EXPANSION ENERGY LTD

Green energy from natural gas pressure letdown
Thermal & process engineering design service
Energy & environmental consulting

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10th March 2011

RE: Electricity market reform (EMR) industry Consultation response
Our Ref: DECC/EMRC/01

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1.Background

The **highly integrated** nature of the power grid, right from the power plant to the home supply connection, means that it is 'a natural technical monopoly' that is best run, from a **technical** point of view, in a fully vertically-integrated and centrally-planned manner. Electricity is a **unique** technical product in that it is instantaneously generated and transmitted to customers at of the order of a speed of a flying bullet, with essentially no storage in the system (by contrast, there is c. **3 days'** total 'natural' storage capacity in the UK gas pipe grid). Bulk storage at grid scale is economically impractical (a 50p torch battery has a stored power cost of c. **£1050**/kWh or **c. £1 million**/MWh). The 'time constant' of stored energy in the rotors of all operating generators is of the order of **10's of seconds**. It is a technological miracle that voltage and frequency can be maintained constant (within +/- 0.5%) **at all** even within an hour**, even without** the complexities of a trading market. To do so at an annual supply reliability of over 99% is close to a miracle and requires major efforts in providing and maintaining spare capacity margins in all parts of the system. (these spare capacity margins are, by **definition**, 'uneconomic' in a trading sense).

1.1 Nationalised CEGB period

Within these severe technical constraints, the nationalised CEGB served the nation well in providing a highly reliable electricity supply and was the envy of many other nations. The entire system was both run and planned long-term (re new-build) as an integrated whole, with a logical fleet build mix and a logical 'merit order' of powerplant dispatch to meet varying demand under direct control of one organisation, looking at system benefits as a whole on behalf of its customers, government and society . It excelled in everything except minimum price, with a much simpler structure than the current market. In particular, it excelled at **logical** fleet mix planning **for the long term** to meet **various government policy targets**, e.g. fuel policy. It was characterised by a low cost of capital (from state funding) and a planning horizon of at least 20-30 years.

1.2 Privatisation

By contrast, the privatised industry since 1990 has indeed achieved lower short-term customer prices, but logical centralised fleet mix planning for the long term to meet government policy targets has essentially largely disappeared. The main driving force has been the **short**-term 'gaming' economic interests of **individual** generating companies. The only reason that there has been any consistency or appearance of cohesion has been that there was an obvious 'direction of flow' due to 'The Dash For Gas', i.e. 15 years of sustained low gas prices coupled with the relatively short build cycle of CCGT plant. The fact that large CO_2 reductions were achieved **was just a fortunate coincidence that** gas (in CCGT plant) has about 50% of the CO_2 emissions of coal, rather than the reverse. In fact, at times when the gas/coal price ratio increased due to market conditions (c. 2003-5) there were periods of up to a year of **increasing** power sector (and UK total) CO_2 output due to the companies' self-centred generating activities. Essentially, National Grid –**the only** organisation with a 'system-wide' view – has no **direct** control over the powerplant build investment decisions of the individual generation players.

2. Analysis of privatised generation market performance

The customer price reductions achieved following privatisation were indeed significant, but in the final analysis it is clear that these were not simply a matter of power market economic 'efficiency'. Much was **actually** due to:

- the very low market price of natural gas (in a longer-term strategic view, some would argue much <u>too</u> low for such a key national resource of such a strategic clean, efficient fuel, with more appropriate end-uses such as high efficiency user-end distributed CHP), coupled with the <u>coincidental</u> low front-end capital cost of gas CCGT generating plant,
- the low aggregate asset share value achieved during the original privatisation sale, well below true value,
- the 'wear and tear (like-for-like) replacement' element of the present predicted £200B system rebuild costs suggests that all the players (both generation and grid) have been operating their engineering assets **unsustainably** for the last 20 years. The 'Dash for Gas' CCGT plant investment rush, driven by a coincidental short-term business imperative **has obscured** the fact that there has been **very little** systematic planned refurbishment/upgrade of other existing assets, other than through such policies as the **externally-enforced** LCPD pollution regulations. The said £200B rebuild costs **significantly exceeds** the <u>entire</u> net worth of the 6 largest generating supply players. It is a shocking fact that the entire power grid would not be 'bankable' as an investment project under current company ROI targets if it did not already happen to exist.

In addition to these factors, the market mechanism has:

- added much complexity and transaction costs,
- essentially **destroyed** the opportunity for strategic long-term optimum fleet planning to meet forecast global fuel supply changes and government targets for renewables and CO_2 reduction,
- has, coupled with high cost of private-sector capital, considerably increased **the risk premium** on project capital costs, especially for more novel technologies such as renewables and CCS.

'Market discovery 'of minimum supply price is often cited as the main justification for a competitive market mechanism. However, I would suggest an alternative viewpoint:

- Since the highly competitive market is **the main <u>cause of</u>** the high risk premium on project capital costs, it fails to 'discover' the costs of alternative lower-risk strategies,
  A recent concrete example is the taking back in-house by Network Rail of ex-Railtrack market-based contracted-out railway track maintenance services. It has recently been reported ('Rail' magazine, Issue 664, 23 feb-08march 2011, p47, 'Open and Shut Case - Greater rail efficiencies') that this has **reduced** average cost per mile from £74000 to £48000, i.e. **a 35% saving**,
- Note that these market risk premiums bear relatively most heavily on the capital-intensive low-CO_2 and renewables technologies needed to meet government policy targets, i.e. they are **relatively** disadvantaged,
- the highly competitive **short**-term market and the now-'fashionable' short-term tenure of most power company senior executives **militates directly against** generating company decision processes leading to even company financial, never mind societal or policy, benefits in the medium term at the expense of even slightly reduced profits in the short term. This has, for example, been one of the main factors leading to the above-noted huge backlog in 'wear-and-tear' replacements. What happens in practice is that the

highly competitive **short**-term market, coupled with uncertainty in long-term fuel input price forecasting and the high cost of private-sector (especially equity) capital, results in effective annual discount factors applied to NPV-type levelised investment cost analysis being so large that anything happening more than c. 8-10 years in the future (e.g. large fuel cost increases or even outright plant abandonment!) being effectively 'discounted-out' of the investment decision process, or assigned low probabilities which amounts to the same thing. The generating companies should be challenged on this, with a joint DECC/Ofgem/industry study on how to alter market conditions to ensure that medium-term effects play a much larger part in key plant investment decisions.

2.1 The market 'efficiency' paradox

There is huge confusion, particularly among theoretical economists, about why the competitive market has worked well in minimising short-term power prices, but has demonstrably failed to incentivise the correct rates or mix of new generation plant build, in particular to meet UK/EU government targets for renewables and CO2 reduction. I would like to offer an 'outside the box' view.

Free markets depend for their efficiency on price feedback signals. These work demonstrably well in **short** life-cycle products such as: supermarket food products (life cycle days-weeks), crude oil (c. a month), or car purchases (3-10 years). But the energy sector in general, and the power sector in particular**, is unique** in:

a) being a physically vertically-integrated and totally inter-dependent system (partly due to the lack of effective product storage),
b) being <u>uniquely</u> highly front end capital-intensive and with **very long** plant lifetimes (up to **65 years** in the case of coal-based plant). In the case of renewables, as the resource commodity is free, they approach **100%** capital intensity; nuclear is similar due to the low running costs,
c) having uniquely long investment cycles, of up to 10 years in the case of nuclear plant, which hugely increases business risks in times of rapid change (for example, even the first new nuclear unit is unlikely to contribute to 2020 CO2 reduction targets, while on **the most** optimistic credible timescales a significant fleet will take until 2030 to even arrest a net decline in nuclear fleet output),
d) being societally obligated to provide a **near-100%** service reliability, over **all** time-scales from 1 second (AC frequency control) to decades, because of its unique contribution to modern industrialised/urbanised life and its many safety-critical end-uses,

e) being subjected in the next 30-40 years to **<u>uniquely large</u>** rates of change in both imposed government policies (e.g. CO2, renewables, distributed generation, 'smart grid' demand balancing, transport and heat electrification) and the fundamental availability and absolute/relative prices of its energy sources,

f) having **<u>unique specific technical</u>** requirements for controllable, 'dispatchable' plant to maintain voltage and frequency control over timescales as short as minutes and seconds (and also as long as seasonal) against fluctuating demand, which does not show up in conventional 'overview' price-based economic analysis. Both nuclear and most renewable energy forms **cannot deliver** on this basic dispatchability criterion, leaving fossil as almost **the sole** credible option for this important large fraction of total grid service provision – a major constraint.

What these aspects collectively mean is that it is vitally important:

f) for system investment planning to be **centrally** co-ordinated on an optimised, **strategic**, **long**-term, **'whole-fleet'** basis, including the equipment and plant erection supply chain, (similar to the old CEGB planning paradigm) for such issues as CO2 reduction, overall fleet efficiency, and system generation security through energy source diversity,

g) for optimisation of overall **life-cycle** outcomes, that medium and long-term outcomes (based on societal policy targets and forecasting of such trends as **relative** input fuel prices) are given much higher weighting in investment decisions than at present, and ideally through policy actions to directly significantly reduce the effective interest cost of capital and increase capital lending periods.

I would submit that, **especially** in the immediate near-term future (next 30-40 years) of very rapid change in the energy sector environment, a free market with fragmented, mutually competing generation players **is fundamentally institutionally inherently incapable** of delivering these essential outcomes, both due to the absence of the necessary long-term price signals and due to the absence of collaborative 'fleet' planning mechanisms with any real impact. Even if* suitable longer–term price signals could be devised (e.g. CO2 floor pricing), the competitive market paradigm is **an unnecessarily complex and inefficient** mechanism of achieving the desired ends. The short-term financial vested interests of individual, competing power companies and their executives **directly militate against** a successful, efficient long-term outcome. It has to be remembered that energy sector privatisation in the period around 1990 was **a globally unique** high-risk experiment with **unknown** long-term outcomes, and it is time for a deep review of whether the entire paradigm is now appropriate or not in the new era of increased risks and very rapid rates of change in externalities like fossil fuel availability.

This implies **much more radical** reform than the bulk of the discussion in, for example, the Redpoint consultants options analysis, which is predicated on retaining a fundamentally fragmented/competitive market-based approach and just applying 'external' incentives constraints.

2.2 ROCs and FITs for renewables

It is often complained by those lobbying interests favouring a competitive market paradigm (especially theoretical academic economists) that ROCs and FITs are 'a gross distortion of the market'. I would observe that ROCs have been (and FITs will be) successful in incentivising renewables build **precisely because** they have been 'a gross distortion of the market', most particularly because of the power purchase '**obligation**' element in 'de-risking' the investment to reduce the capital risk premiums referred to above. What this logically implies is that the market **was unable to** incentivise this rate of build, in fact I would argue that there would have been **near-zero** renewables build under the 'pure market' paradigm, due to their much higher front-end capital cost and greater risk premium and 'short-termist' company NPV investment analysis factors noted above.

However, where I think these mechanisms have been a gross distortion is through their technical 'targeting' in unfairly incentivising unreliable, intermittent, very expensive renewables at the expense of more reliable and cheaper alternative low- carbon technologies such as CHP, fuel cells, CCS and nuclear. This leads in to a discussion below about key issues in UK energy and power sector policy.

I will discuss further below whether incentivising renewables construction is actually a good thing.

3. Key issues in UK energy and power sector policy

I would commend to you major parts of the Consultation submission by DimWatt (messrs Sharman and McClory). While partly written in somewhat 'intemperate' language, I do hope that it will not be rejected or discounted on those grounds because it contains many important truths, from sources with a very good professional grasp of the dynamics of the global energy industry.

Good electric energy policy for the UK for the next 30 years has to balance the following aspects:

1) Consumer price minimisation **both now and in the future**, especially for industry, commerce and agriculture which (while maybe having many fewer votes than households) is still an important sector of the UK's life-blood,
2) Security of supply **both now and in the future** , taking account in particular of dynamic/dramatic adverse trends in fossil fuel availability and prices, and the unexpected reverses in biofuels availability due to sustainability issues,
3) energy efficiency policy objectives, both supply-side and demand-side,
4) effect of energy imports on UK Balance of Payments,
5) gross demand increase though 'electrification' policies in e.g. transport and heat pumps,
6) CO2 reduction policy objectives,
7) non-CO2 environmental policy objectives (e.g. SO2, NOx, particulates, mercury, solid and liquid wastes, water use etc)
7) Renewable energy policy objectives,
8) strategy for the near term and the longer term.

The relative weighting given to these aspects **is absolutely critical to** the medium-term economic well-being of the UK, and of far more importance ultimately than arguments over the detailed structure of the power industry.

The above objectives **are mutually incompatible**, except in rare special cases (e.g. local CHP) impacting only a small % of the total energy demand. Anyone suggesting otherwise is either ill-informed or a charlatan. Renewable energy and CO2 reduction at present considerably increase generation costs and hence consumer prices. Due to rapid changes in fuel prices and CO2 targets, the generating plant mix delivering minimum costs now, **by definition** cannot deliver minimum prices in 20-30, or maybe even 10, years' time. Security of supply will increase short-term costs but may dramatically reduce medium-term costs. Renewable energy is considerably more expensive now (ROC subsidy > 65%, FIT subsidies up to 85%), but **may** (**not** automatically 'will') become cost-effective at some currently unspecified future date, as fossil energy prices rise and physical availability of imported fuels reduces. Intermittent/variable renewables, and especially wind, make minimal contribution to security of supply, requiring near-100% fossil backup, in fact many engineers regard them to have a negative effect. Coal **currently** provides the greatest degree of energy security (typically 3 months' fuel storage per powerplant) , and potentially **could continue** to do so long into the future if there was strategic government policy (costing more in the short term) to revitalise and expand the moribund UK coal industry based on the known large remaining coal resources (the current published industry 'reserves' estimates are highly misleading as they are based solely on **present**-day competitive market economics and **bear no resemblance** to the **known** true resources of **at least 100 years** of total power sector fuel consumption). But it has the highest CO2 emissions in the absence of (higher cost) CCS capture. CCS meets CO2 reduction policy but increases costs **within** the power industry (while being **significantly cheaper** than renewables), but in a strategic 'UK plc' view, the CO2 recovered can be used to benefit the UK economy by Enhanced Oil/gas Recovery EOR/EGR) in the declining, mature UKCS fields **outside** the power industry to help to stave off an imminent critical UK oil supply crisis (as identified by DimWatt). 'Electrification' policies ((5) above) may assist their respective end-use sectors but will have dramatic adverse cost and fuel consequences within the power sector. And so on.

Given that major 'trade-offs' **are inevitable** between the above objectives, their **relative** prioritisation by DECC becomes absolutely critical. Policy trends by the previous governments and EU administrations have created a highly constrained 'box' with too few degrees of freedom, and above all a highly fragmented competitive, rather than collaborative, generation industry primarily dedicated to short-term private profit rather than public service and long-term policy goals. It is essential that this strategic framework is revised and then set, and **locked-in** for **at least** a period of 20-30 years, **before** considering detailed Electricity market reform issues, as it sets the framework within which those reforms must deliver, most particularly the balance between short-term and long-term issues, the mechanism for delivering DECC and wider gov't policy objectives, and the need for strategic collaboration across the whole energy industry.

Regarding the above mix of conflicting priorities, I agree strongly with the analysis of Dimwatt that the issue of national fuel security is being given far too low a priority within the mix (the most severe and imminent crisis is actually for refined oil fuels in the transport sector, but this will have potentially severe 'knock-on' effects on import gas prices for the power sector). A major problem here is that the critical published global imported fuel price forecasts by both the IEA and by DECC and its predecessors (e.g. BERR -Updated energy prices and Carbon emissions White paper, Feb 2008 (URN07-947X) are regarded as (to put it as politely as possible) laughably ill-informed by most energy industry observers. This is easily confirmed by comparing IEA forecasts vs. actual out-turn for the previous decade, and particularly the total failure to predict the late 2008 oil price 'spike', the most important global energy event in the last two decades. As Dimwatt correctly note, coal prices (forecast by IEA, US EIA and others to be relatively 'flat' over the period) have escalated from $30 to $130 per tonne in 10 years and may go as high as $200/tonne; the insatiable Chinese coal demand growth and their recent transition to being a net importer is de-stabilising the whole global export coal trade as we speak. What this means is that **even the highest** previous imported energy price forecasts are now too low. There is an urgent need to review the underlying fossil fuel price and physical availability (e.g. global coal production is relatively inelastic over timescales of less than 10 years, with substantial asymmetry between upscale and downscale) forecasts on to a more robust basis, with a much wider range of uncertainty and some much higher worst-case scenarios

I also agree with them that EU-imposed renewable energy policy (originally agreed by Mr. Blair) is being given far too high a priority.

About the only area on which I disagree with Dimwatt is on CO2 reduction policy and CCS technology for both coal and gas. Dimwatt are inviting DECC to abandon UK CO2 reduction policy altogether, on national interest grounds of near-medium cost reduction and on the grounds that the UK produces a very small % of global emissions. This 'extreme' stance has obscured the CCS issue. It is certainly true that expensive unilateral 'asymmetric' CO2 reductions in the UK, un-matched by collateral reductions by our major industrial competitors like China and India, will directly and rapidly damage the already struggling UK industrial economy. I sincerely hope that an urgent review of CO2 reduction policy (preceding any attempt at EMR) will take place in the light of this critical issue. I incline to the view that DECC will after said review wish to retain some element of CO2 reduction, with maybe considerably reduced numerical reduction targets, on grounds of national moral leadership (re. UNFCCC negotiations) and with an eye to 'Stern Report' longer-term GW impact issues. That being the case, CCS technology (which is far more proven than the industry is admitting - **13 million tonnes** successfully injected underground globally last year, with multi-million tonne amounts for nearly 20 years, mainly in only 3 countries) has an important role because **it is significantly cheaper than renewables** per tonne of CO2 removed, while being coupled to fully reliable forms of fossil fuel generation, unlike unreliable, intermittent renewable sources, especially wind. Also, as noted above, it can provide CO2 for beneficial use to enhance both falling oil and gas production in the UKCS fields. Which begs the question ...why invest in renewables?

4. The place of renewables

There are many fundamental misunderstandings about the true nature and cost of renewable energy.

A What matters re. 'sustainability' and investment timing in any energy technology is not so much the sustainability of the ultimate resource 'commodity' (given that a wide range of basic energy source 'commodities' will remain available for several decades yet), but the investment cycle in the capital equipment that a power company pays for: put another way, the book life (**re**-investment cycle) of the capital investment. From this investment viewpoint, renewables technology **is anything but** 'renewable'; as the commodity resource is free, nearly 100% of the cost is tied up in the investment in the harvesting **equipment** (e.g. wind turbine), which typically only has a life of 15-20 years because of cyclic stresses in the blades, gears and generator. This is **very short** compared with a gas CCGT plant (25-30 years, possibly longer), and coal and nuclear plant (up to 65 years, e.g. planned **actual** service life for Ratcliffe). In other words, the capital investment in current-generation grid-scale renewable energy devices is actually **significantly less** 'sustainable' than in the traditional fossil fuel options. The only thing that could eventually reverse this, **decades hence**, is escalation in fossil fuel prices to the level that they become unaffordable or physically unobtainable. I cannot over-emphasise the importance of this conclusion, as **it totally overturns (reverses)** all the rhetoric of the pro-renewables lobby and policy. I suggest that DECC commissions an independent consultancy report on this aspect (plus the other points below) plus a discussion take place with generation industry representatives to validate this conclusion.
This has an additional aspect. Since renewable energy is currently significantly more expensive than fossil and nuclear energy (viz. heavy RIC and FIT subsides) , it **will only** represent a viable investment choice if that position is reversed within the life cycle of **the first-generation** equipment. This equipment life is so short that that seems unlikely. This is related to point B) below.

B. The concept of using renewable energy often used as a major selling point is that it will 'out-last' fossil fuels in the sense that the latter will become unaffordable, either intrinsically or through CO2-related costs. **This is simply not the case*** at present, **or** in the foreseeable next 1-2 decades (i, e. the entire life of the current installed first-generation renewables equipment, see A. above). While a major cost crisis could credibly develop for oil for transport uses quite quickly, this is of little relevance to power generation (oil use close to zero) the availability of natural gas for the power industry is currently on **an increasing** trend with the new 'breakthrough' shale-gas production methods, while proven global coal reserves are huge (**well over 100 years'** supply, IEA / BP Review). A similar level of real reserves are available within the UK, **at prices below current-generation renewables**, if the government chose a policy to incentivise the reinvigoration of the UK coal industry.

C. most renewable energy forms (especially wind), with the exception of storage-dam hydro power and possibly geothermal (both unfortunately with relatively **small** resource availability in the UK –and geothermal is in any case much more economic for heat supply than for power) are unreliable, intermittent/variable and simply not dispatchable (controllable) to meet grid demand variations. As conclusively shown by the Poyry intermittency study (July 2009), periods of up to several days of near-zero wind do occur coinciding with times of peak demand. Wind energy, the least costly renewable at present, in addition is inherently chaotic and shows alarming short-term variations over periods of minutes and hours (critical to current grid generation tendering mechanisms) and the ability to forecast these ahead, while improving, is currently still poor As a result, most renewables require near-100% backup. Current national grid policy for wind (rightly, in my opinion) is **100%** capacity backup requirement (**zero** 'capacity credit' in their terminology). This means that wind has **zero** alternative capacity investment replacement credit, **unlike any other form of generation ever put onto the UK grid.** Alternative capacity investment replacement credit has always been a main part of a business case for any new generation investment in any rational, centrally co-ordinated power industry structure, but the working of the UK private market has concealed that benefit (or concealed the disbenefit of its absence) for the last 20 years.

D. As shown clearly by Poyry, the impact of wind/renewables in forcing the fossil plants to operate more cyclically ('up-down-off') (low-carbon nuclear plant cannot* perform this economically, even if technically), will:

a) increase rates of physical damage to them, leading to increased maintenance costs and shorter plant life. This **brings forward** the massive capital spend on replacement capacity (by any technology - **not** necessarily 'like-for-like'), and the DCF (NPV) time cost of that re-scheduling is large.

b) significantly reduce their efficiency leading to extra CO2 emissions, **partly offsetting** the CO2 reductions from the renewables, unless flexible CCS is fitted to them,

c) reduce annual load factors, significantly adversely affecting their operating economics.

A 'Parsons' conference was held back in 2003 by the Inst. of Mechanical Engineers specifically to discuss this technical issue, which the engineers 'could see coming' long ago.

E. The workings of the current UK power market means that the wind-farm operators are not made responsible for paying for any of these extra problems/costs 'on the fossil side of the account', or even honestly admitting publically (re. the increased CO2 issue) that the problem exists. In my opinion, the 'polluter pays' principle should be applied to the issue of backup fossil plant. The new EMR 'Capacity Payments' proposal is a (long-overdue) mechanism for **fair** payment for the uneconomic cycling operation forced on the fossil operators by the addition of renewables on to the grid. But in the current proposal, it **would not** be paid by the windfarm operators, but as a levy spread among all power customers....hardly 'fair', and a big hidden subsidy to them.

F. Fuel and savings: There is no capacity credit for wind and all it does is save gas and coal.

In the UK if we had 33GW of wind with a typical average 30% annual load factor this would on average be equal to only about 11GW of CCGT capacity in annual output. If we assumed that CCGTs have an efficiency of 54%, the average gas savings would be 20.4GW of gas. Over a year, this corresponds to about 178 TWh of gas.

In practice because of the frequent start ups and part load operation of CCGTs operating in back-up mode to the wind plants, the actual efficiency will be less than 54%.My guess is 40-45% If we assume 42%, the gas **and CO2** savings will be in the ratio of 42/54 or roughly 138 TWh of gas

UK Gas consumption is currently at about 1150 TWh, so 33GW of wind **rated capacity** will actually only save **about 12%** of UK power sector gas consumption and the equivalent CO2. This CO2 saving is far short of the government target. On the same arithmetic, **if the entire rated capacity** of the grid were replaced by wind, backed up by unabated (non-CCS) fossil, the maximum possible CO2 saving would be **only c. 27% - well short of** DECC targets.

5. The place of CCS

By contrast, CCS is applied to fully reliable, dispatchable, conventional fossil plant which requires no additional backup other than the existing standard system reserve margin.

Contrary to the industry position, all elements of CCS are fully proven.
The process industry has been using carbon capture (with CO2 release into the air) on a global scale for process technical reasons **since at least 1920**. **More than 20** existing guaranteed commercial processes exist.

The pipeline transport for CO2 is essentially the same as for natural gas. **Over 5000 miles** of CO2 pipelines operate in the USA transporting **over 10 million tonnes/year** of CO2 for injection in Enhanced Oil Recovery operations.

The natural gas industry has been storing natural gas underground on a global scale for over 50 years –not merely storing it, but repeatedly withdrawing and re-storing it, perfectly safely with zero leakage.

If CCS CO2 is stored in depleted oil and gas fields, the cap-rock in these fields has been proven leak-tight for circa > 70 million years.

Both pre and post-capture CCS are already proven to recover 90% of CO2. Gasification with pre-capture (only) has the potential for near-total removal (99.99%) at a moderately increased cost: **every** LNG plant worldwide uses **proven** CC technology for this level of removal, for process reasons.

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