The Second National Infrastructure Assessment:
Baseline Report - Call for Evidence

4th February 2022

Progressive Energy Limited ('PEL') is pleased to provide a response to the National Infrastructure Commission's Call for Evidence on its Baseline Report for the Second National Infrastructure Assessment.

PEL is primarily a project is primarily a project development and implementation company in the energy sector, and has extensive experience of both the UK power and heating sectors.

PEL is the originator and lead partner in the HyNet North West project (www.hynet.co.uk). HyNet is an integrated hydrogen and carbon capture and storage (CCS) project which has been selected by Government for fast-tracking to deployment under its 'Cluster Sequencing' process. Progressive is also a partner in the newly launched Vertex Hydrogen (www.vertexhydrogen.com), a joint venture company with Essar Oil UK, to deploy significant low carbon hydrogen production capacity at the Stanlow Manufacturing Complex.

Our responses below focus wholly on the energy-related questions in the Call for Evidence.

Question 8: What are the greatest risks to security of supply in a decarbonised power system that meets government ambition for 2035 and what solutions exist to mitigate these risks?

The UK has made substantial progress with regard to decarbonising its electricity supply. This has primarily been through expansion of renewable generation supported under the Non-fossil Fuel Obligation (NFFO), the Renewable Obligation (RO) and latterly the Contract for Difference (CfD), but also with a base of nuclear generation, although this has been declining in capacity. Further expansion of renewable generation is necessary to meet the targets, and is already planned, for example through the 2030 offshore wind sector deal.

An increasing reliance on 'intermittent' renewables, however, poses a significant supply security risk. This can be on a short-term basis, measurable in hours, or potentially longer-term (such as 10 days); for example, with a cold winter 'high' leading to low levels of wind-based generation.

Very short-term issues can be addressed through conventional (pumped) storage and to some degree emerging solutions such as batteries, or compressed air storage. Demand-side management tools are also likely have a role in this context. However, any period greater than minutes or a few hours cannot be addressed at a grid-scale by these means. Fundamentally this requires fuelled, dispatchable generation.

Whilst biomass generation may be able to provide some flexible power, both the power production equipment, and the fuel supply chains cannot provide the true range of flexibility required. Relying on biomass purely for dispatchable power would also reduce baseload generation, important for grid stability, and with the advent of greenhouse gas reduction (GGR), a lost opportunity for 'negative' emissions.

In reality, gas-based fuel is the only solution that can provide the material volumes of generation required. There is a strong operational track record of both gas turbine and gas engine-based generation from natural gas; this is what currently provides the necessary back-up for the grid. However, currently this is not low carbon, and therefore not suitable for the 2035 requirements. Biomethane could play a role, but in reality, not only is this a valuable tool (over this initial timeframe) to reduce the carbon intensity of heat, but deployable volumes are limited.

The two primary dispatchable low carbon power generation solutions are (a) natural gas generation with CCS, or (b) hydrogen generation.

There may be some opportunity for natural gas generation with CCS, and whilst this may have a role for high load factor/baseload operation, there are likely to be limits to the role it can play for low load factor dispatchable generation as a result of:

a) Economic factors; capture plant requires significant capital, which results in a high unit cost of electricity if this capital is only amortised over limited operational hours; and
b) Operational factors; chemical processing equipment generally operates best baseload, impacting efficiency and operability.

Hydrogen is much more 'natural' solution for flexible generation. It can be generated baseload from natural gas, or from renewables when the resource is available, and then stored geologically, just like natural gas. For example, HyNet is planning 1.3TWh of hydrogen storage prior to 2030, which is a 15-20% increase in the UK's total gas storage capacity today. Power generation can then be completely flexible using gas engines or gas turbines, using the same model as natural gas generation today, but with no emissions at point of use. Both the gas turbine and gas engine community have development programmes to deliver 100% hydrogen machines by the middle of this decade, with many manufacturers having machines already capable of operation on blends of high hydrogen and natural gas.

In all cases, this will require an increase in gas storage (natural gas and/or hydrogen). The closure of the Rough offshore gas storage site was short-sighted. No other country in Europe is as reliant on natural gas with such limited storage as the UK and so this does require rectifying. In an emerging hydrogen economy, producing hydrogen relatively consistently, and then storing hydrogen would be the ideal solution, as it maximises hydrogen production asset utilisation. However, in the short term, the development of greater natural gas storage capacity is advised.

Question 9: **What evidence do you have on the barriers to converting the existing gas grid to hydrogen, installing heat pumps in different types of properties, or rolling out low carbon heat networks? What are the potential solutions to these barriers?**

Residential combustion is currently the single largest source of greenhouse gas (GHG) emissions in the UK, according to the most recent GHG emissions figures published by HM Government.[1] In 2019 a total of 95 $MtCO_2e$ was produced from 'residential combustion', which is dominated by the provision of heat from natural gas boilers. Passenger vehicles were second with 74.7 $MtCO_2e$ and

[1] BEIS (2021) *Final UK greenhouse gas emissions national statistics 1990-2019*, February 2021

industrial combustion (including steel and iron) third with 74.5 $MtCO_2e$. Therefore, decarbonising residential heat is presently the single largest challenge facing the sustainability agenda.

There are two primary energy vectors currently under consideration to tackle the residential heating problem: low carbon gas (principally hydrogen) and electrification with renewables. The use of heat networks is a second order consideration, as these relate to the mode of heat delivery instead of being an alternative heat source. Three broad categories of potential barriers exist with respect to deploying low carbon heating solutions at scale:

a) Supply chain capability (including network capacity);
b) End-user cost; and
c) Household fabric disruption.

All three must be considered collectively to gain a full appreciation of the bottlenecks associated with deploying either a hydrogen-based or heat pump-based solution. A discussion on each of these considerations follows.

Supply chain capability

Supply chain capability concerns the ability to physically deliver any potential solution and encompasses production, storage, transmission and distribution networks, appliances and service providers. The barriers associated with deploying hydrogen at scale are primarily associated with hydrogen production because:

- Low-cost diurnal storage of hydrogen can be delivered via network line pack, and low-cost seasonal storage is possible through salt cavern storage;
- The transmission and distribution of hydrogen through the existing gas network is under investigation through the H21 and HyNTS programmes, with many technical barriers already overcome such as material compatibility and capacity determination. It is not expected that any fundamental engineering barriers will materialise from these programmes as they are mature projects with publicly available outputs; [2] [3]
- The safe design and operation of hydrogen appliances has been demonstrated through the Hy4Heat programme and boiler manufacturers have publicly committed to maintaining price parity with existing natural gas appliances; [4] [5]
- The qualification and training requirements for service engineers is under development through the Hy4Heat programme.[6]

BEIS is seeking to overcome the production constraint by developing a commercially acceptable business model to support low carbon hydrogen production and ultimately achieve 5GW of generation by 2030.[7] Industry, however, would welcome an increase in HMG hydrogen production ambitions in line with the expected 270 TWh pa of hydrogen demand forecasted by the Committee on Climate Change (CCC).[8]

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[2] See https://h21.green/
[3] See https://www.nationalgrid.com/uk/gas-transmission/document/133841/download
[4] See https://www.hy4heat.info/appliances
[5] See https://www.theengineer.co.uk/big-four-make-price-promise-on-domestic-hydrogen-boilers/
[6] See https://www.hy4heat.info/standards
[7] See https://www.gov.uk/government/consultations/design-of-a-business-model-for-low-carbon-hydrogen
[8] See https://www.theccc.org.uk/publication/net-zero-technical-report/

The primary supply chain barriers associated with heat pump deployment are generation and network capacity/storage:

- Both diurnal and seasonal storage to satisfy demand would be necessary through grid-scale battery installations (or other less developed technologies, like compressed air storage), which are currently uneconomic at the necessary scale required;[9]
- The current capacity of the electricity grid is not rated to deliver the nation's heating demand. A significant programme of work would be necessary to increase the capacity of the network, especially if it is also to adopt the expected demand from electric vehicles;
- Heat pumps are a relatively mature technology and therefore at-scale manufacturing has been proven; however, the UK manufacturing baseline would require significant investment given heat pumps currently satisfy circa. 1% of current heating system sales.[10]

End user cost

Additional end user costs are representative of the marginal investment necessary by the supply chain to deliver a certain solution. Both capital and operational costs must be considered. The capital cost of heat pumps is a major barrier to their deployment, with BEIS research finding the average installation cost is circa £14,000.[11] Alternatively, hydrogen appliances are not expected to cost any more than their existing natural gas versions.[12] Due to the 'coefficient of performance' of heat pumps, the running costs can be comparable with existing natural gas boilers. Any increase in the running costs of hydrogen appliances will primarily relate to the marginal cost of wholesale hydrogen compared to wholesale natural gas. The funding of this difference is a principal cornerstone of BEIS' hydrogen business (likely to be a CfD), which is currently in development. First-of-a-kind at-scale low carbon hydrogen production projects are forecasting this delta to be circa £25-30/MWh.

Household fabric disruption

Current household fabric is designed based on an assumption of a low-cost natural gas 'combi' boiler as the heating source. A hydrogen boiler functions as a like-for-like replacement for a natural gas boiler, and therefore no material fabric disruption is necessary. Comparatively, however, the lower temperature heating from a heat pump typically requires fabric upgrades/disruption such as improved insulation, larger radiators or underfloor heating and in more modern house designs, the upgrading of distribution pipework. This disruption is known to be a major barrier as the majority of heating system purchases are 'distressed' in nature, i.e. following failure of an existing system, therefore speed of heat restoration is of paramount importance at the time of purchase.

Summary

The barriers associated with at-scale hydrogen deployment are both regulatory and commercial and relate to enabling the necessary production capacity to be developed. These constraints are

[9] See https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2017/Oct/IRENA_Electricity_Storage_Costs_2017_Summary.pdf
[10] See https://www.greenpeace.org.uk/news/uk-worst-heat-pump-record-in-europe/
[11] See https://www.gov.uk/government/publications/cost-of-installing-heating-measures-in-domestic-properties
[12] See https://www.theengineer.co.uk/big-four-make-price-promise-on-domestic-hydrogen-boilers/

currently being worked through by HMG with industry collaboration. The primary constraints of at-scale heat pump deployment are consumer acceptability, network upgrades (including storage) and end user disruption/capital cost.

Question 11: **What barriers exist to the long-term growth of the hydrogen sector beyond 2030 and how can they be overcome? Are any parts of the value chain (production, storage, transportation) more challenging than others and if so why?**

Low carbon hydrogen delivered at scale is essential if the UK is to achieve its 2050 Net Zero target. Today, while substantial steps have been made to decarbonise the power sector, the heat, industry and transport sectors have seen little progress towards substantial decarbonisation. Collectively, these are referred to as 'hard to abate' sectors, and hydrogen has a substantial role to play in each of them.

At an energy system level, hydrogen has a further key role to play – virtually all the flexibility in the UK energy system today is provided by hydrocarbons. By flexibility, we mean the ability to rapidly respond if demand increases (i.e. heat demand in a period of cold weather) or supply reduces (i.e. wind energy supply during periods of still weather), and also the ability to provide high energy density fuels on demand and on location (i.e. for transport applications). Hydrogen offers the flexibility of a hydrocarbon fuel but without the 'carbon penalty'.

Our energy system today, and increasingly in the future, will require an ability to store energy at scale, and this is best done as molecules of hydrogen rather than electrons. For example, the hydrogen storage system under development for HyNet (led by INOVYN in salt caverns in Cheshire) provides over 2000x more energy storage than the largest battery under consideration in the UK today, and over 40x more energy storage than the new pumped storage system in development at Coire Glas. It is virtually impossible to see a zero carbon power sector heavily dependent on intermittent renewables in the 2030s and 2040s without hydrogen deployed at scale.

In deploying hydrogen at a scale that is meaningful in the context of national Net Zero targets, we need to recognise that we are deploying a whole new energy vector of the scale of today's gas and electricity networks. This requires a system-wide approach comprising market development, regulatory structures and network codes in addition to the physical infrastructure of production, storage and transportation. Specific barriers to deployment can be considered as follows:

- **Policy:** The UK has a comprehensive Hydrogen Strategy, which sets out a deployment for both CCS-enabled ('blue') and electrolytic ('green') hydrogen, and an accompanying low carbon hydrogen standard to ensure that the hydrogen produced is commensurate with climate targets. However, the targets set out in the strategy (1GW by 2025 and 5GW by 2030) are insufficient in themselves to drive the development of a whole new energy system, and, furthermore, current policy is insufficient to achieve the stated targets. The current HMG 'Cluster Sequencing' process is only seeking to provide contracts for up to 1GW of CCS-enabled hydrogen production (and, in parallel, 500MW of electrolytic hydrogen capacity). Delays to the business models required to support CCS-enabled hydrogen risk putting deployment of initial capacity back to 2027, from which there is little prospect of 5GW being achieved by 2030. This is against a backdrop of at least 5GW of CCS-enabled hydrogen in the development pipeline awaiting support contracts. Policy is therefore insufficiently ambitious to deliver.

- **Regulatory:** While hydrogen production policy and support frameworks are being led by BEIS, there is little joined up thinking and clear support evident between Ofgem and BEIS on development of hydrogen pipeline and storage infrastructure. Technically, on the HyNet project, production, pipeline and storage infrastructure are being developed in a joined-up, cohesive approach, ensuring that supply can meet demand in a wide range of dynamic scenarios. However, it is not at all clear that Ofgem is minded to support the development and funding of the pipeline as a regulated asset (and hence the costs socialised), and there is little forward progress on the regulatory model for hydrogen storage (i.e., whether this is a regulated asset in of itself, or whether it is a service procured on a 'merchant' basis). Without a joined-up approach to the regulatory structure for the hydrogen system (to replicate that being undertaken on the physical system design), it is unlikely that hydrogen system development will match ambition. On a related subject, development of a network code for the hydrogen system is essential. This should set out connection charging methodologies and capacity booking etc, as the hydrogen network will need to accommodate multiple sources of hydrogen production, and multiple customer offtakes.

Question 12: What are the main barriers to delivering the carbon capture and storage networks required to support the transition to a net zero economy? What are the solutions to overcoming these barriers?

CCS technology deployed at scale is a necessity for the UK to achieve Net Zero, and this is reflected both in the Committee on Climate Change's (CCC) position, and in the UK Government's Net Zero Strategy. However, to date, the UK has been unsuccessful in its efforts to deploy CCS despite significant investment in programmes over the last two decades.

Earlier CCS deployment competitions have focused primarily on power applications, and have been structured as 'full-chain' projects, in which the power station developer takes the full chain operational, and long-term storage risk of the project, and this is all factored into a single power price. The effect of this structure was to place a significant risk burden on the developer, which was ultimately reflected in the price which increasingly looked unattractive in the context of rapidly decreasing prices for other forms of low carbon energy, principally renewables.

The current approach to CCS deployment has tackled the issues inherent in the previous approach in four ways.

1. CCS is now cross-sectoral and projects include power, hydrogen and industrial emissions capture;
2. Projects are being developed on a cluster basis, not just point-to-point, allowing risk to be shared across multiple emitters;
3. Strongly linked to the previous point, the CO_2 transport and storage system is being developed as a regulated asset, allowing connections from multiple partners and reducing the cost of capital; and
4. Government is holding elements of cross-chain risk, which helps reduce the cost to developers.

This presents a fundamentally different framework for CCS delivery than that deployed for previous programmes and should result in lower overall cost projects and lower risks for developers. However, against this backdrop, significant barriers to deployment remain. They can be broadly summarised as follows:

- **Policy:** At present, deployment targets are not sufficiently ambitious in the short to medium-term to deliver the volume of CCS required to achieve Net Zero. While the 2030 target has been expanded from 10MtCO_2pa (in the Ten Point Plan) to 20-30MtCO_2pa (in the Net Zero Strategy), the short-term allocations of capacity through the Cluster Sequencing process are insufficient to meet this trajectory, and risk momentum being lost.[13] [14] For example, the Cluster Sequencing Phase 2 process is expecting to allocate up to 3MtCO_2pa of industrial capture projects, when we expect that bids have been submitted for around 10MtCO_2pa. At present, there is no roadmap setting out what happens to bids that are unsuccessful in this process (i.e. a second allocation round). Many bidding parties have expended significant resources undertaking early engineering studies and bidding and have no other route to decarbonisation. Given this momentum and corporate appetite from the industrial sector to engage in the process, we need to see a clearer deployment roadmap and shorter term volume ambition.
- **Regulatory:** The regulatory structure for CCS deployment is emerging, and good progress has been made in developing the business model for transport and storage in particular, which will be a RAB (Regulated Asset Base) approach. There remains a substantial amount of work to translate this approach into an investable structure, and to develop the associated network code which will govern the relationship between the CCS network and users. For a multi-user network to be successfully taken through a Final Investment Decision (FID), the following complex structure of legal agreements needs to be in place:
    - Individual capture plants need to have their support agreements in place with the government backed counterparty (likely to be the Low Carbon Contracts Company), and an offtake agreement in place with the Transport and Storage Company ('T&SCo');
    - The T&SCo needs to have its licence in place with the economic regulator, and a contract in relation to any additional revenue support mechanism; and
    - In the case of a hydrogen plant being one of the anchor capture plants, the commercial structure for development of the hydrogen network needs to be in place, alongside any commercial agreements for hydrogen offtake.

  This is a complex landscape of legal agreements, many of which involve government-backed counterparties, and all of which need to be synchronised to enable the cluster as a whole to progress to construction. Given that some elements of cluster projects have longer construction periods than others, some work may need to be sanctioned ahead of a wider project FID, and for this, government backed 'FID-enabling' support contracts (as were given in the early days of renewable electricity CfDs) should be considered.
- **Technical:** Technical barriers are relatively few, as most elements of the cluster projects remain within the normal technical risk and competency threshold of the delivery companies. However, there are benefits to be achieved in the cluster projects collaborating on issues such as CO_2 compositional specification and approach to quantitative risk assessment. This will allow best practice to be shared, and to move the sector away from the competitive environment of Cluster Sequencing, to one of collaboration, will be helpful in this regard.

[13] BEIS (2020) *The Ten Point Plan for a Green Industrial Revolution*, November 2020
[14] HM Government (2020) *Net Zero Strategy Net Zero Strategy: Build Back Greener*, October 2021

- **Planning and Consenting:** The longest lead time item for CCS project deployment is, alongside the commercial framework, the planning environment. Specifically, the majority of CCS projects in England and Wales will require a Development Consent Order (DCO). This is either driven by the size of a connecting power station, or by a pipeline length, or both. A DCO process is approximately three years in duration, with 18 months of pre-application work (including surveys) and a further 18 months of examination and determination following submission. An acceleration of this process would support an earlier, and lower cost deployment of CCS.