Future Billing Methodology Consultation Workshop Q&A

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<tr><th>No.</th><th>Question:</th><th>Response:</th></tr>
<tr><td>1</td><td>Did the tracking require new measurement equipment to be installed, or could it be done with existing equipment?</td><td>The tracking of biomethane for the FBM field trial to validate network modelling used molecular oxygen as the tracing agent, as:
The propane enrichment cannot be turned off at the biomethane site without triggering the LDZ Flow-weighted Average CV (LDZFWACV) Cap, so we had to find another marker, other than CV, to detect the presence or absence of biomethane.
Biomethane (at ~0.2% O_2) has a significantly higher molecular oxygen content than natural gas (<=0.0001% O_2).
The oxygen sensors used for the trial were existing technology, proven in other applications, which we adapted for application at strategic points on the low-pressure system and at medium pressure / low pressure (MP/LP) district governors around the local networks surrounding the trial biomethane supply sources.
The oxygen sensors were tested before and throughout the trial to ensure accuracy and proved to be highly reliable for the duration of the trial.
For implementation of model-based attribution of Meter Points to CV zones (Option B) or model-based attribution of CV at system node → Meter Point (Option C), we envisage that this process would first require trial validation using a strategically located population of CV measurement devices.
This would require changes to / derogation from the existing gas thermal energy regulations (GCoTER) to exclude trial networks from the FWACV cap, alongside specific enabling changes to central systems, including a potential volumetric adjustment to offset the impact of lower CV gas, similar to the mechanism being considered for SGN's H100 project in Fife.</td></tr>
<tr><td>2</td><td>Was BioLPG considered as a potential replacement for currently used 'commercial'</td><td>BioLPG has been considered as an alternative to fossil LPG, but not as part of this project.</td></tr>
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	Propane to enrich NG? BioLPG being seen as a 'green gas' itself.	• The production of BioLPG is linked to the production of Bio Diesel and so availability and cost would be a function of that fuel market, which could potentially limit its economic use in a gas distribution setting.
3	Is option D (Zonal CV Measurement) not just a review of Option A (Existing Frameworks) to review the relevance of the current charging areas?	• First, it is worth restating that all options other than Option A would require changes to gas thermal energy regulations, and to central and shipper / supplier billing systems. These are not considered to be insurmountable barriers but would require substantial feasibility and development work, which will take time. • Option D – Zonal CV measurement envisaged breaking each LDZ down into smaller physical charging areas, within which consumers would be billed based on a CV measured at a CV determination device(s) (CVDD) located at key feed-in points to each zone (but potentially not every feed-in pipe). • This option cannot be recommended at this time, as installing, and operating such high numbers of CV devices (up to 10,000 nationally) would drive very significant cost and, using existing technology, would generate unacceptable levels of vented sample gas. • For Option D, the physical zoning could prove problematic where changes occur to network layout (e.g., mains diversions) and/or where gases / blends of widely differing CVs (e.g an 80:20 blend of natural gas and hydrogen, with a CV of 34-35 MJ/m3 flowing into the same sub-network as natural gas at 39 MJ/m3). • For LDZs which comprise networks which have separate CV-measured sources from the NTS, and which are physically separated, or for sub-networks which are single-fed and physically discrete from the rest of the LDZ, it would be possible to configure these as separate charging areas under the existing gas thermal energy regulations (GCoTER), with the appropriate CV measurement. But this would still require changes to central billing systems and changes to Section F of the Offtake Arrangements Document (OAD).
4	Are 'charging areas' related to the way transporters apply different rates for transportation charges?	• To clarify, this project focuses on ways of attributing the energy content (CV) of gas to consumers' metered gas flows to maintain fair billing through the

		transition either to 100% hydrogen, 100% biomethane, or alternative zero carbon heat source. • The implementation of any of these options would not require changes to the charging methodologies which are applied by gas networks to reflect the costs they incur in respect of each Local Distribution Zone. • A "charging area" is defined within the GCoTER (in simplified terms here) as a physical area of the gas network within which consumers are charged for gas use based on the same CV. • Section F of the OAD presently defines each LDZ as a charging area, but this could be changed for the implementation of Options B / C, whilst leaving the existing LDZ-based charging methodologies intact. • In the case of physically discrete sub-LDZ networks, these could be configured as separate charging areas without changing the existing regulations, provided CV and volume is measured at all input / output points to the charging area, but would require substantial changes to central and client billing systems to properly account for the new charging areas.
5	Would Shippers & Suppliers need to use the CV at MPRN level for their energy billing calculations?	• Options B – E focus on ways to attribute the CV of gases to consumers' metered gas flows more in line with their physical gas source, so enabling gases of more diverse CV than the allowed by the existing framework to share the same LDZ network. • As zones of influence exerted by each input to the LDZ can change under different demand conditions, the potential variability in CV at meter point level would require changes to central billing systems to use a meter point-specific CV for each Gas Day, as opposed to the present LDZ flow-weighted average CV (FWACV). • This would in turn require shippers / suppliers to use the same meter point-specific CV, which would need to be actively provided daily by the Central Data Services Provider (CDSP).

6	Are the costs listed in the CBA table for DN system changes or CDSP or Suppliers or a combination?	• The implementation costs shown for each option in the table in slide 39 include GDN, CDSP and shipper / supplier systems. • In the column labelled "Within which: Client systems costs" the capex element for shipper supplier systems has been broken out as a memo item, so that shippers / suppliers can see these values, which are at very high level and based on early work under workstream 0291 in 2009. • Question 6 in the consultation paper invites input from shipper / supplier organisations to improve on this rudimentary costing for the final CBA, if possible.

7	How would Option A work in the case where there are multiple NTS offtakes, each with different hydrogen percentages? Would Option A still work in that scenario?	• Under Option A, the percentage of hydrogen that would be added at each blending offtake into an LDZ would be centrally coordinated by the GDN to:
		  ○ Take account of the composition of the gas being injected from the NTS and
		  ○ Ensure that the CV of each blending input remains within the overall LDZ FWACV cap.
		• This will require integrated system controls and some minor changes to energy tracking systems but would not need changes to the existing billing systems or to gas thermal energy regulations.

Session 2 – 11th Feb 2022		
No.	**Question:**	**Response:**
8	What about consumer appliance compatibility - will 80/20 natural gas to hydrogen blends work for existing plant?	• Cadent's HyDeploy project is successfully trialling hydrogen blend of up to 20%VOL in natural gas in Winlaton in North East England for domestic and some commercial premises. • This project will also investigate the impact of hydrogen blends on larger commercial and industrial gas appliances. • This should also encompass gas usage for feedstock purposes. • Cadent would welcome engagement with commercial / industrial users on this aspect of the HyDeploy project.

9	Is CV capped in the Calculation of thermal energy regs?	• The Gas Calculation of Thermal Energy Regulations sets a CV cap at 1 mega joule per cubic metre (MJ/m^3) above the lowest CV source to an LDZ. • Under this rule the introduction of even 1 cubic metre of biomethane at 37 MJ/m3 into an LDZ with a flow-weighted average CV of 39 MJ/m^3 would cap the CV for billing purposes across the LDZ at 38 MJ/m^3, so excluding a significantly disproportionate amount of gas energy from billing. • The excluded energy is transferred to the NTS CV shrinkage account and this "shrinkage" cost is recharged to shippers at system average price for the Gas Day in question.
10	Would the unbilled gas resulting from LDZ CV capping be picked up as NTS shrinkage or UIG? Would it depend on where the green gas is injected?	• Under the present "LDZ FWACV" regime, unbilled gas energy resulting from triggering the LDZ flow-weighted average CV (FWACV) cap is picked up by the NTS as CV shrinkage, no matter where the embedded gas supply is located within the LDZ. • Unidentified Gas (UIG) is the residual difference between the top-down attribution of LDZ energy and the total energy billed to Shippers / Suppliers at Meter Point level for a given time-period (excluding capped-out energy) and can result from a wide range of factors, including the averaging, rounding and/or truncation of measured CV values, standard temperature & pressure correction, differences between assumed and actual theft of gas, errors in weather correction, etc. • It is worth noting that the introduction of modelled CV zones under Options B* and C would effectively render the LDZ FWACV CV cap obsolete and any bias in modelling error to create zones / attribute modelled CV would result in a trend in UIG. So, trialling in parallel with the existing regime would be critical. *Where all low-CV sources to an LDZ have been captured by Option B.
11	If we expect the dynamics to shift going forward as we see transition away from gas heating is historic analysis suitable for future demand?	• In the CBA, the reasons for working to a 2050 horizon on a national basis in the CBA are as follows: ○ It is relevant to do so since a transitional gas phase could potentially endure for some time in areas of the network where 100 per cent

		hydrogen / 100% biomethane, electrification or alternative heat delivery vectors remain problematic. ○ At this stage, it is uncertain which areas of the national gas distribution grid would switch to alternative heat provision as in (i) above. ○ Billing system implementation costs include a central systems element, which cannot be meaningfully reflected in a regionalised assessment. ○ The switch either to 100 per cent hydrogen networks, electrification or alternatives are out of scope for this assessment. ○ This approach provides a consistent basis for comparative assessment of the options.
12	Does a "system node" correlate to a postcode - is it identifiable to a shipper / supplier?	• A system node is a section of pipework, fed by specific regulators on the gas distribution system and represents the lowest level of detail at which network models can simulate gas demand from loads connected to it, and hence the travel, mixing and CV of gas. • A system node is smaller than a Post Code and so cannot be correlated. Under Options B or C, the attribution of CV at Meter Point level would be effected via a system node → meter point interface.
13	How is the level of enrichment for Biomethane determined - are they given a site-by-site target?	• Each biomethane site is sent the calculated FWACV for that network every 45 minutes from SCADA. • The biomethane site must enrich to remain within a GDN-specified margin of that target CV, typically 0.5 – 0.8 MJ/m3.
14	If consumers receiving lower-CV gas blends must use more volume, would that mean an increase to capacity charges for the same energy?	• LDZ Capacity charges are designed to reflect the GDN cost for the provision of peak day system capacity in energy terms. • Blending 20% hydrogen at wide scale in the LDZ might potentially trigger some reinforcement at specific points on the network to accommodate higher volumetric flows, but this would be immaterial in relation to the total LDZ

		system, as the Wobbe impact of the blend would be small and generally within existing system design parameters. • Given the above we would envisage no material impact on transportation charges.
15	How would future changes to demand and system flows under blending of lower CV gases be taken into account?	• Any future changes to gas energy demand and/or volumetric flow relating to lower CV gases such as hydrogen blends or biomethane would be accounted for by the network and CV modelling applied to simulate the travel and mixing of gases in the network under given system demand conditions. • The thermal energy modelling applied for this purpose would take account of the relationship between volume and energy content to supply any given demand on the system.
16	Do options B-E reopen GSMR?	• Options B – E all involve reform to the framework for energy attribution and so would require corresponding changes to the Gas Calculation of Thermal Energy Regulations (GCoTER). • The systematic blending of hydrogen up to 20%VOL in natural gas (less in biomethane due to lower Wobbe) would require changes to the Gas Safety Management Regulations (GSMR), which presently has project-specific exemptions in place for this purpose. • The introduction of hydrogen into the network gas mix will also require some changes to the Uniform Network Code.
17	Would Option C be unsatisfactory, being open to challenge by consumers, because the CV is modelled not actual and will vary from the network measured value based on modelling assumptions.	• Both Option B – which uses network and CV modelling to create an embedded low CV zone and allocates consumers within it to the measured CV of the embedded gas source, and Option C – which uses network and CV modelling to derive an output CV at system node level (Option C), would apply network and thermal energy modelling assumptions in the energy attribution process. • Under Option B, any risk that modelling error might potentially result in unfavourable misallocation of consumers outside the embedded low-CV zone could be mitigated by applying a below-average demand level in modelling the

		embedded supply zone, to create a wider zone around the low-CV gas source. Preliminary analysis suggests this could be optimised to ensure a non-material counter-impact on consumers in the wider LDZ outside the embedded zone. • For Option C, the online and offline modelling would use CV measured at all gas inputs to the LDZ, together with a range of critical network asset and operational data to drive modelling of the flow and mixing of gases under the system demand conditions predicted (before-the-day process) or encountered (after-the-day process) to derive output average CV values for each system node / Gas Day. • This process would be augmented / regulated by a strategically sited population of CV measurement devices, for which we are presently investigating new low-power, non-venting technology options. • We envisage that changes to the gas thermal energy regulations would be developed in parallel with specification of the new methods for energy attribution and, taken together, should result in a level of consumer protection that is at least equivalent to that afforded under the existing LDZ FWACV regime. • For assurance purposes, we would need to be able to demonstrate this in a parallel trial with the existing framework in a test environment.
18	Is the potential impact on Gemini considered in the ongoing procurement of a new platform?	• Whilst specific requirements are not yet definable by the business, we did ask the suppliers to submit responses on how they envisage their solution would be flexible for future regulatory change and hydrogen. • We will only select a solution that demonstrates this to our satisfaction. • However, until the industry gets the actual framework defined down to a detailed UNC-type level we cannot design/build, so this will remain something that will need to be applied as a change control in the future.
19	If Option A cannot provide a universal solution, this implies a hybrid risk. How would this be managed in terms of understanding likelihood, timing etc?	• To clarify, the Option A approach would be a “universal facilitator”, in that the installation of the additional system controls, at comparatively minimal cost, would enable controlled blending of green gases to happen within the existing FWACV parameters, wherever the supply of green gases makes blending

		feasible. So, implementation of this option would not preclude or conflict with the implementation of other options. • Implementation of Options B / C would require deep changes to central and Shipper / Supplier billing systems to enable Meter Point-specific CV attribution. • By separating the development of front-end (consumer-facing) and back-end (DN systems) via a system node → meter point interface, this could enable LDZs which continue to operate under Option A to retain use of the LDZ FWACV (and the existing cap), as the LDZ-wide CV value would be allocated by default within those LDZs. • The changes to the gas thermal energy regulations to regulate Options B / C could be housed within a new separate Part of the regulations. • In this way, LDZs could adopt the new Part ("X") of the regulations where billing reform under Options B / C is implemented. • Part II (calculated CV) of the regulations would be retained for LDZs operating under Option A (existing framework), and – • Part III of the regulations (Declared CV) could potentially be adopted for networks switching to 100% hydrogen or biomethane, as they would have a stable CV but – • This would require additional structural changes to billing systems to recognise these new charging areas, which would be physically discrete new or repurposed sections of the gas distribution network. • The fact that the changes to systems and regulations would be developed to maintain a level of consumer protection that is at least equivalent to that afforded under the existing LDZ FWACV regime, should mean that multiple approaches could co-exist without detriment to consumers or competition in gas supply, providing that all shipper / supplier systems were equally configured to handle daily meter point-specific CV. • At this time, we cannot predict how decarbonisation of the gas distribution networks will progress regionally or timewise, but risk quantification could potentially be facilitated by means of a coordinated industry decarbonisation forum and a regional dashboard.
Session 3 – 22nd Feb 2022		

No.	Question:	Answer:
20	Why does H2 need to be pre blended?	• To clarify, hydrogen does not need to be pre-blended as such. It must be injected into the natural gas stream in a way that ensures it is fully co-mingled with system gas upstream of any consumer connection.
21	Is there an assumption that is made that the grid is 100% biomethane or hydrogen as an end point? Is it not more likely that a green gas network uses a variety of sustainable sources (biomethane, hydrogen and other bio/green sources if developed)	• The consultation and CBA focus on the transition period, and the end state – 100% green gas or other low/zero carbon heat source – is out of scope. • However, it is possible that future networks flowing 100% green gas could be a blend of biomethane and hydrogen, subject to safe-burn constraints.
22	What is FWACV?	• FWACV = Flow weighted average Calorific value. • Under the existing gas thermal energy regulations, calorific value (CV) and volume must be measured at every input / output point to the charging area to determine energy inputs / outputs (charging areas are currently defined as each LDZ). • The flow-weighted average calorific value is calculated by dividing the net total charging area input energy by the net total input volume. • Please see link for further information: https://www.nationalgrid.com/gas-transmission/data-and-operations/calorific-value-cv
23	Do FWACVs vary significantly between LDZs at the moment?	• Existing sources of natural gas can vary in calorific value, typically between 38 – 41 MJ/m3 and so, the flow-weighted average CV does vary from one Local Distribution Zone to another. • The following link may help in understanding FWACV: https://www.nationalgrid.com/gas-transmission/data-and-operations/calorific-value-cv
24	How does the FWACV feed back onto the level of CV that biomethane producers must achieve when they inject?	• Each biomethane site is sent the calculated FWACV for that network every 45 minutes from SCADA. • The biomethane site must enrich to remain within a GDN-specified margin of that target CV, typically 0.5 – 0.8 MJ/m3.

25	Could we change the 1 MJ to 2 MJ to provide more flex?	• This change would require an amendment to the regulations. • The existing envelope of 1 MJ/m3 equates to a maximum cross-subsidy of around 3% of the average annual bill for domestic consumers. • Doubling this tolerance would have a corresponding effect on cross-subsidy. • Increasing gas costs would amplify the absolute impact on consumers receiving lower-than-average CV gas within a local distribution zone.
26	Would ballasting (high CV) LNG with hydrogen instead of nitrogen at network entry points help reduce high FWACV LDZs?	• Nitrogen is added to some LNGs in order to make it compliant with the interchangeability requirements of the Gas Safety Management Regulations (GSMR). Although adding nitrogen to LNGs lowers its CV, this is NOT the purpose of nitrogen ballasting. • Adding hydrogen instead of nitrogen to LNGs could also be carried out to make them compliant with the GSMR. More hydrogen would be required than nitrogen in order to make the gas compliant with the GSMR - just over four times more hydrogen than nitrogen. This means that typically around 5.4% hydrogen would be added, compared with around 1.3% nitrogen. • As an example, an LNG ballasted with nitrogen would have a CV of around 39.9 MJ/m^3, whereas one ballasted with hydrogen would have a CV of around 38.9 MJ/m^3. • Ballasting with hydrogen would therefore avoid the cost of ballasting, provided it is strategically located. Because the CV of a hydrogen-ballasted LNG is lower than that of the nitrogen-ballasted counterpart, the FWACV of the charging area would be reduced, which would also reduce the likelihood of CV capping. • In general, hydrogen blending is easier when blending with the higher CV sources into a charging zone, rather than the lower CV sources.
27	Re blending – Would it not be more effective to blend hydrogen into the NTS, for example, adding H_2 at St Fergus?	• Yes, from a billing perspective, hydrogen blending becomes simpler the further upstream the hydrogen is injected. • If the same percentage volume of hydrogen blend were present in the NTS that feeds all LDZ offtakes into a charging area - in theory, billing wouldn’t be an

		issue because the CV of the gas would equally be reduced at all inputs into the LDZ and Flow Weighted Average CV would work. • However, some LDZs receive gas from different "legs" of the NTS which might be influenced by gas from different sources, so blending hydrogen at high flow locations within the LTS could also deliver large hydrogen volumes, even if restricted to within 5% hydrogen initially under Option A.
28	How challenging would it be to update zones in the model as new biomethane plants come online?	• Under Option B (Embedded Zone Charging), each embedded green gas supply will require a detailed assessment to establish that this approach can reliably model the zone of influence of the embedded supply, as network-specific factors, such as large industrial consumers in the vicinity of the embedded supply, and other network factors can have a significant impact on network flows, CV and hence the low CV zone. • There would need to be a set list of network diagnostics to apply this consistently.
29	Could the model account for varying production levels from biomethane/hydrogen facilities?	• Under a daily, reactive zone creation regime, the model would be able to account for variations in delivery levels at the embedded input point, using SCADA information on entry flows, CV, etc.
30	Are there any figures for the rate of carbon abatement per year? Option A starting sooner can skew the benefit when looking at the total abated by 2050 if it can operate for longer	• Within the CBA model carbon abatement values are calculated year-by-year and cumulatively to the 2050 horizon. • The ability of Option A to start sooner is a clear advantage, rather than being a skewing factor in the analysis. • This is because adoption of Option A, as the "no regime change" option, with minimal implementation cost, would not preclude or restrict implementation of Option B (where hydrogen is blended upstream at <=5%) or Option C.
31	Do option C, D and E include an assumption for vented emissions from CVDDs in the carbon abatement? I.e., would be improved figures if zero emission CVDDs?	• Yes. The CBA includes an estimated venting dis-benefit corresponding to the assumed population of CV measurement devices for Option C (500), D (10,000) and E (44,000) across GB gas distribution networks from option go-live to the 2050 horizon.

		• So, the carbon abatement figures would improve accordingly, if non-venting technology were assumed. See table below. **BILLING OPTIONS: ASSUMED CVDD POPULATIONS AND VENTING IMPACT TO 2050 ASSUMING EXISTING GAS CALORIMETER TECHNOLOGY**

OPTION	DESCRIPTION	CVDD no.	Venting mtCO2e
A	WORK WITHIN EXISTING FRAMEWORKS	0	0
B	EMBEDDED ZONE CHARGING	0	0
C	ONLINE CV MODELLING	500	0.149
D	ZONAL CV MEASUREMENT	10,000	2.614
E	LOCAL CV MEASUREMENT	44,000	8.764

32	I'm not quite sure what is different in Option A from what is happening now. Is it just more active management	• This highlights the point and advantage of Option A, as this is the least-change option, which requires no changes to thermal energy regime or billing processes to implement. • So, in this sense it is a universal facilitator, making blending possible wherever the supply of green gases and delivery infrastructure makes this economically viable. • Option A would not preclude or conflict with the onward implementation of the other options, should network circumstances require that, as any stranding cost of enhanced system control software would be minimal.
33	Do the cost figures include the cost of increasing CV for biomethane and hydrogen producers?	• Options B – E include as a benefit the cost savings of propane abatement from that option. • The unit value used for this saving is a price-indexed equivalent of the original unit value applied in the initial CBA in 2017. • The basis for this value (approximately 0.36 p/kWh) is shown and explained in item 9 within Appendix B to the MS14 consultation paper.
34	Option A doesn't seem to be the most beneficial for producers	• In terms of early implementation at minimal cost, Option A would provide the advantage of facilitating blending from the earliest point practicable in any of the Local Distribution Zones.

		• The apparent carbon abatement shortfall of Option A against Option C is that the fully modelled CV solution under Option C would allow blending of green gases at higher volumetric percentages even where blend is still in a "minority energy flow" state within the LDZ. • The more complex approach under Option C requires expensive regime and system changes which would be investment at risk until a favourable policy decision is forthcoming from Government. • Carrying out a detailed feasibility study for Option C in the meantime could provide an optimal balance between minimising investment at risk and making progress towards delivering that capability.
35	If DNs use different methods of blending, blend different % or 100% green gas within an LDZ, would Option A still work?	• Option A works within the existing framework. If none of the other options were implemented until a switch to 100% green gas, the "end state" of 100% green gas would still work under the existing thermal energy regulations, as this would have a stable CV (other than in the case of a variable biomethane/hydrogen blend). • 100% green gas networks would need to be physically separate from the existing gas network (either repurposed or new pipes) and so, would require corresponding changes to central and client billing systems to recognise the new charging areas, but with a stable CV, this would not require the switch to meter point-specific CV that would be necessary for Options B – E, which are designed to handle a diverse CV transition phase within the LDZ network.
36	You quote cost per tonne saved as the key measure but there are big differences in the total saving. if you go further. Also are there not interdependencies in the growth scenarios - Option A seems to be less attractive to producers but a lot of H2 would help	• For the options CBA the NPV and benefits of each option has been quantified in isolation from the other options to generate comparable statistics. • Options A, C and E use the same hydrogen scenario. Option B uses an embedded hydrogen scenario, as it focuses only on embedded green gas supplies. • Option D would not be able to support upstream blending due to its reliance on having non-discrete, physical charging areas within the network, as distinct from the highly localised CV measurement structure envisaged under Option E.

		• For Option A, the apparent carbon abatement shortfall of this option against Option C is due to the fact that the fully modelled CV solution under Option C would allow blending of green gases at higher volumetric percentages even where blend is still in a “minority energy flow” state within the LDZ. • But, this more complex approach requires expensive regime and system changes which would be investment at risk until a favourable policy decision is forthcoming from Government.
37	Option A appears to prioritise hydrogen over other forms of renewable gases.	• Hydrogen appears to be a greater point of focus since it is the new low/zero carbon option, additional to biomethane, and we would like to maximise the potential for hydrogen supply growth to support the transition to net zero, given Britain’s current dependency on gas for heat. • Option A incorporates both strategic-level hydrogen blending and an assumption about the proportion of future biomethane connections which could benefit from a blending connection configuration, which is being developed presently by Cadent. Table 7-3 in the consultation paper covers this. • So, the CBA has not prioritised hydrogen over biomethane but evaluates the potential benefits of both gases together in terms of the projected capabilities of each option.
38	Why not return to pre-1996 lowest source CV for charging? An unbilled energy smear could be lower than other costs on the transition to net zero path (but not at this winter gas price!) and could be a hybrid approach instead of just going back to the lowest source CV we have for 20 years or so prior to FWACV.	• Returning to a lowest-source CV for charging, for example by adopting Regulation 4, as opposed to Regulation 4A within Part II of the gas thermal energy regulations (GCoTER) could obviate changes to billing systems but would not provide the required level of customer protection from overbilling in a diverse CV gas transition. • Under Regulation 4, introducing low CV blends, such as $20\%_{VOL}$ hydrogen in natural gas would lower the billing CV for the relevant LDZ to 34-35 MJ/m^3, but unless this blend constituted the bulk of the LDZ energy flow, it would leave a large proportion of LDZ gas energy unbilled. • Customers receiving the lowest CV gas would be billed correctly initially but would then suffer enduring disadvantage from the smearing back of significant unbilled energy costs, as these could not be absorbed within the gas chain.

		• As a simple example, consider one LDZ transporting 100 GWh total per day on average, to approximately 2.7m domestic consumers, with 10 GWh per day being delivered as hydrogen blend at a CV of 34.5 MJ/m3 (natural gas CV 39.0 MJ/m3) and so, consumers billed at 34.5 MJ/m3. • This would result in the exclusion of over 10 GWh/day from billing and result in an annual energy smear of nearly £33 per consumer (using 2020-21 SAP) to recover just under £88m unbilled energy per year. • For consumers receiving natural gas, the smear would partially compensate for underbilling, but for customers receiving the blend, the smear would be punitive. • In this context, it is not clear what a “hybrid approach” would consist of and how it would better balance transition costs with consumer protection. However, we would welcome views and suggestions.
39	Is there a risk that Option A becomes an argument not to do further options? Once blending has been introduced then wouldn't that equipment be redundant if Option B or C is implemented? How costly is that equipment and how easy is it to re-use it? Apologies if over thinking here, but is this a valid point, even if in principle?	• Option A is a low-cost enabler for blending and would not preclude or conflict with the onward implementation of the other options, should network circumstances require that, as any stranding cost of enhanced system control software would be minimal. • Hydrogen-compatible gas calorimeters would not be installed where hydrogen blending is not feasible and additional software for coordinating blend flows within FWACV limits would be a minimal cost in relative terms.
40	Do you want formal consultation responses as well as the survey?	• Yes – Formal consultation responses are vital, as they provide the opportunity for freeform comment and for respondents to provide additional information.
41	What option do the project team think would suit producers best?	• The options presented for this consultation should not be considered as mutually exclusive. Implementing Option A in LDZs which will have access to large scale hydrogen supplies would enable hydrogen blending to begin at the earliest point practicable. This assumes a favourable policy decision on hydrogen blending for homes and heat, but with the least investment at risk.

		• Progressing feasibility work on Option C in the meantime would help ensure preparedness to implement the changes required to regulations, codes, systems and processes to implement Option C and potentially Option B, if feasible as an early win, as both could bring earlier benefits from maximising the benefit of green gases.
42	Would options a, b & C be mutually exclusive, or would additional meter points help with the modelling?	• Options A and C would not be mutually exclusive, in that Option A, due to minimal implementation costs, could facilitate a start to hydrogen blending wherever and as soon as practicable and economic to do so. • Implementing Option A is really only about doing what is necessary to maintain the existing arrangement unless/until Option C could be developed. • Hydrogen-compatible GCs would only be installed where required, and the only cost stranding that would result from moving from A to Option C would likely be the coordinating system control software that would be required to ensure that blends from multiple inputs would remain within the LDZ FWACV cap. • Option C will require a detailed feasibility study to establish whether it can facilitate diverse CV gases sharing the same LDZ and would only be acceptable if consumers were afforded a similar level of protection from overbilling as today. • Option B could effectively be a partial early release of Option C, as the regime and system changes required are essentially the same. • We envisage that Option C would require initial validation and ongoing verification using a limited, but strategically located population of CV measurement devices. For the CBA, we have imputed a total population of 500 devices to support Option C.
Session 4 – 23rd Feb 2022		
No.	**Question:**	**Answer:**
43	Is there green gas volume availability to widely achieve blending that avoids capping?	• Hydrogen blending is still at a very early stage today. However, blending provides a vital route to grow upstream hydrogen supply without direct dependency on demand levels downstream, so Option A would effectively facilitate this process of growth.

		• For biomethane, this market is set for growth under current incentives and with Cadent's blending connections strategy, we aim to enable a greater proportion of future biomethane connections to be able to minimise propane-related costs.
44	In this model - should we assume a [daily] CV value would need to be sent to the Smart meter (and/or IHD)? Or if not SMART, daily usage readings will be required.	• On the basis that this question relates to Option C, the attribution of daily CV at meter point level would require changes to central and client billing systems to support this, and part of these changes would be the active provision of these daily CV values to shippers / suppliers for onward billing to consumers. • This could include the population of in-house display units for smart meters but would not be achievable in real-time within the same Gas Day, so would need to be a historical rolling average over a set period. • Invoicing would need to use the actual daily Gas Day CV for the relevant billing period, in line with the approach for the commodity element of transportation charges.
45	Has the validation and confidence in the CV model of Option C been compared to countries that have similar billing regimes (if any) that are already in place?	• The project did not cover the validation of the conceptual solution proposed in Option C. If this option is taken forward to be looked at in more detail this would be done. Online systems are already in use elsewhere for supporting billing, for example on transmission networks where SCADA information is available. • The project looked at the ability of the network models to replicate the travel and mixing of the biomethane using oxygen as a marker. • The tracking of molecular oxygen levels in the gas at the population of field trial sites in the East of England had to focus on the range 0 – 200 ppm for maximum resolution in observing the outer edge of the zone of influence of the embedded biomethane supply. • The correlation between network/CV modelling of the presence / absence of biomethane and measurements recorded at sites which saw higher levels of oxygen (above 60 ppm) was above 90 per cent. • At 60 ppm, the level of biomethane in natural gas would be around just 3 per cent, so 3 per cent of the difference between 39 MJ/m3 and 37 MJ/m3, which would represent an immaterial impact on CV and billing. Therefore, providing a high degree of confidence in the modelling.

		• For pre-implementation trials, we would expect network/CV modelling to be validated by reference to strategically located CV measurement within and around the trial area. • This would require the appropriate regulatory arrangements and temporary billing adjustments to support it. • The target level of accuracy for a model-based CV zoning and/or CV attribution would be the <= 1 MJ/m3 range presently experienced under LDZ FWACV, so maintaining existing levels of consumer protection. • This accuracy target is exemplified in modelled approaches deployed elsewhere.
46	Has any consideration been given to how downstream connected IGT networks would fit in with options D&E?	• We are unable to recommend either Option D or E at this time, due to the cost and complexity associated with intensive CV measurement within each Local Distribution Zone, so we have not assessed impacts for IGTs for these options. • However, we will engage with IGTs on any future work towards implementation of Options A – C.
47	Statement re CV data - need CV at meter point level, is this CV at 'node' level, for Options B & C as MPRNs would be mapped to a node?	• Correct. For Option C, each system node would be a charging area, and CV modelled at system node would be attributed to meter points connected to the relevant system node via a system node to meter point interface, which would need to be updated to take account of changes to the connected meter point population.
48	Has the CBA and deployment timeline been compared to 100% hydrogen? If blending is not yet confirmed as an option, it will need to provide some benefit as a quick and low cost stepping stone to full hydrogen I assume - cost and time for D and E clearly don't work for a stepping stone.	• We have deliberately excluded the end-state of either 100% biomethane / 100% hydrogen, or alternative heat vectors due to the levels of uncertainty surrounding when / where this would be achieved. • This project focuses on the transitional stage for growth of green gas supply and deployment, and so a 2050 horizon has been applied to each option to derive comparable NPV and carbon abatement metrics. • Achieving a direct switch from current state to 100% green gas would likely be problematic in terms of matching green gas network build or repurposing with supply and demand. Blending provides a vital opportunity to grow the supply of green gases ahead of network switching.

49	Worth noting that Govt Hydrogen strategy has a 100% H2 village trial in 2025, H2 town trial in 2030. To provide a resilient enough hydrogen supply to convert large areas will take significant time going forwards beyond 2030 and towards 2050. This would not necessarily stop the other options being relevant, but clearly option A is quickest.	• Agreed. Please refer to the response to question 48.
50	Vicki - is the final date inclusive or exclusive? I.e., can consultation response be submitted on Tuesday?	• Responses would be accepted on 1st March. (Confirmed verbally in session.)
51	What are the downsides to Option A, with least change it seems like the most positive option, but what are the downsides please?	• For hydrogen, which has a significantly lower CV (12 MJ/m3) than natural gas (~39 MJ/m3), a limitation of Option A is that, unless/until there is sufficient hydrogen to enable the natural gas / hydrogen blend to represent a majority energy flow within the Local Distribution Zone, the volumetric percentage at which hydrogen can be blended in is constrained to around or below 5 per cent. • Having said this, blending at ~5% at a large NTS/LDZ offtake could deliver almost 0.5 TWh of hydrogen per year, abating nearly 60 thousand tonnes of CO2 equivalent. So, blending, even at low percentages, into a primary upstream gas source could have a significant positive impact and help grow the hydrogen supply base. • Another potential downside is that in a multiple-source hydrogen blending scenario into a Local Distribution Zone (LDZ), a hydrogen supply interruption at one input point could require a reduction of blend levels elsewhere to stay within LDZ FWACV cap parameters. • So, biomethane producers without a biomethane blending connection into the LDZ would still need to make provision for propane enrichment of embedded supplies, although propane costs would be saved overall.

		• Where hydrogen supply is sufficiently mature to support blending at multiple primary inputs to an LDZ, the likelihood of upstream supply failure should be limited, and depending on the location, timing and duration of any fault, there may also be scope for rebalancing flows between LDZ blending inputs to mitigate the impact on LDZ FWACV. However, the system, and contractual/commercial/code implications of any such flexing arrangement would need to be worked through.
52	If you start to ramp up hydrogen demand with option A, is there then a risk that if the Hydrogen plant goes down Biomethane plants will need to propanate quickly to bring the CV levels back up?	• Yes. Please refer to the response to question 51.
53	We need to think carefully about how the measurement and accuracy of billing will be presented to consumers, as although there is the megajoule envelope currently, that's not clear to consumers so we will need to message this carefully.	• Agreed, and especially important with increasing energy costs.
54	Does Option D/E rely in smart meters? I didn't think it did.	• No. Option E envisaged a potential further option in which locally measured CV data could be transmitted to smart meters, but this was not an essential component of this option and was found to be unfeasible in practice, as highlighted in the MS11 report of the smart meter field trial.
55	Don't discount Option D/E completely, we don't currently have the technology available to do them at the current costs, but that may change as we progress through Hydrogen development.	• This is noted, although even with non-venting, low-cost technology, ongoing testing, maintenance of and communications with CV measurement devices at such scale across a Local Distribution Zone would drive significant additional operating costs, which would be reflected to consumers.
56	Regarding Option E – Having read the MS11 report on the smart meter trial, which looked at	• Observation noted and appreciated as a further reason why the smart meter option considered for Option E would not be practicable.

	the potential impact of CV data transfer on battery life, the report refers to a battery life assumption of 10 years. As an asset owner I would point out that we expect these to last 15 years. So, this adds more weight to the decision that CV data transfer is not practicable, as there is a risk of asset stranding if you are shortening the life of the meter by shortening the life of the battery.	
57	Will there be any impact to IGT costs in Options B-E and how will they be considered? (IGTs bill Shippers directly, not via CDSP)	• This is an important point, and we will engage with IGTs on any future work towards implementation of Options A – C. (D and E cannot be recommended at this time.)
58	Asset stranding really needs to be considered in all of these options, reducing battery life will absolutely affect asset lifecycle so how will this be reflected in the predicted Industry costs?	• Observation noted and appreciated as a further reason why the smart meter option considered for Option E would not be practicable.

END