GT27 price control approach

1. Introduction

This response is on behalf of Mutual Energy ("MEL"), which owns three of the four licenced gas TSOs in Northern Ireland: Premier Transmission Ltd ("PTL"), Belfast Gas Transmission Ltd ("BGTL") and West Transmission Ltd ("WTL").

We welcome the opportunity to respond to this consultation on the approach to the GT27 gas transmission price control. As the consultation did not propose any specific questions, we have included our thoughts on some aspects of the approach which we believe should be considered further.

2. GT27 approach feedback

2.1. Energy transition/decarbonisation

2.1.1. Staffing

There has been ongoing significant investment in staffing across the Northern Irish energy industry to ensure sufficient resourcing is in place to support the delivery of legislated emission reduction targets, including within DfE and the Utility Regulator ("UR").

MEL has a vital role to play in decarbonisation as a trusted industry partner who can maintain a non-partisan position and instead is focussed on the long-term interests of NI energy consumers as a whole. We hope that UR see the value in MEL's role and our contribution to date and, whilst previous price controls have not awarded any allowances for staff in this area, we strongly believe allowances for these staff, and more recent network planning resources, should be provided for GT27, with their need now well established.

2.1.2. Hydrogen

The consultation states *"Gas networks in Northern Ireland are preparing for the possibility of biomethane and hydrogen blends to support decarbonisation, but the pace of this work will be dictated by government policy" and "Our vires will affect the extent to which our regulation can deal with issues. We also recognise that supporting innovation relating to the future of the gas network will be important"*.

Whilst the reference to government here relates to Stormont, given the increasing reliance on gas imports from GB to maintain Northern Ireland's security of energy supply, the required pace of work on hydrogen blends is likely to be driven instead by GB's hydrogen policy, which is significantly ahead of NI. If the GB government makes a decision to allow hydrogen blending on the NTS, which (as would then be expected) results in hydrogen blends at Moffat, there will be a need for UR to allow funding to prepare the Northern Irish gas network to accept blends within GT27. The extent of the work required to ensure Northern Ireland's hydrogen readiness is significant and should not be underestimated.

2.1.3. Key role of renewable gases

The stance towards development of renewable gases in Northern Ireland has tended to be reactive. This is arguably a result of a lack of government policy development in this area due to a focus on the 2030 80% RES-E target.

Renewable gases however will be required to successfully deliver upon NI's emission reduction targets. Biomethane can complement electrification as a decarbonisation pathway for heat, especially for existing housing stock in proximity to the gas network. Green hydrogen production combined with salt cavern storage offers a means to help manage dispatch down, deliver large-scale long-term energy storage of renewable energy, as well as a decarbonised fuel for dispatchable power generation. Production and use of both gases can therefore help maintain our energy security as we decarbonise.

Regardless of the rate of renewable gas development in NI, our reliance on imported natural gas from GB means we will have to adapt to potential renewable gas policy developments in GB – e.g. in relation to hydrogen blending on the NTS. In conjunction with the substantial benefits indigenous production and use of renewable gases offer it is important that a more proactive stance in adopted to help support their development and implementation in GT27.

2.1.4. Energy transition project funding and framework delivery

We would welcome a proactive and pragmatic approach to energy transition projects and framework delivery funding. There will inevitably be a number of workstreams, studies, projects and mitigation works arising throughout the price control period which will be unforeseen, or for which we will not have sufficient certainty on the need, scope or expected costs at the time of submission to be able to accurately forecast these. A mechanism to deal with such costs, which is not limited to unforeseen costs, during GT27 is therefore considered essential.

Whilst we appreciate the need for appropriate justification we have found that the Energy Strategy Unforeseen Expenditure process used to date, while suitable as a workaround for smaller studies under GT22, requires significant resourcing and time on both the part of MEL and the UR to secure necessary approvals, and would be too unwieldy for potential multiple submissions under a large-scale project, while being disproportionate to the incurred spend for smaller pieces of work. Whilst this process has enabled some 'one-off' projects, which we welcome, we recommend a lighter touch approach is considered for smaller projects (where spend is not significant), and a more pragmatic approach is adopted for larger pieces of work – e.g. so that the overall outline of a major project is considered and agreed, with a more detailed submission for expenditure up to a certain amount, with a flexible approach for future work packages or ongoing annual spend thereafter. We would note that for large energy transition projects such as hydrogen blending, it may not be possible to get an accurate cost estimate for the full scope of works prior to their commencement, because the scope of work is likely to depend upon the outcome of initial assessments that will be carried out as part of the project. While appreciating that it is important that robust regulatory oversight of expenditure is in place, a new or revised mechanism, if appropriately designed, could help ensure approvals are made in a timely manner and reduce the administrative burden, both for MEL and UR, without undermining the efficacy of regulatory controls.

We would welcome further engagement with UR to discuss options for a development of this mechanism for GT27.

2.1.5. Innovation

We expect most innovation costs should either be self-justifying (i.e. result in savings which offset the required costs) or be related to Energy Strategy (in which case the Energy Strategy mechanism could be used). Where this is not the case and there are material costs, we believe the existing additional BCO mechanism is suitable to deal with any such projects and therefore do not see the need for a separate mechanism to be created.

2.1.6. Emissions

Requirements in this area should be set so as to only provide information which UR intends to use. Such information should not be more onerous than, and should be aligned so far as possible with, other legislation already applicable to the businesses to ensure there is no undue burden on TSOs.

2.1.7. Whole system planning

This has been a welcome addition to address network development, much of which is driven by the energy transition and resultant need for better forecasts over all timeframes. Now this function has been established it has become part of our business as usual and we believe should be included within our price control allowance, in a suitable cost classification, with only unforeseen developments in this area to be considered under the Energy Strategy mechanism should they arise.

2.1.8. Capital expenditure

The consultation notes: *"The price control process does not set allowances for capital expenditure." And "There is no provision for setting capital expenditure allowances in either the PTL or the BGTL licences. For the purposes of this price control capital expenditure is any expenditure that results in an increase in the overall capacity of the network to convey gas"*.

While the need for capital expenditure will be informed by network planning and developments on the power system, we anticipate that meeting peak gas demands in future may well require investment that increases the capacity of the network (e.g. compression) and so this may need to be addressed in the future. Developments in the gas networks, such as reverse compression to facilitate biomethane, could also result in an increase in overall capacity of the network to convey gas and the requirement for capital expenditure. Capital expenditure could also be required to address security of supply concerns.

2.2. RPIH to CPIH change

As RPI will align with CPIH from 2030 it seems reasonable to move to CPIH, which will be calculated consistently throughout the price control period. It should be noted that the differences in methodology and coverage create a "wedge" or gap, between RPI and CPIH, with RPI generally being higher. This should therefore be taken into consideration when determining the value of X under the CPI-X framework, to ensure that the target remains appropriate.

2.3. General approach

2.3.1. Timing

As one of MEL's main strategic objectives is to operate cost effectively in the interest of NI consumers, the group has adopted a lean staffing structure and does not have any staff dedicated to, or with a core focus on, price control submissions. As such, timelines for the business plan reporting (from publication of the templates through to required submission) are very tight and largely align with the group's year end and audit period, during which the relevant staff are already stretched. It therefore is essential that there are no delays on the publication of the templates and guidance, as this would likely to have a knock-on impact on submission of the business plan.

2.3.2. Profit margins and contingencies

The GT27 approach consultation notes that allowances for profit margins and contingencies will not be given.

The Mutual Energy group is not profit-driven and as such its gas business licences are designed so that they cover their costs, without any additional profits built in. Our businesses do, however, have requirements under their finance documents, and through tax legislation, to operate on an arms' length basis and therefore, where shared services are provided to the gas businesses, small uplifts are applied to comply with these requirements. Our belief is that through: 1) efficiencies of scale in providing shared services; 2) the minimisation of uplifts charged; and 3) other costs incurred by the service providers which are borne directly and not recharged to the licenced entities e.g. procurement and legal costs of shared services etc, any impact of these uplifts are insignificant and therefore should be allowed within the price control allowance.

It is inevitable that some unforeseen works will be required during the 5-year price control period, particularly due to issues which are likely to be identified through scheduled inspections. Whilst we can forecast costs for inspections, in the absence of any contingencies being allowed for defects identified we will need to request allowances for any such costs through the additional BCO mechanism as these arise.

2.3.3. Additional cost categories

The current business plan reporting schedules do not include appropriate categories for costs such as energy transition/decarbonisation and cyber security, which are now significant, and therefore we believe additional categories should be set up for these and any other new or relevant areas. We are happy to discuss this further.