Memorandum

To	Edward Mountain, Convener
Date	19 March 2023
Copies	N/A
Reference number	N/A
From	Clare Lavelle, Director Arup
File reference	N/A
Subject	Scottish Government Net Zero Energy and Transport Committee ***Scotland's electricity infrastructure: inhibitor or enabler of our energy ambitions?*** Call for Views – on behalf of Arup

---

Electricity network readiness

1. Do the current business plans from Scottish and Southern Energy Networks (SSEN) and ScottishPower Energy Networks (SPEN) (in relation both to transmission and distribution) allow for sufficient investment in networks to realise the Energy Strategy's ambitions?

The Scottish Government draft strategy, published in January 2023,[1] sets out an ambitious plan for 20GW of additional renewable electricity generation on and offshore by 2030, including increasing the contributions of solar, hydro and marine energy to the generation mix. Prior to the publication of the strategy, the Scottish Government also updated its ambition for offshore wind to 11GW by 2030, which is being consulted on within the strategy.[2]

Both sets of businesses updated their business plans in 2019 for transmission[3,4] and 2022 for distribution[5,6]. This aligned with the RIIO T2 (2021-2026) and ED2 (2023-2028) price control periods. Both SPEN and SSEN emphasised the importance of facilitating net zero in their plans. Business plans were informed by Government policy at the time. The networks would have had a limited opportunity to reflect changes in policy in the plans themselves. As a result, the four licensees would not have been able to take full account of the Scottish Government's updated strategy or ambitions when developing their plans or the full capacity leased under ScotWind and Innovation and Targeted Oil & Gas (INTOG[7]) (when the latter is announced).

SP Transmission and SHE Transmission received an upfront totex allowance as part of T2 that were not as high as originally requested, i.e. £1.2bn and £2.1bn[8] respectively. Distribution allowances were also not as high as requested, SP Distributions totex allowance is 12.4%[9] below that which it requested, while SSE Distributions was 14.6%[10] below that which was requested.

The changes in Government policy since the finalisation of the controls means more funding is likely to be required to facilitate the achievement of Government targets, particularly in relation to offshore wind. The development of the Accelerating Strategic Transmission Investment (ASTI) reopener in such a short period, is demonstration of the regulators desire to facilitate the change required.

---

[1] https://www.gov.scot/publications/draft-energy-strategy-transition-plan/documents/

[2] https://www.gov.scot/news/increased-offshore-wind-ambition-by-2030/

[3] SPEN-T: https://www.spenergynetworks.co.uk/pages/our_riio_t2_business_plan.aspx

[4] SSEN-T: https://www.ssen-transmission.co.uk/information-centre/riio-t2-plan-and-uncertainty-mechanisms/

[5] SPEN-D: https://www.spenergynetworks.co.uk/pages/our_riio_ed2_business_plan.aspx

[6] SSEN-D: https://ssenfuture.co.uk/

[7] https://www.crownestatescotland.com/our-projects/intog

[8] SSEN-T: https://www.ofgem.gov.uk/sites/default/files/docs/2021/02/final_determinations_-_shet_annex_revised.pdf

[9] https://www.ofgem.gov.uk/sites/default/files/2022-11/RIIO-ED2%20Final%20Determinations%20SPEN%20Annex.pdf

[10] https://www.ofgem.gov.uk/sites/default/files/2022-11/RIIO-ED2%20Final%20Determinations%20SSEN%20Annex_.pdf

2. To what extent are SPEN and SSEN able to alter investment plans in response to a fast-moving policy environment?

While the business plans and the allowances that were made available by the regulator do not take full account of the latest Government policy, Ofgem did recognise that policy was moving quickly.

The price controls all include uncertainty mechanisms, but even without using uncertainty mechanisms, licensees are able to reallocate expenditure without necessarily having this signed off by the regulator. This allows licensees to be agile in where they may invest.

On the other hand, reopeners are a type of uncertainty mechanism that allow the licensees and/or Ofgem, depending on the specific mechanism, to reopen aspects of the price control settlement.

A ‘Net Zero’ Reopener has been included within the price controls for distribution and transmission. The purpose of this reopener is to allow the licensees to react when there is a change in policy or a new technology is available that allows them to facilitate the net zero transition. How quickly such a process could be implemented is likely to be linked to the scale and complexity of any request on the part of a licensee.

The regulator recently published a decision on a new reopener – the Accelerating Strategic Transmission Investment (ASTI) reopener. Given the ambitious wind targets of both the Scottish and UK Governments there is a need for significant new transmission infrastructure. The ASTI framework is intended to facilitate the transmission owners in delivering the network needed.

<u>System resilience</u>

3. What role will dispatchable* electricity sources – pumped hydro, battery technologies, thermal generation (hydrogen power, gas with CCS) – play in ensuring security of supply and system resilience? Should any other technology play a role in supporting Scotland's electricity system?

The UK's net zero strategy has very ambitious targets to decarbonise the power sector by 2035. This challenging target, set in 2021, was based on recommendations provided by the Climate Change Committee (CCC) on the achievable pathways to net zero.

This transition will create significant challenges to the energy system. Growing penetration of intermittent renewables and significant shifts of energy demand to electrification solutions creates an ever-increasing role for efficient system balancing through storage, interconnection, flexibility and dispatchable electricity sources. In particular the electrification of heat demands will increase the needs for inter-seasonal energy storage, which creates significant challenges for an electricity dominated energy system. A well planned system with appropriate infrastructure and market signals can offer significant benefit to consumers.

The pathways to net zero rely on a rapid expansion of some proven technologies, such as offshore wind, and the deployment low carbon technologies which have yet to be commercially deployed at scale. However, the scale and pace of the change inevitably creates risks that some technologies might not be delivered at the necessary pace, while bottlenecks in supply chains and backlogs of new grid connections present risks to the delivery of the new generation plants.

To understand the risks to security of supply for 2030 and 2035 requires robust assumptions and adequate sensitivities around both the generation supply mix, as well as the demand. Currently, the principal modelling on future GB generation is based on the National Grid Electricity System Operator (NGESO's) Future Energy Scenarios (FES). These scenarios take a long-term view and aim to be consistent with Government's net zero targets.

The electricity demand and supply forecasts, shown in Figure 1 below, provide the current status of FES forecasts (by National Grid ESO, 2022) and what generation (TWh) will be required for each technology. By 2035, electricity generation is expected to reach between 416 and 612 TWh, depending on FES scenario. In the same year, demand for electricity needs will be between 369 and 476 TWh.

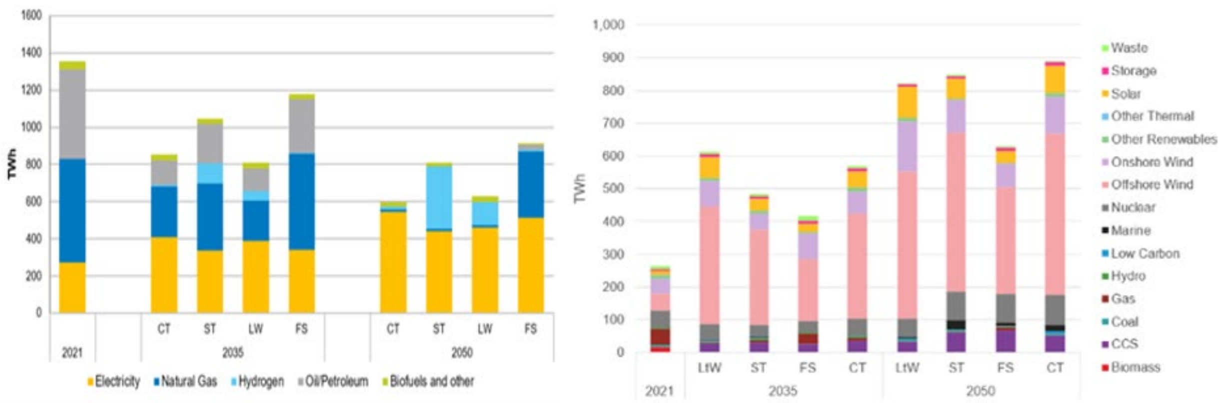

Figure 1 Demand forecasts by scenario / fuel (left); Electricity generation forecasts by scenario / technology (right) in GB. Source: FES 2022. CT = Consumer Transformation; ST = System Transformation; FS = Falling Short; LtW = Leading the Way.

In all FES scenarios, including 'Falling Short', ambitious rates of decarbonisation are envisaged. So in principle, all the technologies mentioned above could play a role in decarbonising Scotland's energy mix. However, the eventual balance between them will be determined by a host of social, technological and economic factors.

What we can say for certain is that dispatchable electricity sources will play a large part in both resilience and security of supply, but this will require complex trade-offs across the energy trilemma.

Given the broad mix of challenges and uncertainties, any strategy should strive to ensure a mix of dispatchable sources to diversify risk and keep technology pathways open. And clearly, dispatchable power strategies will have to be tested robustly against periods of low wind and solar generation.

4. What are the key barriers to deploying these technologies and how should they be addressed?

There are numerous barriers that impact each technology to varying degrees, from technical immaturity at scale to basic economics. For example:

- **Pumped Hydro / Large-scale, long-duration storage**: Scotland has significant opportunities to build new pumped hydro facilities, and to extend existing plant, and several large-scale projects are at advanced stages of development including Coire Glas and Cruachan Expansion. Projects are capital intensive and there are few long term contracted revenue streams to support a financial investment decision[11]. Developers are suggesting a cap and floor regime[12] [13], similar to interconnectors as the most beneficial solution not unlock investment. Of course, if policymakers can help solve the finance questions, Scotland's geography offers numerous opportunities to expand both pumped hydro and other storage options.

- **Hydrogen:** Hydrogen uptake covers a wide range in the FES scenarios, but it is likely to play a critical role in decarbonising the network. Some scenarios suggest very large amounts of hydrogen will have to be produced or imported by 2035. This represents a challenge given today's low production base, but investors and developers are responding well to the incentives and price signals, suggesting good potential to scale up. In Scotland, large-scale hydrogen is most likely to be green hydrogen made in bulk from offshore wind energy. However, the success of each 'colour' of hydrogen will depend on economics and issues such as the public policies related to the transportation and storage of hydrogen or global gas prices in the case of 'blue hydrogen'. (See question 8 and 9 response for more detail.)

- **Carbon Capture Use and Storage (CCUS) and Biomass Energy Carbon Capture Storage (BECCS):** From late 2020s, CCUS from gas / biomass are expected to come online in the generation mix. CCUS gas, either from the atmosphere or at source, is expected to generate between 10.4TWh and 21.4TWh by 2035 according to FES. 'Leading the Way' and 'System Transformation' both deploy two industrial CCUS clusters by 2026 and four by 2030. The hub approach, alongside the dispatchable power policy for CCUS, provides policy tool to help deliver CCUS. However, the fact that CCUS is commercially unproven presents a risk to this deployment at the scale required. Between 4.8TWh - 25.0TWh are expected to be generated from BECCS by 2035. While BECCS

[11] https://www.drax.com/press_release/potential-solution-to-unlock-investment-in-climate-critical-storage-technologies/

[12] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1095997/benefits-long-duration-electricity-storage.pdf

[13] https://www.sserenewables.com/news-and-views/2022/04/sse-renewables-renews-call-for-policy-action-on-long-duration-energy-storage/

would significantly contribute to delivering to targets, there is no agreed full certification, monitoring, reporting and verification scheme for such technologies in place as yet. Combined with high LCOE estimates there is not, as yet, a viable business model for BECCS, or other negative emission technologies.

- **Battery Storage:** FES expects uptake of battery storage in homes to increase gradually through the 2020s and accelerate through the 2030s, making up the largest share of energy storage capacity in all scenarios to help with demand shifting / managing network constraints as battery costs fall. Battery storage capacity will increase from 1.6GW in 2021 to as much as 20GW by 2030 and 35GW by 2050 ('Leading the Way' scenario). This reflects a very large pipeline of battery storage sites. However, with large-scale deployment of batteries expected worldwide, there will be significant competition for the component parts of batteries, including rare earths such as lithium.

- **Interconnectors**: The FES scenarios all assume significant increases in interconnection to GB. The capacity for 2030 is between 13.1MW to 19.4MW and for 2035 it is between 13.1MW and 24.5MW. This represents a significant increase from the 7.4MW in place in 2022. Interconnectors involve large-scale investment and long lead times. Political, technical and economic considerations often delay commissioning. The Ofgem Cap and Floor regime has had significant success delivering new interconnectors projects. However, with GB no longer in the EU there may be a reluctance for new interconnection across countries, especially at the scale required. To address this risk, policymakers would likely have to try and drive rapid progress to test market appetite.

- **Gas:** In Europe, the structural decline of nuclear power has placed renewed emphasis on natural gas plants. However, increased investment, operational profile (low running hours/load) and long lifespan (at least 25 years) are key barriers that will affect the supply of new gas and the continuation of existing unabated gas assets. Only two new build Combined Cycle Gas Turbine (CCGT) plants have been signed off in the last 10 years and risks increase for plants that cannot be used past 2035 given their conflict with net zero targets and ambition. The government aims to provide clarity on the future of unabated gas assets through the Capacity Market and the Decarbonisation Readiness consultation. This will be important as CCGTs are currently the mainstay of dispatchable power in GB and it will take time to develop zero carbon dispatchable technologies. Effectively addressing the issue of funding and operating what will become a stranded asset may not be possible without significant guarantees.

As always, the economics of developing and deploying these technologies will be a significant barrier to deploying any of these technologies, but one challenge applicable to all of them is the long lead time required to get a grid connection in many parts of the country.

5. Do proposed UK Government reforms to the electricity capacity market align with the Draft Energy Strategy?

The proposed reforms to the Capacity Market and the changes to GB capacity adequacy policy are being considered more widely as part of the Review into Electricity market arrangements. From initial comments it appears to mostly align with the draft energy strategy. However, there are a broad array of options – for example Strategic Reserves – where outcomes will be determined by the detailed design of the policies.

Wind energy

6. What are the key barriers to achieving the Scottish Government's ambition for onshore and offshore wind contained in the Draft Strategy; could the readiness of the electricity network to accommodate new projects affect the business case for the proposals?

There are a number of potential barriers to achieving the Scottish Government's onshore and offshore wind targets. These include:

- Long lead times and risks to securing consents within the planning system both for onshore and offshore wind, but also the associated network infrastructure (see ScottishRenewables' response).
- A route to market for renewables, including access to funding support (e.g. Contract for Difference or equivalent) and financing. This requires the UK Government to ensure a secure and stable route to market for renewables with regular funding rounds, recognising the varying needs for different technologies, e.g. floating wind is likely to have a higher cost base in the early stages of deployment.
- Investment in the supply chain and critical infrastructure is key to drive growth in the offshore wind sector. Port and harbour infrastructure is likely to represent a constraint in the late 2020s as offshore wind construction accelerates. Support may be required from Government to intervene in areas of market failure where the lead times with investment for this critical infrastructure are not aligned with the financial investment decision timescales of the offshore wind farms.
- Investment and delivery of grid infrastructure represents a critical risk to delivery of onshore and offshore wind infrastructure. The System Operator's Holistic Network Design (HND) sets out the high-level transmission network requirements. However, there are risks to deliverability associated with the significant scale up. The supply chain for suitably qualified engineers, as well as the supply chain for network equipment is also constrained and likely to remain so for some time.

7. Given the generation potential, and market ambition, is there a risk of oversupply if options for use of surplus electricity (e.g. green hydrogen production) do not become reality?

There is potential risk in alignment of growth of electricity supply, demand shifts to electrification and/or hydrogen, and delivery of flexibility and storage solutions, that may result in periods of oversupply of generation while long lead assets and infrastructure is delivered. Market reform and design and more co-ordinated and strategic infrastructure planning is necessary to ensure that risks to consumer and industry are appropriately managed and mitigated.

ARUP

<u>Hydrogen and the electricity system</u>

8. How much of the Scottish Government ambitions for 5 GW of hydrogen production capacity by 2030, and 25 GW by 2045 should come from green hydrogen?

Overview

While blue hydrogen can potentially provide low-cost low-carbon hydrogen at scale through the Scottish Cluster, its contribution to the 2030 targets is contingent on clear funding and policy support from the UK Government. In Scotland, in both the medium and long term, green hydrogen is likely to be the lower cost solution for low-carbon hydrogen and offers significant economic opportunities. As such, it is likely to play a significant and increasing role in contribution to both 2030 and 2045 targets.

The Role for Hydrogen in Net Zero

Arup's Scottish Hydrogen Assessment report[14] recognised the broad consensus that hydrogen will play a critical role in decarbonisation of the energy system. Key policy and publications such as the Scottish Hydrogen Policy Statement (2020), Committee on Climate Change (CCC) Delivering a Reliable Decarbonised Power System report (2023) and National Grid ESO's Future Energy Scenarios (FES) 2022 have all identified hydrogen as vital to decarbonising the energy system. Within these, hydrogen generally plays a role in decarbonising sectors where electrification is challenging.

The ultimate scale of hydrogen deployment in the energy system will depend on technology commercialisation pathways for both electrification and hydrogen options. A future energy system will see significant increase in electrification. However, it is likely that another energy carrier will be required to enable a more flexible, resilient and integrated system, and hydrogen is increasingly seen as playing a complementary role to electricity.

The benefits of hydrogen for the energy system are becoming increasingly clear and the economic opportunity is significant. In the most ambitious scenario in the Hydrogen Assessment, establishing Scotland as an exporter of green energy to Europe could result in a £25bn contribution to Gross Value Added (GVA) with over 300,000 jobs by 2045. This would be achieved by unlocking Scotland's vast offshore wind potential, but would be dependent on Scotland producing green hydrogen that is cost-competitive.

Supporting a domestic hydrogen market is likely to support anywhere between 70,000 to 175,000 jobs (£5bn-16bn GVA) and is dependent on the extent of the penetration of hydrogen in the energy system.

Blue Hydrogen

Blue hydrogen coupled with CCUS offers transition opportunities for the oil and gas (O&G) industry. Depending on global gas prices, it may be lower cost than green hydrogen until cost reductions for green are realised. Blue hydrogen could be a useful transition technology, but given it is not zero carbon its role will likely diminish by 2045 and beyond.

Many of the supply chain elements required for blue and green hydrogen production and CCUS already exist in Scotland's O&G industry. There are significant geological stores in the North Sea with potential to store carbon, a critical enabler in the production of blue hydrogen, alongside existing gas network infrastructure offshore and onshore.

Natural gas is the feedstock of blue hydrogen production and so securing a supply is critical to investment in blue hydrogen production. Scotland plays a key role in the supply of natural gas to the wider UK system,

[14] Scottish hydrogen: assessment report - gov.scot (www.gov.scot)

both from its indigenous production, but also as an importer from the wider North Sea gas network. The total flow of gas through St Fergus, both imports and indigenous, varies on an annual basis. In 2019, it was approximately 240 TWh – almost four times Scotland's current natural gas demand. However, the UK Continental Shelf (UKCS) is an ageing basin and the total production of natural gas is in decline. Predicting the remaining economically viable reserves in the North Sea is challenging. It is possible that a hydrogen market, and more integration of offshore renewables with O&G assets, would increase the economic viability of reserves and slow the decline, thereby increasing overall production.

The UK Government's 'Maximising Economic Recovery' strategy seeks to slow the decline. However, Oil & Gas UK predicts that by 2045, UK production will be approximately 30% of 2020 production[15]. The majority of the UK's existing natural gas supply does not come from indigenous supply. In 2018, the UK imported 54% of its total natural gas demand from global markets[16]. The proportion of UK gas imports will increase over time if reliance on gas does not reduce as indigenous reserves decline. This clearly presents significant risks to security of supply in an increasingly volatile geopolitical environment.

Blue hydrogen costs are essentially the wholesale natural gas price plus a production 'premium'. This covers the efficiency loss (i.e. the additional kilowatt hour (kWh) of natural gas required for each kWh of hydrogen produced), the cost of transporting and storing the carbon, and the operational and capital costs of the plant itself. Blue hydrogen costs are expected to increase out to 2050 as the cost of natural gas rises and further carbon taxes are introduced.

Scotland's Blue Hydrogen Developments

Published plans for blue hydrogen production in Scotland include the St Fergus Acorn project developed by Storegga, Shell UK, Harbour Energy and North Sea Midstream Partners[17] and Ineos' hydrogen plant at Grangemouth[18].

The cluster sequencing process was established by the Department for Business Energy & Industrial Strategy (BEIS) (now the Department for Energy Security and Net Zero (DESNZ)) to identify and sequence carbon capture, usage and storage (CCUS) clusters suitable for deployment in the mid-2020s. Track 1 emitter projects (which include CCUS enabled hydrogen) have a target commercial operations date of end of 2027. These projects will also need support under the Net Zero Hydrogen Fund (NZHF) and the Hydrogen Business Model, which will run concurrently with the Phase 2 of track 1 cluster sequencing process[19].

The Scottish Cluster, which included the St Fergus Acorn project, was not successful as a Track 1 project, but was selected as a reserve project. A reserve cluster is one which met the eligibility criteria and performed to a good standard against the evaluation criteria. BEIS/DESNZ committed to continue to engage with the Scottish Cluster throughout Phase 2 of the sequencing process, to ensure it can continue its development and planning. The intention is that if government chooses to discontinue engagement with a cluster in Track 1, it could engage with this reserve cluster instead.

---

[15] OGUK. OGUK Pathway to a Net-Zero Basin: Production Emissions Targets Report 2020. https://oilandgasuk.cld.bz/OGUK-Pathway-to-a-Net-Zero-Basin-Production-EmissionsTargets-Report-2020/2/ (2020).

[16] OGUK. OGUK Pathway to a Net-Zero Basin: Production Emissions Targets Report 2020. https://oilandgasuk.cld.bz/OGUK-Pathway-to-a-Net-Zero-Basin-Production-Emissions Targets-Report-2020/2/ (2020).

[17] https://www.theacornproject.uk/

[18] https://www.ineos.com/news/shared-news/ineos-at-grangemouth-announces-plans-to-construct-a-low-carbon-hydrogen-manufacturing-plant/

[19] https://www.gov.uk/government/publications/hydrogen-production-business-model

The BEIS/DESNZ published roadmap shows an intention to support four clusters operational by 2030 latest[20] with a further Track 2 competition to be progressed. As such, the Scottish Cluster could still pursue and secure funding for deployment of blue hydrogen by 2030. However, the scale of deployment by 2030 may be more modest given the later phasing of the Scottish projects.

Green Hydrogen

Scotland's resources in onshore and offshore wind, wave and tidal are vast. Hydrogen offers the potential to unlock more of these renewable resources and improve the competitiveness of Scottish renewable production.

The Hydrogen Assessment indicated that Scotland could export hydrogen to Europe, e.g. Germany has already declared an intent to import green hydrogen. However, this would be reliant on Scotland's ability to produce hydrogen that is cost-competitive on the international market.

Arup's assessment showed that production of green hydrogen for export and domestic use provided the greatest additionality in terms of GVA and employment – an estimated £19bn of value-added and nearly 220,000 jobs in 2045. The evidence suggests that the required skills frequently align with those already present in the renewable and offshore industries. Capturing more of the green hydrogen production value chain, including electrolyser integration or even manufacturing upstream, would result in greater economic benefits.

Green hydrogen costs are also mostly determined by feedstock costs, in this case renewable electricity. Other cost factors include the capital expenditure (CapEx), operational expenditure (OpEx), and the efficiency of the electrolyser system. The diminishing cost of renewable electricity, increased scale of electrolyser manufacture, and improved efficiencies mean that the cost of green hydrogen is expected to drop substantially out to 2050. For Scotland, driving down the cost of offshore and onshore wind electricity production will be the key to driving cost-effective green hydrogen production.

Scotland's Green Hydrogen Developments

Funding for green (and blue) hydrogen is available through the Net Zero Hydrogen Fund (NZHF). Worth up to £240 million, NZHF will fund the development and deployment of new low-carbon hydrogen production to de-risk investment and reduce lifetime costs. The fund is designed to support multiple low-carbon hydrogen production technologies that meet the eligibility criteria.

Strand 1 will provide development expenditure (DEVEX) for front end engineering design (FEED) and post-FEED activities, aiming to build the pipeline of hydrogen production projects to measurably move these closer to deployment. Strand 1 closed on 23 June 2022, but the successful projects are yet to be announced, so it is not yet clear how this funding round will impact the Scottish green hydrogen development portfolio.

The Hydrogen Business Model (HBM) is a contractual business model for hydrogen producers to incentivise the production and use of low carbon hydrogen through the provision of ongoing revenue support. BEIS/DESNZ aims to run yearly electrolytic allocation rounds for the HBM and move to price-competitive allocations by 2025 as soon as market conditions and legislation allow[21].

An intention to support at least 250MW via the first allocation round was announced, although BEIS/DESNZ retain the right to allocate less if we there are not sufficient projects coming forward that meet

[20] Cluster Sequencing for Carbon Capture Usage and Storage Deployment: Phase-1 - background and guidance for submissions (publishing.service.gov.uk)

[21] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1067159/hydrogen-business-model-net-zero-hydrogen-fund-market-engagement-electrolytic-allocation.pdf

the eligibility criteria and present Value for Money to government. The 2022 funding round has closed, but winners have not yet been announced.[22]

Success for Scottish projects in securing funding through the HBM and NZHF will be necessary for Scotland to develop and deliver a pipeline of projects that meets the 2030 targets. There are a number of green hydrogen projects in Scotland already in the public domain, including ScottishPower and Storegga's Cromarty Hydrogen Project[23], which aims to scale to 300MW, and ScottishPower's 20MW electrolyser at Whitelee[24]. Support has also been provided by Scottish Government and Ofgem to SGN's H100 project, which will utilise green hydrogen to supply 100% hydrogen to domestic properties through the world's first hydrogen network in Fife.

A number of the ScotWind developers have signalled an intent to explore green hydrogen, including the 2GW West of Orkney wind farm where developers are investigating opportunities at the Flotta Terminal[25]. Cerulean Winds has published its ambitions for O&G decarbonisation and hydrogen production. Cerulean hopes to secure a scheme through the Crown Estates Scotland INTOG leasing round[26], which aims to have operational projects in the next decade[27]. This aligns with the North Sea Transition Deal, which aims to have 25% emissions reduction from O&G by 2027, and 50% by 2030[28].

Currently, there are only a few, relatively small-scale, green hydrogen projects deployed in Scotland, including the <1MW scheme at the European Marine Energy Centre[29]. Scaling to multi-GW ambitions by 2030 represents a significant challenge to the industry and supply chain. The 2030 targets are likely to be achieved only with strong sustained support from UK and Scottish Government and the regulatory authorities to remove regulatory barriers and provide a route to market through the Hydrogen Business Model funding. This will be in addition to appropriate support for the transportation, storage and use of hydrogen.

In the long term, green hydrogen will likely represent the lowest cost form of low carbon hydrogen in Scotland, given the significant offshore wind resources and large development pipeline. It is anticipated that green hydrogen will be the dominant contributor to the 2045 hydrogen targets.

[22] https://www.gov.uk/government/publications/hydrogen-business-model-and-net-zero-hydrogen-fund-electrolytic-allocation-round-2022

[23] https://www.cromartyhydrogenproject.co.uk/

[24] https://www.scottishpower.com/news/pages/green_hydrogen_for_glasgow.aspx#:~:text=The%20green%20hydrogen%20facility%20at%20Whitelee%2C%20the%20UK%E2%80%99s,Glasgow%20to%20Edinburgh%20and%20back%20again%20each%20day.croma

[25] https://www.flottahydrogenhub.com/

[26] https://ceruleanwinds.com/targeted-oil-gas-decarbonisation/scheme-overview/

[27] https://www.crownestatescotland.com/our-projects/intog

[28] https://oeuk.org.uk/the-north-sea-transition-deal/#:~:text=The%20North%20Sea%20Transition%20Deal%20%28NSTD%29%20is%20the,emissions%2C%20and%20create%20new%20jobs%20in%20the%20UK.

[29] https://www.emec.org.uk/facilities/hydrogen/

9. What are the key infrastructure barriers to building a hydrogen economy in Scotland and how should they be addressed?

Overview

Hydrogen gas and electricity network planning appears to be happening independently, with strategic planning for hydrogen infrastructure still in its infancy. Key decisions on use, transportation and storage of hydrogen are due to be taken over 2023-2026, and the Future System Operator will take responsibility for integrated gas and electricity planning from 2024 onwards. However, the rate of progress of these activities creates a risk to delivery of Scottish and UK Government's hydrogen ambitions.

Barriers and the Hydrogen Economy

Despite significant investor and industry appetite for the hydrogen economy and the development and deployment of low-carbon hydrogen, there are still a number of key challenges and barriers facing the market. These include:

- An understanding of the **funding and regulatory models** which will enable an end-to-end market spanning production, transportation, storage and demand/use, and
- Development of a **strategic infrastructure plan** that identifies the distribution and scale of hydrogen production and demand, which will inform decisions for future gas and electricity network investment.

Current low carbon hydrogen production projects are being progressed through the Cluster Sequencing and Hydrogen Business Models (HBM)[30]. However, these first projects are required to identify and secure offtakers, determining the end-to-end system and infrastructure that offer best value for money and deliverability within the constraints of the HBM funding.

Key decisions on use of the gas network with regard to hydrogen are still pending. The UK Hydrogen Strategy[31] anticipates that strategic decisions regarding the role of hydrogen for heat and progression to a decision on a hydrogen town will be made in 2026, with a decision on gas blending to be made in 2023. National Gas's Project Union[32] explores the development of a UK hydrogen network, which would join industrial clusters around the country, potentially spanning 2,000km. The UK government committed in the British Energy Security Strategy to design new business models for hydrogen transport and storage infrastructure by 2025.

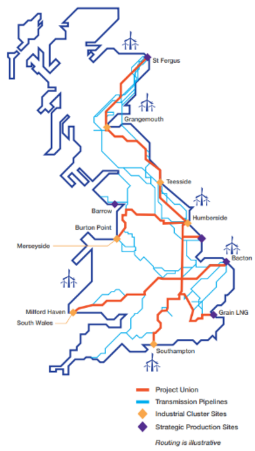

Figure 1 Project Union Potential Infrastructure

The European Hydrogen Backbone (EHB) initiative consists of a group of 32 energy infrastructure operators. The initiative aims to accelerate Europe's decarbonisation journey by defining the critical role of hydrogen infrastructure, based on existing and new pipelines, in enabling the development of a competitive, liquid, pan-European renewable and low-carbon hydrogen market.

---

[30] https://www.gov.uk/government/publications/cluster-sequencing-for-carbon-capture-usage-and-storage-ccus-deployment-phase-1-expressions-of-interest/october-2021-update-track-1-clusters-confirmed

[31] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1011283/UK-Hydrogen-Strategy_web.pdf

[32] https://www.nationalgas.com/document/139641/download

Figure 2 The European Hydrogen Backbone Potential Infrastructure

As a result, strategic hydrogen gas infrastructure is likely to play a limited role for the early projects, and the emerging infrastructure vision is in its infancy.

While there is an understanding of the wide range of potential uses for hydrogen in transportation, industry and heat, there is still uncertainty in the short and longer term uses of hydrogen and their spatial distribution. This uncertainty creates challenges in development of an infrastructure vision.

What does this mean for Offshore Wind in Scotland?

Arup's work for Crown Estate Scotland, BEIS, and The Crown Estate in the Future Offshore Wind Scenarios[33] identifies the complex interactions between offshore wind, different activities in our seas and protection of the marine environment, and the influence on relative levelized cost of energy (LCOE) of different future decisions in achieving 2050 net zero targets.

The modelling highlights the significant influence of network charging (TNUoS) on the geospatial distribution and portfolio cost of offshore wind, in particular the impact on developments in Scotland. Network charging aside, the remote nature, water depths and metocean conditions of some of the ScotWind sites are likely to impact on the LCOE of some of the project sites.

Delivery of the electricity infrastructure that can realise the ScotWind development pipeline represents a significant challenge in terms of finance, planning and supply chain constraints. The focus of the holistic network design is to identify the most efficient electricity network solution to connect offshore wind to the onshore electricity grid.

Gas pipelines are typically the cheapest way to transport hydrogen (compared to shipping and road transportation). Over long distances gas pipelines may even be a lower cost solution for transporting energy than electrical cables[34]. An offshore hydrogen gas network is likely to play a key role in creating a European export market and creates opportunities for ScotWind developers to find alternative routes to market for their green energy.

The Future System Operator[35] will have responsibilities across both the electricity and gas systems and the ability to expand its remit to additional energy vectors when needed. This remit will consider whole energy planning, strategic network planning and market strategy across both gas and electricity to provide a whole energy system view. This could also expand over time, to cover additional other energy sources such as hydrogen, heat, transport and CCUS. The FSO could be established by 2024.

Prior to the establishment of the FSO, electricity and hydrogen network planning is largely happening in parallel and independently. This creates a lack of vision for developers such as ScotWind and INTOG on

---

[33] https://www.futureoffshorewindscenarios.co.uk/assets/report/20220421_FOW_Final_Report.pdf

34 Renewable energy transport via hydrogen pipelines and HVDC transmission lines - ScienceDirect

[35] https://www.nationalgrideso.com/who-we-are/what-we-do/future-system-operator-fso

how hydrogen production, either offshore or onshore, might offer route to market opportunities for sites where the electricity grid represents a deployment constraint.

In their Delivering a Reliable and Resilient Decarbonised Power System report[36], the Climate Change Committee (CCC) stressed the important role for Government in setting strategic direction for uses of hydrogen. CCC notes that hydrogen infrastructure will be required regardless of decisions in 2026 on its potential use for heat in buildings. As such, the CCC suggests the Government should identify a set of low-regret investments that can proceed now. Decisions on hydrogen transmission and the development of business models for hydrogen transportation and storage should be fast-tracked, given long lead times associated with hydrogen storage.

Delays in the delivery of hydrogen infrastructure could limit the role for hydrogen in the 2035 energy system, including its role in providing low-carbon back-up capacity. CCC also notes that if hydrogen use in the electricity system is towards the high end of its potential range, the UK Government's targets for hydrogen production capacity in 2030 look insufficient.

[36] file:///C:/Users/Clare-M.Lavelle/Downloads/Delivering-a-reliable-decarbonised-power-system.pdf

Ofgem

10. Ofgem are "working with government, industry and consumer groups to deliver a net-zero economy". What changes have recently been made to support the delivery of net-zero? What more could be done to support a regulatory regime that delivers decarbonised energy supplies affordably?

As noted above, the current network price controls include reopeners intended to facilitate the transition to a low-carbon economy. The speed at which the ASTI reopener was developed moving from a blank sheet of paper to draft licence conditions in ten months demonstrated an ability to respond with agility to meet the challenges of net zero.

In other areas, Ofgem has published a call for input on the development of distributed flexibility.[37] If the use of distributed flexibility can be maximised, it will have an impact on the amount of network infrastructure and generation required.

One of the areas where it may be possible for the networks and Ofgem to make more change is in queue management. However, this is largely driven by a duty to be technology neutral. This means that it is not possible to prioritise renewable sources of generation, when allocating network capacity. Networks therefore connect on a first-come first-served basis.

We would support SSEN's position that Ofgem would benefit from having a more central and explicit statutory obligation to enable net zero. The UK and Scottish Government policy requires balancing of the ambition and obligations of achieving net zero, with the requirements to consider a Just Transition, economic opportunity and the impact on consumers. Ensuring a very close alignment of Ofgem's statutory obligations with the overarching government policy will ensure a better alignment of government policy and the role of the regulator.

Given the critical role of Scotland in delivering the UK's net zero targets, identified by the Climate Change Committee, there is significant benefit in closer collaboration between Scottish Government and Ofgem in future.

11. What are the most important issues for the UK Government's Review of Electricity Market Arrangements to address? What are the benefits of the current system, and the potential pitfalls of moving away from it? What are the implications for the Draft Energy Strategy of the Review?

The Review of Energy Markets Arrangement (REMA) work programme set out a compelling case for exploring a redesign of the GB system and looking at the policy support mechanisms required for net zero. The implications of REMA strongly suggest that the current market is not working, especially for consumers. Further, the challenge of rapid decarbonisation by 2035 (10 years earlier than planned prior to 2021) requires re-examining policy support packages.

Balancing and constraint costs have risen dramatically – In 2008, NGESO spent some £500m on balancing costs in GB. Last year, it was over £3.5bn. Part of this increase arises from rapidly growing constraint costs, which are forecast to grow even further. The transmission network simply cannot build quickly enough to reduce them. The current system has to re-dispatch (undo, then re-do) large parts of the market outcome. The costs are a direct result of a market design that is not producing the right outcome.

[37] https://www.ofgem.gov.uk/publications/call-input-future-distributed-flexibility

Growing market power concerns – Concerns have been growing that firms can exploit market power, especially when behind transmission constraints.

The GB market design lends itself to being dominated by gas-fired generation – As gas is the marginal pricing source in a uniform market, this puts GB at greater risk from a volatile global gas market. There are other approaches that could alleviate this risk, but obviously each alternative comes with its own advantages and disadvantages, whether it is nodal pricing or anything else.

What are the benefits of the current GB system?

Traditionally, GB has been viewed as a good place for renewables investment, with a relatively stable policy environment and strong support mechanisms. As a result, GB has done reasonably well in decarbonising its power sector, with significant growth in wind generation in particular. A large part of the reason of this success was because the subsidies for renewables were attractive (e.g. ROCs).

Despite progress to date, it is difficult to make a case that the current market design is working well. Scottish and GB consumers face some of the highest wholesale costs in Europe and indeed the world. This is partly because the market design is no longer fit for purpose.

Not only that, but global competition is increasing. The incentives in the Inflation Reduction Act are likely to make the US more attractive, while the EU is following suit with greater incentives and subsidies.

Pitfalls and prospects

The principal concern with undertaking a major market redesign is the potential for an investment hiatus as developers and investors wait to assess cost of capital and likely returns. However, this is not necessarily the experience witnessed in other markets (i.e. in the US, CAISO, ERCOT) some of which have experienced significant renewables growth despite ongoing market reforms.

Some groups argue that moving away from the current design to, say, a nodal market, will increase the costs of capital for low-carbon investment. Inevitably, there are trade-offs involved in any system. The key challenge remains minimising the amounts needed to constrain some sources or pay others to fill gaps in a balanced energy supply mix.

One of the other pitfalls is that groups for various interests may aim to stymie any attempt at reform, leading to prolonged periods of policy indecision which will potentially have a negative impact on consumers and delivery of net zero by industry.

Community energy

12. Are community and locally owned projects inhibited by the current electricity network?

Anecdotal evidence certainly suggests that both grid connection costs and long delays to secure access inhibit enthusiasm and delivery across locally driven projects.

We would refer the Committee to the work of groups such as Community Energy Scotland for a more detailed response.

13. What are the key infrastructure barriers to Scottish Government community energy ambitions and how should they be addressed? Is it enough to "encourage" shared ownership models, or should a more formal mechanism be implemented?

Again, we would defer to Scottish Renewables and Community Energy Scotland.