Low Carbon Gas Ltd,
54 Waterside Court
Paper Mill Lane,
Alton, Hants,
GU34 2PQ.
Mob 0791 256 0740
Email tony.day.1@outlook.com

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Attn. J. Brearley
OFGEM,
10 South Colonnade,
Canary Wharf,
London,
E14 4PU.

Dear Jonathan,

THE FUTURE OF GAS

Gas supplies chemicals; power generation; commerce and industry; transport. Decarbonising gas upstream must, therefore, decarbonise all downstream energy uses. The basic physics, chemistry and economics of gas making, separation and purification, compression and transmission all favour high pressure. Decarbonising the high pressure gas transmission system is complimentary to decarbonising the low pressure gas distribution system, and gas end uses. In order to minimise the societal impact of delivering net-zero emissions in 2050, we have concentrated our efforts on decarbonising high pressure gas making. Prior to 1992, the same logic applied to all British Gas R & D.

I recently discussed the proposed reduction in regulated gas transmission infrastructure payback period from 45 to 25 years, and increase in WACC from 4.8 to 5.5%, with some City investment managers. Their view was that the projected increase in the cost of money relative to long-dated Gilts is not due to the economic cycle, but the uncertainty in investor sentiment due to gas assets being seen as increasingly risky in a 'green' future. The change in gas infrastructure payback and WACC, plus the predicted 33% reduction in gas demand by 2050, will increase the annual capital recharge per unit energy by over 50%, and reduce gas system operational capability. Gas assets are long lived and highly capital intensive. As UK relies heavily on the resilience (Fig A), operational capability and flexibility of the gas grid, the assertion that gas interchangeability will be abandoned; total gas supply reduced, and cast iron gas main renewal delayed, is having a negative effect on investor confidence and consumer welfare.

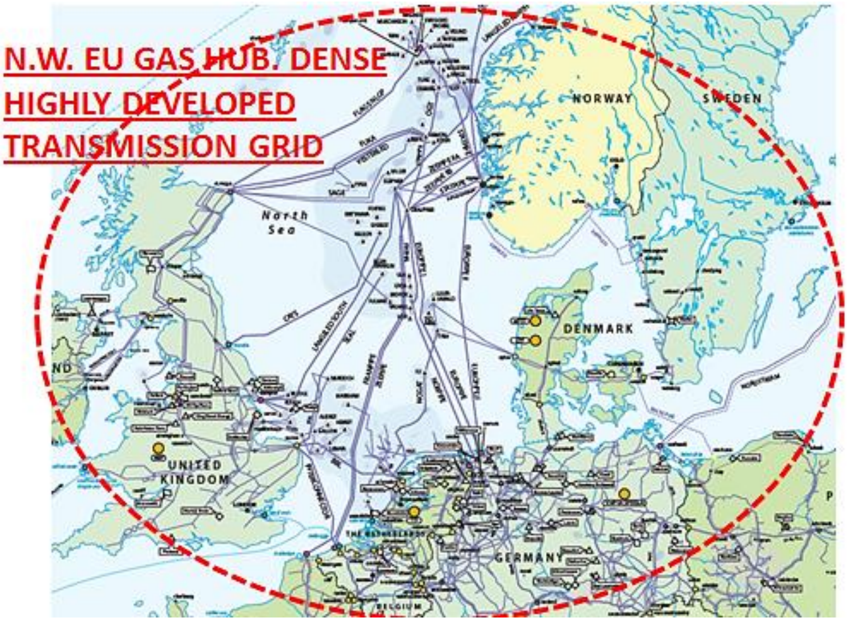


Fig A. UK gas transmission system part of an integrated resilient North Europe gas transmission and storage network.

It has not been demonstrated that the electricity grid can physically deliver the instantaneous energy ramp and flow rates, or diurnal and inter-seasonal energy storage, to enable the economic bulk transfer of energy flows from gas to electricity. At around £400/tonne carbon abated, domestic hydrogen will be massively expensive and disruptive. Methane is the cleanest hydrocarbon, and the easiest and cheapest to synthesise using carbon negative BECCS.

My colleagues and I have worked for the last 10 years on using a combination of existing proven progressively deliverable high pressure gas industry methane and hydrogen synthesis technologies with carbon negative BECCS to deliver a net-zero emissions gas system at current scale in 2050 without abandoning gas interchangeability in the Public access gas grid. At a ‘whole system’ cost around £50/tonne carbon abated, this is within IEA’s projected range of carbon costs for OECD countries to deliver the Paris Agreement. Industrial ‘clusters’ will be served by local hydrogen networks. <6% hydrogen by energy may be used in the low pressure gas distribution networks.

Between 1927 and 1992, the UK gas industry developed a suite of technologies to progressively supply synthetic gas from around 2010 onwards. The core technology was originally developed in 1943 to gasify ultra-low grade Italian lignite, and can successfully gasify a wide range of mixed waste based solid and liquid fuels. Various Synthetic methane and hydrogen mixtures were successfully trialled in Portsmouth in 1972/3.

The same technology is inherently carbon capture ready, and was demonstrated at full commercial scale using mixed part biogenic/part fossil waste based fuels in Germany between 1985 and 2007. Methane synthesis has been in commercial operation in USA since 1985, and with full scale CCS since 2000. The technology to decarbonise high pressure methane and hydrogen using carbon negative BECCS is fully commercialised, but no support for methane currently exists among UK policy makers, notwithstanding methane being UK’s principle energy vector.

Gas interchangeability is the keystone of the UK gas system: any molecule of gas can enter or exit at any point; be transported in any pipeline, and be used in any appliance. The historic conversion from Town Gas to Natural Gas does not justify changing to hydrogen as the circumstances are different. UK uses nearly 10x more gas than in the early 1960’s. Natural Gas was half the price and double the calorific value of Town Gas, whereas Hydrogen is three times the price and one third the calorific value of Natural Gas. The conversion to Natural Gas: “UK’s largest peace time engineering operation” was carried out at zero net cost to consumers. No such plan for hydrogen is possible.

Gas interchangeability is equivalent to frequency harmonisation in the electricity grid enabling energy to flow between all synchronous devices. Nobody proposes abandoning a single electricity frequency in UK’s electricity system. We demonstrate that the existing interchangeable Public access gas grid can be retained in a net-zero carbon future (briefing note Fig’s 18 & 19), provided that policy makers do not rule out methane altogether. We argue it is wrong to undermine investor confidence in gas’ future, thus increasing consumer gas prices.

Fig 1 of the attached briefing note shows 4 long-term net-zero pathways for gas currently being considered within the constraint of projected 200TWh bioenergy being available in 2050. In fact, this is an underestimate, as it is only 20% of current solid fuel production in UK, 50% of which is in the form of mixed residual wastes of all kinds (Fig B). Pathway (1) is the cheapest and easiest to deliver as it retains gas interchangeability in the Public access gas grid. Pathways (2) to (4) are more or less expensive and complex attempts to ‘fudge’ the issue of gas interchangeability.

UK INDIGENOUS ENERGY-BEARING FUEL SUPPLY (Based on DECC/AEA 2011 and Defra/E4Tech 2010 reports)

Wastes	Quantity 2010 to 2030	Notes
• Residual biomass bearing Municipal Commercial and Industrial wastes	47.0Mt pa	Excludes 20% non-combustibles (exclusion
• Non biomass bearing residual C and I wastes	58.0	double counted?) " "
• Waste wood (including contaminated wood)	5.0	
• Sewage sludge (dried fraction)	1.5	
• General plastics	3.0	Possible double-counting with MSW/C & I?
• Landfill and coal tip mining	Unquantified	Large potential energy resource.
• Meat bone meal (MBM)	?	Statistics not available. Also used in cement kilns
• Clinical, biochemical and biogenetic, R and D	?	Statistics not available
Sub-total	114.5m tonnes pa	
Bio-fuels		
• Agricultural manure (dried fraction)	66.0	
• Woody forestry and arboricultural arisings	10.0	
• Food and garden waste	20.3	
• Saw wood	5.0 to 7.0	Mostly used for non-energy purposes
• Straw, seed husks and chicken litter	11.0	
• Energy crops, tallow and cooking oil	7.0	
• Miscanthus and short rotation coppiced willow	4.0 to 15.0	Strongly policy/financial incentive driven
Sub-total	123 to 136m tonnes pa	
High Carbon content fuels		
• Petcoke	0.75 to 2.0	Not all marketed. Much reused at source
• End of life vehicle plastics and tyres	0.5	Also used in cement kilns
• Hazardous wastes, inks, sludges, solvents	6.5	Also used in cement kilns
• Coal (deep and surface mined)	17.5	Low grade coal could be increased
Sub-total	25.25 to 27.5m tonnes pa	
TOTAL	**263 to 275 m tonnes pa**	

Fig B. UK solid fuel production statistics 2009/10. Includes bioenergy bearing wastes. Excludes non-energy bearing mineral and construction wastes.

The economic implications of HMG's support since 1960 for expensive electricity and hydrogen is entering Public discourse. HMG has often seen gas as merely a revenue stream. NGO hostility to: shale gas; the deployment of carbon negative BECCS by the fossil fuel industry, and to using mixed residual wastes of all kinds as a low cost sustainable indigenous fuel resource, is confusing the issue. The gas industry's failure to demonstrate it can deliver the energy trilemma cost effectively, plus its willingness to abandon interchangeability, has weakened its position vis a vis electricity. National Grid's Future Energy Scenarios are primarily electricity not gas transmission driven, notwithstanding gas being 1/3rd the unit price, and delivering <25x greater peak winter ramp rate at <5x greater flow rate, and providing 2000x more long-term energy storage, than electricity, at near zero marginal cost to consumers.

The political debate is whether re-balancing of anthropogenic and biological emissions and withdrawals of methane and carbon dioxide, from the Earth's atmosphere, should be led by inevitably complex engineering led cost benefit analysis, or by simplistic 'silver bullet' solutions, on the basis that the 'climate emergency' supercedes all normal economic considerations? In which case: 'who pays'?

Current electricity and hydrogen policies envisage a massive transfer of national wealth from the rest of the economy to the energy sector, which is the least productive in the UK economy. As the cost of energy affects all economic activities, the projected transfer of investment from high to low productivity industries will likely have a negative effect on planned GDP growth per capita and consumer welfare.

Only OFGEM has a statutory remit to protect the economic interests of consumers. I trust that OFGEM will take the above facts into consideration in the forthcoming RIIO-2 public consultation and decision process. Please see attached summary briefing note prepared for National Grid.

Yours sincerely,

Tony Day

Cc Tony Nixon. Head of Regulation National Grid Gas Transmission.

<u>TECHNICAL NOTE: THE USE OF 'BLENDED' GAS INFRASTRUCTURE ASSET VALUATIONS</u>

The use of 'blended' gas infrastructure asset valuations is incompatible with sound economic management of the gas grid and the protection of consumers' interests:

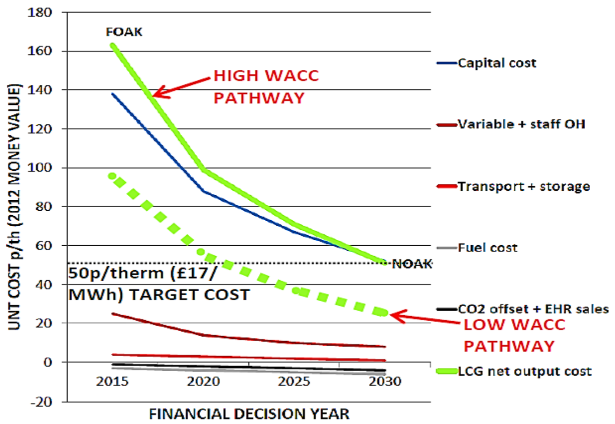
1 Asset 'blending' is a form of 'cost smearing' making it impossible to soundly value assets and to maximise their economic utility. Valuing (say) a 100 year lifetime gas pipeline and a 3 year lifetime computer within the same 25 year 'blend' or 'basket' is a classic method of confusing regulatory authorities, and of concealing both under and over-performing assets. A classic example was the CEGB's accounting for all power stations within a single asset class concealing the fact that the nuclear power fleet was essentially bankrupt and uninvestible. It also distorted levelised costs, and hence the electricity dispatch merit order.

2 Uncertainty in gas transmission pipelines and associated assets lifetimes, due to the uncertainty in future gas interchangeability requirements, should be explicitly accounted for and not hidden within the 'blended' assets. This will enable both existing and future gas transmission assets to be properly valued and re-valued as future of gas policy is clarified.

3 Once investors have the 'taste' for regulated gas infrastructure assets being valued at 25 year payback with associated higher WACC, compared with 45 year payback with associated lower WACC, it may be difficult to 'entice' investors back to accepting lower WACC valuations for long life gas assets. This will increase the cost and risk to consumers of capital intensive gas asset investments.

<u>LOW CARBON GAS FIRST OF A KIND TO Nth OF A KIND PATHWAY ANALYSIS</u>

FID YEAR	2015	2020	2025	2030
ENERGY INPUT (GW_{th})	0.25	0.5	0.75	1.00
FUEL INPUT (mtpa)	0.375	0.75	1.125	1.5
GASIFICATION PRESSURE (bar)	55	60	65	70
NET ENERGY EFFICIENCY (%)	75	76	76.5	77
ANNUAL LOAD FACTOR (%)	75	80	85	90
LCG PRODUCTION (million th pa)	42.0	90.9	145.8	207.2
CAPITAL RECHARGE RATE (pa)	14	12	11	10
CAPITAL COST SCALING FACTOR	1.580	1.257	1.100	1.000
CAPITAL COST (£bn/GW_{th} ENERGY OUT)	2.212	1.76	1.54	1.4
LEVELISED CAPITAL COST (p/th)	138.2	88.3	66.7	52.0
FUEL COST (p/th)	-3.0	-4.0	-5.0	-6.0
NON-FUEL VARIABLE OH (p/th)	5.0	4.0	3.5	3.0
STAFF VARIABLE OH (p/th)	20.0	10.0	6.6	5.0
CO_2 TRANSPORT & STORAGE (£/tonne)	65.0	45.0	25.0	5.0
CO_2 TRANSPORT & STORAGE (p/th)	4.0	2.8	1.5	0.3
OUTPUT COST OF LCG (p/th)	164.2	101.1	73.3	54.3
EU ETS COST OF CO_2 (£/tonne)	5.0	15.0	35.0	45.0
CO_2 SALES FOR H/C RECOVERY (£/tonne)	0.0	5.0	10.0	20.0
TOTAL CO_2 REVENUE (p/th)	-0.3	-1.5	-2.8	-4.0
<u>NET LEVELISED LCG COST (p/th)</u>	<u>164</u>	<u>100</u>	<u>70</u>	<u>50</u>
LCG COST AFTER CAPEX PAY OFF (p/th)	25.0	12.0	3.0	-2.0



2015 TO 2030 COST REDUCTION PATHWAY FOR CARBON NEGATIVE SYNTHETIC METHANE WITH 'HIGH' WACC REDUCING FROM 14% TO 10%, AND SECOND 'LOW' WACC PATHWAY REDUCING FROM 7% TO 5%.

Fig C. High and low WACC cost reduction pathways for carbon negative BioSNG.

High pressure synthetic gas making plants (both SNG and hydrogen) with carbon negative BECCS are long-lived capital intensive investments. Levelised output costs vary dramatically with the cost of money and economies of scale (Fig C for BioSNG plant scale up). The same process can be seen in the H21 project with the change from low CAPEX/OPEX Steam Methane Reforming (SMR) plant to high CAPEX/OPEX Auto Thermal Reforming (ATR) plant requiring scale up from $1GW_{th}$ to $12GW_{th}$ throughput to deliver the same end cost of hydrogen.

[Note: SMR is an air blown process, whereas ATR is an oxygen blown process. ATR is preferred to SMR to deliver net-zero emissions due to the elimination of the external Natural Gas fired reformer, but has high oxygen consumption. In the N E England H21 scheme, product hydrogen is used to fire gas turbines to generate electricity to run the Air Separation Unit (ASU) to produce oxygen. The combined CAPEX and OPEX for oxygen production is the principle driver of the planned 12x scale up to obtain the necessary economies of scale to deliver the same end cost as the Leeds H21 scheme.]