Workgroup 0391 - Distributed Gas Charging Arrangements
Workgroup Minutes
Tuesday 15 November 2011

at the ENA, 52 Horseferry Road, London SW1P 2AF

Attendees

Tim Davis (Chair)	(TD)	Joint Office
Mike Berrisford (Secretary)	(MB)	Joint Office
Brian Durber	(BD)	E.ON UK
Dave Pickering	(DP)	National Grid
Jo Parker	(JP)	Scotia Gas Networks
John Baldwin	(JB)	REA
John Edwards	(JE)	Wales & West Utilities
Jonathan Wisdom	(JW)	RWE npower
Lesley Ferrando	(LF)	Ofgem
Richard Pomroy	(RP)	Wales & West Utilities
Steve Armstrong	(SA)	National Grid Distribution
Steve Howells	(SH)	Scotia Gas Networks
Will Guest	(WG)	Northern Gas Networks

Copies of all papers are available at: http://www.gasgovernance.co.uk/0391/151111.

1. Introduction and Status Review

TD welcomed all to the meeting and apologised for the late start, as the meeting would not be quorate until the delayed delegates arrived.

1.1 Review of minutes

The minutes of the previous meeting were approved.

1.2 Review of Actions

WG0391 09/001: National Grid Distribution (SA) to develop and present a more detailed version of option 3.

Update: SA had provided the 'Detailed Charging Proposals for DN Entry Under Option 3 (shallow boundary with entry charge) presentation for consideration under item 2.1.

Closed

2. Discussion

2.1 Proposal for DN Entry Charging – option 3 development

SA explained that the opening slides reflected discussions at the inaugural workgroup meeting.

In trying to ascertain how confident the Workgroup is that customer charges would be unaffected, RP pointed out the roughly 80% of all gas escapes are on the customer downstream pipes and, therefore, he believes the statement holds true.

In considering which costs are incurred by each party and those items yet to be determined, SA advised that ownership aspects (i.e. Connectee or DN or a combination of both) are being considered by Ofgem's Review of Energy Market Issues for Biomethane Projects. When asked whether an entry facility would need to pressurise biogas prior to injection into the network, JB confirmed this to be true, and in the region of 7 to 10 bar being typical. SA went on to add that under option 3, as presented, the assumption is that costs would take the form of a Transportation Charge and any network incurred costs would be included within this.

BD enquired how the ‘Reliability Factor’ would be calculated, and SA suggested that initially this could be based on average load factors. Further down the line, utilisation of historically building data would inform review of the factor levels. SA went on to suggest that for individual connections you may not need a reliability factor, but for multiple connections you would. JB wondered if consideration of diversity aspects and impacts would be helpful. However, SA emphasised that the costs impact of reliability factors is relatively small.

Moving on, SA suggested that lower usage of the network pipeline tiers would typically result in a cost credit being accrued. When asked, SA confirmed that there is a possibility that we may observe some shippers entering gas to the system without actually taking any off, but that this would potentially put them out of balance. BD felt situations such as these would be covered under the nominations aspects of the regime. SA pointed out that there is no concept of LDZ system balancing. He went on to state that odorant costs for distributed gas could be addressed in use of system charges.

In considering the ‘Entry Credit for Deemed Reduction in NTS Exit Capacity Requirements’ slide, SA pointed out that the LDZ ECN charge would be applied on a DN basis. He went on to wonder whether or not you would wish to apply different reliability factors for different gases (i.e. biogas or shale gas etc). It was suggested that initially we would start off with a single average reliability factor. Considering the example presented more closely JB accepted that the difference between an 80% and 90% reliability factor would be relatively small.

Looking at the new LDZ system capacity charge graph on slide 7, SA suggested that the results reflected the fact that the larger LSPs connect to the network higher up in the network tier structure.

When looking at the higher tier usage table on slide 8, SA advised that the Low Pressure tier is the dominant cost tier for domestic users before going on to suggest that utilising the 0 – 73MWh figures would be beneficial as these are closer to average utilisation. When asked if there could be short-haul tariffs for biogas plants that reside close by, or next to, operational plants, SA indicated that these may be possible but further consideration would be needed.

In continuing to consider the ‘Derivation of Credit for Reduced LDZ System Usage’ aspects of the presentation, TD summarised discussion so far as being that broadly speaking, you only get credited for those tiers in the network that you do not utilise. SA believed that in future we could consider compression of low-pressure gas to a suitable level for injection into the medium pressure network whereby a credit would be given for tiers above the medium pressure tier. SA also believed that providing credit for the lower LP tier or even taking into account the precise pressure tier of connection is a complex matter in practice. When asked if a good rule of thumb was that we debit the total and thereafter apply credits for the remainder, SA suggested that this simplified approach could work. Furthermore, from a (capacity) invoicing perspective parties could see both credit and debits being applied.

Looking at the annuitisation factor of 20 years in the example provided on slide 10, SA confirmed that this was deemed to be the effective plant life expectancy – SA is happy to discuss in more detail along with identification of a suitable Opex % of capital. When asked, SA believed that network entry agreements would cover instances where biogas production and injection increases or decreases did not change the existing plant status. He also believes that there could be merit in adopting a standardised cost approach, with consideration of variations to this approach for different types of gas. SH enquired if the proposed model catered for plant equipment replacements. In response, SA indicated that he believed that existing knowledge of similar NTS gas entry equipment replacement requirements could be utilised, but ultimately the question boils down to cost reflectivity and consequently may not be reflected in the Transportation Charge change. SA suggested setting a charge at the time of entry and not seeking to recover costs for individual items – it is a balanced approach that is needed.

Moving on to consider the 'Entry Charge for Network Reinforcement or Compression' slide, SA noted that this would be similar to the previous slide and again assumes that charges would be established at the time of connection rather than being reviewed year on year – an approach supported by JB. Moving on, JB believed that providing a 'banding range' for different Opex %'s of capital such as 5%, 10%, 15% etc. could prove beneficial. Asked if different agreements applied to different biogas producers would be an acceptable way forward, JB indicated that, whilst possible, it may be preferable to adopt a 'socialised' cost approach. SA suggested that current network provisions establish a precedent in terms of contribution variations (i.e. consistent with current exit approach). RP felt that care would be needed to avoid incentivising parties to deliberately connect at different tiers within the network. Asked if Ofgem would have any discriminatory related issues with a first come, first served approach, LF suggested that this may be the case although we may need to live with the issues in the initial stages, but Ofgem would expect to see a thorough regime review undertaken as the regime develops and historical data builds. TD suggested that take up numbers and potential queuing issues may need considering in due course. RP indicated that the GDNs are already aware that this area needs considering.

Looking at the final slide for the 'Example of Potential Entry Charge', SA suggested that this pulls together the various elements described previously in the presentation. Whilst acknowledging that this was a good presentation, JB believed that a Biomethane flow of 300 – 350 m^3/hr would be more representative of an average rate. He went on to suggest that the entry facility cost was the tricky element, as there remain issues around liabilities etc. In response, SA advised that current Code provisions cover liability payments, especially where the GDNs are unable to accept gas into the system. SA went on to suggest that as the indications are that these are unlikely to be significant costs, the level of detail should be tailored to suit requirements and not be over engineered. TD also suggested that shipper charges via capacity levels established in NEAs would need considering as well.

Summarising discussions, TD believed a broad consensus had been reached that this proposal was a plausible approach. SA requested that interested parties provide feedback on the presentation to enable him to develop a formal Transportation Charging proposal, which could then be targeted for a 2012 introduction.

JB suggested consideration of how the methodology would be applied for converting capital cost into an appropriate charge, including identification of various component factors would be beneficial – possibly a menu of options style approach supported by a common methodology. TD envisages the methodology could be based on an amount identified in the NEA. SA indicated that he would be happy to provide more detail. RP wondered if we should also include consideration and provision of Xoserve implementation costs and timescales – a point supported by SA.

In closing, TD indicated that SA should now draw up some draft business rules with a view to arranging a meeting to review these early in 2012.

New Action WG0391 11/001: National Grid (SA) to prepare a set of draft business rules based on workgroup discussions and any feedback ready for consideration at a follow up meeting in early 2012.

3. Any Other Business

None.

4. Diary Planning for Workgroup

A meeting in early 2012 would be scheduled once National Grid provide an indication on the delivery of a set of draft business rules.

Action Log – UNC Workgroup 0391

Action Ref	Meeting Date	Minute Ref	Action	Owner	Status Update
WG0391 09/001	26/09/11	4.	Develop and present a more detailed version of option 3.	National Grid Distribution (SA)	Update provided. **Closed**
WG0391 11/001	15/11/11	2.1	To prepare a set of draft business rules based on workgroup discussions and any feedback ready for consideration at a follow up meeting in early 2012.	National Grid Distribution (SA)	Update to be provided.