considers the impact of the new Apprenticeship Levy as part of the final determination. The Government's National Wage was introduced on 1 April 2016. Employers are required by law to pay applicable employees a minimum of £7.20 per hour worked. NLW is scheduled to increase to £9 per hour by 2020. In order to comply with the NLW PNGL has been required to provide (in 2016), and will	We consider that there is uncertainty over both the impact and timing of the apprenticeship levy and the living wage but that they are unlikely to be of such an extent that an efficiently run utility cannot manage them within the determined allowances.

No	Ref.	Section & Topic	Comment	Our Response
			continue to be required to provide (during the GD17 period) salary increases to lower paid workers in excess of the level of inflation. PNGL estimates that these salary increases will, in total amount to £25k-£30k per annum. UR's final determination should include these additional salary costs across GD17.	
81	4.3	Advertising and Market Development (Non-OO)	PNGL's New Build Sales Manager and New Build Sales Consultant are responsible for all aspects of private new build sales. PNGL incorrectly used an 85% allocation to owner occupied activities in its GD17 BPT submission. As advised by PNGL during the consultation process, UR should therefore reallocate New Build Sales exclusively to non-owner occupied activities, to accurately reflect activities undertaken.	We have accepted this correction and it has been reflected in the final determination.
82	Section 4.4	Emergency Costs	PNGL acknowledges the GD17 draft determination allowance as an appropriate allowance to deliver an emergency response service under non-extreme conditions across the PNGL network in GD17. While PNGL was able to meet the short-term spike in demand in Winter 2010/11, PNGL is concerned that the allowances proposed by UR would make managing a similar extreme event in GD17 unfeasible. Notably PNGL's contract for utilisation of the National Grid Emergency Control Centre in Hinckley requires consultation were call volumes increased by over 15% for a period of time. PNGL would highlight that the benefits arising from this change have arisen across two relatively benign winters and as such activity levels have been set in that context. PNGL would therefore be concerned that in the context of a more extreme winter, emergency response costs are likely to be abnormally affected. PNGL would request that UR considers how	We have considered the points raised by PNGL but have not made any adjustments to the allowances in this regard for the following reasons: • We would expect PNGL to be prepared for all scenarios as a responsible and prudent operator and to have allowed for all reasonable costs in its submission. There were no reductions in PNGL's requested emergency cost allowances as a consequence of the modelling undertaken. PNGL's requested funding for emergency costs was therefore allowed in full following removal of the PES profit margin element. The allowances are therefore considered sufficient. • Allowances are made for an average year and while costs in any year may be higher or lower, we would expect this to largely balance out over the price control period. • A review of the Hinckley contract letter indicates that calls need to exceed the

No	Ref.	Section & Topic	Comment	Our Response
			additional expenditure required in an extreme event is accounted for under the UR's proposal for GD17.	upper banding threshold for a consecutive period of 3 months before consultation occurs and that changes would only be made if this was proven to be a sustained increase. Short duration peaks in demand associated with extreme weather events would not meet these criteria and therefore wouldn't result in a sustained increase in costs.
83	Section 4.5	Maintenance	PNGL notes the maintenance costs included in UR's draft determination make no allowance for the staff costs nor transport and plant attributed by PNGL to maintenance activities; the draft determination allowance is therefore understated by c.£230k each year.	We have further examined staff, transport and plant costs within the maintenance budget and have adjusted the allowance as described by PNGL.
84	Section 4.5.2	Valve Accessibility Project	PNGL would contend that their proposed strategy for including the entire underground valve asset within the project is the most prudent and appropriate approach with regards to controlling the risks posed by inaccessibility across the underground valve asset. UR should therefore reconsider its position in the draft determination accordingly and provide an allowance to cover works on the entire underground valve asset.	PNGL included its valve accessibility project as a new item in GD17 having managed to operate their network safely for over 15 years. In our draft determination, we asked the company to consider how it could develop a clear risk based approach to targeting this work. In the absence of any further information from the company we have maintained the position of the draft determination. It is for the company to take all steps necessary to continue to manage its network safely.
85	4.6	IT & Telecoms	PNGL notes the allowances for IT & telecoms in the draft determination but has requested additional allowances for the final determination for: • Maintenance and support costs of IT equipment • System development support • Resources to protect its network, internet and mail services • Upgrade to financial software solutions • Costs associated with reviewing hosting	On reviewing this area, we consider that we allowed sufficient allowances within the draft determination to facilitate PNGL to undertake IT maintenance and updates. Based on historic costs incurred in the past and compared aginst other regulatory decisions, we are content with the allowances granted.

No	Ref.	Section & Topic	Comment	Our Response
			requirements	
86	4.7	Property management	Ofgem's three price control reviews under the RIIO model treat business rates as non-controllable opex and therefore treat network rates as pass-through. The effect of the Competition Commission's decision in relation to PNGL's network rates was essentially to implement a pass-through mechanism for rates since 1996. Furthermore it would be unreasonable for UR to align the price controls of NI's GDNs while treating this uncontrollable cost differently for PNGL and the other NI GDNs. PNGL would therefore expect UR to allow a pass-through of rates in line with the body of relevant precedent.	We have considered how Ofgem has treated business/network rates, which is deemed to be an uncontrollable cost. This basis was on the assumption that "once the rating valuations are concluded the costs that they incur will be non-controllable" Although they went on to indicate that "Each network company is able to influence the valuation that is given and hence the business rates that it will incur in the future" We disagree with PNGL suggestion that the CC indicated that this should be pass through in PNGL12. We have considered the comments made by the CMA on RP5, in this area, which said the following; "We have not sought to characterize NIE's costs as either 'controllable' or 'uncontrollable' costs. Instead, we recognized that NIE has some ability to influence its rates liability. For the reasons set out above (paragraphs 5.348 to 5.357), we did not consider it appropriate for NIE's rates liability to be passed on to consumers in full or to use the Ofgem approach that NIE referred us to". For the final determination we have concluded it is not appropriate to maintain FE rates as a pass-through and therefore there is now consistency of how we treat network rates for FE and PNGL. We are following the principle of the CMA in this area and not treating rates as pass through.
87	4.8	Audit, Finance & Regulation	UR proposed allowances for Professional and Legal costs are based on actual costs incurred by PNGL during 2014 of £308k.	We consider that 2014 provides the best basis for a typical base year. PNGL's actual spend in 2014 was in line with the GD14 allowances.

No	Ref.	Section & Topic	Comment	Our Response
			PNGL disagrees with the use of 2014 as the base year as 2014 does not reflect the underlying average costs PNGL has incurred or will incur during the GD17 period. For example: • 2014 was the first year of the GD14 price control • There were no major changes to PNGL's structure or activities • Supply competition has stabilised • There was no major Licence modifications The allowances proposed by the UR for the GD17 period are understated by c.£130k per annum. PNGL would request UR to reconsider its proposal on this basis. Additional consultancy costs forecast around each price control e.g. in 2015, 2016 and 2017 for the GD17 review; and in 2021, 2022 and 2023 for the GD23 review. Given the scope and duration of this and future price control reviews, PNGL would request UR to reconsider its proposal on this basis.	In using 2014 as a base year we accept that some costs may be higher or lower in different years but expect that this will average out.
88	4.8	NIED project	PNGL expects that any costs associated with the NIED project will be included within the GD17 Uncertainty Mechanism.	We await a business plan in this area, before any assessment of costs can be made.
89	4.9	Insurance	UR is proposing to grant PNGL a business insurance allowance based on a three-year average of the actual costs incurred during 2012 to 2014. PNGL's GD17 business insurances are driven by inflation, turnover, capex and number of employee's. PNGL's business insurance requirements will therefore flex with the outputs of UR's final determination.	The business insurance costs requested by PNGL represent a significant increase on historic premiums for the GD17 control period. For example, the increase between 2014 actuals and the request for 2017 is over 30%. We do not have sufficient evidence to justify such an increase. We have used an average over 3 years costs, which differs from using the 2014 year, to reflect the variability of the insurance market on premiums.

No	Ref.	Section & Topic	Comment	Our Response
			PNGL has no scope to reduce the car insurance premiums further. The allowances provided by the UR should be sufficient to cover the actual premiums paid by PNGL. PNGL would request UR to reconsider its proposal on this basis.	We consider that PNGL requested allowance for car insurance is unreasonably high when compared to the other GDNs requested allowances. We are using benchmarked information, that is specific to the NI market We have therefore maintained the approach and allowances used in the draft determination.
90	Section 5.1	Capital Expenditure - Reinforcement	PNGL has included a project to reinforce the intermediate pressure main for the Bangor/Donaghadee/Millisle area during GD17. PNGL is required to review its design for a 1 in 20 year event recurrence interval with interruptible supply loads switched off to confirm the need for the project. UR's final determination for GD17 should therefore reflect the investment as proposed in the consultation. PNGL acknowledges the GD17 draft determination allowance as an appropriate allowance to undertake the reinforcement.	We have reviewed the paper (Appendix 7) PNGL submitted as part of the draft determination response and have retained the capital expenditure for this reinforcement project in the final determination. The unit rate also remains unaltered from the draft determination. PNGL demonstrated the need for this reinforcement based on increasing forecast load and the marginal effects of interruptible loads on this section of network.
91	Section 5.2.1	Capital Expenditure - I&C Properties Passed Correction	PNGL notes an error in Table 88 of the consultation; PNGL is proposing infill for small numbers of I&C properties in GD17. 10% of the existing properties PNGL is proposing to pass are I&C properties (which is consistent with the property split in GD14).	We have again reviewed a sample of properties which PNGL propose to pass in GD17 reviewing maps and street view. The properties are mainly domestic and we did not find evidence to support the view that 10% of properties in this selection will be I&C.
92	Section 5.4	Capital Expenditure - Properties Passed in East Down	The properties passed detailed in the consultation must be aligned with PNGL's forecast development plan for each town. As part of the licence extension application, PNGL provided a programme of mainlaying for East Down. UR's property passed target does not align with this.	The properties past in the draft determination were sourced from 'DRIVERS!' contained in PNGL's final East Down submission to us. The 'Build Programme!' as submitted by PNGL did not align with any other worksheet submitted by PNGL in the East Down Final Model. The 'Build programme!' only indicated a general phasing of mainlaying by 3 zones. PNGL has since made an additional submission of properties past and connections

No	Ref.	Section & Topic	Comment	Our Response
				to us and this submission forms the basis for the final determination.
93	Section 5.5	Capital Expenditure - Domestic Meters, End of Life Replacement	PNGL does not consider a volume driver for domestic meter replacements is required. PNGL's forecast of the number of domestic meter replacements included within their GD17 submission is based on the data held within their asset register which records the meter installation date. PNGL would therefore be provided with a pre-determined amount of investment with PNGL carrying the risk and benefit of having over or under-forecast the number of meters to be replaced across GD17.	We do not agree with PNGL. An amount of capital expenditure has been allocated to replace meters as they come to the end of their useful life and we agree with PNGL in their submission that 20 years is a reasonable life expectancy for said meters. It is therefore important that an account of meters replaced and expenditure incurred is maintained and reported to aid future determinations.
94	Section 5.6	Capital Expenditure - I&C Meters, End of Life Replacement	UR should allow PNGL the costs to replace all diaphragm meters (U6 to U40) at 20 years. UR should either (i) provide PNGL with appropriate capex allowances to replace all rotary and turbine meters at 20 years; or (ii) provide PNGL with appropriate capex and opex allowances to implement procedures to attempt to extend the end-of-life of rotary and turbine meters from 20 to 25 years.	We have accepted PNGL's arguments for replacing U6-U40 meters as complete meter installations for the GD17 price control. PNGL has submitted additional information indicating the cost of replacing necessary components of larger meter installations. These costs have been included in the final determination subject to minor changes for capitalised opex allowing PNGL to replace all meters as they reach end of life.

No	Ref.	Section & Topic	Comment	Our Response
95	Section 6	Innovation	PNGL considers that given that the scope and scale of the CNG project is not sufficiently advanced, PNGL is not in a position to provide a business plan of all identified costs at this stage. PNGL agrees that there is a reasonable prospect that the CNG project may not be sufficiently advanced to allow for a decision on cost allowances at the time of the GD17 determination. PNGL therefore agrees with UR's proposal and expects that any costs associated with the CNG project will be included within the GD17 Uncertainty Mechanism.	We consider that any CNG project needs to be aligned with the government policy on alternative fuels (and CNG in particular) infrastructure. We also note that whilst INEA (Innovation and Networks Executive Agency) decided to grant EU funding towards the project, the funding is lower than requested. The GDNs informed us that further talks were scheduled with INEA on this matter for August/September 2016. In light of these uncertainties, we have decided not to grant any allowances for a CNG project at this stage. For further details see section 8 Innovation, Detailed Approach – UR Decisions, Innovation Initiatives, Development of Infrastructure for CNG vehicles of the GD17 final determination.
96	Section 6.5	Consumer research	PNGL notes how consumer engagement is one of a number of issues to be considered during the GD17 period and suggests a reconvening of a previous Gas Distribution Forum to agree a timetable which is transparent and workable.	We note PNGL's suggested way forward and would re-iterate our Draft Determination intention to build on our experience when progressing a similar developmental objective with NI Water over the last couple of years during the PC15 period. Our Draft Determination timetable was based on what we consider to be realistic and workable timescales, including the necessary milestones, to bring in new customer service metrics and satisfaction surveys. The development of an agreed timetable can be itself a developmental objective for the first 6 months of the GD17 period and we shall work to develop this through a partnership working group approach of all GDNs, the CCNI, DfE and the UR.
97	Section 7.1	Uncertainty Mechanism	PNGL acknowledge that the GD17 Uncertainty Mechanism is in line with that used for GD14, however, suggest that the following items be added to the table of	We have considered these comments. For further details see section 9.s

No	Ref.	Section & Topic	Comment	Our Response
			allowances subject to the mechanism for the FD: • Costs associated with the Northern Ireland European Development (NIED) Project as a pass through allowance, due to the fact that the scope and scale of the project are outside the control of PNGL; • The proposed treatment of costs associated with a Supplier of Last Resort (SoLR) event; and, • Costs associated with the Compressed Natural Gas (CNG) Project due to the fact that the scope and scale of the project are outside the control of PNGL;	
98	Section 7.2	Materiality Thresholds	PNGL state that the intention to increase the materiality threshold to £150k is “misguided” and “not appropriate to the size of PNGL’s operations and should be removed”. PNGL feel that this could mean that key projects benefiting the industry could be unfunded such as projects planned with PTL and other GDNs which are likely to be below the threshold. Projects scoped by European Directives are outside a GDN’s control and can expose PNGL to unnecessary risk if they cost below any materiality threshold.	We have noted the concerns PNGL have in this area and have taken the decision to reduce this to a £100k.
99	Sections 9 and 11	Further Issues	PNGL suggests that the Gas Distribution Forum is reconvened following the GD17 FD to address issues relating to the following areas and agree a suitable related timetable: • Consumer engagement • Shrinkage review • Review of conveyance charges • Revision of annual/cost reporting templates and associated RIGs	We note the suggestion made by PNGL. Meetings to discuss these matters should be arranged as appropriate.

No	Ref.	Section & Topic	Comment	Our Response
			• Provision of a single low pressure network code together with a consistent switching system and consistent switching processes • Delivery of a common branding approach in relating to promoting natural gas in NI Delivery of a common low pressure network tariff in NI	
100	Section 9	Outputs, outcomes and allowances: Supplier of last resort	PNGL notes that the allowed costs relating to a supplier of last resort event must be an automatic pass through item for GDNs under the uncertainty mechanism as GDNs have no ability to influence or control these costs and should not be exposed to unnecessary risk. PNGL notes its concerns with the options proposed in the GD17 draft determination for building the supplier of last resort costs into the GD17 price control. PNGL notes in particular that option one could result in a significant delay in the GDN ability to recover costs as adjustments would only be made at the next price control. PNGL also notes that option two presents significant risk: • A specific monetary allowance is subjective and may still result in significant delay of GDN ability to start to recover costs. Key to establishing such an allowance are estimated costs; potential allowable costs have not yet been identified to allow a proper consideration of cost recovery amounts. • It is essential that UR provides clarity on the treatment of cost incurred by the SoLR for providing additional credit support as this could significantly affect the level of costs required under any uncertainty mechanism. • It cannot be assumed that this option will	See response to no. 49 above.

No	Ref.	Section & Topic	Comment	Our Response
			not present financing issues given that scope and scale of a SoLR event may never be sufficiently advanced to allow for a decision on cost allowances at the time of GD17 FD. PNGL considers that a more pragmatic solution would be an amendment to the GDN licences to allow supplier of last resort payments to be recovered through a specific and limited special review, such as the one referred to in Condition 4.7 of the SGN licence. PNGL also encourage the UR, irrespective of the SoLR cost recovery solution, to reconsider inclusion of appropriate wording within GDN licences which details the SoLR cost recovery process to provide the necessary transparency and governance of the cost recovery process.	
101	Section 9.2	Outputs, outcomes and allowances: East Down	PNGL notes that the inclusion of the Postalised Distribution Pipeline should have no impact on distribution tariffs. PNGL does not believe that the Pis model published by UR currently achieves this. PNGL notes their intention to work with UR on resolving these issues as part of the separate Pi modelling workstream.	Work has progressed on dealing with this and is covered in Chapter 11 of the FD.
102	Section 9.3	Outputs, outcomes and allowances Designated Parameters and Determination Values	• PNGL notes an error in Table 189 of the GD17 DD: In line with licence Condition 2.3.26 parameter m should be 2016, not 2017.	We note the comment made by PNGL. This has been corrected for the GD17 final determination.
103	Section 10.3	Proposed licence modifications: licence alignment between GDNs pursuant to the Gas to the West project – Independence of the	PNGL notes in relation to proposed licence Condition 1.16.1 that the equivalent provision in the SGN Licence also includes the following wording: "(a) *it conveys, or is authorised to convey, gas through low pressure pipe-lines*;". PNGL notes that this	We note the comment and have amended the licence drafting proposed in the consultation paper on Licence Modifications Pursuant to the GD17 Final Determination and other Regulatory Decisions for FE and PNGL accordingly.

No	Ref.	Section & Topic	Comment	Our Response
		licensed business	appears to be an oversight, and should be included for consistency with the SGN Licence.	
104	Section 10.3	Proposed licence modifications: licence alignment between GDNs pursuant to the Gas to the West project – Connection charges and obligation to permit a connection	PNGL notes in relation to proposed Conditions 2.4.19 and 2.4.20 that it is unnecessary to duplicate legislative requirements within PNGL's licence and that PNGL is already obliged to meet the requirements of The Gas (Individual Standards of Performance) Regulations (Northern Ireland) 2014.	See response to no. 56 above
105	Section 10.3	Proposed licence modifications: licence alignment between GDNs pursuant to the Gas to the West project – Complaints handling procedure	PNGL notes that the definition of a complaint has been discussed at length at the Distribution Operators' Forum and that PNGL does not reiterate its concerns in their response to the GD17 draft determination. PNGL asks for confirmation if the proposed changes are required as the current definition contained in the PNGL and in the FE licences is unduly narrow and is no longer deemed to be IME3 compliant.	We note that the reason for the proposed licence modification is not IME3 compliance (or lack of same). Rather, we consider that complaints relating to any aspect of the GDNs' activities, if not properly addressed, could damage the reputation of the natural gas industry in Northern Ireland and thus potentially hinder its development. Properly addressing such complaints is important to safeguard the reputation of the gas industry in Northern Ireland. Therefore, obliging the GDNs to have complaints policies which cover the entirety of the GDNs' activities contributes to the development of the natural gas industry in NI, in line with our principal objective set out in Article 14(1) of the Energy Order. This is all the more important as during the GD17 price control period all three NI GDNs are expected to undertake major network development. We also note that the proposed modification to the FE and PNGL conveyance licences leads to an alignment of Condition 2.8A.2: Complaints Handling Procedure, The Code in the FE and PNGL conveyance licences with the corresponding Condition 2.14.3 of the SGN licence. It thus furthers the consistency between the NI low pressure conveyance

No	Ref.	Section & Topic	Comment	Our Response
				licences and helps ensure that NI GDNs are regulated on an equivalent basis.
106	Section 10.3.1	Proposed licence modifications: licence alignment between GDNs pursuant to the Gas to the West project – Common branding approach	PNGL notes in relation to Condition 2.16.1(a) that GDNs would be required to develop, implement and comply with the Common Branding Approach in conjunction and co-operation with any other person that holds a licence granted under Article 8 of the Order i.e. GDNs and transmission, supply and storage licence holders. PNGL notes that this appears to be an oversight, and that the following wording should be included: *"(a) in conjunction and co-operation with all other distribution system operators authorised to convey gas through low pressure pipelines;"* given that the Common Branding Approach would apply to GDNs only. This wording would ensure consistency with that proposed for delivering a common low pressure network tariff (Condition 2.17.1) and with that proposed for producing a single low pressure network code (Condition 2.5.13).	When we considered this suggestion, it was noted that due to differences with respect to the definition of the term "*distribution system operator*" in the SGN conveyance licence compared to the FE and PNGL conveyance licences[4], the wording "*all other distribution system operators authorised to convey gas through low pressure pipe-lines*" could not be directly transferred from the SGN to the FE and PNGL licences. We therefore propose to amend the related wording in the common branding, network code and network tariff licence conditions of the SGN conveyance licence to "*any other person authorised by virtue of a licence granted under Article 8(1)(a) of the Order to convey gas through low pressure pipe-lines*". We consider that this wording has the same effect as the one contained in the current SGN licence but also makes sense in the context of the FE and PNGL conveyance licences. We also propose to apply this revised wording in the proposed related FE and PNGL licence conditions as well. In particular, in line with the PNGL suggestion, we propose to limit the obligation for co-operation with respect to the common branding approach to co-operation with "*any other person authorised by virtue of a licence granted under Article 8(1)(a) of the Order to convey gas through low pressure pipe-lines*" only. We have amended the licence drafting

4 In the SGN conveyance licence, the term "*distribution system operator*" "*means any person authorised to convey gas through local or regional pipe-lines by virtue of holding a licence granted under Article 8(1)(a) of the Orde*r", in the FE and PNGL conveyance licences it "*means any person authorised to convey gas through distribution pipelines by virtue of holding a licence granted under Article 8(1)(a) or the Order*".

No	Ref.	Section & Topic	Comment	Our Response
				proposed in the consultation paper on Licence Modifications Pursuant to the GD17 Final Determination and other Regulatory Decisions for FE, PNGL and SGN accordingly.
107	Section 10.3.1	Proposed licence modifications: licence alignment between GDNs pursuant to the Gas to the West project – Common branding approach	PNGL notes that any common branding approach must allow each GDN to meet the distinct needs of consumers in its Licensed Area and not force GDNs into diluting their current practices by overextending the focus of their campaigns or by forcing GDNs to make generic points in each campaign. Otherwise GDNs' ability to launch targeted campaigns unique to their Licensed Area could be hindered with detriment to the overall development of the natural gas market in NI.	We consider that a common branding approach would and should not prevent GDNs from launching campaigns targeted at specific geographic areas, in specific formats and/or with specific messages and/or specific timing, as may be best suited to the customers and stage of network development in that area. Rather, the intent of a common branding approach is to further branding synergies. As natural gas is a homogenous product, we expect significant overlap in marketing benefits with respect to the three GDNs. It is our view that the GDNs have not maximised this potential. Whilst we do not propose to dictate details, we expect issues of common branding approach are addressed.
108	Section 10.3.1	Proposed licence modifications: licence alignment between GDNs pursuant to the Gas to the West project – Single low pressure network code, consistent switching system and consistent switching processes	PNGL notes that they struggle to understand what benefits a single low pressure network code will bring as the PNGL network code, including retail competition processes and necessary supporting systems, was the blueprint for those in other NI distribution networks; as network code modifications and modification rules are already consistent across NI; and as certain processes and key network activities would still need to be undertaken by each GDN, even if there was a single low pressure network code.	We note the comments made by PNGL. However, we consider it appropriate to propose the introduction of a condition relating to performance of obligations and co-operation between GDNs with respect to the Network Code in the FE and PNGL licences. It is our view that co-operation and consistency with respect to network codes is an important aspect of the development and maintenance of an efficient, economic and co-ordinated gas industry in Northern Ireland and should hence be enforceable. We note furthermore that the proposed licence drafting does not explicitly oblige the GDNs to put in place a single low pressure network code, even though it could be used to issue related directions, if deemed appropriate in the future. However, as stated in the proposed

No	Ref.	Section & Topic	Comment	Our Response
				licence drafting, any such directions could only be issued following a consultation process.
109	Section 10.4	Proposed licence modifications: licence modifications pursuant to the extension of the PNGL licensed area to East Down	PNGL considers that the properties passed detailed in the proposed development plan need to be aligned with PNGL's forecast development plan for each town. PNGL also considers that new build properties should be excluded from the development plan as their construction, timing and magnitude are outside PNGL's control. PNGL furthermore suggests that in determining whether PNGL has succeeded their obligations under the development plan, the Utility Regulator should apply the same principles as under PNGL's original mandatory development plan, detailed in Schedule 4, paragraphs 1(b) and 1(e) of the PNGL licence.	Having considered the points raised by PNGL, we have updated the proposed development plan to account for PNGL's forecasts. We have also excluded new build properties from the development plan and revised the proposed licence drafting to reflect this. We also note the points made by PNGL with respect to the application of the targets set out in Schedule 4, paragraphs 1(b) and 1(e) of the PNGL licence to the new development plan. However, we do not propose to link the development plan targets stated in the new proposed sub-paragraphs (f) and (g) to the new sub-paragraph (i) (former sub-paragraph (e)) of paragraph 1 to Schedule 4 of the PNGL conveyance licence. We consider that the target percentages set out in the proposed wording are appropriate and allow for an appropriate level of flexibility to address the uncertainties associated with the network development.
110	Section 10.70	Depreciation	PNGL notes the differences between the PNGL and firmus asset life assumptions. PNGL is not averse to UR's proposal to align the depreciation approaches within the GDNs; in fact a 5 year depreciation of IT expenditure seems more appropriate than the 40 year depreciation currently applied under PNGL's regulatory model. AC However PNGL does not agree that services should change from 35 to 40 years. This would only serve to lengthen PNGL's cost recovery period. PNGL would therefore suggest that the following asset lives are used:	As PNGL has noted the changes to the depreciation profile proposed would increase and decrease different elements and so is somewhat balanced. We note PNGL comments on services but can find no evidential reason why services should not be depreciated over the same period as mains. There seems to be a strong engineering and regulatory basis to align the two. Also 40 years follows our approach to economic assessment of gas extensions and therefore is a reasonable basis to set the depreciation profile for mains and services.

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<tr><th>No</th><th>Ref.</th><th>Section & Topic</th><th>Comment</th><th>Our Response</th></tr>
<tr><td></td><td></td><td></td><td><table><tr><th>Asset Categories</th><th>Asset Lives (years)</th></tr><tr><td>Mains</td><td>40</td></tr><tr><td>Services</td><td>35</td></tr><tr><td>Meters</td><td>15</td></tr><tr><td>Other</td><td>5</td></tr></table></td><td></td></tr>
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Table 2: Responses on Comments from PNGL

SGN Response

3.6 The SGN responses and our high level views are summarised in Table 3: Responses on Comments from SGN. More detailed information to address specific issues is included in the GD17 final determination document and/or in technical annexes to same where appropriate.

No	Ref.	Section & Topic	Comment	Our Response
111	Section 1.3	Duration of the price control	SGN notes that, whilst in its response to the overall approach document it has been supportive of a duration of the price control until the end of 2022, SGN would support some sort of mid price control review, given the gaps in allowances evident in the GD17 draft determination.	We note the comments made by SGN. However, we are of the view that the price control packages for the GDNs presented in the GD17 final determination are well-rounded, and reflective of the uncertainties and business needs the GDNs are likely to face during the price control period. We therefore consider that a mid-period review would not be proportionate and is not required. We note furthermore the arrangements for special reviews contained in Condition 4.7: Special Reviews of the SGN conveyance licence and that the G2W application pack did not propose a mid-year review.
112	Section 1.3	Duration of the price control	SGN notes that paragraph 3.51 of the GD17 draft determination outlines the fact that SGN will have gas available in its towns from Q4 2017, but that in reality, the current uncertainty surrounding the HP/IP build at	The question of gas not being available in many towns in 2017 has been given consideration and we have made changes to SGN volumes accordingly. We will still commence the price control for SGN from

No	Ref.	Section & Topic	Comment	Our Response
			present could significantly affect these timescales. SGN asks that this is given consideration when the Utility Regulator sets price control allowances, to allow SGN Natural Gas to recover the agreed rate of return for the full 5 year duration it bid on. SGN also notes a need to ensure that its reasonably incurred mobilisation and business as usual operating and capital costs are fully accounted for in an appropriate TRV, prior to commencement of the start of the first year of their price control.	2018, which will allow the 5 years rate of return duration. This is dealt with as per the competition, with extra costs included, in section 6 of the FD.
113	Section 2.1.7	Volumes and Connections	SGN has significant concerns about the gap between its submitted business plan volumes and the current draft targets in the DD. SGN states it will continue to engage to reach an agreement on volumes that are reasonable and achievable.	UR welcomed SGNs engagement between the draft determination and the final determination to achieve reasonable volumes. At the draft determination stage SGN were developing the detailed design of its network and following publication of the DD further information was provided. We have taken account of the revised information and responses to the DD and as a result SGN volumes have changed in all categories. We have revised downwards the volumes (reduction from DD of 28%) and we consider that the volumes determined in the final determination are reasonable and achievable.
114	Section 2.4.2	Volumes and Connections (NIHE)	SGN considers a penetration rate of 100% as included in the DD for NIHE connections is not achievable primarily due to the tenant having veto power on whether gas is installed in the property.	We stated in our GD17 approach document that we will use the profiles included in the AIP. Therefore, we have included a penetration rate of 100% for NIHE properties again based on the AIP profile.
115	Section 2.4.5	Volumes and Connections (OO)	OO property – a peak of 70% has been assumed by UR in the DD. Whilst SGN considers that this could be achieved over 40 years, SGN states it is important to consider the annual PP when applying an annual penetration to this.	We stated in our DD that we would consider the 70% penetration rate further and we may consider using a penetration rate of 85% in our final determination. Have done so, we still consider 70% penetration rate suitable.

No	Ref.	Section & Topic	Comment	Our Response
116	Section 2.6.6	Volumes and Connections (Medium, Large and Contract)	Timing and Phasing SGN will engage with the Utility Regulator to substantiate that the AIP profile connection percentages are not appropriate for the current circumstances on the Gas to the West network, especially with the profile of year 1 25%, year 2 75%, year 3 100%	We stated in our GD17 approach document that we will use the profiles included in the AIP. We welcomed SGNs engagement between the DD and the FD. We still consider the profiles as set out in the AIP are appropriate and these have been used in our FD.
117	Section 2.6.8	Volumes and Connections (Medium, Large and Contract)	Additional Volumes SGN states that as it has not requested any 'general' closure allowance to be made, and therefore it requests that the 'general' additional load assumption is removed.	We have not included additional load assumptions in the FD.
118	Section 2.6.12	Volumes and Connections (Medium, Large and Contract)	80% Volume Assumptions SGN considers that it would not be prudent to include a 100% volume assumption in the GD17 period. SGN considers there is a significant risk of under recovery which would lead to an increase in tariffs at a critical time resulting in a significant detrimental impact.	We have considered the new evidence presented regarding business taken on and the risk of duel fuel. We do not consider an 80% volume assumption is appropriate. We view the volumes decision holistically and have made some changes e.g. additional volumes, since the DD, which provides more flexibility for SGN to outperform. We consider the volumes in the final determination are reasonable and achievable yet challenging.
119	Section 3.1.2 and 3.2.2 and	Mobilisation	SGN Natural Gas would like to reiterate their position concerning the mobilisation dates. Throughout the bid process and the submission, SGN Natural Gas has taken the mobilisation date to end on First Operational Commencement Date (FOCD), as stated in the bid application pack (page 3, Annex 6) and further understood this date to be the date that gas was first available, which is scheduled for Strabane in October 2016. However from the draft determination it is stated that FOCD is currently envisaged to be Q4 2017. SGN Natural Gas is of the opinion that this would be Full Operational Commencement Date and the time between the two dates will in effect be the first year of	We do not accept SGN position as SGN bid document states in paragraph 3.3.1 'our mobilisation activities are taken to be those activities up to FOCD'. This is consistent with page 5 of the Low Pressure workbook which states that mobilisation costs run up to FOCD. In relation to Strabane we consider that section 4.5.9 of the NIEH High Pressure Licence clarifies that the early section completion i.e. Strabane is intended to be operational before the First Operational Commencement Date. The FOCD is defined in the high pressure licence, as is Early Section Completion which

No	Ref.	Section & Topic	Comment	Our Response
			business as usual. As at mobilisation end the bid shows all necessary resources, systems, processes and procedures being in place. This is also consistent with subsequent discussions with UR following grant of Licence in relation to compliance. Chapter 3 of the bid document shows the period following mobilisation to Full Operational Commencement date (when gas is available at all Transmission AGIs i.e. Q4 2017) as “Business As Usual” or Year 1. Figure 1 on page 46 of the bid document and Figure 3 on page 50 show all necessary resource being in place by the end of mobilisation i.e. October 2016.	was drafted specifically with Strabane in mind and clearly takes place before FOCD. The term ‘Full Operational Commencement Date’ referred to by SGN was not defined or used in any UR documentation. Furthermore, if mobilisation was to end in 2016 then, by extension the price control should start then and SGN has not made this argument. However the UR recognises that there are costs associated with Strabane which need to be covered. As envisaged in the licence SGN should be allowed an element of opex pre First Operational Commencement Date to reflect those areas that are operational in that time i.e. Strabane. This cost is rolled up into the OAV at the time the first price control comes into effect.
120	Section 3.2.3 and 3.2.4	Mobilisation	SGN notes that there is no mention of price control periods in the bid document Chapters. Details were simply presented for mobilisation leading directly into FOCD and Years 1 to 10 inclusive. SGN believes the confusion may have arisen as a result of the structure of Annex A in the bid document. SGN notes this has mobilisation sitting under Year 1 and introduces the concept of Price Control Periods. This structure of the table assumes Year 1 to 5 falls under Price Control Period 1 and Year 6 to 10 under Price Control Period 2 but there are no dates set against any year. If Year 1 were to be taken as the first year of the Gas to the West price control period i.e. 2018, the table would also suggest SGN Natural Gas has not yet entered mobilisation and will only do so in 2018. This is not a credible argument. The format is inconsistent with the narrative and tables in	We do not agree with the view set out by SGN. The table which captured mobilisation costs within the AIP had a cell which captured mobilisation costs separately from year 1 opex. We do not consider that the format of the table to be inconsistent with the narrative or tables in the main document. As set out in section 6 of FD it was clear that mobilisation costs ran up to the FOCD of the HP pipeline.

No	Ref.	Section & Topic	Comment	Our Response
			the main document but was completed by SGN Natural Gas in good faith.	
121	Section 3.2.5 to Section 3.2.8	Mobilisation	In relation to the additional costs of £0.6m that SGN has highlighted in previous response to supplemental question 19, having been incurred in participating in a price control process prior to mobilisation and First Operational Commencement Date, SGN cannot find any evidence in the applicant pack of any requirement to carry out early design work or prepare a business plan ahead of First Operational Commencement Date. Figure 2 in Chapter 3 of SGN's bid clearly outlines that design of spine and feeder main was not envisaged to start until mobilisation and was not due to be complete until month 6 of mobilisation i.e. the end of April 2016. This confirms the work that SGN has undertaken to date is in addition to costs and guidance provided for in our bid and the applicant pack. There are additional GD17 costs linked to the build/IP. The price control process was expected to take place following FOCD, when all internal resource would be in place. In summary, to remain consistent with the SGN bid, SGN believes the Final Determination should provide for 1 year of mobilisation costs for the period up to O4 2016 followed by 6 years of opex through to the end of 2022.	The AIP was clear that mobilisation costs should include all opex up until the FOCD. There was no reason to suggest that SGN would not be involved in a price control or significant design work in the early stages of the project and we see no basis to describe this as unforeseen. We consider that it is matter for SGN to decide what resource they wish to use on issues relating to network design and price control issues and it was up to SGN to provide appropriate opex costs within their G2W Application. The FOCD is defined in the high pressure licence, as is Early Section Completion which was drafted specifically with Strabane in mind and clearly takes place before FOCD. The term 'Full Operational Commencement Date' referred to by SGN was not defined or used in any UR documentation. Furthermore, if mobilisation was to end in 2016 then, by extension the price control should start then and SGN has not made this argument
122	Section 3.5	Additional Opex allowed	The DD document states in chapters 6.427 – 6.434 that certain Opex costs have been increased using a proxy of total domestic connections as the driver determined by UR in GD17 versus the SGN Gas to the West application, due to a significant change in customer numbers and volumes. SGN	For the final determination we have updated our proxy calculation to take account of GD17 forecast SME I & C customer numbers in order set allowances for cost items related to the change in build programme.

No	Ref.	Section & Topic	Comment	Our Response
			Natural Gas agrees with this approach. However, SGN is in the process of finalising their designs and once UR has reconciled the small and medium I&C numbers which have been included in this calculation as the category has grown significantly from the application pack as more detailed information of the Licensed Area has become available.	
123	Section 3.6.1	Connection incentive	SGN Natural Gas notes that UR has removed the 25% non-additional assumption to the connection incentive used in the application pack. However the incentive allowance is set on a reducing glide path to maintain consistency with the other GDNs. Throughout GD14 these allowances were set the same per annum for the entire price control. SGN would feel that as a new business in NI and as chapter 6.441 of the DD states "*SGN is at the beginning of its network development and therefore some of its challenges are different to that faced by FE and PNGL in terms of convincing domestic owner occupied customers to connec*t" there is surely a more 'Greenfield' company specific allowance that could and should be set.	We consider that the 'new area' allowance for each of the GDN's in recognition of the challenges in promoting gas, for the respective areas, will deal with these concerns.
124	Section 3.6.2	Connection Incentive	In relation to SME customers, SGN urges UR to consider some sort of pot, linked to targeted connections, in order to recognise the 'Greenfield' nature of our business to aid targeted education and brand awareness for these business. This will help ensure natural gas becoming the 'fuel of choice' in the West of NI in a much faster timescale.	We don't consider it appropriate to change from a figure provided by SGN for incentives for non-owner occupied customers which was submitted as part of a competitive application. This is particularly true in the circumstances where the other applicants included substantially higher incentive costs than SGN.
125	Section 4.1.4 to 4.1.6	Connection Incentive	The non-additionality percentages set for the GDNs are used as the differentiating factor by UR to reflect the differing levels of maturity i.e. the level of customers who would lift the phone of their own accord, without direct	In addition to the incentive allowance set out in the draft determination we have provided and an additional 'new area' allowance for each of the GDN's in recognition of the challenges in promoting gas as the fuel of choice in areas

No	Ref.	Section & Topic	Comment	Our Response
			sales and marketing required. These levels were set at 0%, 25% (i.e. 1 in 4) and 33% (i.e. 1 in 3) for SGN Natural Gas, FE and PNGL respectively. Whilst it is positive that UR acknowledges there are differing levels of maturity involved, SGN feels that this isn't even close to being enough recognition of the issues SGN Natural Gas will face, especially at this stage of the business development, given they are a new entrant into an area within NI, that has never seen natural gas before. SGN believes the one year delay to 2018, in the start of the SGN Natural Gas price control, already has SGN Natural Gas at a disadvantage, given that their OO per connection rate starts at £520 per connection as opposed to the £550 in 2017. The 'one size fits all' approach recommended as part of the draft determination does not fully reflect SGN's business needs and SGN welcomes the opportunity to respond to UR. Through their response, SGN aims to explore possible mechanisms that will allow UR to suggest an alternative allowance as part of the final decisions that allows SGN Natural Gas to achieve success in connecting as many domestic OO properties as possible throughout GD17 and beyond.	and therefore potential customers who are unfamiliar with natural gas, as detailed in section 6 of the FD We note the comments from SGN and for the final determination we have ensured that the connection incentive rate commences from 2018.
126	Section 4.5.2	Connection Incentive	SGN requests that UR considers the 'Greenfield' nature of their extension and the significant issues SGN are likely to face in making OO connections a success. Consideration of a fixed 'pot' of money to help achieve the initial objectives of SGN's	In addition to the incentive allowance set out in the draft determination we have provided and an additional 'new area' allowance for each of the GDN's in recognition of the challenges in promoting gas as the fuel of choice in areas and therefore potential customers who are

No	Ref.	Section & Topic	Comment	Our Response
			business will hopefully form part of the continued engagement.	unfamiliar with natural gas.
127	Section 5.1	Capex Unit Rates	The outcome of the price control process should recognise that SGN is different to the other GDNs and is at a different stage in its development. The process should also recognise that regional differences between the GDNs exist. These differences together with other factors such as business maturity and low population density need to be accounted for within any benchmark analysis. The introduction into Northern Ireland of a third gas distribution network operator will impact the market for contractor and supply services.	We recognise that SGN are a new entrant into Northern Ireland but also that SGN brings with it a wealth of experience gained from operating in other regions of the UK. NI is relatively small (~1/10 size of England) and as such regional differences within NI are minor. The two existing GDN's have successfully operated different network types drawing on resources throughout NI without the need for special factors. We do not believe that SGNs operational area is significantly different from other parts of NI. We believe that there is sufficient resource available within NI to enable SGN to build out their network without stressing the market place. We acknowledge that during the early stages of network development SGN will install a higher proportion of large diameter mains than average, we have made adjustments to our BoW rates for larger diameter mains and the road type they are likely to be installed in.
128	Section 5.4	Capex Unit Rates - Benchmarking	Due to regional issues, business maturity, workload mix, contact interdependencies etc, SGN does not believe that the appropriate adjustments can be made to ensure equity in any benchmark comparison. Competitively tendered contract rates will provide the market view of costs applicable to the work SGN requires. If comparative analysis is required, SGN believes regional price effects and company specific factors should be incorporated and evidenced appropriately.	We do not view SGN's network as significantly different from FE's network or indeed PNGL's East Down extension. We recognise that during the early stages of network development SGN will install a higher proportion of large diameter mains than average, we have made adjustments to our BoW rates for larger diameter mains and the road type they are likely to be installed in.
129	5.4	Benchmarking	SGN stated that they do not believe that a top-down approach to benchmarking including the use of regression analysis, of Northern Ireland and potentially GB GDNs, is	As was the case at draft determination we have not undertaken top-down benchmarking of SGN's opex costs for the GD17 final determination.

No	Ref.	Section & Topic	Comment	Our Response
			appropriate for a new 'Greenfield' business such as SGN Natural Gas.	We have detailed our final determination benchmarking methodology within our GD17 Annex 5 - Top-Down Benchmarking.
130	Section 5.5	Capex Unit Rates - Company specific factors	An adjustment to SGN costs to account for sparsity effects should be applied. As a `greenfield' business SGN has significant hurdles to overcome to establish themselves.	We do not view any town in SGN's network as significantly different from any other town in Northern Ireland. Our detailed response to capex special factors identified by SGN is included in Chapter 7 of the final determination.
131	Section 5.7	Capex Unit Rates	Entering into a new distribution contract in Northern Ireland will be the start of a process for SGN as it builds relationships with prospective contractors. As with any new contract risk will be a key component and for two parties who do not currently have working relationships this risk will likely attract a price premium. The level of activity is unprecedented in Northern Ireland and will stretch the ability of the contracting resources to meet this demand.	We recognise that SGN are a new entrant into Northern Ireland but also that SGN brings with it a wealth of experience gained from operating in other regions of the UK. We consider than SGN can draw on this experience to drive costs down and achieve tendered rates at least on a par with the existing NI GDN's. SGN proposes a relatively slow build up in work activity levels which we believe gives contractors sufficient time to develop any necessary resource.
132	Section 5.7	Capex Unit Rates - Strabane low pressure tender	SGN will be required to agree tendered unit rates in excess of what the Utility Regulator considers efficient.	Our BoW approach ensures that in the round the work activities that SGN will undertake have been sufficiently funded based on what other GDN's in NI have been able to achieve in the past for the same or similar activities.
133	Section 5.7	Capex Unit Rates – Dis-aggregation of the Basket of Works	The large diameter spine mains that currently support the other GDN's networks were laid when they were in the early stages of deployment, as such their proportion of large diameter mains will be significantly different to SGN's.	We acknowledge that during the early stages of network development SGN will install a higher proportion of large diameter mains than average, we have made adjustments to our BoW rates for larger diameter mains and the road type they are likely to be installed in.
134	Section 6	Innovation – Materiality threshold	SGN suggests that the uncertainty mechanism threshold for innovation projects should be brought down from the £150,000 level to £25,000. SGN considers that this is	We consider that the materiality threshold for innovation projects should not be different from the general materiality threshold applicable under the uncertainty mechanism.

No	Ref.	Section & Topic	Comment	Our Response
			appropriate given the size of the NI market and the fact that it would allow projects of a similar scale to the smaller projects funded through the GB Network Innovation Allowance.	We note that, as detailed in section 9 Uncertainty Mechanism, Materiality Thresholds of the GD17 final determination, we have changed this materiality threshold from £150k proposed in the draft determination to £100k (i.e. to the same level as had been used for the GD14 final determination) to reflect feedback received from the three GDNs in response to our GD17 draft determination. This threshold will be the same for each of the three GDNs.
135	Section 6	Innovation – Assessment criteria	SGN notes that the very stringent assessment criteria in paragraph 8.7 of the GD17 draft determination may limit the proposal of the higher risk, higher cost saving to consumer projects, as well as increasing the costs of submissions due to the time and resource required relative to level of funding.	We are conscious that quality assessment criteria for funding of innovation projects may impact on the time and resource GDNs need to invest if they wish to request funding. However, we consider that this is appropriate, proportionate and necessary to provide protection to consumers who would bear risk and cost of such innovation projects. We do not agree with the view that our assessment criteria preclude the submission and consideration of higher risk projects with higher cost saving potentials. However, we consider that the riskier a proposed innovation project is and the higher the associated costs consumers will be asked to bear, the more diligent and detailed the upfront assessment needs to be.
136	Section 6	Innovation – Innovation incentive mechanisms	SGN Natural Gas is still of the view there should be a competition for funding of flagship innovation projects of a commercial, operational or technical nature. SGN believes that its proposal recognised the relative size of the NI market compared to GB, as NI GDNs were to compete for up to £2.0m of funding a year, to be recovered through postalised transmission charges.SGN	We note the points made by SGN. However, we remain of the view that due to the size of the NI market, the administrative effort involved in setting up a funding competition compared to the level of competition that it would be likely to generate would be questionable. There may be a merit in a co-operative approach to innovation, but we consider that it is not clear why the price

No	Ref.	Section & Topic	Comment	Our Response
			considers that, contrary to paragraph 8.17 of the GD17 draft determination, a competition for funds naturally raises the standard of projects submitted versus individual GDN submissions on an ad hoc basis, and raises the profile of innovation and its benefits. SGN also notes that although the scale of the NI gas distribution industry is smaller than GB, the number of ownership groups is the same, and that the competition for innovation funds works well in GB.	control framework which allows the GDNs to propose well argued business cases for projects is not flexible enough to allow this, robust enough to ensure high quality of innovation initiatives or unsuitable to further the profile of innovation and its benefits.
137	Section 6	Innovation – Innovation incentive mechanisms	SGN believes that an Innovation Roll Out mechanism in NI, whereby GDNs can take up best practice through funding provided, would maximise the benefits from individual GDNs successful projects.	As detailed in section 8 Innovation, Detailed Approach – UR Decisions, Innovation Incentive Mechanisms, Innovation Roll-Out Mechanism of the GD17 final determination, we consider that our treatment of requests for funding of innovation projects through specific innovation allowances has a similar effect as the innovation roll-out mechanism proposed by SGN and allows for the roll-out and implementation of innovations. We therefore consider that a separate innovation roll-out mechanism for NI is not required.
138	Section 7.2	Uncertainty Mechanism - Capex	SGN believes that the Capex adjustments subject to uncertainty outlined in the DD are appropriate, however, suggest we add the following to the list of items: • Special Engineering Difficulties (SPEDS) as a ‘ring-fenced’ allowance; and, • An appropriate Capex sharing mechanism regarding capital rollout over the GD17 period to protect SGN/consumers should unforeseen efficiencies/efficiencies occur.	SPEDs have been included in the uncertainty mechanism as a ring fenced allowance and referenced in the relevant table of Chapter 9 under the category of “Company specific issues”.
139	Section 7.3	Uncertainty Mechanism - Opex	SGN believes that all the Opex adjustments subject to uncertainty outlined in the DD are appropriate.	We note and welcome this comment.
140	Section	Uncertainty Mechanism	SGN believe that the suggested materiality	We have noted all that SGN has said in its

No	Ref.	Section & Topic	Comment	Our Response
	7.4	– Materiality Threshold	threshold of £150k is not reflective of the size of their business and suggest £75k as being fairer.	representations on this matter but not think the roles and responsibilities of the GDNs differ to such an extent that different materiality thresholds are required.
141	Section 8	Financial aspects	SGN states that it disagrees with the UR's proposal to switch to a vanilla WACC. SGN considers this to be late and unforeseen alteration to the regulatory framework. If there is to be a change, SGN argues that its bid pre-tax WACC should be converted into a vanilla WACC equivalent using SGN's effective tax rate. This approach will make the change NPV-neutral. It will also enable all parties to side-step the computational issues that the UR's consultant highlighted in the report published alongside the DD.	The possible change in the treatment of tax was signalled to bidders in the Application Information Pack published in April 2014. Paragraph 3.30 of this document states that: "For the purposes of this competition, the WACC will be treated as pre tax. However we will review the treatment of tax at each price control review in line with best regulatory practice." The UR considers that bidders will have understood from this statement that the UR would assess whether to use a pre-tax or vanilla WACC during the GD17 review, with its decision implemented from 2017 onwards. Insofar as regulatory practice in a majority of other sectors involves converting between pre-tax and vanilla cost of capitals using the statutory corporation tax rate, the UR considers that its approach to taxation in GD17 is consistent with the intent signalled in 2014. The UR has considered SGN's alternative computation suggestions, but has opted for the approach set out in Chapter 10 for the reasons stated therein. In particular, the UR judges that it is reasonable to assume that an efficiently financed company would seek to maintain an investment-grade credit rating and pay normal investment-grade interest rates on its debts.

No	Ref.	Section & Topic	Comment	Our Response
142	Section 9.1	Risk sharing mechanism	SGN notes it has previously discussed with UR that the rollers contained within its licence require simplification for clearer understanding and application in practice. SGN would also welcome ongoing discussions with the UR and other GDNs concerning GB incentives, in particular the RIIO process as they feel appropriate incentives drive the correct behaviour, forming an important part of their business.	The UR has switched SGNs rollers to "off" in line with the DD and note SGN's agreement with our approach in its response. In the case of SGN we have determined the capex sharing mechanism will be 25:75 for company: consumer respectively. We are open to discuss any potential licence modifications or other aspects of regulation with GDNs.
143	Section 9.3	Under Recoveries	SGN notes there may be a need to incentivise connections by using the under recovery mechanism. Should this be the case throughout GD17 to drive connections and make natural gas a more attractive proposition for customers, SGN feels there may be a discussion to be had with the UR regarding current Libor + 2% rate of recovery.	The under recovery mechanism is included within the SGN licence and was also set out in the AIP. We have no plans to change this condition.
144	Para 9.4	Supplier of last resort	SGN has significant concerns around the quantification of what would be allowed within the price control should a supplier of last report event occur. SGN prefers the related process to be included explicitly in the licence.	As detailed in Chapter 11, we have included in the uncertainty mechanism a ring-fenced allowance for a SoLR event.
145	Section 10.3	Use of opex and capex rollers	SGN noted the UR's intention to "switch off" the opex and capex rollers copied across from the FE licence. SGN hoped to engage with the UR to find a solution that enables SGN to achieve some of the benefit and protection of the rollers, and subsequently sought to focus engagement upon some form of risk sharing.	We have noted all that SGN comments and have determined to incorporate such risks within the uncertainty mechanism for SGN, using a 25:75 risk ratio for consumers and the company respectively as set out in Chapter 11 – Risk Sharing Mechanism of the FD.

Table 3: Responses on Comments from SGN

CCNI Response

3.7 The CCNI responses and our high level views are summarised in Table 4: Responses on Comments from CCNI. More detailed information to address specific issues is included in the GD17 final determination document and/or in technical annexes to same where appropriate.

No	Ref.	Section & Topic	Comment	Our Response
146	Para 5.3-5.7	Form of control for FE	CCNI considers that with a revenue cap price control, consumers in the future carry the risk of paying higher prices if volumes or connections do not increase as forecast. CCNI furthermore considers that this risk is heightened: • due to removal of inherent incentive to increase volumes and customer numbers that a price cap price control provides; • if oil prices continuing to remain lower than gas prices; • if other barriers to gas conversion are not addressed; • due to FE's disproportionally high reliance on IC customers and risk of any more of the large users to stop burning gas. CCNI therefore suggests that mitigation measures should be put in place for GD17 to counteract the potential risks that the loss of large IC customers represents. CCNI asks furthermore that the Utility Regulator considers the Reckon proposal to address some of the risks for consumers by reversing the decision to use a total revue form of control (with a connections incentive).	We note the points made by CCNI. We note, however, that as part of our consultation in June 2015 on changing the form of price control for FE from a price cap to a revenue cap[5], we asked for views on this matter. We duly considered all comments received prior to publishing, in September 2015[6], the outcome of the consultation which was to proceed with this change. The reasons behind this, including that FE had limited control over volumes and the move aligned with GB, have not changed and we see no reason to change our position at this stage.

[5] Utility Regulator: Consultation on modifications to the Price Control conditions of the firmus Energy (Distribution) Limited Licence, 18 June 2015.
[6] Utility Regulator: firmus energy (Distribution) Limited licence, Outcome of Consultation paper on moving to revenue cap regime, 16 September 2015.

No	Ref.	Section & Topic	Comment	Our Response
147	Para 5.5	Form of control	CCNI asks that mitigation measures are put in place for GD17 to counteract the potential risk that the loss of large I&C customers represents	The general risk that longer term volumes may be less than forecast is covered by the volume adjustment in section 5 of the FD.
148	Para 5.10	Under-recoveries of revenue accumulated by FE	CCNI asks that the Utility Regulator quantifies the financial impact that the proposals set out in 11.81.a of the GD17 DD would have on consumers up to 2019.	The financial impact on consumers is not possible to accurately forecast as it will depend on what approach FE takes to under recoveries in setting its tariffs. However it is likely that tariffs would be higher up to 2019 under option a compare to b.
149	Para 5.13	Under-recoveries of revenue accumulated by FE	CCNI asks that the Utility Regulator considers whether clearing the accumulated under recovery of £13m over three years is a fair distribution of risk and reward between consumers and FE.	We have recognised that the treatment of under recovery could give rise to potential unfairness and are proposing to change this – albeit FE will keep significant benefit of under-recoveries building up at 7.5% to 2016. In relation to the time period there is an argument that those who benefited from lower prices should pay for it. Therefore the closer the period of under and over recovery the less the problem of intergenerational unfairness.
150	Para 5.18	The profile adjustment mechanism	CCNI asks that we postpone any decision on the profile adjustment at least until the next price control.	We agree with the FE proposal and have reflected this in Chapter 10 of the final determination.
151	Para 5.24	Extension of the forecasting Horizon for FE from 2035 to 2045	CCNI considers they cannot assess the impact of extending the forecast horizon from 2035 to 2045 due to the absence of information. CCNI respectfully asks that the Utility Regulator remedies this data shortfall and provides a clear evidence based decision in the FD.	We have provided the evidence of the customer impact in the DD section 11 and have retained the 40 years in the FD.
152	Para 6.3	Rate of return	CCNI would have expected to see at most of the middle of the range (0.35) Asset Beta.	We have decided to take a somewhat conservative approach and set the beta slightly above that of GB GDNs and other GB utilities. The detailed reasoning is set out in section 10 of the FD.
153	Para 6.7	Treatment of the cost of debt for FE and PNGL	CCNI supports UR's preferred option 3 – target cost and pain/gain sharing.	We have considered the Reckon proposals. They do not address the fundamental issue which was the basis for our Dent Mechanism

No	Ref.	Section & Topic	Comment	Our Response
			CCNI draws attention to the proposal made by Reckon as per point 2.e, 6.c, and 17 to 19 in Annex 2 of their submission. Reckon suggests reversing the proposal to pass-through part of the cost of debt, and instead using Ofgem datasets to index the cost of debt for FE and PNGL. CCNI asks the Utility Regulator to fully consider whether such proposals would be a valid and viable alternative to those set out in Annex 7 of the DD paper as CCNI believes they may ultimately be of benefit to consumers in NI.	proposal i.e. that FE and PNGL need to raise 100% of their debt in GD17. Therefore we have retained the principle of the Debt Mechanism and this is detailed in Annex 14.
154	Para 6.11 and Para 6.12	Connection Incentive	The connection incentive was never intended to be a long term allowance and with this in mind, both PNGL12 and GD14 proposed reducing the incentive allowance by 50% from 2017. It is therefore reasonable to expect GDNs to have implemented strategic measures to adequately manage this reduction. The Consumer Council is concerned that despite giving significant notice of this proposed reduction, UR has reviewed and subsequently suggested moving away from the proposed 50% reduction and allowing a glide path from £573 at present to £420 in 2022.	We have considered the evidence as presented by the GDNs on the challenging market conditions that they are facing. We consider the effect it will have on future connections and the challenge to have more gas connections. We have reflected this by introducing a glide path downwards for the connection incentive with the exception of the additional allowance for 'new areas'. We intend to review the connections incentive in advance of the GD23 Price Control as detailed in Chapter 13 of the FD
155	Para 6.15	Connection Incentive Targets	It is also important that connections targets and the level of connections allowances are fair and challenging. In previous years GDNs have in the final analysis comfortably exceeded connections targets. However, if we look at the connections targets proposed for PNGL in GD17, they appear to be based on a 2016 forecast that is well below the outturn for the previous four years. At this point in time CCNI can see no firm evidence of what UR's GD17 targets are based on and would	We recognise that GDNs have outperformed the OO connections target in the past although we view this as largely positive. As explained in section 6 of the FD we have set the targets for FE and PNGL taking into account their historic level of connections and the level of new infill which they are allowed in GD17. We expect increasing levels of infill will result in increasing connections.

No	Ref.	Section & Topic	Comment	Our Response
			respectfully ask that the UR provides transparent detail in this regard. Ultimately the consumer needs to be assured of the validity of the target and the value for money of the proposed incentive which sets out to achieve this.	
156	Para 6.16	Connection Incentive expenditure	As far as CCNI can see there is no requirement on the companies to show how the connection incentive allowance is actually spent. Consumers therefore cannot see a direct correlation between the connections allowance and connections made. The CCNI would not expect the UR to micro manage a company and instruct it in detail about how the allowance is spent. However, the CCNI believes there is an issue of trust and transparency in this regard and would argue consumers are paying the connections allowance in their bills and are entitled to know the money is being used for the activity that creates new connections.	The Connection Incentive has never been explicit in exactly how the GDNs should spend this allowance. This is due to the fact that the circumstances that make a customer make a new connection are different and varied for every individual. We believe that the GDNs have more information, understanding and interaction with potential customers to determine an appropriate allocation. Furthermore they have an incentive to maximise connections so if using all the money on direct customer payments was effective they are incentivised to do this. We introduced a new cost reporting matrix in 2013 and used its structure for the GD17 Business Plan Reporting requirements. This requires each of the GDN's to report costs associated with OO connections. We intend within the GD17 period to publish 'annual cost and performance reports', on the GDN's which will include analysis of the costs of OO connections.
157	Para 6.21	Connection Incentive 'collar'	The CCNI sees these incentives as key elements of this price control to help maximise the number of OO properties connected. However, the CCNI is not convinced by the inclusion of a 50% cap on the maximum reduction of the allowance that UR proposes. The CCNI believes that the reduction of the connection allowance should be allowed to drop below 50% if the GDN's fail to meet the relevant targets. In CCNI's	We recognise the point made by CCNI. We have removed the cap for the final determination and amended the collar regime as set out in section 6 of the FD. We believe this regime ensures the GDNs have sufficient incentive to connect as many OO properties as possible.

No	Ref.	Section & Topic	Comment	Our Response
			view by removing the collar UR would be ensuring that GDNs have sufficient incentive to connect as many OO properties as possible even when the maximisation targets are not met.	
158	Para 6.22 - 6.26	Economic Allowance	CCNI agrees in principle that overall, gas mains should only be laid where there is a reasonable prospect that the initial outlay cost will be paid back by consumers connecting and burning gas within the useful economic period, whilst recognising a degree of judgement is required within GDN network areas to ensure that the overall consumer base benefits. That is to say that the benefits of an individual economically positive project should be used to potentially counterbalance an economically negative project and therefore in doing so, ensuring that gas is brought to as many consumers as possible. CCNI welcomes the application of a capped retrospective mechanism to adjust for the actual numbers and length of properties passed to ensure consumers are not overpaying for the benefits received.	We welcome CCNI's comments and confirm that our assessment is made on average basis giving each GDN the flexibility to build out its network as it deems most appropriate up to a limit where there is a reasonable likelihood that the investment will be repaid by those customers for whom the investment was made. We believe that the uncertainty mechanism is necessary in order to maintain the necessary balance between each GDN's forecast and actual activity patterns.
159	Para 6.27 – 6.31	Customer service / Ongoing consumer engagement	CCNI welcomes the inclusion of the developmental objective for delivery of new customer service metrics and satisfaction surveys during GD17, noting excellence in customer service can only be achieved through shared learning and transparency. CCNI notes similar measures and metrics are being developed in the water sector locally and that in so doing for the GDNs UR opens up the possibility for greater comparability across all energy and water companies. Finally, CCNI welcomes the possibility that with improved performance monitoring UR allows consideration of incentivised mechanisms in future price controls.	We note CCNI's strong support for our proposals at Draft Determination and will seek to include CCNI in the development of our new partnership model for continuous consumer engagement across all GDNs during GD17.

No	Ref.	Section & Topic	Comment	Our Response
160	Para 6.32 – 6.35	Benchmarking	CCNI welcomes the benchmarking the UR has undertaken during GD17 which provided CCNI with the confidence similar benefits to those in evidence with NI Water are likely to benefit gas consumers. CCNI further believes the UR's choice of Model 5, including a consideration of network quality, to be the most appropriate means of benchmarking local GDNs to a much older GDN network in GB. CCNI accepts the rationale for the UR to also apply a regional wages adjustment.	We note CCNI's comments and support for our approach to benchmarking and efficiency modelling. We shall continue to develop this as we strive towards an annual refresh of local GDN relative efficiencies and publication of same within our annual Cost and Performance Reports (monitoring to begin with the 1st year of actual GD17 out-turn costs and performance data).
161	Para 6.40	Fuel-poor incentive	The CCNI notes that the SGN Business Plan submission for Gas to the West included a proposal for a £50 incentive payment to target fuel poor households. The CCNI would like to see such proposals explored by the UR, to see if they could help reduce fuel poverty without reducing the overall benefits of the Price Control to the wider consumer base.	We have provided an additional 'new area' allowance for each of the GDN's in recognition of the challenges in promoting gas as the fuel of choice in areas and therefore potential customers who are unfamiliar with natural gas. For SGN this covers all of its OO connections in the GD17 and therefore will include 'fuel poor' households.

Table 4: Responses on Comments from CCNI

Manufacturing NI Response

3.8 The Manufacturing NI responses and our high level views are summarised in Table 5: Responses on Comments from Manufacturing NI. More detailed information to address specific issues is included in the GD17 final determination document and/or in technical annexes to same where appropriate.

No	Ref.	Section & Topic	Comment	Our Response
162	Letter	General	Manufacturing NI noted a few comments as follows: • 6 Year price control period is appropriate for long term planning • Importance of Manufacturing to NI Economy	We welcome the support as noted and consideration for comments will be reflected in the main sections of the FD

No	Ref.	Section & Topic	Comment	Our Response
			• Welcome the reduction of WACC from 7.5% to 4.3%, which is attractive for business • Credit Agencies “Negative Watch” is not of concern • The companies are Financeable based on the DD • SGN costs should be aligned to the competitive competition that they won and keep to the timelines of putting gas into new areas. • Support the FE 40 year forecast horizon • FE Under Recoveries should be changed to LIBOR +2% • Profile Adjustment should stay, as have concern in its removal and the increase in prices • Support Pain/Gain Mechanism	
163	Letter	Financeability	NI Manufacturing notes it would encourage the UR to provide some review to ensure that the UR proposals offer the opportunity for greater penetration of commercial gas users in their network area. NI Manufacturing notes that perhaps some further clarity on the Firmus financeability plan in particular would be beneficial.	We encourage all connections and regard our allowances as offering opportunities for all types of users to take advantage of natural gas. Please see FE section on financeability, which provides better clarity on this area
164	Section 8	Profile Adjustment	NI Manufacturing notes it is concerned about the potential removal of the profile adjustment. Removing the profile adjustment now would have a negative impact on bills at a time when all the companies are keen to get more connections, which for business users is largely decided on a straight cost saving basis.	We have considered this area in general and have chosen to keep the Profile Adjustment for GD17.

Table 5: Responses on Comments from Manufacturing NI

NEA NI Response

3.9 The NEA NI responses and our high level views are summarised in Table 6: Responses on Comments from NEA NI. More detailed information to address specific issues is included in the GD17 final determination document and/or in technical annexes to same where appropriate.

No	Ref.	Section & Topic	Comment	Our Response
165	Letter	General	NEA made 2 key points as follows: • Incentive Connections – NEA has no real detail on how this is spent by the GDN, but , NEA has concerns that any reduction in this allowance may impact on future connections and believes that in the current climate that gas connections have become more challenging • Infill Mechanism – NEA recognises the need for an economic test in further expansion of the gas network and would wish to see a balance for future and existing customers	. See the CCNI Response No.131, that addresses this issue We note the comment and have retained the economic test as described in section7 of the FD.

Table 6: Responses on Comments from NEA NI

NINGA Response

3.10 The NINGA responses and our high level views are summarised in Table 7: Responses on Comments from NINGA. More detailed information to address specific issues is included in the GD17 final determination document and/or in technical annexes to same where appropriate.

No	Ref.	Section & Topic	Comment	Our Response
166	Letter	General	NINGA disagrees with the proposals made in the DD and that it would have a detrimental impact on the development of natural gas. They consider that a network operator sustained presence in the local market is vital to keep a co-ordinated approach in new connection and the associated effect on the	We have provided and an additional 'new area' allowance for each of the GDN's in recognition of the challenges in promoting gas as the fuel of choice in areas and therefore potential customers unfamiliar with natural gas. See section 6 that deals with this area

No	Ref.	Section & Topic	Comment	Our Response
			industry, in terms of Gas Retailers, Trade merchants, product manufactures training centres and service engineer and the continued level of private investment in the wider gas industry. NINGA indicates that as a minimum, the same level of support that has been given in previous price controls is maintained to stimulate new connections, of which the current network operators have a solid track record in delivering.	

Table 7: Responses on Comments from NINGA

Fermanagh and Omagh District Council Response

3.11 The Fermanagh and Omagh District Council responses and our high level views are summarised in Table 8: Responses on Comments from Fermanagh and Omagh District Council. More detailed information to address specific issues is included in the GD17 final determination document and/or in technical annexes to same where appropriate.

No	Ref.	Section & Topic	Comment	Our Response
167	Letter	General	Fermanagh and Omagh District Council welcomes efficient growth of the gas industry in the context of the Gas to the West Project It notes the particular challenges faced by residents and businesses across the district in relation to alternative energy choices. The Council wishes to emphasise that GD17 provides the maximum incentives for consumers.	We have considered this response and believe the New Infill Area allowance, will be most advantageous to SGN. This allowance will be the largest, in terms of a cash incentive, compared to any other GDN. This we believe will provide a strong incentive for SGN to have as many customers at the start up phase of the business. See section 6 that deals with this area

Table 8: Responses on Comments from Fermanagh and Omagh District Council

AGSNI Response

3.12 The AGSNI responses and our high level views are summarised in Table 9: Responses on Comments from AGSNI. More detailed information to address specific issues is included in the GD17 final determination document and/or in technical annexes to same where appropriate.

No	Ref.	Section & Topic	Comment	Our Response
168	N/A	Supplier Interactions	AGSNI considers that it would be for the network operator to increase direct interactions with customers to deal with queries in a more efficient and timely manner through its customer service department. AGSNI encourages the Utility Regulator to consider the potential customer benefit of directing network related queries to the network operators. AGSNI considers that in the meantime, it would be useful for a document explaining the calculation and basis for the network operator's statement of charges to be published either on its own website or in a collective document on the UR website. AGSNI considers that this could serve as a FAQ (frequently asked questions) document for customers and should reduce the level of queries suppliers receive.	The UR does not dictate the arrangements for GDNs and suppliers interacting with customers. Therefore GDNs and suppliers can choose to review these arrangements at any stage. All charges that are proposed by the Network Operators are approved by UR. We have encouraged all network operators to have a consistent methodology in how charges are made and that the costs are reflective based on size and scale.
169	N/A	Supplier Interactions	AGSNI notes that it interacts with the network operator through the site-works system for a number of reasons including switching and to access the asset register. AGSNI notes furthermore that there are a number of minor adjustments that could be made to this system to make it more useful for suppliers and encourages the UR to ensure adequate resources are provided to improve IT systems in the next price control period as the industry continues to evolve.	We note the comments made by AGSNI. We consider that such minor adjustments as referred to by AGSNI are part of business as usual for the GDNs and are covered by the GD17 allowances.

Table 9: Responses on Comments from AGSNI

MEUC Response

3.13 The MEUC responses and our high level views are summarised in Table 10: Responses on Comments from MEUC. More detailed information to address specific issues is included in the GD17 final determination document and/or in technical annexes to same where appropriate.

No	Ref.	Section & Topic	Comment	Our Response
170	Letter	Wider Consultations & Price Reductions	MEUC appreciates the level of engagement through GD17 and welcomes the UKRN peer review on certain aspects of the price control. MEUC would have liked more transparency for its member on the impact on prices.	We welcome the comments made and have made some further examples for all classes of consumers in Section 11
171	Letter	Pain Gain Limitations	MEUC agreed on the approach to limit any over and under recoveries.	We note the comments made
172	Letter	Forecast Horizons & Under Recovery	MEUC agrees that it is positive to move the FE forecast horizon to 2045 and recognises the smoothing of tariffs will be of benefit for its members. MEUC does not accept that future customers will be disadvantaged. MEUC welcomes the proposal to reduce FE's under recoveries rate of return from 2017 onwards	We retained the change the forecast horizon for FE from 2035 to 2045. We will change the Under Recoveries for FE to LIBOR +2% from 2017 onwards
173	Letter	Volume Changes	MEUC states that the volume calculations from 2017-2022 suggest a 20% increase over the period. MEUC states it is unclear whether these figures include the significant gas reduction volumes associated with the closure of JTI and Michelin.	The loads included in the draft determination for I&C are taken directly from the FE business plan. The DD volumes included Michelin but excluded JTI Gallahers from 2018. The final determination takes account of the close of Michelin and the load has been excluded from 2018 to take account of this.

Table 10: Responses on Comments from MEUC

Appendices

Appendix 1: Links to Consultation Responses

A1.1 Table 11: Links to Non-Confidential Consultation Responses provides an overview over the responses received to consultation on the GD17 draft determination (with the exception of the response marked as confidential), including the links through which the response documents can be accessed.

Document	Document Link
FE Response to GD17 Draft Determination	http://www.uregni.gov.uk/uploads/publications/FE_GD17_Response.pdf
PNGL Response to GD17 Draft Determination	Phoenix Natural Gas Ltd. Response to the Utility Regulator: Price Control for Northern Ireland's Gas Distribution Networks, GD17 Draft Determination, May 2016
SGN Response to GD17 Draft Determination	SGN: GD17 Draft Determination Consultation Response, 31 May 2016
CCNI Response to GD17 Draft Determination	The Consumer Council: Response to UR's Price Control for NI's Gas Distribution Networks GD17, May 2016
Manufacturing NI Response to GD17 Draft Determination	Manufacturing Northern Ireland: Manufacturing NI's response to the "Price Control for Northern Ireland's Gas Distribution Networks (GD17) Draft Determination"
NEA Response to GD17 Draft Determination	NEA: National Energy Action Northern Ireland's response to the Northern Ireland Authority for Utility Regulation Price Control for Northern Ireland's Gas Distribution Networks GD17, May 2016
Ninga Response to GD17 Draft Determination	Ninga: Re: Draft determination for gas distribution network operators (GD17)
Fermanagh and Omagh District Council Response to GD17 Draft Determination	Fermanagh and Omagh District Council: Response to GD17 Draft Determination, 24 May 2016
AGSNI Response to GD17 Draft Determination	AGSNI: Response to GD17 Draft Determination, Gas distribution network price control
MEUC Response to GD17 Draft Determination	Major Energy Users' Council: Response to GD17 Consultation Document, 31 May 2016

Table 11: Links to Non-Confidential Consultation Responses