DN Charging Methodology Forum (DNCMF) Minutes
Tuesday 27 September 2016
Consort House, 6 Homer Road, Solihull, B91 3QQ

Attendees

Bob Fletcher (Chair)	(BF)	Joint Office
Helen Cuin (Secretary)	(HC)	Joint Office
Colette Baldwin	(CB)	EON
Craig Neilson	(CN)	National Grid Distribution
Chris Shanley	(CS)	Joint Office
Gemma Truran	(GT)	RWE npower
George Moran*	(GM)	British Gas
Joanne Parker	(JP)	Scotia Gas Networks
Jonathan Trapps	(JT)	Northern Gas Networks
Paul Whittaker	(PW)	Scotia Gas Networks
Rebecca Hailes	(RH)	Observer
Robert Wigginton	(RW)	Wales & West Utilities
Sean Hayward	(SH)	Ofgem
Simon Vicary	(SV)	EDF Energy

**via teleconference*

Copies of all papers are available at: http://www.gasgovernance.co.uk/dncmf/270916

1. Introduction and Status Review

1.1 Review of Minutes (28 June 2016)

The minutes of the previous meeting were approved

1.2 Pre-Modification Discussions

See item 5.3 - Extending the Notification Period of Charges (npower)

2. Issues

2.1 New Issues

No new issues raised.

3. Allowed and Collected DN Revenue (MOD0186) Reports

3.1 National Grid Distribution

CN provided an overview of the Revenue Report and provided details of the headline movements.

He explained that the September forecast is aligned to the RRP submission in July 2016 in respect of 2015/16 final performances, and the forecast data set for the remainder of RIIO GD-1. The largest movement was the +£17m impact to 2016/17 revenue collection driven by SOQ increases from 01 October indicated by the 2016 AQ review. This will be repaid to Shippers in 2018/19. The PCFM forecast updates for 2017/18 were aligned to the AIP dry runs, and utilised RRP forecast data thereafter. The broad measure incentive had been updated for the 2015/16 Stakeholder Engagement Outcome determined in July.

CN confirmed that the Bank of England base rate change hadn't had a particular impact on the revenue forecast.

In terms of the PCFM, CN confirmed the figures provided were at a variance to the previous forecast. These reflected the latest Totex forecast as submitted in 2015/16 RRP; the TIM impacts driven by back-ended capex spend, largely flat opex, and accelerated repex spend; a principal change to the UMs related to the interaction of CNI expenditure with capital allowances; and the cost of debt for 2017/18 updated based on 2016 AIP dry run positions, reflecting an increase of 0.03%

CN further explained that the largest movement was within Totex, which had not been anticipated in the CNI uncertainty (i.e. the interaction with the Totex incentive, some interaction between tax and allowances) driven by a cost movement and capital allowance pool. It had been difficult to isolate the elements of movement.

He confirmed that the impact of the FGO program and information released by Ofgem on funding and allowances needed to be included within the forecast. He also confirmed that the quantification of rate risk was also still pending, along with the separation of National Grid Gas Distribution (NGGD) liabilities from National Grid Gas Plc. He expected to have a firm position to report at the end of September. However, it was anticipated that a transition mechanism would apply a liability cap at a maximum of 12% +RPI. The impact to Shippers will be subject to a two-year lag in the normal way.

For the Shrinkage and Leakage volumes there was a low-level impact from the RRP volume forecast, and a slightly lower benefit from Repex.

CN confirmed that the Gas Price Reference Cost (GPRC) is tracking upwards from June, pushing shrinkage costs and therefore pass-through revenue up. There was also a slight increase in the value of the Shrinkage incentive.

CN provided 3 tables in relation to the Revenue Collection forecast, he explained that the 2016 AQ Review reversed the position resulting in an over recovery. The first table provided showed the forecast carried forward inclusive of the of load factor changes, he was expecting an SOQ reduction swinging to a forecast increase. This was driven by the impact of new load factors and that underlying AQs are much flatter. NGGD are trying to anticipate what the load factor impacts will be by holding discussions with Xoserve. The best view from the AQ review from the NDM data set was that there could be some variance when it comes to October, within the 0.5% category assuming Nexus implementation at the start of the year. CN explained that had Nexus been implemented this would have introduced fixed SOQs. Assuming fixed SOQs from next year NGGD will need to deal with the transitional movement. Where showing SOQ reduction this will roll up into the next years price change. Pricing Managers are meeting with Xoserve to discuss the impacts of Nexus and will provide an update to the slides in due course.

Action 0901: DNs to provide a further update on the assumptions with fixed SOQs (Project Nexus Implementation) to provide clarity on the October stepped change.

CN summarised his presentation providing the Risks and Uncertainties, these included: maintaining FGO sensitivity; the Business Rates risk remaining un-quantified; the finalisation of AQs and SOQs which may have further impact; and the uncertainty mechanisms relating to smart meters which remained unchanged from the last report.

3.2 Northern Gas Networks

JT presented the NGN information explaining his update was broadly similar to NGGD. The AQ and SOQ will over collect by £8.3m and the AQ review window has resulted in a +1% increase. For the Price reduction unit rate a reduction unit rate decrease was expected next year.

JT explained for the Rates, NGN had forecast 25% last time but this had now been revised to a 28% increase this related around Repex treatment and the value change in Stirling.

The impacts of FGO had not been included within the figures, this needed to be assessed and added to the next model update and will feed into the indicative reports and January 2017 report, coming through the ARP reports for next year.

CB enquired if there is expected to be a drop off with the past warmer winters, over recovery and the impact of the 2-year pricing lag. CB questioned if DESC should be looking at the Load Factors and the historical use of a 3-year period and whether this is an appropriate measure and if this should be 5 years. CB also asked if Project Nexus Class 2 customers setting AQs would have an impact.

JT explained after Project Nexus implementation it is expected that the over/under recovery positions will be minimised, due to the timing of price setting in January for October and more certainty being provided in December due to AQs and SOQs being known.

GM enquired about the rates assumption and the fixed percentage increase with the transitional arrangements, JT confirmed NGN have provided the worse case scenario. JT offered to make a note on the reports when further clarity is available.

GT also asked if some consistency across the Networks could be added to the reports as a sensitivity measure to understand the worse case scenario and magnitude.

Action 0902: DNs to consider and provide a consistent assumption approach as a sensitivity measure for Project Nexus transitional arrangements.

3.3 Scotia Gas Networks

JP provided an overview on the key changes. JP noted that the Business Rates are currently being re-evaluated which is expected to impact 2019/20 revenue and will be incorporated in the December modification.

JP confirmed an assumption of a 0.5% reduction with the SOQ and for the tariff a 2.1% increase (a swing of 3%) resulting in an over collection this year and a price decrease in 2017/18. Some reduction was also expected in 2017/18 for FGO.

3.4 Wales & West Utilities

RW presented a summary of the updates for WWU which included a change in RRP outturn, latest gas forecast prices, NTS Exit costs (small decrease), August RPI, the 2016 AQ Review and lower interest rates.

RW summarised the key points of Cost Pass through, the Reopeners and the Annual iteration process (smart metering).

GM enquired about the changes in the exit capacity figures. RW confirmed a request has been put in for +£9m increase from 2018/19.

4. Review of Actions

No outstanding actions to consider.

5. Any Other Business

5.1 DN Entry Presentation – RW, Wales & West Utilities

RW noted that the attendance at the DNCMF had been much less than that of the NTSCMF and that the industry is trying to engage with parties more to provide them information and a better insight to aspects of DN charging. To support this, WWU provided on behalf of all DNOs an explanation of what a DN entry site is and its pricing methodology.

RW explained there is an increase of DN entry sites injecting Greener Gas rather than from the usual NTS producers and is usually a bi product of operations from such places as farms and distilleries. Decisions have been taken to inject gas into the local network rather than NTS or use the gas for electricity generation. He confirmed there are 78 injection sites recorded for 2016/17 with more expected.

These sites have marginal costs of being connected to the local network when compared to NTS connections and there is a calculation to establish the individual entry costs and if the site will be debited or credited.

The benefits of these sites are, if the Network receives gas it should not need to book a similar capacity with NTS and can meet some of its needs with its own providers. However, there are only a small number of sites and there is no certainty on the amount of gas that will be injected, but the cost savings are considered and prices are changed to reflect savings made.

RW explained the LDZ Credit System and the savings on upstream costs. He explained that the commodity is worth 5% of the income and in the UNC an apportionment is taken into account to calculate the unit cost saving. As Networks collect allowed revenue it is the consumers on that network which will fund though a higher commodity charge any net payment to the sites (or receive lower charges where the sites are a net debit).

RW noted that the process of cost allocation is very simplistic in the UNC and there is no true up process, it is assumed a site will flow as it has requested to do so. IT would be worth reviewing the UNC to make it more cost reflective should the number/capacity of sites significantly increase.

CN enquired if parties had a particular interest in any other topics that they would like to be presented at the next meeting. BF suggested some of the items reported within the Revenue Reports may wish to be covered for example the DESC Demand estimation Models which have an impact on pricing and the what timelines are involved. It was agreed to have this presented at the January 2017 meeting with the support of Xoserve.

Action 0903: DNOs/Xoserve to consider and provide an explanation of the Demand Estimation Models and their impact on pricing.

5.2 Revenue forecasting beyond RIIO GD-1 (All DN's)

CN concluded from the UNC and Ofgem implementation letter there was some ambiguity with the provision of the Mod0186 Revenue Reports. Last time discussed it was assumed there would be a continuation of same regime. However, due to the amount of uncertainty and how meaningful it would be to incorporate into Shipper Price Forecasts, it was questioned the benefits of forecasting beyond RIIO GD-1.

RW had anticipated the forecast would be Year + 4 and the best way to deal with this would be to collectively agree an approach to ensure consistency.

CN also highlighted that there would be a need to agree what the opening base revenue assumption would be. He suggested that the Networks could take the last Year (Year 8) as Year 1 and then carry forward the Year 1 true up.

SV suggested DNs provide an opening position with options layered to consider which would be the best route.

Action 0904: Networks to consider and provide a suggested opening base revenue position for revenue forecasting beyond RIIO GD-2, with an outline of the key assumptions.

5.3 Extending the Notification Period of Charges (npower)

GT provided a presentation on extending the Distribution Tariff Notification Period of Charges to demonstrate how an increased tariff notice period would impact customer bills. GT explained that customers would benefit from a 3 Year view of prices and this would reduce the risk and uncertainty to Shippers and lead to more reliable pricing.

GT explained the consequences of existing the notice periods.

RW suggested that the variability in Transportation charges that had the biggest impact was RPI and SOQ. CB also highlighted any unpredictability that has not been anticipated with signals within forecasts.

GT recognised that there are volatile factors that cannot be controlled by the Transporters, however the uncertainty impacts customer bills as Suppliers need to factor in pricing risk premiums. SV explained for domestic customers where pass through is not an option, with the increased demand for fixed price tariffs, Suppliers are faced with an amount of unknown risk and risk premiums may result in customers being overcharged.

JP suggested the fixed SOQ would drive out some uncertainty within K once Nexus is implemented.

CN believed there are other aspects of the regime within the price control framework/structure and the overall cost of capital; everything is based on a cost base.

JT asked about the materiality of the impact to domestic customers and the use of risk premiums. GT suggested that the part of the average bill transportation accounts for approximately 17%, and this error could be in the order of 5%.

GT summarised that having 15 months' notice of tariffs would provide shippers and consumers with greater certainty of future Gas Distribution charges that they will face and could ultimately reduce risk premiums. The Gas Distribution risk premium for non-pass through contracts covering the period where the tariffs are published would be removed, removing the unnecessary cost of risk to Suppliers from customer bills. This would result in improved competition between Suppliers by reducing the uncertainty around the Gas Distribution tariffs. Pass through customers would also benefit from the increased budget certainty. An increased notice period may lead to a larger under/over recovery (K) to be rolled forward to later years. However customers will benefit as their contract is unlikely to span a period that covers a tariff year subject to a potentially significant unknown true-up.

It was questioned if the same challenges would be made to NTS. It was highlighted that the element of Distribution volatility although in terms of % variation was greater for NTS, the value at risk was higher for DNOs charges. JP suggested with the fixed SOQ, price volatility would reduce and it would be worthwhile the industry waiting to see how the SOQ fix will improve the situation. RW asked about the extent of realised volatility within the Electricity Market.

BF suggested to take this forward there would need to be a UNC modification and a it would be preferable for the proposer to obtain a view from Ofgem on the potential licence change impacts. The Workgroup considered the best approach to managing an assessment of the change and whether an early view from Ofgem would be necessary. It was recognised that an early view from Ofgem on the modification would provide reassurance to the industry that is not pursuing a change that cannot be made.

SV explained the approach taken by the Electricity industry to change the notice period and that a notice of 200 days was considered as stepped change.

It was acknowledged that small shippers and iGTs would need to be aware and involved with the assessment and more regular DNCMF meetings would need to be organised to facilitate discussion.

GT agreed to consider the matter further with a view to raising a UNC modification for further discussion.

5.4 CSEP Administration charge (ScottishPower)

CN confirmed that ScottishPower had raised a question around the CSEP administration charge. He confirmed that at the point of Project Nexus implementation the CSEP administration charge would cease. It was understood that the charge would drop from the Transporter's tariff.

CN explained the cost/charge is managed/provided by Xoserve. He explained that this is a Project Nexus transitional related issue, and the year would start with the cost being included and then there would be a mid year price change to remove the cost. CN suggested the Transporters would need to better understand how to administer the change within the licence conditions and the associated impacts.

CN confirmed he would need to clarify with Ofgem how the charge will be administered and he will provide clarity to Scottish Power on the value of the charge.

6. Any Other Business

6.1 Change meeting date January 2017

The January meeting was changed to 09 January 2017.

7. Diary Planning for Workgroup

Details of planned meetings are available at: www.gasgovernance.co.uk/Diary.

The following meetings are scheduled to take place:

Time/Date	Venue	Workgroup Programme
10:30, Monday 09 January 2017	Consort House, 6 Homer Road, Solihull, B91 3QQ	*To be confirmed*
10:30, Tuesday 21 March 2017	Consort House, 6 Homer Road, Solihull, B91 3QQ	*To be confirmed*
10:30, Tuesday 20 June 2017	Consort House, 6 Homer Road, Solihull, B91 3QQ	*To be confirmed*
10:30, Tuesday 19 September 2017	Consort House, 6 Homer Road, Solihull, B91 3QQ	*To be confirmed*

Action Table (27 September 2016)

Action Ref	Meeting Date	Minute Ref	Action	Owner	Status Update
0901	27/09/16	3.1	DNs to provide a further update on the assumptions with fixed SOQs (Project Nexus Implementation) to provide clarity on the October stepped change.	All DNs	**Pending**
0902	27/09/16	3.2	DNs to consider and provide a consistent assumption approach as a sensitivity measure for Project Nexus transitional arrangements.	All DNs	**Pending**

Action Table (27 September 2016)

Action Ref	Meeting Date	Minute Ref	Action	Owner	Status Update
0903	27/09/16	5.1	DNOs/Xoserve to consider and provide an explanation of the Demand Estimation Models and their impact on pricing.	All DNs / Xoserve (FC)	**Pending**
0904	27/09/16	5.2	Networks to consider and provide a suggested opening base revenue position for revenue forecasting beyond RIIO GD-2, with an outline of the key assumptions.	All DNs	**Pending**