# Decarbonising the UK's Gas Network

## Realising the green power-to-hydrogen opportunity in the East Neuk

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# EXECUTIVE SUMMARY

To meet the ambitious net zero carbon reduction targets set by the UK and Scottish Governments, the UK will need to satisfy a significant proportion of energy demand with low-carbon sources. While the power sector is already rapidly decarbonising, other sectors, such as transportation, domestic and commercial buildings and industry, are lagging behind. The timely decarbonisation of these hard-to-abate sectors will require the implementation of a range of low-carbon solutions: many of which already exist, but are yet to be trialled at a commercial scale.

Hydrogen, produced from renewable electricity or natural gas with carbon capture and storage, represents an attractive low-carbon alternative for hard-to-decarbonise sectors. Like electricity, hydrogen is an energy vector which may be produced from a variety of sources and has application across a wide range of end-uses. Unlike electricity, hydrogen can be stored in multiple ways, e.g. in gas networks, and over both long (e.g. inter-seasonal) and short timeframes.

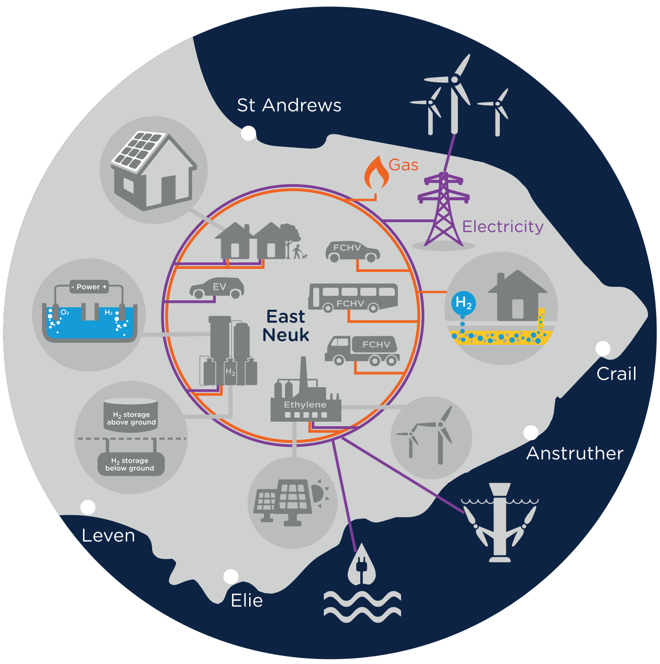
Combining the electricity and hydrogen vectors in a power-to-hydrogen configuration could help create a more integrated energy system, allowing energy to be stored and delivered flexibly across multiple sectors and helping to address the challenges associated with a high penetration of renewables in the electricity system. Scotland has over 1000GW of renewable electricity generation potential, but realising this would require significant investment in infrastructure. Costly transmission and distribution capacity or short-term storage could be delayed or eliminated if excess electricity could be converted to a storable fuel and used in the gas infrastructure already present.

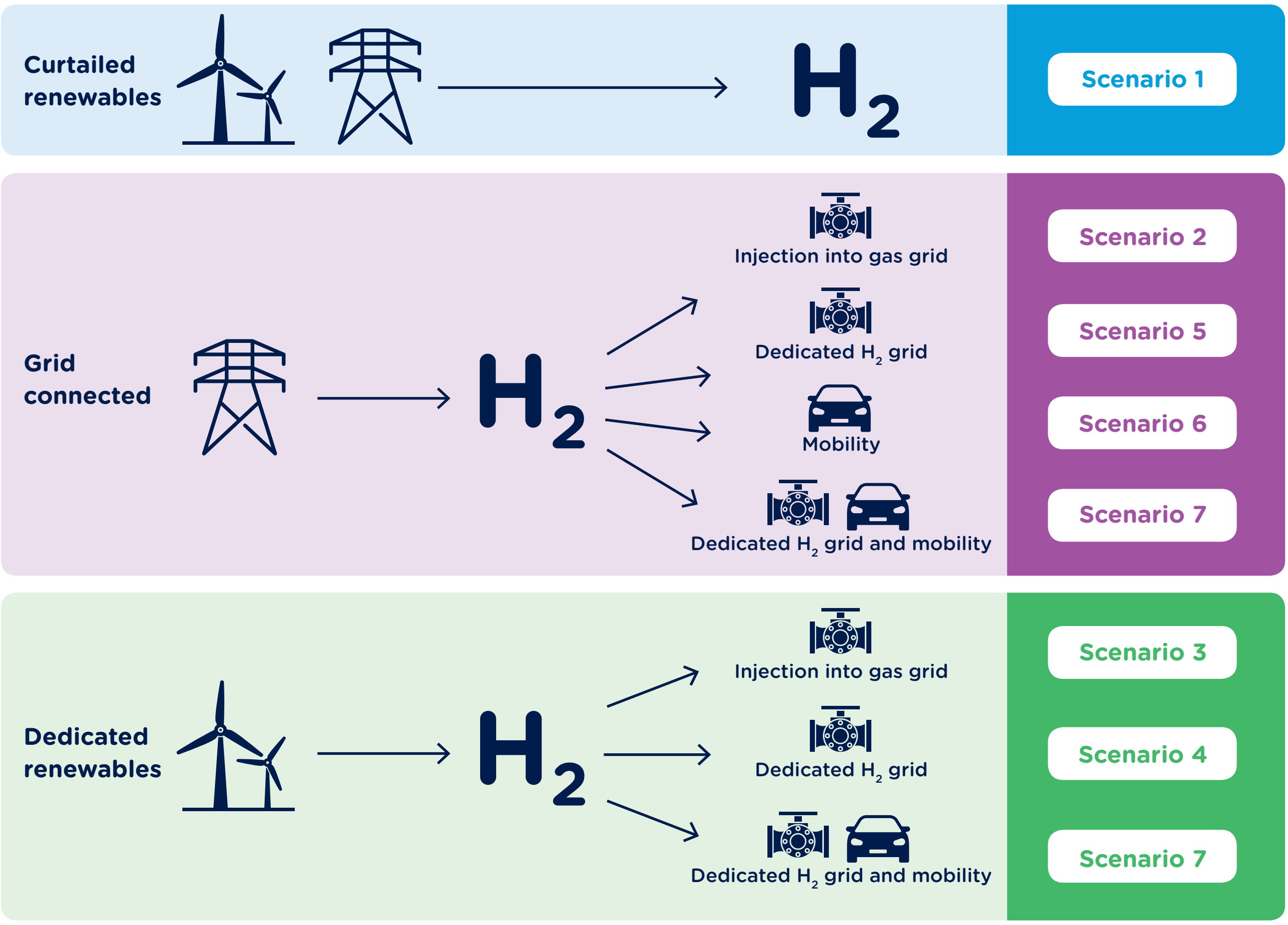
## Objectives of study and approach

Realising the power-to-hydrogen opportunity will require the deployment of pilot and pre-commercial projects designed to explore different aspects of system design and delivery. One such programme, SGN's H100 Fife project, has the remit of evaluating all aspects required to deliver a pure hydrogen grid and will culminate in the roll-out of a small dedicated hydrogen network in Levenmouth, Fife.

This study in part supports the H100 Fife initiative and was designed to explore the potential for power-to-hydrogen to deliver the foreseen benefits through an analysis focused on the East Neuk of Fife. The scope of the study is illustrated in the diagram opposite.

The aim is to create a link between the electricity network - fed by renewables from a variety of sources - and the gas network, which would be used to carry hydrogen to a variety of end-use applications including heating, transport and industry. Fife is rich in renewable energy resource, both onshore and offshore, and has well-developed electricity and gas networks. Current demand encompasses domestic, commercial and industrial consumption and there is existing hydrogen by-production from the ethylene plant located in the western part of Fife. In addition, there is strong evidence of geological storage potential in the local rock formations. These factors together present a positive picture for trialling power-to-hydrogen in the Fife region.






The study described in this report was focused on answering the following critical questions relating to the implementation of power-to-hydrogen in Fife:

1. How much low-cost, low-carbon electricity would be available to a power-to-hydrogen operator in Fife, and how much hydrogen could be produced today and in 2040?
2. What would be the cost of hydrogen produced from the electricity grid today and in 2040, and how does this compare with hydrogen produced from a) dedicated renewables and b) steam methane reforming (SMR)?
3. What would be the optimal electrolysis capacity in Fife when either a) connected to the grid or b) supplied by dedicated renewables?
4. How much hydrogen storage would be required to meet demand under three end-use cases: a) injection into the natural gas grid; b) use in a dedicated hydrogen grid for heating; and c) use as transport fuel for a small fleet of vehicles?
5. What, if any, network upgrades could be avoided through the implementation of power-to-hydrogen?
6. Which hydrogen end-use markets would be the most attractive for a power-to-hydrogen operator?
7. What regulatory, legislative or market barriers would need to be overcome in order to realise large-scale deployment of power-to-hydrogen?

In order to explore the feasibility of hydrogen production in the Fife region, we utilised a high-level model of the European electricity system on the Artelys Crystal platform. Generation and load across Europe are modelled as an hourly annual time-series using the principles of least cost despatch of generation and exchanges of power between countries to be limited by net transfer capacities.

In our model, each country is represented as a single node except for the UK, which is modelled as two nodes: one for Fife and the other for the rest of GB. This allows hourly wholesale prices and generation volumes by generation type in Fife to be established and any constrained generation to be identified.

Our analysis considered two-time horizons; the present day (2019) and 2040 based on the “Two Degrees” scenario defined by National Grid in their Future Energy Scenarios (FES).

We explored a number of different configurations of power generation and hydrogen end-use to assess the value associated with producing hydrogen, as shown in the diagram above.

In parallel with the modelling work, we undertook a review of the current legislation and regulation relating to power-to-hydrogen as well as reports and academic papers that have been written on the subject. This allowed us to: **a)** identify the current characteristics and direction for power-to-hydrogen, **b)** observe where most progress had been made with the roll-out of pilot project to date, and **c)** highlight general lessons learned.

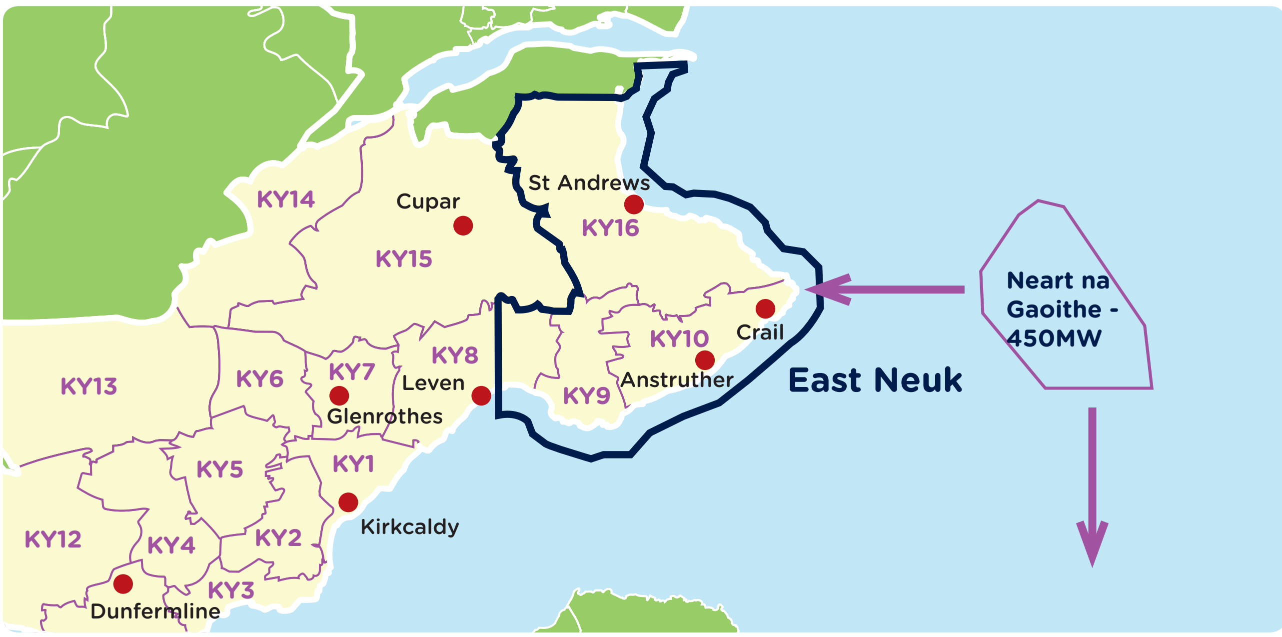
## Key findings

- **Cheap, low-carbon power could underpin hydrogen production in Fife.**

  The relatively high interconnection capacity between Fife and the rest of GB (~600MW) could allow cheap renewable and nuclear generation to be used in conjunction with local constrained generation to produce hydrogen cost-effectively in Fife. Our two-node model estimates that more than 2TWh of low-carbon grid electricity could potentially be available for hydrogen production in Fife, more than sufficient to meet the East Neuk heat demand of approximately 400GWh. It is unlikely that locally constrained generation alone can deliver enough low-cost hydrogen to fuel a meaningful amount of heat and/or transport demand in the region. We estimate a total of 15GWh of curtailed generation would be available, which equates to approximately ~ 8GWh hydrogen. There may be other regions, however, where curtailed electricity may be able to offer a more compelling business case, especially as renewable penetration increases significantly.

- **Dedicated renewable generation to produce hydrogen can encourage deployment and lessen the need for network upgrades.**

  Our analysis shows that additional large-scale deployment of offshore renewables around Fife may be restricted by the inability to connect directly into the Fife electricity network. The network capacity between Fife and the rest of GB is significant but is more restricted within Fife, particularly in the East Neuk which is more rural. These constraints and the lack of a ready local market for power in part explain why the Neart na Gaoithe offshore wind farm has been connected to the Lothian coast (see figure below). Since the distance to shore is roughly double the shortest route to the Fife coast, we estimate that the costs avoided by making the connection in Fife rather than Lothian to be in the range £25 – 30m (based on a cost of £2,800 per MW/km as reported by the Offshore Renewable Energy Catapult in 2016). It should be noted that offshore production of hydrogen could be an alternative solution to bringing power ashore and producing hydrogen onshore and may be cheaper according to the analysis in the Dolphyn study.



- **Low-cost electricity is key to successful power-to-hydrogen business cases.**

  Electricity price is the principal determinant of the cost of electrolytic hydrogen. If we assume that electrolyser owners would be able to access wholesale prices (i.e. excluding grid fees and taxes), grid power-based electrolysis could be as low as £1.2/kg. By contrast, if the electrolyser owner pays the commercial or industrial electricity price, including transport costs and other levies, the cost of hydrogen would be considerably higher (£3.35/kg). The use of dedicated renewable power could be an attractive option, with better electrolyser load factors than can be achieved with low-carbon grid power. Hydrogen production costs would be in around £2.8/kg, which could be competitive with hydrogen produced with grid electricity at commercial or industrial power prices. In practice, the extended periods of low wholesale prices predicted by our model may be over-stated, since we use the National Grid's "Two Degrees" **Future Energy Scenario** as the basis of our analysis, which anticipates higher volumes of nuclear power than may credibly be achieved.

- **The optimal electrolyser configuration must weigh capital cost and utilisation.**

  In our modelling we sized the grid connected electrolyser injecting hydrogen into the gas grid (with no blending limit) at 300MW, reflecting the high interconnection capacity. By contrast, limiting the local proportion of hydrogen to 20% by volume in the KY8, KY9, KY10, KY15 and KY16 postcodes would restrict the optimal size of the electrolyser plant to a maximum of 35 MW. However, the optimal size will vary depending on subsidy level provided to hydrogen producers. The optimal scale for an electrolyser connected directly to a dedicated 450MW putative wind farm (at the same geographical location as Neart na Gaoithe) would be 400MW, assuming that hydrogen storage capacity is available. If the hydrogen producer were required to follow gas consumption (i.e no storage) in the East Neuk, a much smaller unit would be optimal (179MW). The wide variation illustrates the dependency on end-use application, source of power, level of support and availability of storage.

- **Access to storage will be a crucial factor for the viability of a pure hydrogen grid.**

  The ability to capture excess renewable generation or low-cost electricity and use it during periods of generation shortfall or high cost electricity will critically influence the cost of hydrogen and security of supply. Fully converting the gas grid in the Leven area (KY8) to hydrogen from dedicated renewables would necessitate hydrogen storage capacity of over 700 tonnes. Producing the same amount of hydrogen from grid electricity would allow the electrolyser and storage size to be better optimised according to wholesale price, resulting in lower required storage capacity (less than 5 tonnes). The counterfactual case, supplying hydrogen from an SMR plant and transporting it to Leven, is more expensive in both cases.

- **Transport fuel is likely to be the most attractive market in the short-term.**

  Our analysis supports the findings of other studies, in that the transport market is relatively insensitive to premium-cost hydrogen and may represent the most attractive initial market for hydrogen. We envisage scenarios where hydrogen produced from low-cost, low-carbon (or renewable) electricity could be competitive with transport fuels depending on the carbon price applied. We also show that where low-cost, low-carbon grid power is available, injection into the gas grid could also be economically viable with subsidies of around £0.7/kg. Grid-connected electrolysers could improve grid performance and a grid connection means that the electrolyser operator can offer grid services, with opportunities to generate additional revenues. The "stacking" of services in this way could improve the economic viability of delivered hydrogen.

- **The legal status and legislative arrangements surrounding power-to-hydrogen remains unclear, with potential to limit market development.**

  The classification of power-to-hydrogen from a legal and regulatory perspective has not been established, which creates uncertainty for parties wishing to enter the market. This could limit players entering the market and delay the development of a vibrant market environment. Clearly defined boundaries will need to be applied to areas being dedicated to 100% hydrogen with customer opt-out not being a feasible option once the decision has been taken to convert a specific region to hydrogen (unless a natural gas grid is operated in parallel). Ring-fencing will likely also be required in a blending scenario, where blend levels will need to be carefully controlled for safety and metering purposes on a local or regional basis.

## Recommendations

- **An increase in the maximum limit on blending hydrogen.**

  The blending limit into natural gas should be increased once the safety case has been established. This would require the Gas Safety Management Regulation 1996 to be altered to reflect an increase from a current maximum limit of 0.1% of hydrogen in volume terms. Such a modification would improve the business case for power-to-hydrogen in the short term and represent an important step towards the establishment of pure hydrogen grids.

- **Incentivising uptake through incentives including lower electricity costs.**

  Creating a suitable market framework that recognises the benefits that result from dedicated renewables and supports the deployment of renewable generation in combination with electrolysis could boost investment. For example, the viability and benefits or double incentives (both for renewable generator and power-to-hydrogen provider) could ensure faster roll-out of power-to-hydrogen. The Renewable Heat Incentive (RHI) should also be reviewed and overhauled to ensure it provides adequate and effective incentives for power-to-hydrogen. One further way to incentivise hydrogen uptake is for fees and taxes to be waived on electricity used to produce hydrogen, which in turn can be directed to the decarbonisation of other sectors like heat and transport.

- **A widening of the definition of green hydrogen.**

  The current narrow definition of green hydrogen as being 100% from dedicated renewables risks preventing the low-carbon excess power from GB contributing to low-carbon hydrogen production, allowing the perfect to be the enemy of the good. Allowing green tariffs or power-purchase agreements (PPAs) with renewable generators to qualify for green hydrogen production, and including nuclear in the same definition would be a positive first step to driving down hydrogen costs. Loosening the requirement for power to be sourced from 100% renewable generation under the RTFO might encourage greater quantities of hydrogen to be produced; while the carbon savings might be somewhat less than with 100% renewable power, this approach would allow electrolyser owners to access larger quantities of low-cost, low-carbon power. An important element of such an approach would be the ability to time-stamp green certificates in order to validate that power used is truly low-carbon.

- **Creation of a market mechanism to utilise curtailed power.**

  Enabling power-to-hydrogen providers to bid for potentially curtailed power in a short-term market could result in a better economic scenario for all parties, supporting the business case for deployment of electrolyser capacity and reducing curtailed power (payments for which have been controversial).

- **A review of the interim and long-term legislative framework for power-to-hydrogen.**

  A rapid clarification of the legal and regulatory status of power-to-hydrogen is critical to ensuring rapid and effective deployment. This should include a review of the legal status of power-to-hydrogen and should consider how investment is encouraged while at the same time ensuring that end customers are not adversely affected by such investments. There may be a need for interim legislation and regulation during the early stages of the introduction of hydrogen (whether by injection to natural gas grids or through localised 100% hydrogen networks). Derogations from current market principles may be required to facilitate the rapid switchover of networks and to ensure consumers are not disadvantaged by the switch since they will be unable to opt-out. There may be a case, for example, for allowing distribution networks to own storage facilities, to control security of supply and or blend levels adequately. Alternatively, this responsibility could be left to the electrolyser owner-operator, or a third party. This should be discussed with Ofgem, to determine their appetite for the different options and progress towards clarity on the responsibilities of each player in the supply chain. The creation of parallel network infrastructure could be supported through the application of a regulated asset base (RAB) model which decouples infrastructure from both power and gas commodity prices and capital recovery can be amortised over a longer period. In this model the customer or GB resident is charged RAB + Maintenance, minimising price volatility.

- **A rethink of ownership structures.**

  The increasing complexity around market convergence may require a loosening of regulations around whether network operators can own hydrogen production (for balancing) and storage to optimise market functioning. This could be especially valuable during any transition phase, where optimisation of the use of expensive assets will be critical to project viability. While this may run counter to Ofgem's long term objectives for generating competition in energy markets, a short-term derogation may boost investment while risks remain significant.

- **Creation of a supportive environment for customers in hydrogen regions.**

  There is a need to work with Ofgem to determine the best way to support customers in localised areas where a blended or H100 grid is established. This would include reviewing how gas is metered and how appliances can be modified or replaced in a cost-neutral way. Approaches to encourage the early entry of multiple retailers of hydrogen blends or 100% hydrogen, as regions are converted, should be investigated. The potential for sector coupling from power-to-hydrogen and power-to-hydrogen-to-power, especially at high levels of penetration of power-to-hydrogen, and the negative impact on competition should be explored further.

- **Proving the case for power-to-hydrogen providing grid support.**

  It is suggested that a demonstration should be undertaken to investigate the potential for power-to-hydrogen to support network operation in practice, potentially through a pilot project with the support of the innovation allowance.

*Cheap, low-carbon power, like that produced by onshore wind farms, could underpin hydrogen production in Fife.*

# 1 INTRODUCTION

## 1.1 Background

To meet decarbonisation targets under the UK Climate Change legislation (Department of Energy, 2008), a significant proportion of energy demand will need to be met from low-carbon sources by 2050[1]. While the power sector is already decarbonising at a rapid rate, other sectors, such as transportation, domestic and commercial buildings and industry are lagging. The timely decarbonisation of these hard to abate sectors will be crucial in ensuring the UK achieves its net zero target by 2050. The implementation of a range of low-carbon solutions, of which many already exist, will be required to achieve this level of significant $CO_2$ emissions reduction.

Hydrogen, when produced from renewable electricity or natural gas with carbon capture and storage, could be a low-carbon alternative fuel for hard to decarbonise sectors. Once produced, hydrogen can be stored in multiple ways and delivered to different end-use applications, such as transport, heat, industry or electricity generation. For example, hydrogen can be stored in gas networks, either blended with natural gas or in pure form, which many other end-use applications can subsequently access for a decarbonised energy source.

As variable renewable energy penetration increases, matching electricity supply and demand becomes more challenging. Solutions such as batteries or pumped-hydro technologies can store excess electricity in the short-term but may not be cost-effective for longer term, seasonal storage. Converting excess electricity into hydrogen – power-to-hydrogen – would couple the power and gas networks creating a more integrated energy system, allowing for energy to stored and delivered flexibly across multiple sectors.

Scotland has considerable renewable electricity generation potential but much of this is intermittent and non-dispatchable. Further, capacity constraints currently limit the ability to transmit the electricity generated to the rest of the UK. To fully benefit from its renewable energy potential, significant investment is required in both generation capacity and infrastructure. Infrastructure investments could be reduced if excess electricity could be converted to a storable fuel and stored in the gas infrastructure already present. This could delay potentially costly investment into expanding transmission and distribution capacities or adding significant short-term storage.

*Grangemouth Refinery, Scotland.*

*Hydrogen could be a low-carbon alternative fuel for hard-to-decarbonise sectors.*

[1] *https://www.theccc.org.uk/wp-content/uploads/2018/11/Hydrogen-in-a-low-carbon-economy.pdf*

## 1.2 Project overview and objectives

Scotland and Southern Gas Networks (SGN) and Scottish Power Energy Networks (SPEN) are considering an integrated hydrogen energy system in the East Neuk of Fife in Scotland (Figure 1). They envisage a coupling of the power and gas networks, where renewable electricity is converted into hydrogen via an electrolyser. This hydrogen could then be used in a variety of end-use sectors, such as transport, heating and industry.

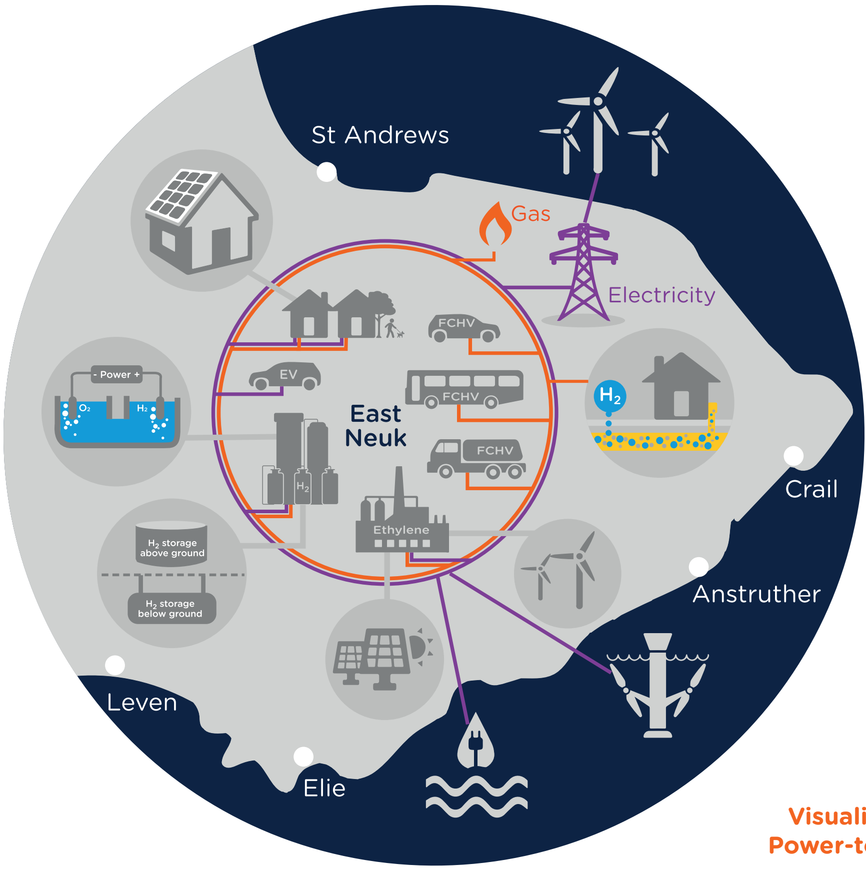



**FIGURE 1:**

**Visualisation of East Neuk Power-to-Hydrogen project**

The project seeks to create a link between the electricity network fed by renewables from a variety of sources and the gas network, carrying hydrogen to a variety of end use applications including heating, transport and industry. The region is rich in renewable resource, both onshore and offshore, and has well developed electricity and gas networks. Demand is well-contained and encompasses domestic, commercial and industrial consumption as well as existing hydrogen by-production from the ethylene plant located in the western part of Fife. In addition, there is strong evidence of geological storage potential in the local rock formations. These factors together present a positive picture for trialling power-to-hydrogen in the Fife region.

In this report we describe an analysis performed on behalf of SGN and SPEN designed to better understand how the gas and electricity networks could be coupled to maximise value and decarbonisation potential. It offers an assessment of the potential value of power-to-hydrogen, with a focus on the East Neuk of Fife, but with implications for the broader energy system. It involves investigating the potential business cases for producing hydrogen from curtailed and dedicated renewable energy. This report is intended to support ongoing discussions with Ofgem, which is updating the regulatory framework for power and gas networks. Consequently, this report also seeks to understand the market access and commercial barriers to power-to-hydrogen.

# 2 STATUS OF HYDROGEN AND POWER-TO-HYDROGEN IN THE UK

## 2.1 Hydrogen in end-use applications

Hydrogen can be used in a variety of end-use sectors, including mobility, buildings, industry and energy, either directly as hydrogen or, if further transformed, as a drop-in ‘synthetic fuel’ or ‘e-fuel’ (Figure 2). The gas grid offers the potential to directly deliver hydrogen to all end-use sectors, in a similar role to the one currently played by natural gas in the energy sector.

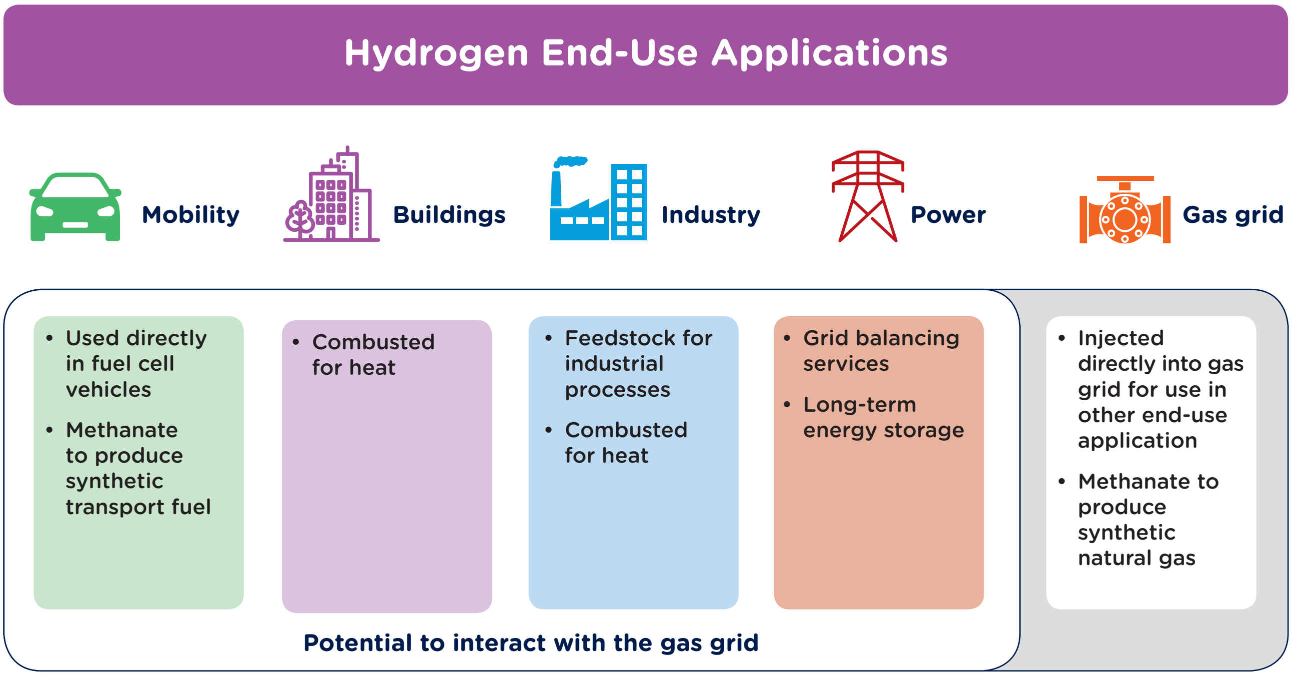



**FIGURE 2: Potential end-use applications of hydrogen**

Decarbonisation of the gas grid through the use of hydrogen has a number of benefits: Notably it allows the full utilisation of existing gas assets (Speirs, et al., 2017) and exploits the flexibility provided by the gas system. The gas network is inherently more flexible than the power system as it can handle a range of pressures, while the power system must maintain a balanced state at all times (Quarton & Samsatli, 2018). Producing hydrogen from excess electricity can shift the intermittency concerns of increased renewable electricity penetration from the power grid to the gas grid (Clegg & Mancarella, 2015) which is better equipped to handle it.

There are, however, technical challenges that must be addressed if hydrogen is to play a larger role in the energy system. A large portion of the gas network pipelines are made from unprotected iron and carbon steel, which can suffer embrittlement due to the diffusion of hydrogen (Speirs, et al., 2017). Upgrading or retrofitting these pipelines to plastic pipework or lined steel would alleviate this issue and iron mains are currently being replaced as they are reaching the end of their natural life under the Iron Mains Risk Reduction Programme (Health and Safety Executive, n.d.). However, this programme has primarily focussed on the distribution network

(Speirs, et al., 2017) whereas the transmission pipelines all rely on carbon steel. Studies carried out by SGN on their own transmission lines corroborates work carried out on the national transmission system (NTS) suggesting that, depending on the grade of steel, they may be suitable for carrying hydrogen. However, some would need to be upgraded from the point of hydrogen production to the local distribution network (Speirs, et al., 2017) to facilitate the transport of hydrogen. Hydrogen will also need to overcome challenges relating to end-use applications. Hydrogen has differing properties to natural gas and it is likely that many existing appliances, e.g. gas boilers, will require modification or replacement if the gas system is to be fully given over to hydrogen. Some appliances can already accommodate up to 30% hydrogen blends, while some industrial applications will find it challenging to accept hydrogen blends above a very low level. However, considerable research is underway to develop appliances and technologies that would be 100% hydrogen-ready (Hydrogen Europe, 2019) and upgrades of equipment could follow natural replacement cycles (Hy4Heat, n.d.).

## 2.2 Hydrogen production

Hydrogen is widely used in industries as diverse as oil refining, chemicals, electronics and food production and it is estimated that the global market for hydrogen exceeds 50m tonnes per year. Hydrogen is predominantly derived from fossil fuel sources, with nearly three-quarters of production reliant on reforming of natural gas (steam methane reforming or SMR). Hydrogen produced via SMR has a carbon intensity of around 285g$CO_2$/kWh of hydrogen (Arup, 2016). CCS could be used during the production of hydrogen to reduce its carbon intensity by as much as 90%. However, when deployed at large-scale, the carbon intensity may still be too high to comply with strict decarbonisation targets, i.e. in a net zero emissions target (Committee on Climate Change, 2018).

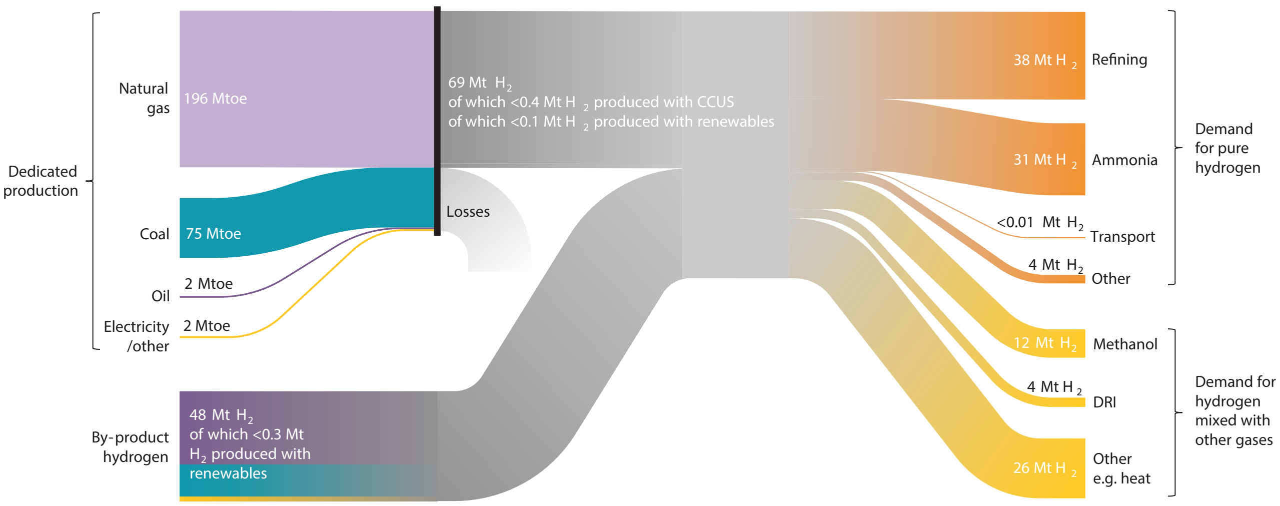



**FIGURE 3: Global hydrogen production and end-use sectors (IEA, n.d.)**

Around 2% of hydrogen is currently produced via electrolysis in a power-to-hydrogen configuration (IEA, n.d.). The characteristics of the electricity source play a large role in determining whether electrolytic hydrogen is a lower carbon solution compared to conventional energy sources. For example, in transport, hydrogen would need to have a carbon intensity below 180 $kgCO_2$/MWh to provide carbon savings compared to diesel and CNG fuelled vehicles (IEA - Renewable Energy Technology Deployment, 2016). By way of comparison, the UK grid has an average carbon intensity of 208 $kgCO_2$/MWh (Department for Business, Energy & Industrial Strategy, 2018). However, electrolytic hydrogen has the potential to deliver a fully decarbonised option, especially as grids continue to decarbonise or if renewable generation is dedicated to hydrogen production. Natural gas consumption across all sectors in the UK was over 880 TWh in 2018[2], and producing enough hydrogen to meet that demand would be challenging. Policy Exchange (2018) suggest that if hydrogen is to replace natural gas in all its current applications by 2050 in the UK, a minimum of 6GW of newly installed hydrogen production capacity would be required per year, assuming that a large-scale ramp-up commences in 2030. This would imply a sector growth rate three times greater than has been observed in the wind sector. Further, if the hydrogen were produced from renewable electricity, this implies unprecedented growth in renewable generation capacity (Committee on Climate Change, 2018).

## Potential of Hydrogen in the UK

The UK already has a hydrogen generation capacity, with an annual production of nearly 30 TWh, approximately 2% of global production[1] (Energy Research Partnership, 2016). Further, the UK gas network is well positioned to deploy hydrogen for several reasons:

- Work is underway to replace many of iron pipes to polythene pipes suitable for hydrogen transportation (Speirs, et al., 2017), (Health and Safety Executive, n.d.), (Cadent, n.d.).
- The UK's history of using 'town gas' means that there is adequate pipeline capacity for hydrogen, despite the lower calorific value[1] (Keay, 2018).
- The gas transmission network is relatively short, suggesting lower costs (Keay, 2018).

Current legislation restricts the hydrogen content in the gas network to 0.1% by volume but despite this, future energy modelling scenarios developed for the decarbonisation and transition of the energy sector out to 2050 still see hydrogen playing a significant role as an energy vector:

- CCC models hydrogen demand in the UK by 2050 between 100 and 700 TWh depending on the extent of electrification. The Net Zero scenario modelling by the CCC requires at least 270 TWh of low carbon hydrogen in 2050, with more required if hydrogen plays a significant role in heat decarbonisation.
- In the Two-Degree Scenario from the UK National Grid's 2019 **Future Energy Scenarios**, hydrogen demand is projected at 312 TWh. However, this is entirely produced from steam methane reforming with carbon capture. Conversely, in their 'Community Renewables' scenario, where hydrogen is produced solely from electrolysis, hydrogen has a much smaller demand of just over 30 TWh and exclusively for HGV transport.

In the CCC Net-zero scenario modelling, supplying hydrogen mainly from electrolysis, instead of fossil fuel sources with CCS, would increase the cost of decarbonisation significantly and require build-rates of low carbon electricity and electrolysers that could be difficult to meet. Nevertheless, electrolytic hydrogen is shown to have an important role in large scale production where electricity prices are cheap, and it could also provide value to the electricity grid that is not fully captured in whole energy system models.

[2] *Includes both energy and non-energy uses*

## 2.3 Power-to-hydrogen status

Power-to-hydrogen is frequently cited as a key element in the continuing decarbonisation of electricity and gas networks (Lambert, 2018), (IRENA, 2018), (Quarton & Samsatli, 2018).
It has the potential to increase the flexibility of the energy system, especially in the context of greater renewable energy penetration (Quarton & Samsatli, 2018), by converting “excess” electricity into hydrogen. This hydrogen can then be used directly or converted into a drop-in fuel, often referred to as power-to-x. Further, hydrogen can be used as an energy store, allowing excess generation to be used in the wider energy system at other times of day or year (Clegg & Mancarella, 2015).

Three final products are potentially available (Thomas, et al., 2016); (Eveloy & Gebreegziabher, 2018); (Dickinson, et al., 2017) from a power-to-x system depending on the production route taken (Figure 4).

1) Hydrogen through power-to-hydrogen
2) Synthetic Natural Gas (SNG) through power-to-Gas
3) Liquid fuel through power-to-liquids

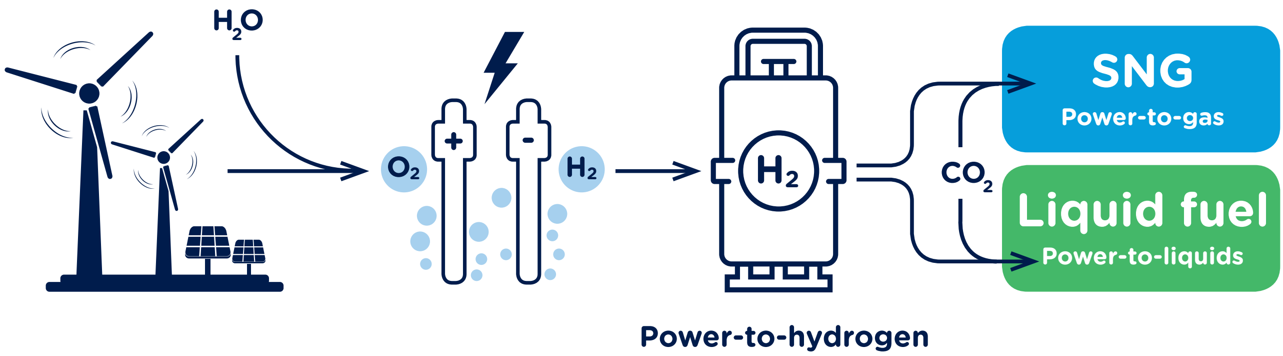



**FIGURE 4: Simplified diagram of PtX conversion routes**

Table 1 overleaf outlines the key differences between these products. Power-to-Hydrogen is the common step in all the different pathways, where electrical energy is used to split water into hydrogen and oxygen (Dickinson, et al., 2017). The hydrogen can be further processed with $CO_2$ to produce SNG or liquid fuels (Dickinson, et al., 2017).

Eveloy & Gebreegziabher (2018) conducted a review of PtX deployment scenarios in the literature and found that most scenarios model SNG as the final product. This is likely related to the drop-in nature of SNG which would not require infrastructure changes to the current natural gas system. Further, LBST (2018) suggest that SNG, despite efficiency losses, is the cheapest option, compared to hydrogen, when the required changes to downstream infrastructure, including end-use appliances, when converting to a hydrogen system are accounted for.

**TABLE 1: Overview of key differences between the different products of PtX systems**

| | Hydrogen | Synthetic Natural Gas | Synthetic liquid fuels |
|---|---|---|---|
| **Production** | Produced directly from electrolyser | Hydrogen (produced from electrolyser) is chemically combined with a $CO_2$ stream | |
| **Energy efficiency of system** | 62-87% (Maroufmashat & Fowler, 2017) | 34-63% (Maroufmashat & Fowler, 2017) | 38-63% (German Environment Agency, 2016) |
| **Additional production costs after electrolyser production** | None | Additional $CO_2$ cost + process cost/effects of efficiency loss | Additional $CO_2$ cost + process cost/effects of efficiency loss |
| **Integration into current energy systems** | Limited by current infrastructure | Considered a drop-in | Considered a drop-in |
| **Additional end-use application cost** | High if converting to an all/high-blend hydrogen system | None | None |

## 2.3.1 Current power-to-X projects

The review of literature identified projects around the globe that have been developed to enhance understanding of producing electrolytic hydrogen and how it can be utilised. As discussed, the hydrogen produced is either the final product or is used as an intermediate product in the production of synthetic natural gas or synthetic liquids fuels. A plant database was created, detailing the location, size and end product of the identified PtX plants from the literature, and a visualisation is provided in Figure 6. As this is an active field of research and new plants are being announced while other demonstration projects are finishing, the database is likely to not be fully exhaustive. However, it provides an indication of the current and future activity in the PtX environment.

A total of 337 PtX plants were identified in the literature, of which 166 are currently operating and a further 53 are planned[3]. Hydrogen is the end-product in over 80% of the identified currently operation plants, with the remaining 20% adding an additional step to produce a drop-in fuel (e.g. SNG). Further, nearly 70% of planned plants are expected to produce hydrogen as their final product. PtH plants also dominate PtG/PtL plants in terms of electrolyser installed capacity, with nearly 85% of the current and planned installed capacity. This contradicts the modelling literature which tends to focus on SNG as the end-product, as discussed above.

As Figure 6 illustrates, the plants are regionally clustered and mainly in Europe, where nearly two-thirds of worldwide operational plants are located. A further 38 plants are planned in the region, maintaining Europe's potential share of PtX plants at around 63%. Europe has over 66 MW of installed PtX capacity, with an additional 1.8GW planned. Within Europe, Germany is most active in PtX where currently there are 44 active plants with a combined installed capacity of 27 MW. A further 21 plants are at varying stages and development and have a combined announced capacity of 302 MW. This large increase in capacity is driven by two 100 MW plants: (1) Element one, which is planned for 2022 and will be producing SNG; and (2) GreenChemHydro, which will be producing hydrogen as the end-product. Figure 5 suggests that the United States will have the greatest installed capacity of PtX plants in the future. However, it is important to note that the large capacity increase is due to the announced partnership between NEL and Nikola. Together these firms are aiming to build the largest hydrogen fuelling network in the world, with a total electrolyser capacity of 1,000 MW.

[3] *The remaining plants are either completed demonstration projects, are no longer operational or have an unknown status*

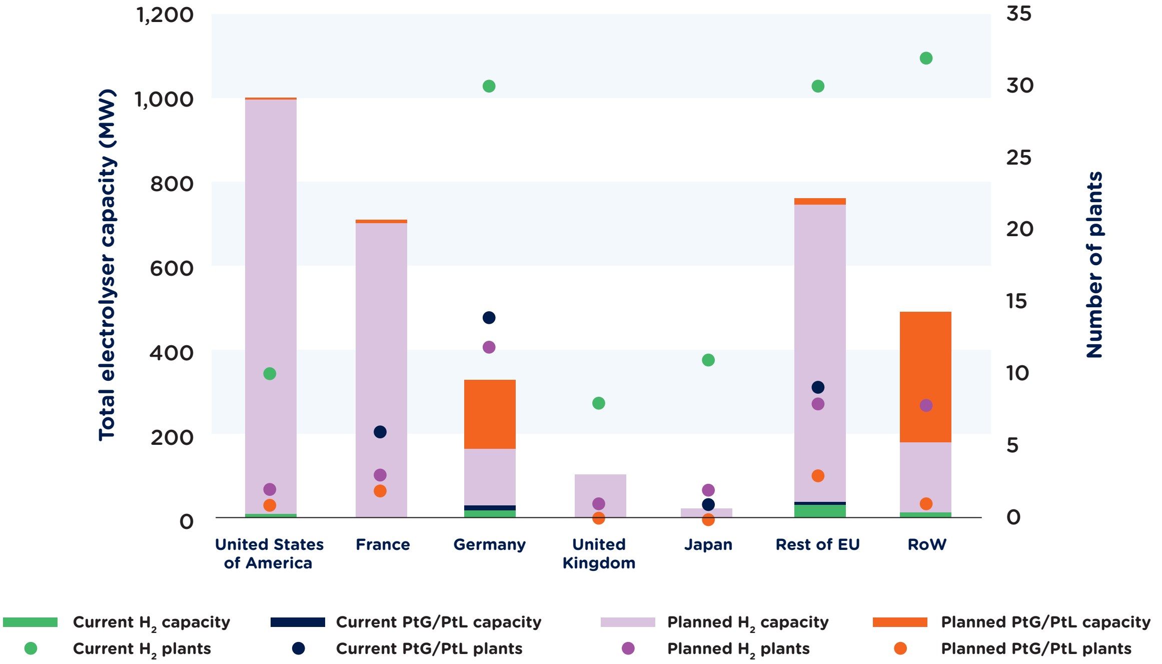



**FIGURE 5: Total electrolyser capacity and number of plants, both current and planned, by country or region**

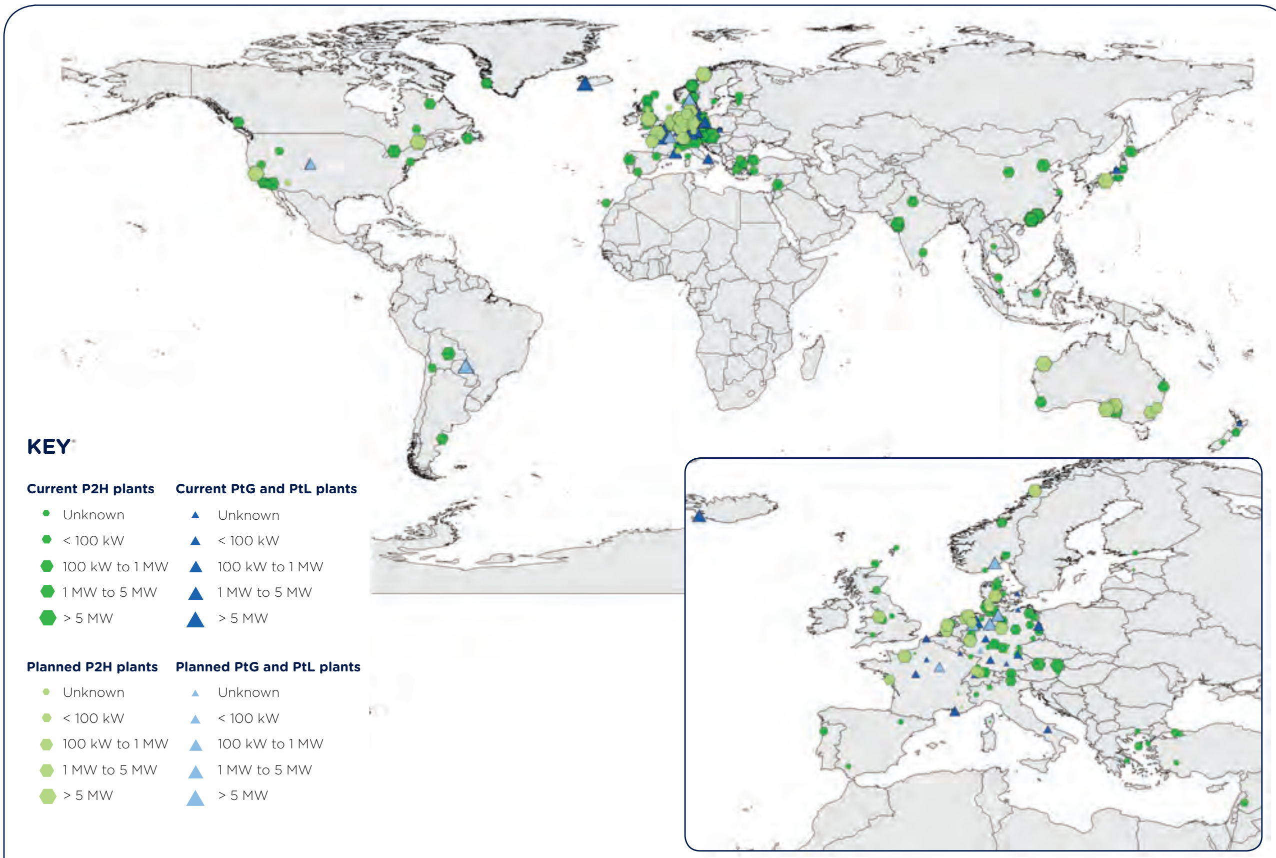



**FIGURE 6: Power-to-X project around the world, classified by product and size. Source: E4tech analysis**

# 3 MODELLING HYDROGEN PRODUCTION IN THE FIFE REGION

In this section we introduce the key assumptions affecting the economics of a power to hydrogen system, followed by a description of the model used to determine the amount of hydrogen that could be produced in Fife and the resulting economics. Our assessment involved an analysis of the likely availability of low-carbon power available from the grid or from dedicated renewables.

According to National Grid's Future Energy Scenarios (FES), significant deployment of renewable generation is expected out to 2050 in both Great Britain more generally and Fife in particular. Many renewable technologies, such as solar PV, wind power, and hydro run-of-the-river have intrinsically variable power generation patterns. These variable technologies pose known challenges to power systems and networks, namely their inherent inflexibility, and it is likely that at times at significant renewable generation, there is not enough demand, leading to power surpluses on the grid. These power surpluses could be used to produce hydrogen.

## 3.1 Key assumptions affecting economics of power-to-hydrogen

We performed a detailed literature review to identify key assumptions, parameters and approaches relevant to estimating the economic viability of a power-to-hydrogen (PtH) system. Evidence was collected from multiple sources including Google, Scopus and internal documents. An initial list of 160 pieces of relevant literature was compiled in a database, which was further scoped down to 102 references to examine in greater detail. We identified two key assumptions which are generally agreed to have the greatest impact on business case of a PtH system: the source electricity used to produce the hydrogen and the end-use market for the hydrogen. These are discussed in greater detail in the sections to follow.

### 3.1.1 Key assumption: Electricity used for hydrogen production

If hydrogen is to be used to achieve decarbonisation targets, then any PtH configuration needs to draw power from low-carbon sources (IEA - Renewable Energy Technology Deployment, 2016). Most previous modelling work has been based on the assumption that electricity supplying the electrolyser is from wind and solar sources. However, some also include power sources, such as hydro, biomass and nuclear power (Eveloy & Gebreegziabher, 2018) which may be more appropriate in certain jurisdictions.

A review of the literature by the IEA – Renewable Energy Technology Deployment (2016) – found that most studies further assume that the renewable power used to produce hydrogen is from curtailed sources rather than from dedicated plants. However, the Committee on Climate Change (Committee on Climate Change, 2018) argues that it is unrealistic to assume that curtailed generation alone would be sufficient to provide the amount of hydrogen necessary to meet demand from multiple sectors. Policy Exchange (Policy Exchange, 2018) estimates that in 2017 about 1.5TWh of wind electricity in the UK was curtailed, which if turned into hydrogen would replace less than 0.5% of domestic natural gas consumption. This supports the view that curtailed electricity will be insufficient to produce the volumes required to decarbonise gas grids and, in any case, no mechanism currently exists for accessing the curtailed power.

It has also been argued that using curtailed electricity may not be operationally economic or feasible for the electrolyser. Policy Exchange (2018) and EY, LBST & BBH (2013) argue that to produce cost competitive hydrogen, requires electrolysers to be operated with high utilisation rates and that this cannot be guaranteed by solely using curtailed renewables.

LBST & Hinicio (2015) further point out that transmission grid constraints and local distribution level bottlenecks may further interfere with the amount of excess renewable electricity that is available locally to a specific electrolyser or specific region of hydrogen production, exacerbating the issue of poor utilisation. Aside from the question of utilisation, using curtailed renewable electricity could pose issues with system performance. Alkaline electrolysers in particular, are unable to cope effectively with large variations in load owing to slow ramp up and frequent load variation may reduce system lifetime.

In an energy system with greater renewable penetration there may be larger and longer curtailments, increasing utilisation and reducing output variability of the electrolyser. (LBST, 2018) has gone on to argue that the benefits of providing flexibility services may outweigh the costs of not running an electrolyser at more constant load. It should also be noted that polymer electrolyte membrane (PEM) electrolysers are more responsive and may be able to cope better with fluctuations in supply.

The final cost of hydrogen is critically influenced by the total cost of the electricity used to produce it taking into account grid fees and taxes (Lambert, 2018), (Tractebel Engie and Hinicio, n.d.). This in part explains why some economic models favour the use of excess electricity for hydrogen production, as it is seen as a cheap, often free, source of electricity (Policy Exchange, 2018). This assumption improves the economics of hydrogen production (even where utilisation rates are poor), but may be optimistic. Renewable energy generators which currently receive compensation payments in exchange for curtailing output when there is excess supply (Tractebel Engie and Hinicio, n.d.) may not be prepared to sell potentially curtailed power at low cost. Tractabel et al (Tractebel Engie and Hinicio, n.d.) assume a price of curtailed electricity at 40% of the market price in their study and conclude that hydrogen production can still be profitable under certain conditions. They further conclude that to build a profitable business case for hydrogen, the baseload electricity price (including taxes and fees) would need to be less than €50/kWh (Tractebel Engie and Hinicio, n.d.).

In order to address the issue of market mechanism, Hinicio & LBST (2016) suggest an approach, whereby an electrolyser operator could enter into a take-or-pay agreements with renewable power generators. In this scenario, the electrolyser only consumes electricity when the spot price for electricity is below an agreed threshold (they estimate that a strike price of €26/MWh would achieve a breakeven point by year 10). The authors argue that this would be favourable both to the renewable electricity generator which can ensure all its production is sold (i.e. not forced to curtail) and the electrolyser which keeps both cost and utilisation at a reasonable level.

The assumptions made with regard to the fees and taxes to be included in the electricity price is also identified as a key determinant of green hydrogen cost. A number of studies (Robinius, et al., 2017), (Tractebel Engie and Hinicio, n.d.), (EY, LBST and BBH, 2013) have argued that exemptions from fees and taxes are necessary to improve the economics of power-to-x. For example, Robinus et al (Robinius, et al., 2017) estimate that hydrogen could be cost-competitive with gasoline as a transport fuel by 2030 if electricity for hydrogen production was tax exempt; this would not be achievable until 2050 if no tax exemption is granted. Others (Tractebel Engie and Hinicio, n.d.) make the assertion that exemptions are justified as the electrolysers are providing benefits to the electricity grid.

*Surplus power from onshore wind farms could be used to generate hydrogen.*

### 3.1.2 Key assumption: Highest value end-use application for hydrogen

The literature converges on three potential markets that offer the highest value end-use application for hydrogen: transport, injection into the natural gas grid and power generation (Robinius, et al., 2017). Many studies define highest value based solely on economics, i.e. which applications offer the highest returns while others take account of a wider set of assessment criteria. The Committee on Climate Change (2018), for example, defines highest value applications as applications where there are few other decarbonisation options, such as heat provision for industrial applications.

#### 3.1.2.1 Hydrogen for transportation

European Power to Gas (n.d.) argues that developing the hydrogen market for transport is key to commercialising power-to-hydrogen although they make the caveat that there is not currently a business case for many power-to-x applications. Green mobility offers a promising market for power-to-x and could be the primary application to encourage large-scale deployment of the technology (Enea Consulting, 2016), (Tractebel Engie and Hinicio, n.d.). For example, hydrogen produced from renewable power could be used in refineries to produce less carbon intensive transportation fuels, offering a short-term option for transport decarbonisation (Robinius, et al., 2017). In some instances, the hydrogen to fuel pathway is already cost competitive with other low-carbon fuels, though it is not yet cost competitive with traditional fossil fuels (Robinius, et al., 2017).

The IEA has investigated hydrogen in transport with a focus on the highest value application in non-individual[4] transportation modes. Non-individual vehicles includes mass transit vehicles such as buses and coaches, commercial vehicles such as vans and small van fleets, goods logistics vehicles from local delivery to long-haul trucks and vocational vehicles such as refuse or cement trucks. They argue that concentrating deployment on collective or commercial transport applications could reduce infrastructure requirements as transport patterns tend to be more predictable compared to individual transportation modes. Their research concludes that long range, light-duty vehicles are the most promising transportation segment to initially adopt hydrogen produced by electrolysis. In the longer term, power-to-x may provide a viable low-carbon alternative for heavy-duty vehicles but will likely require policy intervention to help bridge the TCO gap between incumbent diesel and hydrogen heavy-duty vehicles. The IEA stresses that hydrogen is best suited for long range applications, while short range will be dominated by battery powered vehicles (IEA - Renewable Energy Technology Deployment, 2016). European Power to Gas (n.d.) points out that if all EU states achieve their hydrogen mobility targets by 2030 and if all the required hydrogen was supplied by electrolysis, this would result in significant electrolyser demand. This, in turn, could result in a meaningful decrease in capital costs, improving the business cases for other applications.

#### 3.1.2.2 Hydrogen as an energy vector for the gas and power systems

Much of the literature reviewed has stressed the valuable role that hydrogen can play for power and gas systems. Injection into the grid is cited as a possible market for hydrogen, making use of the already well-developed infrastructure network and providing a ready market for the hydrogen as the technology for hydrogen production continues to develop. It is recognised that hydrogen can play a significant part in the decarbonisation of the gas grid, prolonging the life of network assets and allowing them a continuing place in a decarbonised economy (European Power to Gas, n.d.). One challenge presented by injection into the gas grid is that as the proportion of hydrogen increases so the energy storage capacity decreases, owing to the lower energy density of hydrogen compared with natural gas (Hydrogen Strategy Group, 2018).

[4] *IEA – Renewable Energy Technology Deployment, 2016*

This has led some to speculate that hydrogen may be more commonly considered as a feedstock to produce synthetic natural gas, which can then be injected without blend limits (Vandewalle, et al., 2015).

As renewable penetration in the electricity grid continues to rise, greater flexibility will be required to maintain the integrity of the system and hydrogen has the ability to deliver flexibility in several ways. Hydrogen can be used as surplus energy storage (European Power to Gas, n.d.) (Policy Exchange, 2018) (LBST, 2018), generating electricity from the stored hydrogen when electricity demand is high and replenishing stores when there is excess generation from sources such as wind and solar (Vandewalle, et al., 2015).

While some have pointed to the benefits of hydrogen for short term storage, others argue that batteries and pumped-hydro are better suited to this role and that hydrogen's value is in providing long-term (e.g. seasonal) storage (Lambert, 2018), (European Power to Gas, n.d.). Tractebel Engie and Hinicio (n.d.) argue that storing and re-electrifying renewables through hydrogen will likely be reserved for niche applications and not make up a large portion of the market for hydrogen produced from power. ECN & DNV L (2014) also acknowledges hydrogen's ability to provide storage to the electricity grid but concludes other options have lower societal costs.

Conversely, DLR, ifeu, LBST & DBFZ (2014) suggest that hydrogen and methane chemical energy storage are the only options that have the potential to provide the required energy storage (and re-electrification) given the projected high shares of renewables on the grid. Power-to-x can also defer or replace the need for electricity network upgrades, providing value to areas with high curtailment of generating assets (Advisian, Siemens & Acil Allen, 2017).

Hydrogen can also be used to generate dispatchable low-carbon power counterbalancing the increasing quantities of intermittent, low inertia power generation capacity from wind and solar. Hydrogen production through electrolysis can also provide ancillary services to the electricity grid such as frequency response by balancing supply and demand through varying load as discussed in Section 3.1.2.3.

Policy Exchange estimates that for every MW of electrolyser capacity installed, 150MWh of hydrogen per annum could be generated from intermittent sources (Policy Exchange, 2018). Based on savings in the Levy Control Framework and Contracts for Difference as well as the provision of an additional 150 MWh/year of low-carbon generation, this is calculated to represent an economic benefit of £70,000 per year for every additional MW of hydrogen production capacity.

### 3.1.2.3 Stacking hydrogen services

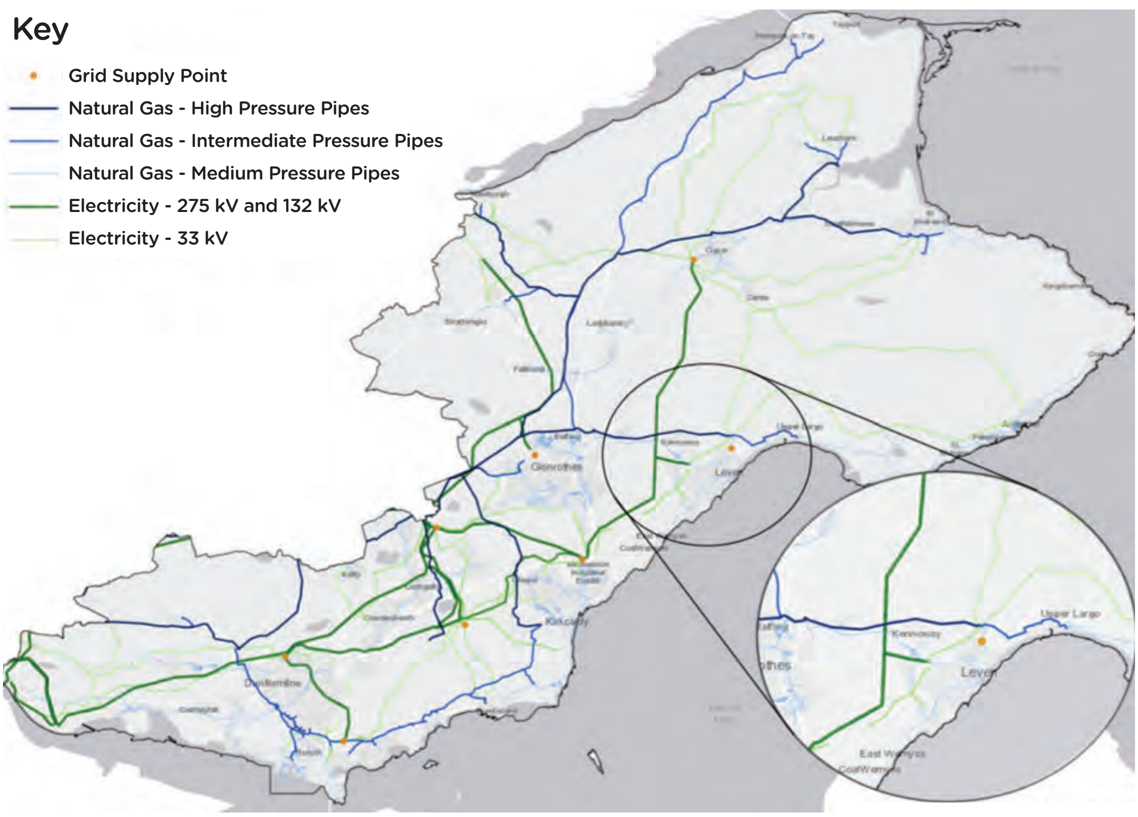
Several studies point to the fact that the high value applications identified in Sections 3.1.2.1 and 3.1.2.2 do not necessarily generate a positive business case for power-to-x alone. Combining multiple revenue streams is often cited as a key condition for economic balance and financial risk management, especially as high value markets are still developing (Tractebel Engie and Hinicio, n.d.), (Policy Exchange, 2018), (Hinicio and LBST, 2016), (Roland Berger, 2018). For example, many suggest that on top of providing hydrogen to a main market (e.g. transportation), other secondary services, such as provision of frequency support to the power system (Tractebel Engie and Hinicio, n.d.) or direct injection into the gas network, can improve the economics of a power-to-x installation (Tractebel Engie and Hinicio, n.d.), (Hinicio and LBST, 2016). In their market model for water electrolysis, Lemke et al. (2015) point to the transport market being served first ahead of the industrial sector and gas grid injection (Lemke, et al., 2015) but recognise the potential to supply multiple markets.

Tractebel, Engie & Hinicio (n.d.) argue that in some cases power-to-x may still be profitable without stacking, but that the payback period is much longer. However, their modelling suggests that the most attractive business case for power-to-x arises from mobility and industry applications of hydrogen complemented by injections into the gas grid. Interestingly, Tractebel, Engie & Hinicio (n.d.) further state that revenues from primary applications of hydrogen (e.g. industry and mobility applications) are at least an order of magnitude higher than those of secondary applications (e.g. gas grid injection and power grid services). However, the additional revenues from these secondary applications usually make up most of the margin (up to 85%), enabling in many cases a profitable business case to be achieved. They therefore conclude that once an electrolyser has been deployed the additional cost of producing these secondary services are low when compared to their potential revenue.

## 3.2 Gas and electricity network configuration

Figure 7 shows the physical location of gas and electricity networks in the Fife region identified by pressure and voltage respectively. High and intermediate pressure pipelines extend as far as Leven in the south of the region and St Andrews in the north. The East Neuk more generally is relatively under-served by higher pressure pipeline network, reflecting the relatively small population, although a medium pressure line exists running between the southwestern coastal towns and villages. Meanwhile, the electricity transmission network also extends as far as Leven in the south but reaches only as far as Cupar in the north. Otherwise the region largely lacks high voltage, high capacity network in the East Neuk. The presence of both significant gas and power capacity at Leven singles it out as being attractive for locating an electrolyser for delivering power-to-gas.

**FIGURE 7: Physical representation of gas and electricity networks in Fife**




## 3.3 Power to hydrogen model description

As discussed in Section 3.1, the source of electricity used to produce hydrogen and the ultimate end-use for that hydrogen will have a significant impact on the overall economics of a PtH system. Therefore, for this assessment various permutations of both electricity generation and hydrogen end-uses were investigated.

The following sections describe in greater detail the model used to assess a PtH system in Fife. It further outlines the key assumptions made.

### 3.3.1 Sources of power and uses of hydrogen

Three sources of electricity were modelled to determine the potential volumes of hydrogen that could be produced and at what cost. These sources were:

1) curtailed renewables;
2) grid electricity; and
3) dedicated renewable generation.

The characteristics of each source if discussed in Table 2. In all these cases, the electrolyser must be sufficiently flexible to capture the most value from the variable electricity production.

**TABLE 2: Sources of power - Analysis of pros and cons**

| | Sources of electricity | | |
|---|---|---|---|
| | **Curtailed renewables** | **Grid electricity** | **Dedicated renewables** |
| **Description** | Electrolyser is directly connected to the grid<br><br>Functions only when there are power surpluses on the grid | Electrolyser is directly connected to the grid<br><br>Functions only when price of electricity is low, reflecting marginal renewables or nuclear generation | Electrolyser is directly connected to renewable generation<br><br>Follows the renewable generation pattern |
| **Advantages** | No additional investment<br><br>Use of normally curtailed generation | No additional investment<br><br>Could produce large volume of hydrogen | Assured 100% renewable hydrogen<br><br>Could produce large volume of hydrogen |
| **Disadvantage** | Likely low volumes of hydrogen produced due to limited curtailment | Difficilty in tracing source of electricity consumed by electrolyser | High fixed costs to cover additional investment of dedicated renewable generation |

**Two potential end-use applications are modelled for the hydrogen produced.**

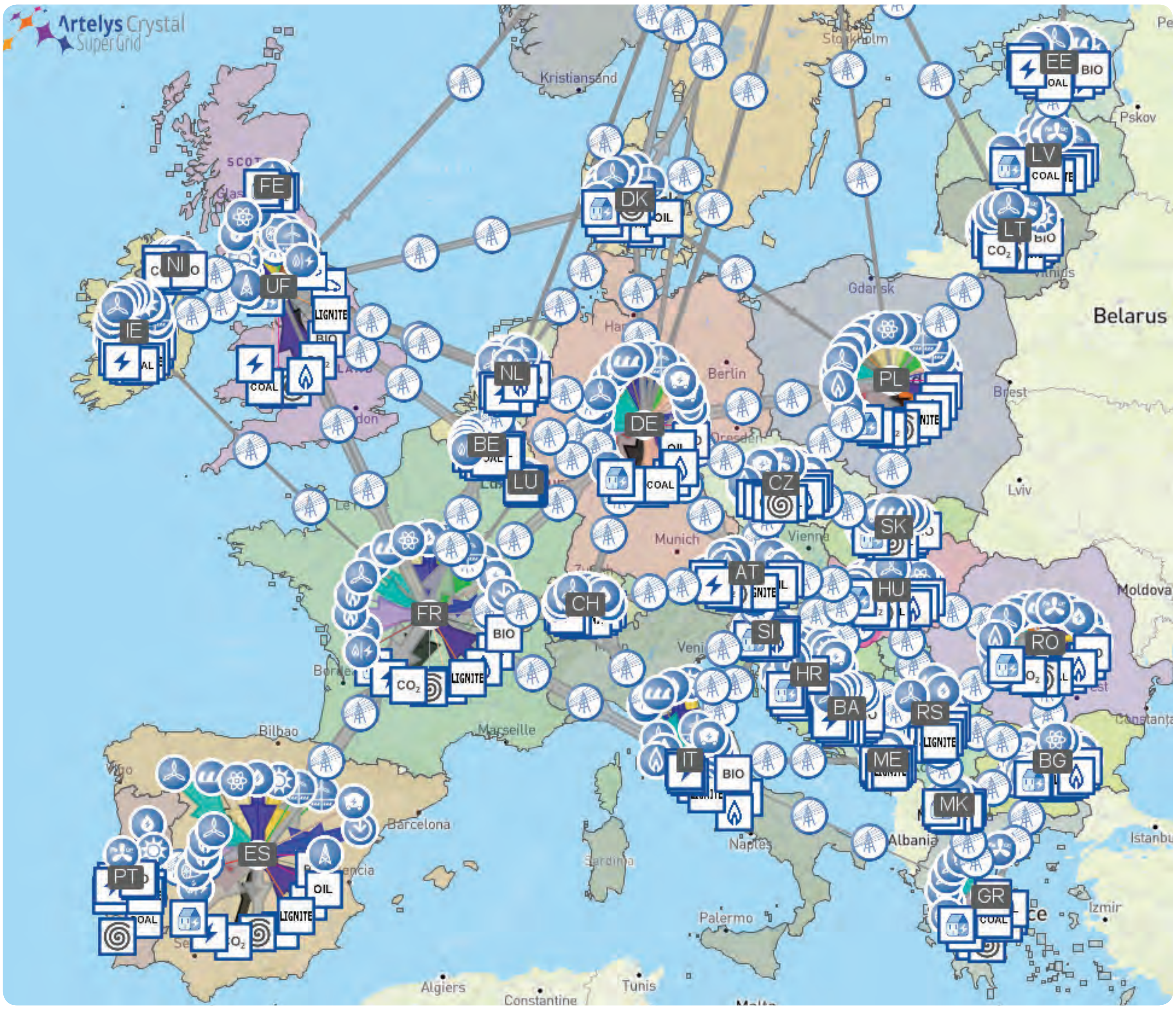
**1)** Injection into the natural gas grid: As discussed hydrogen can contribute to the decarbonisation of the gas sector through direct injection into the current natural gas grid. The hydrogen is blended into the grid, sold at the gas price, and the blend is directly used in standard gas appliances. Blend limits are usually in place to maintain the integrity of the gas network and ensure proper and safe functionality of end-use appliances.

**2)** Direct use: Hydrogen can also be used directly in mobility or in a dedicated hydrogen grid to fulfil heating needs which are conventionally supplied by natural gas.

## 3.3.2 Method: Quantifying availability of electricity for hydrogen production

A power system model was built in Artelys Crystal Super Grid (ACGS)[5], in which each area is represented as a single grid node. At each node, consumers, storage providers and producers exchange energy (e.g. power, hydrogen, fuels) and, where necessary and feasible, exported to or imported from adjacent nodes. This is illustrated in Figure 8.

**FIGURE 8: The European power system model in ACSG**

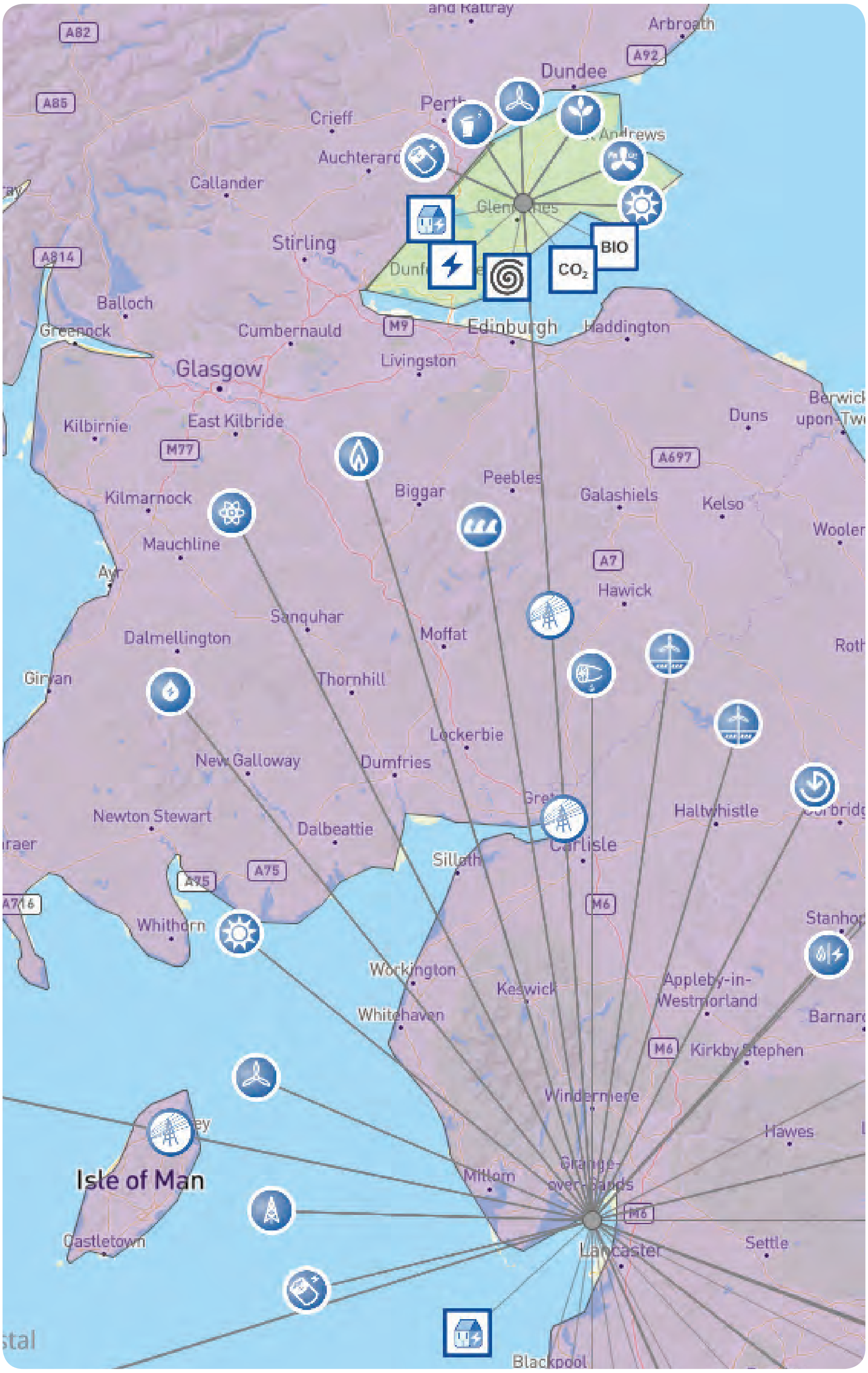



The Fife region is modelled as a single node, with the rest of GB as separate node. Further, European countries are each modelled as additional nodes. The interconnections between Fife and GB (and other European countries) are modelled based off Net Transfer Capacities and based on grid lines connecting neighbouring nodes. As Fife is represented as a single node, the internal distribution network is not modelled explicitly.[6] Therefore, curtailment at the Fife distribution level is not considered in this study.

[5] *https://www.artelys.com/crystal/super-grid/*

[6] *This is because relevant data could not be sourced at a smaller granularity than the Fife region.*

**FIGURE 9: Fife and Rest of GB nodes as modelled in ACSG**



The model simulates the entire power system across an entire year with an hourly time resolution. It aims to mimic the actual behaviour of operators, seeking to minimise variable costs through least cost generation dispatch. These simulations assess potential power surpluses (or shortfalls in Fife and in the rest of the UK in 2020 and 2040. These surpluses are subsequently translated into hydrogen generation potential.

For each time-horizon assessed, the model structure has been populated with data pertaining to projected demand, generation by type, storage, net transfer capacities (NTC) between nodes and fuel prices. The sources for data is set out in Table 3. To ensure the robustness of the results, three different weather scenarios were modelled for the 2040 time horizon. These weather scenarios affect both the quantity of renewable generation produced (wind speeds and sunshine hours) and consumption profiles (temperature).

**TABLE 3: Main data sources**

| | 2020 | 2040 |
|---|---|---|
| **Installed capacities in Fife (distribution grid)** | Renewable Energy Foundation (REF) | GSP level data from the FES 2018 – Two Degrees pathway |
| **Grid Supply Points** | CUPA, LEVE, REDH, GLRO, WFIE, GLNI, DUNF and INKE | |
| **Installed capacities in the rest of GB** | FES 2018 – Two Degrees pathway | |
| **NTC between Fife distribution grid and the GB power system** | SPEN - 632 MW | |
| **Generation by technology (except for wind and solar)** | Assumptions on the average load factor are taken from REF historical data for distribution-connected capacities in Fife and from FES 2018 – Two Degrees pathway for other capacities. | |
| **Wind and solar load factors** | Generation profiles tailored to local wind and solar conditions | |
| **Load factors for other « must-run » generation** | REF for distribution-connected capacities in Fife<br>FES generation for other capacities | |
| **Consumption profiles** | Artelys database, relying on ENTSO-E TYNDP 2018 | |
| **Consumption volumes in Fife** | Sub-national electricity and gas consumption summary report 2017, National statistics | |
| **Consumption volumes in the rest of GB** | FES 2018 – Two Degrees pathway | |
| **Rest of Europe** | Artelys database, relying on ENTSO-E TYNDP 2018 | |
| **Fuel costs** | FES 2018 – Two Degrees pathway when available<br>TYNDP 2018 for biomass and lignite | |
| **Electric Vehicles flexible demand pattern and V2G appliance** | None | Artelys database, relying on previous works for the European Commission |

The modelling relies extensively on National Grid's Future Energy Scenarios (FES) Two Degree scenario, which provides projections at GSP level for several key metrics, e.g. deployment of electric vehicles and capacities for distributed renewable energy sources (Figure 10 and Figure 11).

Fife power demand in 2040 is derived from the GB demand projection contained in the FES demand projections. It further assumes that Fife maintains the same share of GB power demand in 2020 and 2040 – i.e. 0.5% of total GB power demand. This suggests Fife's power demand increases from 1.6 TWh/y to 1.8 TWh/y in 2040, while demand for the rest of GB goes from 292 TWh/y to 343 TWh/y.

The generation profiles for each technology have been scaled to match FES generation projections. For most technologies, generation profiles are explicitly modelled. However, since no significant generation pattern is observed for must-run technologies (other than wind and solar), they are assumed to have a flat generation profile, scaled according to REF records. Load factors used for 2020 are maintained for 2040 projections, implicitly assuming that the weather conditions and operating remain broadly similar.

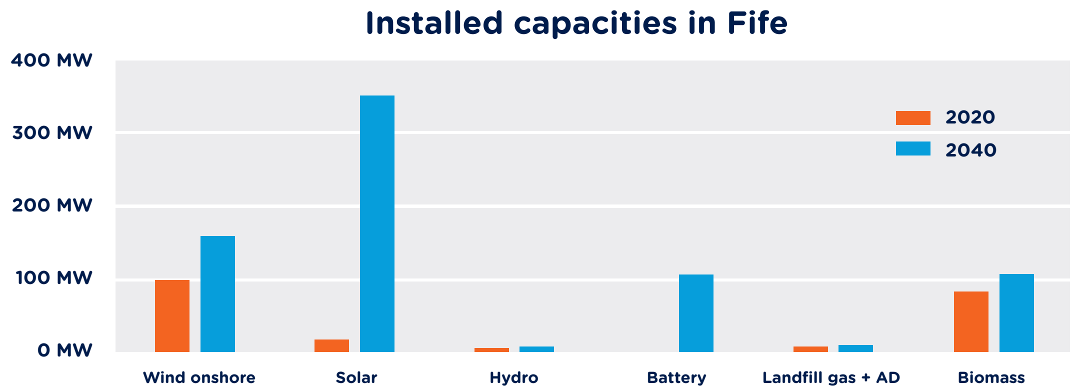



**FIGURE 10: Generation capacity mix for Fife**

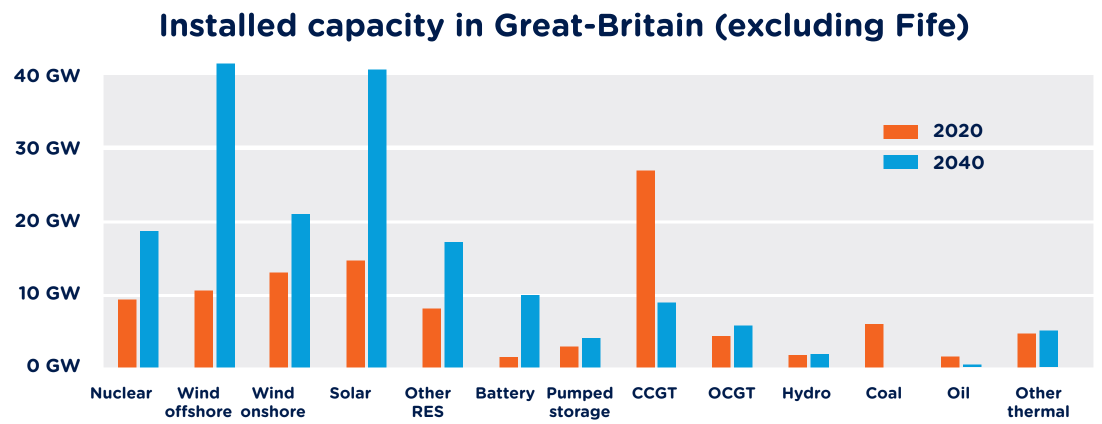



**FIGURE 11: Generation capacity mix for Great Britain**

The Fife area benefits from strong and relatively stable wind patterns, which are favourable to wind turbine deployment. Hydrogen production from a dedicated wind energy source is also considered through a putative windfarm with similar characteristics to the Neart na Gaoithe project[7] in the Firth of Forth. The potential electricity generation and the hydrogen production profile are also modelled in ACGS. Since the analysis is made from the perspective of co-owned and co-located wind farm and electrolyser assets the wind farm is dedicated entirely to hydrogen production and is not connected to the electricity grid. Any electricity surplus not captured by the electrolyser would be curtailed in this scenario.

[7] *450 MW wind farm made up of wind turbines with 130m hub heights.*

## 3.4 Method: Assessing end-use applications of hydrogen

The hydrogen produced can be used in several end-use applications, such as being blended into the current natural gas grid or being used directly for mobility or in a dedicated hydrogen grid. These end-use applications are explicitly added into the model to determine optimal electrolyser sizing and operation, as well as potential storage needs. The end uses are described in more detail in Table 4.

**TABLE 4: Description of hydrogen end-uses**

| | Hydrogen uses | | |
|---|---|---|---|
| | **Gas grid injection** | **Mobility** | **Dedicated $H_2$ grid** |
| **Description** | • Produced hydrogen is directly injected into the grid<br>• Hydrogen blending limitedby regulation | • Used in fuel cell vehicles<br>• Requires refuelling station | • Hydrogen replaces natural gas for all uses<br>• Appliances must be retrofitted or replaced |
| **Scale** | • Blending occurring in the whole region of Fife | • Covering mobility of Fife Council owned vehicles and local buses - approx 2,000 vehicles, requiring 6.5 kt of hydrogen | • Converting the KY8 postcode to a dedicated hydrogen grid, requiring 530 GWh (15.4 kt) of hydrogen to cover all needs currently covered by natural gas. |

## 3.5 Power to hydrogen scenario descriptions

In this study, the potential of PtH deployment in Fife is investigated through several potential scenarios, addressing both several options for electricity source for hydrogen generation and several options for potential end-uses for the hydrogen. The scenarios represent different combinations of the electricity generation and hydrogen end-use cases described in Section 3.2. The scenarios are illustrated in Figure 12.

For each of these scenarios, generation and consumption was calculated at each hourly time step, taking into account the cost and storage requirements in order to determine the optimal configurations.

Table 5 outlines the techno-economic assumptions used in all the scenarios. Hydrogen produced from steam methane reforming (SMR) is used as a benchmark (counterfactual) to which the cost of hydrogen in each scenario is compared. The additional costs of storage has not been included in the cost estimates for hydrogen as this introduces significant complexity to the optimisation model. However, the costs of storage are explored ex-post.

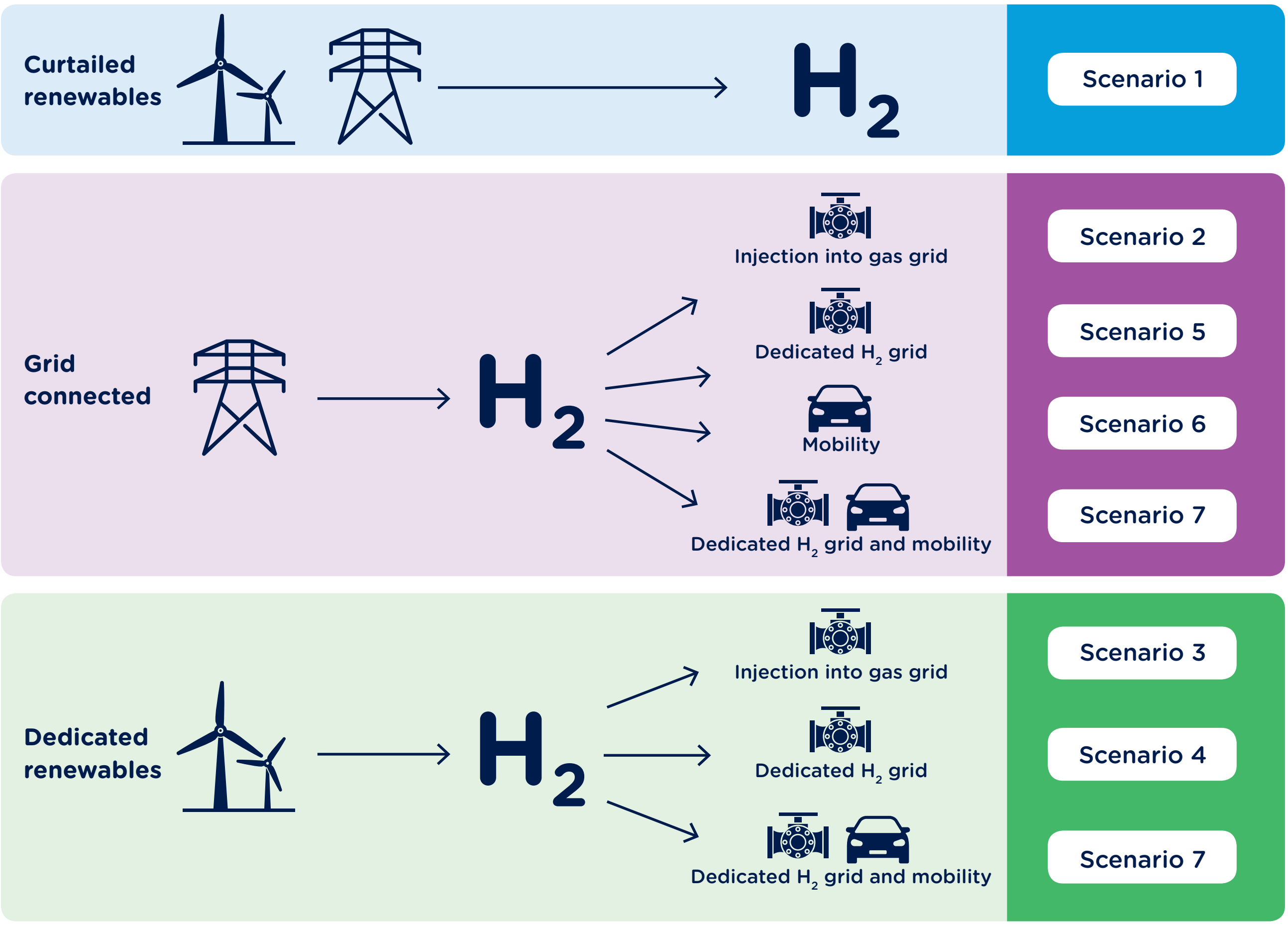



FIGURE 12: Schematic of scenarios considered in this study

TABLE 5: Techno-economic assumption for hydrogen generation in 2040

| | Electrolyser | SMR |
|---|---|---|
| **Yearly investment costs** | 39 k£/MW/yr (i.e. 400 £/kW) | 263 k£/MW/yr |
| **Fixed operation and maintenance costs** | 16 k£/MW/yr | 66k£/MW/yr |
| **Efficiency** | 69% | 76% |

For wind farms, the investment cost of 2200 €/kW was used, based on data from the Joint Research Centre of the European Commission.

# 4 HYDROGEN PRODUCTION POTENTIAL IN FIFE

## 4.1 Scenario 1: Hydrogen production from curtailed electricity in Fife

- Supply and demand modelling for the Fife region suggests that it is unlikely that there will be any electricity surplus in 2020 and limited surplus in 2040 (about 15 GWh). This is predominantly linked to the 600 MW Net Transfer Capacity (NTC) between Fife and the rest of the UK.
- The modelled surplus electricity, however, does not reflect potential surpluses due to local grid congestions in the Fife distribution grid.
- The model further projects over 2TWh of low price, low carbon electricity surplus in GB in 2040, which could be used in an electrolyser.

### 4.1.1 Generation mix projections for 2020 and 2040

As modelled, the 2020 generation mix in Fife will be highly reliant on onshore wind and biomass, compared to the GB system which is balanced between nuclear, renewables, gas and coal (Figure 13). By 2040, the generation mix diversifies in Fife, but continues to rely extensively on low-carbon power generation. Interestingly, the FES Two Degree pathway forecasts strong growth in solar generation for the region (Figure 14). Nationally, a strong deployment in offshore wind is projected to occur as well as an increase in nuclear capacity.

FIGURE 13: Generation mixes as modelled in ACSG for the horizon 2020

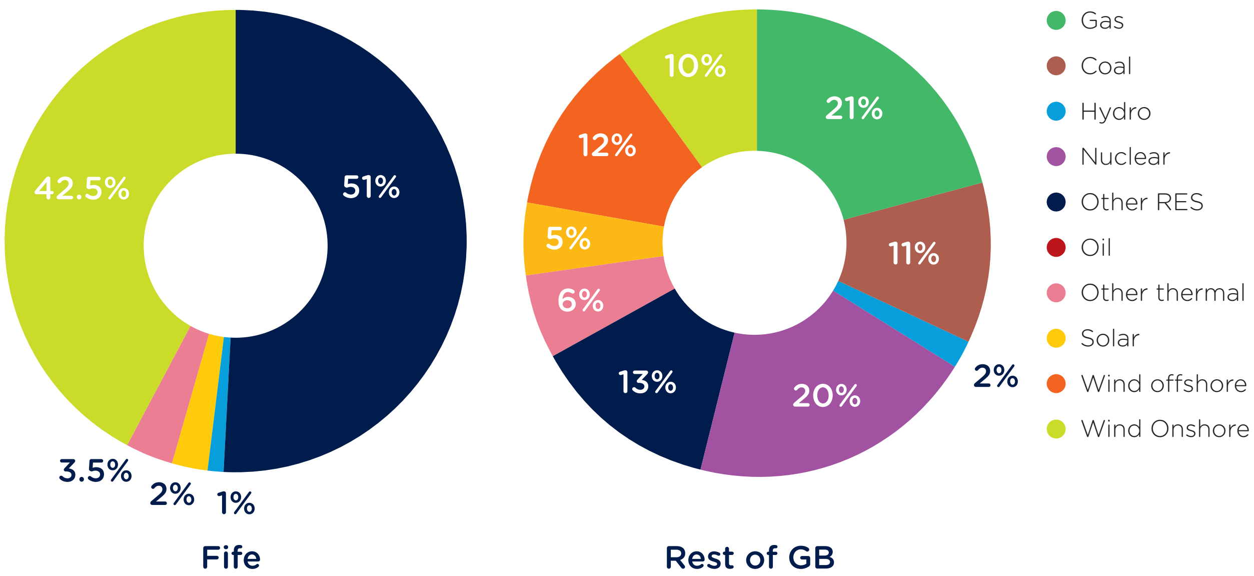
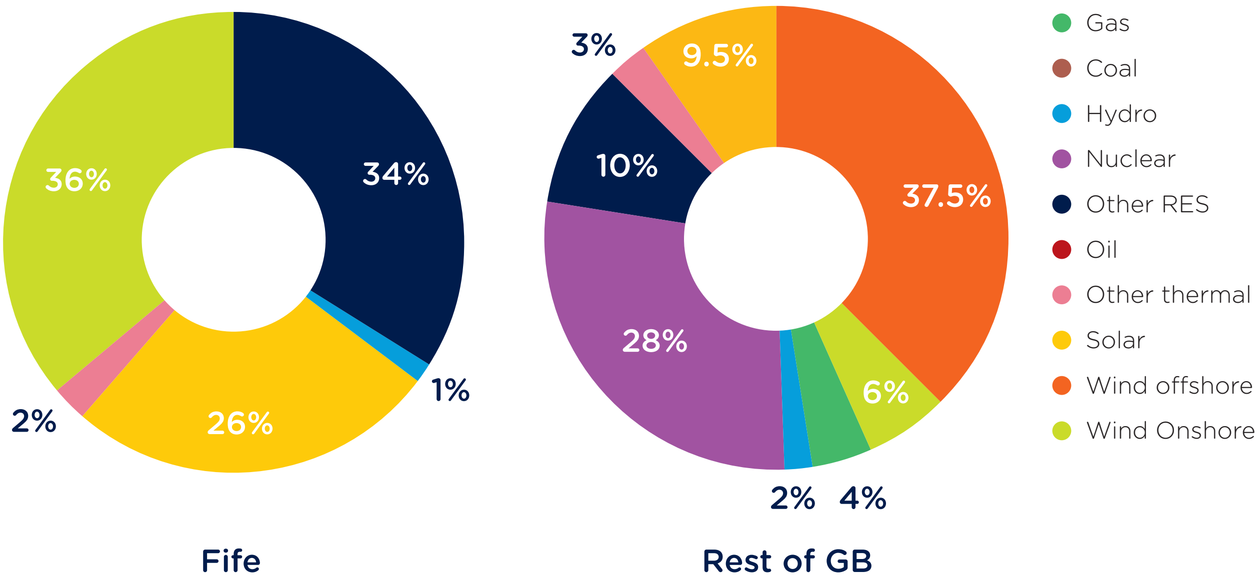


**FIGURE 14: Generation mixes as modelled in ACSG for the horizon 2040**




## 4.1.2 Hydrogen production from curtailed electricity in 2020 and 2040

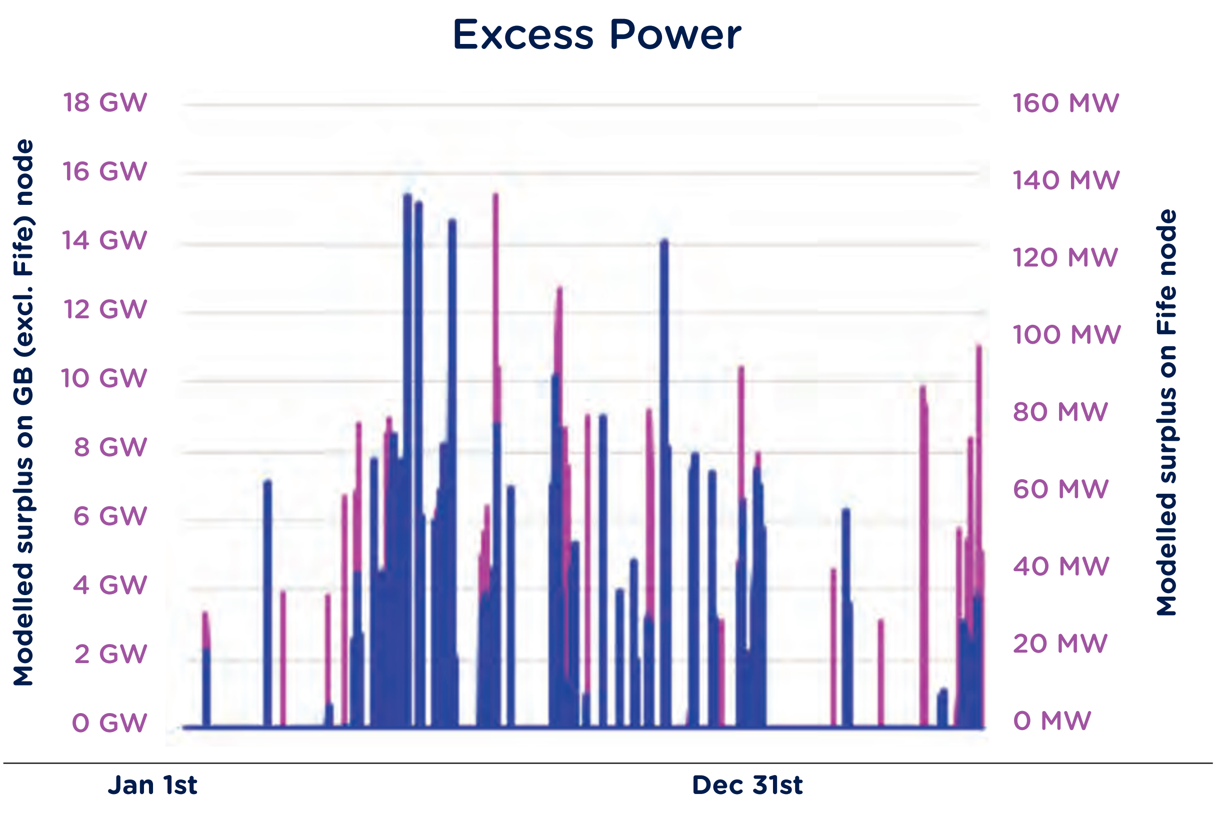
In 2020, Fife is projected to be highly dependent on the rest of GB to supply its electricity needs, with over half of the region's energy consumption being supplied from the Rest of GB node. Further, the comparatively low generation volumes never exceed the 632 MW Net Transfer Capacity between Fife and the rest of GB. Consequently, no curtailment is projected in Fife in the 2020 model. However, in 2040, the model projects 15 GWh of curtailment in the Fife region, which is equivalent to about 3% of local solar and wind generation.

**TABLE 6: Main power system figures for Fife**

| GWh | Fife 2020 | Fife 2040 | Growth (%) |
|---|---|---|---|
| **Annual generation** | 730 | 1,390 | + 90% |
| **Annual demand** | 1,560 | 1,850 | + 19% |
| **Net imports** | 830 | 460 | - 45% |
| **Curtailment at node level** | 0 | 15 | NA |

Figure 15 shows curtailment profiles in Fife and GB, for the modelled year 2040. Curtailment periods are correlated in the two areas due to the similar RES generation profiles, determined by the close geographic proximity, and demand patterns, in part owing to the way Fife demand is calculated. In consequence, when one region is experiencing high generation and low demand, it is likely that the same phenomenon is occurring in the other region. This points to the curtailment observed in Fife being due not to transmission network constraints but rather to wholesale market behaviour. Because periods of excess generation or generation shortfall are coincident, no energy transfer is required between the

**FIGURE 15: Curtailed electricity time-series in 2040, in Fife and in GB (excluding Fife)**




Curtailed generation in Fife is unlikely to deliver enough low-cost hydrogen to meet its heat and/or transport demand in the region; the annual gas demand in the East Neuk alone exceeds 400 GWh. However, it is important to note that the curtailment resultant from the modelling does not account for any local congestion that may be occurring on the distribution network within the Fife region.

Interestingly, in terms of the business case for hydrogen, curtailment in the rest of GB features high surplus peaks, reflecting significant amounts of low-carbon, low-carbon power, estimated at nearly 2.5 TWh of curtailed power in 2040. This surplus, mainly from RES and nuclear, offers an opportunity for the deployment of grid-connected electrolysers to convert this cheap and low-carbon electricity source into hydrogen.

## 4.2 Scenario 2: Hydrogen production from a grid connected electrolyser for injection into gas grid

**Scenario 2: Main Findings**

- The simulations performed show that grid-connected electrolysis for hydrogen injection into the gas grid is close to profitability.
- Given the high number of hours of cheap electricity in the scenario considered, only a limited amount of support would help access to a large and robust to weather variations volume of hydrogen.
- However, the development of electrolysis depends on the evolution of the generation mix in GB and of competitors in other areas (other P2G capacities or other type of electric flexibility).

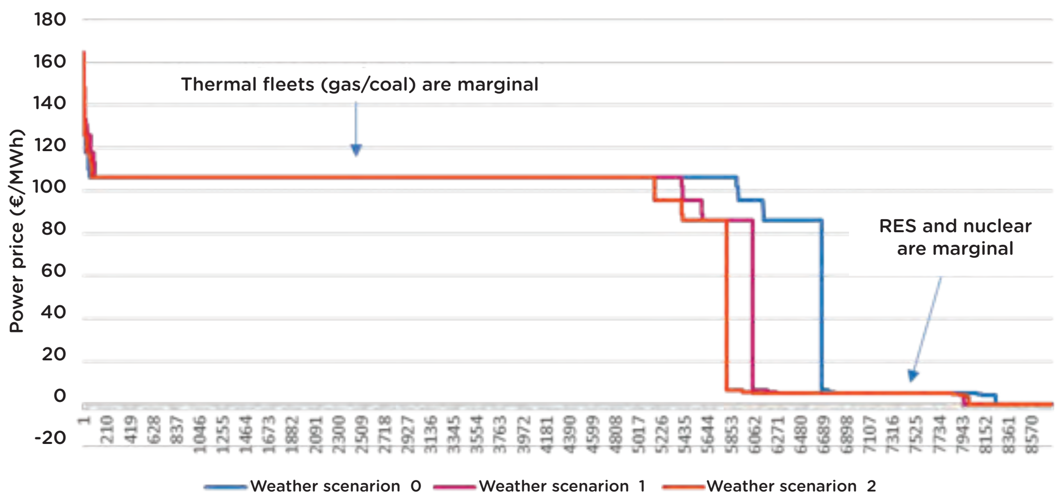
### 4.2.1 Hydrogen production from a grid connected electrolyser

According to the Two Degree scenario from FES, the electricity system in GB is projected to rely heavily on variable renewable energy sources and nuclear in 2040, ensuring that low power prices will become increasingly common. Based on simulations run for this study, low power prices could occur between 2,000 and 3,000 hours a year, depending on weather conditions (Figure 16). If a 1 MWe electrolyser relied only on electricity at these lower prices, it could produce between 1.4 and 2.1 GWh of hydrogen annually.

The addition of a wind farm connected to the electricity network in Fife does not substantially change the price structure and hence the results presented below which are mostly driven by the structure of the mix in UK for the grid connected electrolyser.

FIGURE 16

**Power price duration curves for Fife in 2040**



### 4.2.2 Hydrogen injection into the natural gas grid

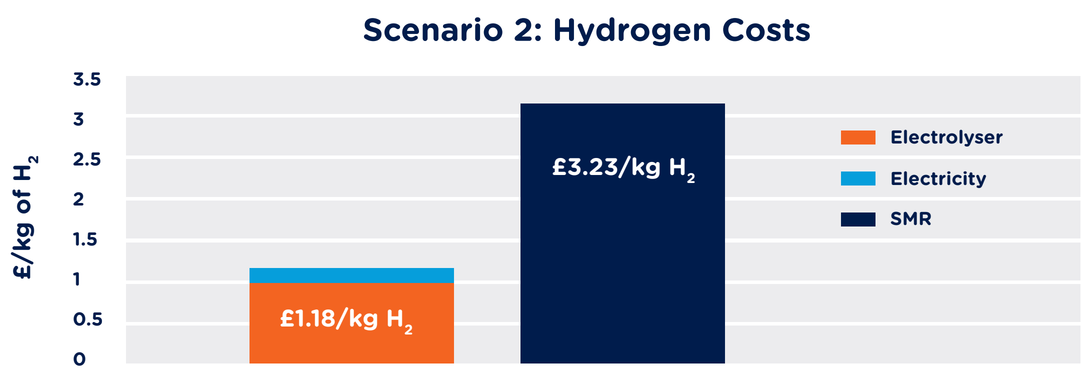
Despite using the cheapest electricity, injecting the hydrogen produced into the gas grid at the current natural gas price of £33.24/MWh[8] (i.e. £1.1/kg$H_2$) does not result in a profitable business case. However, with an additional price support of £0.4/kg$H_2$, the hydrogen sold could cover the cost of production.

Based on model optimisation, if the price support is maintained and hydrogen injection is not constrained, it could be economical to invest in a 300 MW electrolyser. This electrolyser would produce 16.3 kT of hydrogen using 792 GWh of electricity. The average load factor of the electrolyser would be 30%.

The increased electrical load implies that additional power would need to be imported into the Fife region. The hydrogen produced for this electrolyser configuration would be at a cost of £1.18/kg $H_2$.

By comparison, hydrogen produced by SMR is projected to cost £3.23/kg $H_2$, including a carbon price of 81.56 £/t. Therefore, a relatively large grid-connected electrolyser has the potential to produce hydrogen that is competitive with SMR produced hydrogen in light of the large amounts of low-cost generation.

**FIGURE 17: Economic results for a grid-connected electrolyser without injection limit**




Due to technical and/regulatory constraints, the volume of hydrogen injected into the gas grid may be constrained to a nominal fraction (by volume) of the hourly gas demand. In practice, this constraint varies by country – e.g. 0.1% in the UK versus 8% in France – and is linked directly to the gas flow at the injection point. In this scenario, we have set the injection limit to 20% of gas demand, as this is in line with recent studies suggesting minimal changes are required to upstream and downstream infrastructure. Further, the gas demand is scoped down to include only the KY8, KY9, KY10, KY15 and KY16 postcodes, which together have a combined gas consumption of around 900 GWh. In this scenario the maximum amount of hydrogen injected into the grid is 5,500 tonnes (or 180 GWh) of hydrogen.

A variety of economic optimisation scenarios were investigated taking into account that hydrogen injection is constrained to 20% of the gas demand of the area. The optimisation is aiming at balancing:

1) producing hydrogen at the injection level limit; and
2) maximising the load factor of the electrolyser.

Without any additional price support, the cost of hydrogen generation varies between £1.4 and £1.5/kg, suggesting there is not a positive business case for injected hydrogen into the grid. However, we also investigated the effects of including price support and how this would affect the optimum sizing of the electrolyser. As the support level increases, the optimum electrolyser size increases (Table 7) but not in a linear manner, since the amount of additional low-cost electricity that can be captured decreases with successive increases in size.

[8] *This price does not include a valuation of the $CO_2$ avoided by the injection of a $CO_2$-free fuel in the grid.*

**TABLE 7: Capacity and generation of a grid-connected electrolyser injecting in a grid, with an injection limit, for different support levels**

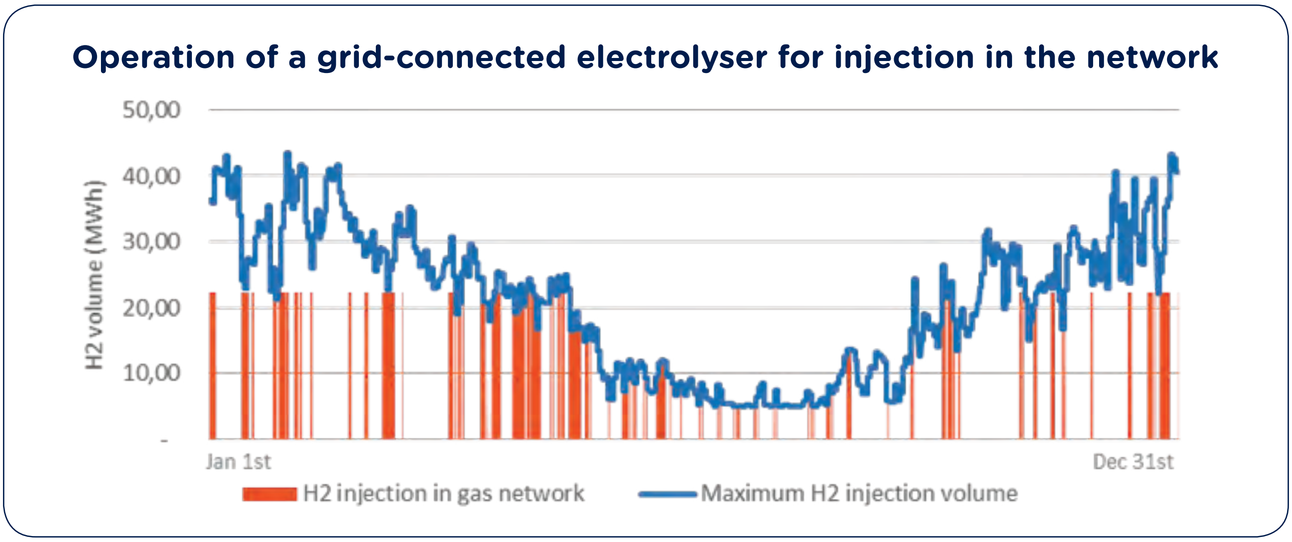
| | Additional support provided on top of gas price | | | |
|---|---|---|---|---|
| | None | £0.7/kg $H_2$ | £1.15/kg $H_2$ | £1.6/kg $H_2$ |
| **Electrolyser capacity (MW)** | 0 | 25 | 32.5 | 35 |
| **Yearly generation (ktonnes)** | 0 | 1.16 +/- 0.2 | 1.4 +/- 0.2 | 1.46 +/- 0.2 |

**TABLE 8: Economic results for a grid-connected electrolyser with injection limit**

| Electrolyser capacity (MWe) | Electrolyser production (kt) | Electrolyser consumption (GWhe) | $H_2$ average production cost (£/kg) | $H_2$ average production cost (£/MWh) | $H_2$ cost from SMR (£/kg excl. Transportation) |
|---|---|---|---|---|---|
| 35 MW | 1.46<br>load factor of 23% (2027h) | 70.6 | 1.5 | 45.1 | 3.23 |

Without storage capacity, hydrogen blending does not exceed the maximum yearly blending allowance[9] (Table 10). However, if adequate storage capacity is introduced, then 5.5 thousand tonnes of hydrogen could be produced at a cost around £1.4/kg $H_2$ (excluding the cost of storage).

**FIGURE 18: Generation of hydrogen from a grid-connected electrolyser, for the injection into the gas network in 2040 in Fife**




[9] *It is possible that in some hour demand periods, hydrogen production exceeds blending limits and therefore production needs*

## 4.3 Scenario 3: Hydrogen production from dedicated renewables for direct injection into the gas grid

**Scenario 3: Main Findings**

- Although hydrogen produced in this scenario is cheaper than hydrogen generation with SMR (without CCS), this is not profitable in itself – generation costs are around 2.8 £/kg, i.e. 84 £/MWh with a gas price of 33.3 £/MWh – excluding $CO_2$.
- This is due to the significant costs of the wind farm. A $CO_2$ cost of 250£/t would be required to make it profitable.
- This case however looks interesting to provide a reliable source of hydrogen regardless of the evolution of the electricity mix in UK.

### 4.3.1 Hydrogen production from dedicated renewables

In this scenario, hydrogen is produced via an electrolyser connected to a dedicated 450 MW windfarm off the coast of Fife, the sizing of which reflects the, the sizing of which reflects the sizing of the proposed Neart na Gaoithe offshore wind farm. The optimisation model balances the volume of hydrogen produced (i.e. high electrolysis capacity) and maximising electrolyser load factor. As the windfarm is assumed to already exist, the optimisation model does not seek to also size the windfarm, only the electrolyser. In this scenario, the economic optimisation generally reaches an equilibrium favouring a high volume of hydrogen production. The electrolyser capacity is dependent on the potential selling price for hydrogen. If we were to consider a wind farm of higher capacity, the economics for the electrolyser and hydrogen generation will remain similar: the capacity of the electrolyser will be set to around 90% of the capacity of the farm to be able to have a load factor of the electrolyser sufficient to cover its capital costs when selling hydrogen at the price of gas.

This would lead to a proportionally higher $H_2$ generation which will make it easier to cover the $H_2$ consumption (less storage needs) but will also create more surpluses (i.e. the $H_2$ generation will become oversized relative to the $H_2$ needs).

Figure 19 and Figure 20 display illustrative yearly and weekly load duration curves of a wind farm (red dotted line) against the electrolyser capacity. The area shaded in green represents curtailed electricity.

FIGURE 19: Dimensioning of an electrolyser connected to a wind farm

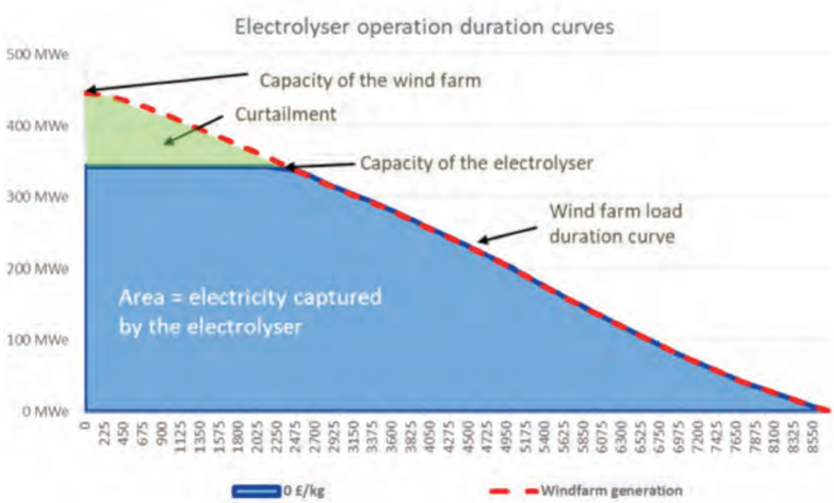
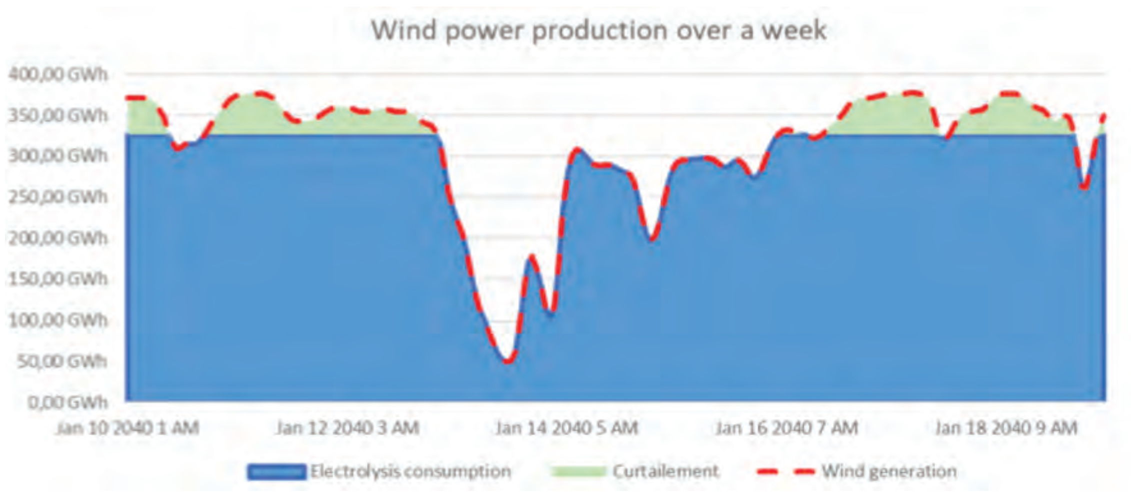


Figure 20: Electrolyser operations during a typical week

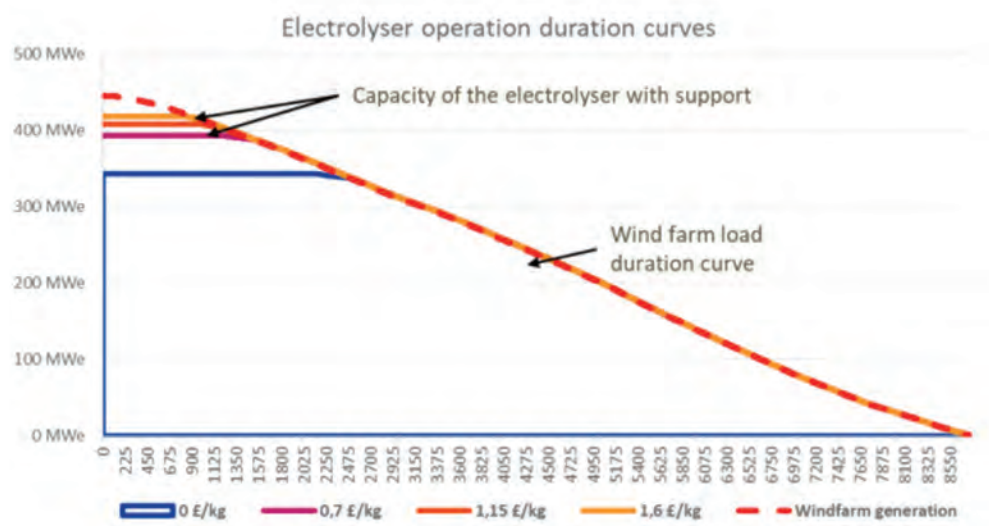



## 4.3.2 Hydrogen injection into the natural gas grid

Several optimisation scenarios were investigated based on varying levels of additional price support the hydrogen could receive if injected into the natural gas grid. As the level of support increases, the electrolyser capacity increases and thus the load factor decreases. This is because the less effective use of the electrolyser is offset by the higher value attributed to hydrogen. Furthermore, the higher the capacity, the less electricity is curtailed which may be favoured by regulators.

The optimisation models show that even without support, only 10% of the electricity produced in the year is curtailed (Figure 21). If a price support of £1.5/kg $H_2$ is assumed on top of the natural gas price, the optimum electrolysis capacity reaches 406 MW, which is equivalent to 90% of the wind farm capacity. In this case, only 1% of electricity is curtailed. The electrolyser could produce between 40 and 43 thousand tonnes of hydrogen per year, with an average load factor of 39%.

FIGURE 21: Dimensioning of an electrolyser connected to a wind farm depending on the support level



When the cost of the wind farm is included in the economic analysis, hydrogen can be produced at around £2.8/kg $H_2$, assuming a 406 MW electrolyser. While this is still lower than the cost of producing hydrogen via steam methane reforming, the cost is higher than for natural gas. An additional support of around £1.7/kg $H_2$ would be required to ensure a positive business case. This is effectively equivalent to setting a carbon price of £250/t$CO_2$ on natural gas. However, given the relative stability of the generation, dedicated renewables could be used to ensure a minimum level of green hydrogen production ensuring at least partial decarbonisation of heat and/or transport, for example.

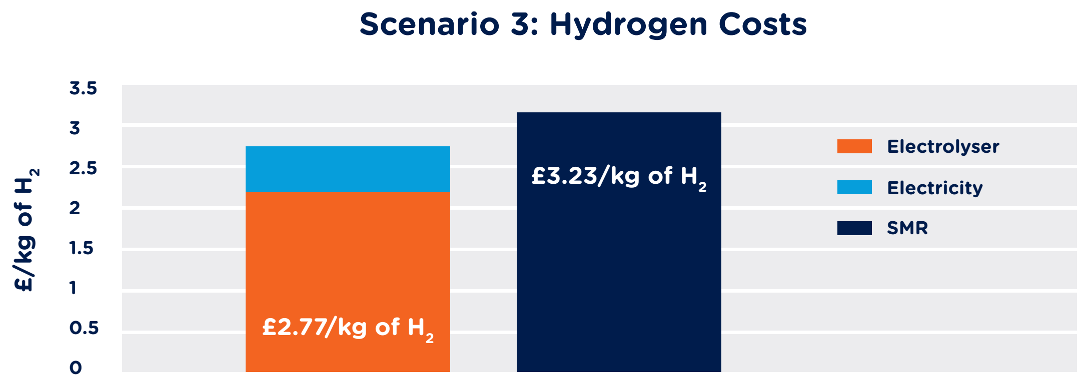



FIGURE 22: Economic results for an electrolyser produced from dedicated renewable energy

## 4.4 Scenario 4: Hydrogen from dedicated renewables for direct use

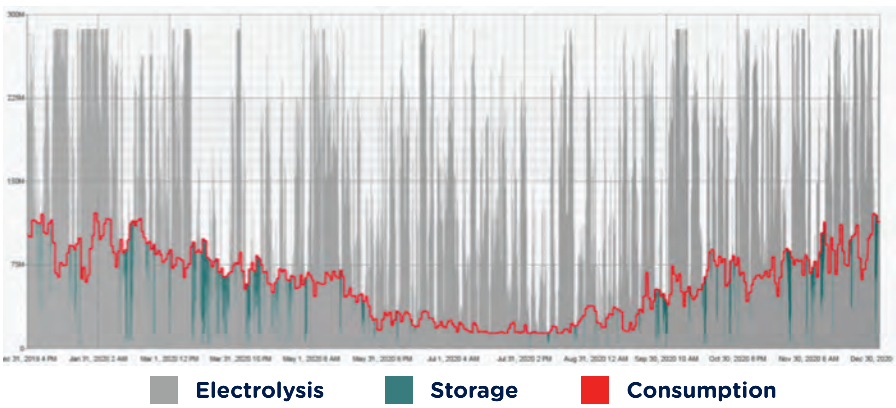
### Hydrogen grid fuelled by an electrolyser with dedicated renewables – Main Findings

- The electrolyser can provide enough hydrogen to meet the needs of KY8.
- A relatively small storage capacity is required to ensure effective utilisation of the electrolyser.
- This case is relatively expensive but provides a reliable source of hydrogen, robust to weather variations and to the evolution of the electricity mix in Great-Britain.
- It could therefore be a solution to consider to decarbonise the gas sector.

This scenario investigates generating hydrogen from dedicated renewables and injecting it directly into a dedicated hydrogen grid – as opposed to the natural gas grid. The dedicated grid has been envisaged for the KY8 postcode, where current gas consumption is equivalent to 15.4 thousand tonnes of hydrogen. The heat (and hence hydrogen) demand profile for KY8 and the other nearby postcode areas considered in the model is based on the following assumptions:

- We assume that 70% of the consumption is used in space heating, with the remainder for cooking + hot water + other uses that are relatively constant over the year. The share is lower than today to account for energy efficiency.
- The profile for the heating consumption is built using the daily temperature curve for the area (consistent with the weather year for renewables and demand in Europe) using a linear model with threshold: daily consumption is proportional to the threshold temperature less the current day temperature. The temperature is averaged at daily resolution to account for thermal inertia and gas grid internal storage.
- Threshold temperature is around 15°c. The quantities and costs of hydrogen production are discussed in Section 4.3.1 and 4.3.2, where it is estimated that as much as 43 thousand tonnes of hydrogen could be generated. This is significantly larger than the gas demand of the envisaged hydrogen grid. However, at an hourly level, it is likely that at some times the electrolyser may not be able to produce enough hydrogen to cover the instantaneous load on the gas grid – i.e. wind is not blowing and therefore hydrogen is not produced – and therefore, storage is required. Figure 23 illustrates the hydrogen production profile (grey bars) against the gas consumption profile of KY8 (red line). The areas in green represent moments when the electrolyser is not producing enough hydrogen to meet consumption demand. At those points, the gas grid would need to rely on stored hydrogen to meet demand. It is estimated that for this configuration a storage capacity of nearly 25 GWh (or 720 tonnes of hydrogen) would be required to ensure demand is met, even during periods of low renewable generation. This storage volume may be reasonable considering there is an estimated potential underground hydrogen storage capacity of 6,750 GWh in Fife.

**FIGURE 23: Operation of an electrolyser with dedicated RES generation to fuel a hydrogen grid**



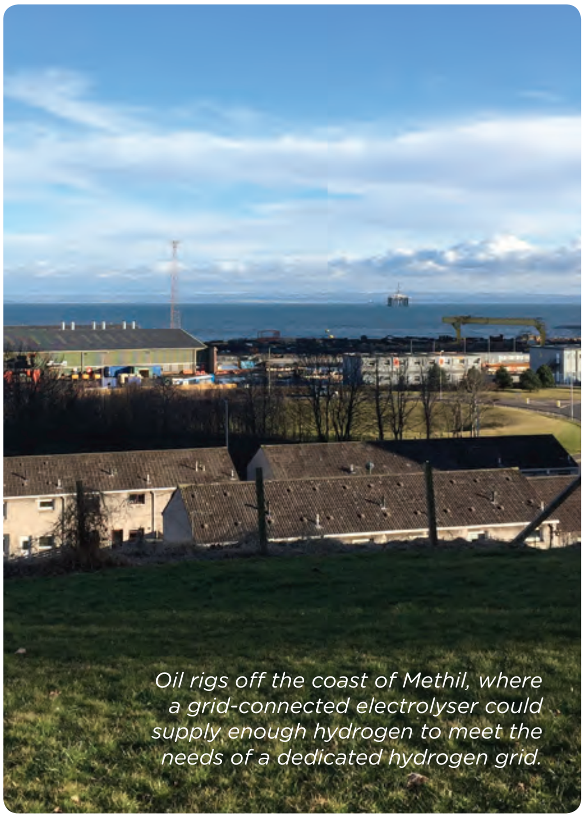

This configuration would result in a large surplus of hydrogen, and a no regrets solutions could be to inject this into an adjacent natural gas grid. Alternatively, it could be possible to extend the dedicated hydrogen grid beyond KY8 postcode or alternatively use the excess hydrogen for other direct use applications, such as transportation.

## 4.5 Scenario 5: Hydrogen from a grid connected electrolyser for injection into hydrogen grid

### Hydrogen grid fuelled by a grid-connected electrolyser – Main Findings

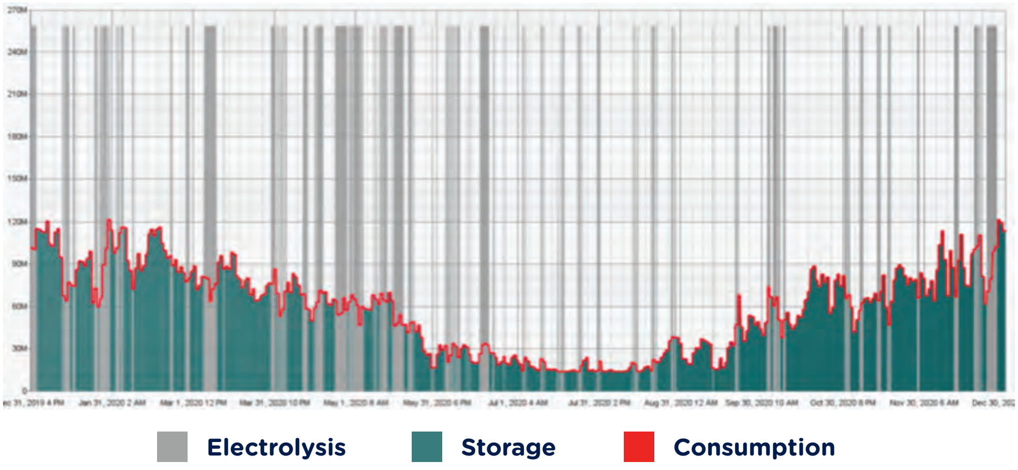
- A grid connected electrolyser could supply enough hydrogen to meet the needs of a dedicated hydrogen grid in postcode KY8, due to the high electricity import capacity from the area and the frequent occurrence of low prices in Fife and UK.
- This case depends on the evolution of the generation mix in UK in the years to come and is inherently less robust than the case with the dedicated wind farm, but the cost of this solution is lower given no additional electricity generation capacity is required.
- A more significant hydrogen storage capacity would however be required to ensure the adequacy between generation and consumption of hydrogen. Without storage or back-up for hydrogen production, a grid-connected electrolyser is not an economic or an environmentally attractive solution to cover the needs of a hydrogen grid.
- Such a configuration would indeed require the electrolysis to load-follow throughout the year even when the prices and $CO_2$ content are high, leading to an equivalent $CO_2$ content of hydrogen of twice the content of gas.
- A solution with a grid-connected electrolyser combined with imports is more expensive than a solution with storage by a significant margin. From an economic and environmental perspective, it makes more sense than a solution with a load-following electrolyser while remaining too expensive overall. A solution with storage is preferred to ensure grid-connected electrolysis is efficient.

This scenario investigates producing hydrogen from a grid-connected electrolyser and injecting it into a dedicated hydrogen grid. As presented in Section 4.2.1 and 4.2.2, a sufficient quantity of hydrogen could be produced to meet gas requirements of KY8 – i.e. 15.4 tonnes of hydrogen – as long as electricity is imported from the rest of GB. However, the electrolyser will likely only operate at times when the price of electricity is low (i.e. 2,000 to 3,000 hours each year depending on weather profiles). It is likely, then, that the hydrogen generation profiles will not match the consumption profile and hydrogen storage will be required to ensure demand is always met. Figure 24 illustrates the relationship between the production of hydrogen (grey bars) and the consumption profile of the region (red line). There are significant periods of mismatch between generation and consumption, and therefore stored hydrogen (green areas) is required to ensure the hydrogen grid meets demand. In this scenario, the required storage capacity is estimated at 150 GWh (or 4.5 thousand tonnes) of hydrogen, ensuring hourly consumption needs are met throughout the year. The storage capacity in this scenario is greater than that required in Section 4.4, related to fewer hours of available electricity for production.



*Oil rigs off the coast of Methil, where a grid-connected electrolyser could supply enough hydrogen to meet the needs of a dedicated hydrogen grid.*

FIGURE 24: Operation of a grid-connected electrolyser to fuel a hydrogen grid




An electrolyser of 375 MWe is required to produce the 15.4 kt of hydrogen each year at an overall price of 1.47 £/kg. With this electrolyser capacity the required hydrogen can be produced in 2000 hours of operation, requiring imports (for GB) of an additional 750 GWh of low-price electricity.

As this scenario is heavily reliant on storage, two additional configurations were investigated to determine the impact if storage were not available.

### 4.5.1 Scenario 5a: Hydrogen production from a grid connected electrolyser for direct grid injection without storage

In this first variant, the electrolyser is built to follow hydrogen consumption, where the capacity is set to ensure that peak hydrogen consumption is met. Further, the electrolyser consumes each hour the exact amount of electricity required to meet the demand in that hour. Given that this scenario is based on producing to match consumption rather than producing at times of low prices, the electrolyser will consume high priced electricity. The average electricity price in this scenario is £60.9/MWh versus £2.8/MWh in previous grid-connected scenarios (Table 9). The resulting hydrogen would cost £3.60/kg $H_2$, which is greater than the projected cost of hydrogen produced from SMR (£3.23/kg $H_2$).

TABLE 9: Results for the load-following grid-connected electrolyser

| Installed capacity of the electrolyser | $H_2$ production by the electrolyser | Part of demand fulfilled by the electrolyser | $H_2$ generation costs | $CO_2$ emissions | Equivalent $CO_2$ content of hydrogen |
|---|---|---|---|---|---|
| 179 Mwe | 15,4 kt | 100% | 3.60 £/kg | 204 kt/yr | 0,4 t/MWh |

$CO_2$ emissions are also high in this scenario, as the electrolyser uses, in some instances, fossil fuel-based electricity. To produce 15.4 thousand tonnes of hydrogen – KY8 gas demand – over 200,000 tonnes of $CO_2$ would be produced, suggesting the carbon intensity of the hydrogen would be 0.4 $tCO_2$/MWh, roughly twice the carbon intensity of methane. Therefore, a load following, hydrogen production configuration without storage is not only uneconomic but also not in line with decarbonisation aims.

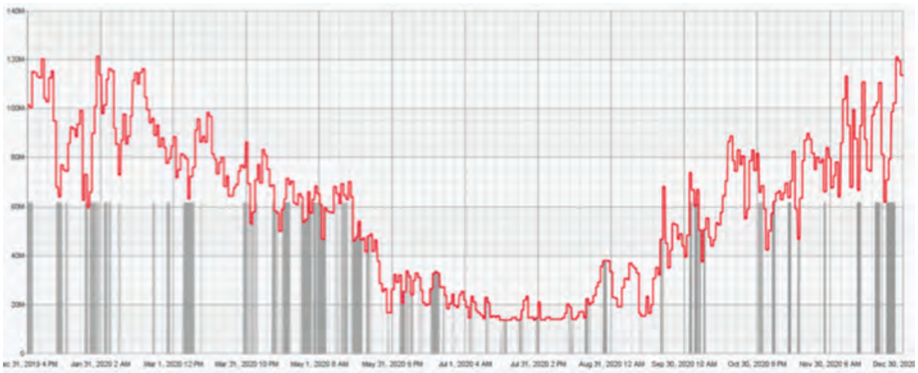
### 4.5.2 Scenario 5b: Hydrogen production from a grid connected electrolyser for gas grid injection without storage and with hydrogen imports

The second variant examined investigates the potential for combining local electrolysis and imported hydrogen from SMR to fulfil consumption requirements in the KY8 postcode region. The electrolyser is therefore dimensioned to cover part of the consumption and only produces when electricity is cheapest – i.e. when nuclear or variable renewable energy sets the marginal price. Hydrogen produced from SMR and imported to Fife covers the remaining consumption requirements.

Assuming that the costs of the imports are those of a production by steam methane reforming, i.e. 3.23 £/kg with a $CO_2$ price of 81.56 £/t, the economic optimisation of the capacity of the electrolysis leads to a relatively smaller capacity of electrolysis, covering about 25% of the required hydrogen generation (the shortfall being made up with SMR hydrogen).

Indeed, following the same operational mode as in the case with storage, the electrolyser only functions when the prices of electricity are low, i.e. between 2000 and 3000 hours each year (in 2040), and not necessarily up to the consumption of hydrogen given that the electrolysis capacity reaches half the peak consumption of hydrogen (as presented below).

**Figure 25: Operation of a grid-connected electrolyser to fuel a hydrogen grid, without storage and with imports from the rest of UK.**




In this scenario, the average cost of hydrogen is £3.51/kg $H_2$, which is higher than the modelled cost when storage is include (£1.47/kg $H_2$) or SMR-produced hydrogen (£3.23/kg $H_2$) (Table 10). This is related to a relatively low load factor for the electrolyser – especially in the summer months – and the high cost of imported hydrogen from SMR.

This scenario also generates $CO_2$ emissions. While 25% of the consumption is effectively met with low-carbon or decarbonised hydrogen, 75% of the hydrogen demand is fulfilled with hydrogen from SMR production. Therefore, to meet the yearly hydrogen demand without storage, over 100,000 tonnes of $CO_2$ are emitted. The average carbon intensity of the consumed hydrogen is 0.2 $tCO_2$/MWh, which is similar to the carbon intensity of methane. The imported hydrogen could be low-carbon-free if the SMR is paired with carbon capture and storage or if other carbon-free hydrogen production methods are used.

**Table 10: Results for the grid-connected electrolyser with back-up**

| Electrolyser installed capacity | $H_2$ production by the electrolyser | Part of demand fulfilled by the electrolyser | $H_2$ cost | $CO_2$ emissions (assuming the back-up is produced by SMR) | $CO_2$ content of hydrogen |
|---|---|---|---|---|---|
| 90 MWe | 4 kt | 25% | 3.51 £/kg | 103 $ktCO_2$/yr | 0,2 $tCO_2$/MWh |

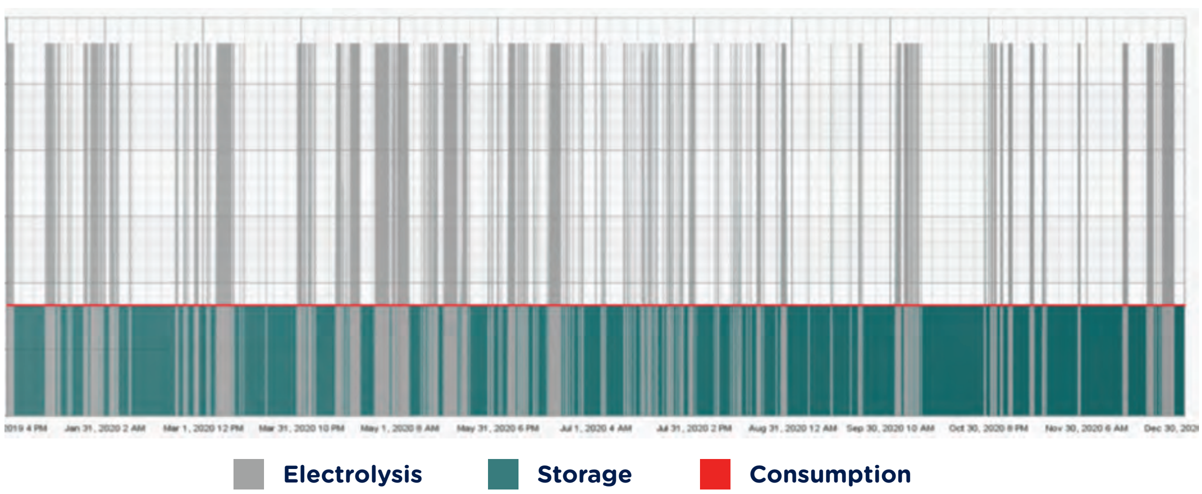
## 4.6 Scenario 6: Hydrogen production from a grid-connected electrolyser for direct-use in mobility

### Hydrogen mobility fuelled by a grid-connected electrolyser with storage – Main Findings

- A solution with a grid-connected electrolyser proves to be economic and environmentally compelling to cover the needs of a potential fleet of hydrogen vehicles in Fife in 2040.
- The flatter demand profile (compared to a typical hydrogen grid consumption profile) lowers the storage needs.
- Similar to the other cases with grid-connected electrolysis, the costs remain relatively low compared to competitors in hydrogen generation and emissions remain low, but the case remains dependent on the evolution of the electricity mix in UK by 2040 and on the development of competitors in the use of low-carbon low-price electricity.

In this scenario, hydrogen is produced from a grid connected electrolyser to be used directly in transport. Around 2,100 vehicles, owned by Fife Council, are assumed to be hydrogen-fuelled by 2040, and will have an annual demand between of 214 and 244 GWh – the equivalent of 6.5 to 7.4 thousand tonnes of hydrogen. This demand is assumed to be consistent throughout the year, unlike heat demand. We consider here the case of a grid-connected electrolyser which would be used with storage to satisfy the hydrogen consumption of the hydrogen vehicles, assumed to be 6.9 kt of hydrogen yearly (the midpoint in the consumption range). The economic and GHG impacts are presented in the preceding scenarios. The regular demand profile from transport reduces storage capacity requirement since the storage capacity needs to be sized based only on the generation profile as opposed to generation and demand profiles simultaneously. In this scenario, storage requirements are estimated at 49 GWh or 1.45 thousand tonnes of hydrogen. This level of storage cannot be satisfied with the standard equipment at $H_2$ refuelling stations, which are generally configured to cover daily or weekly variations. Therefore, additional storage facilities will be required.

**FIGURE 26: Operation of a grid-connected electrolyser and storage to cover the hydrogen demand of a hydrogen vehicles fleet in Fife**



## 4.7 Scenario 7: Hydrogen production for both injection into the gas grid and mobility requirements

**Combined end uses fuelled by a grid-connected electrolyser or dedicated renewables with storage – Main Findings**

- Hydrogen heating and mobility needs can be combined and served either with a grid connected electrolyser or with dedicated renewables.
- Providing storage availability, the electrolyser capacities required to provide hydrogen for mobility or heating needs independently would simply sum to provide hydrogen for combined end-uses.
- The production cost of hydrogen would remain the same as in non-combined end-uses cases.
- Similarly, storage needs would increase to satisfy the combined demand during high electricity prices hours. However, the increase remains moderate thanks to the uncorrelated patterns of both end-uses.

This scenario investigates the provision of hydrogen for both a dedicated hydrogen grid and transportation, equivalent to a total hydrogen consumption of 740 GWh. Storage is also considered in this scenario. Therefore, the optimized electrolyser capacity is the sum of those from Scenario 5 and 6; he cost of hydrogen remains the same.

**FIGURE 27: Operation of an electrolyser with dedicated RES generation to fuel a hydrogen grid**

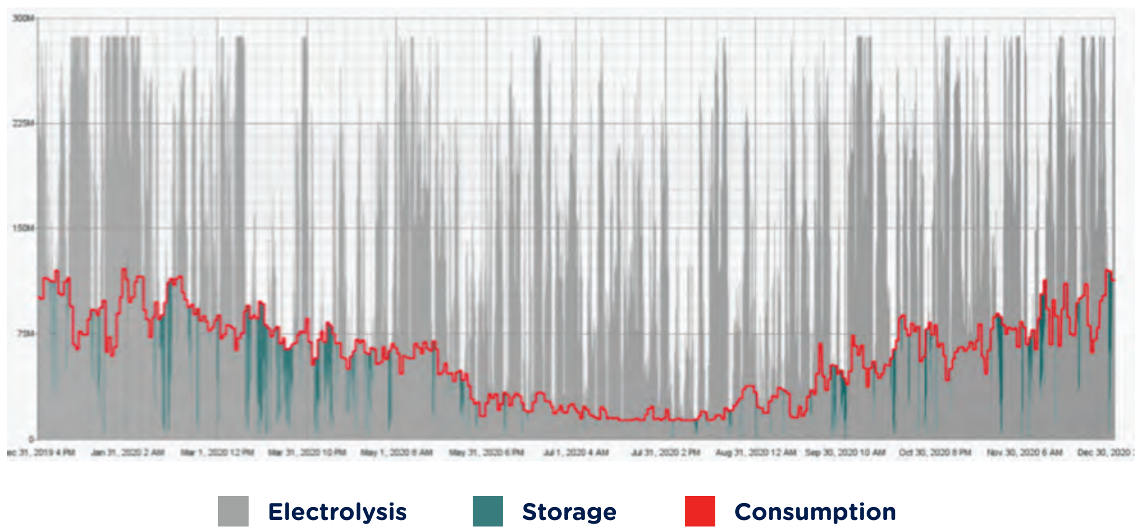
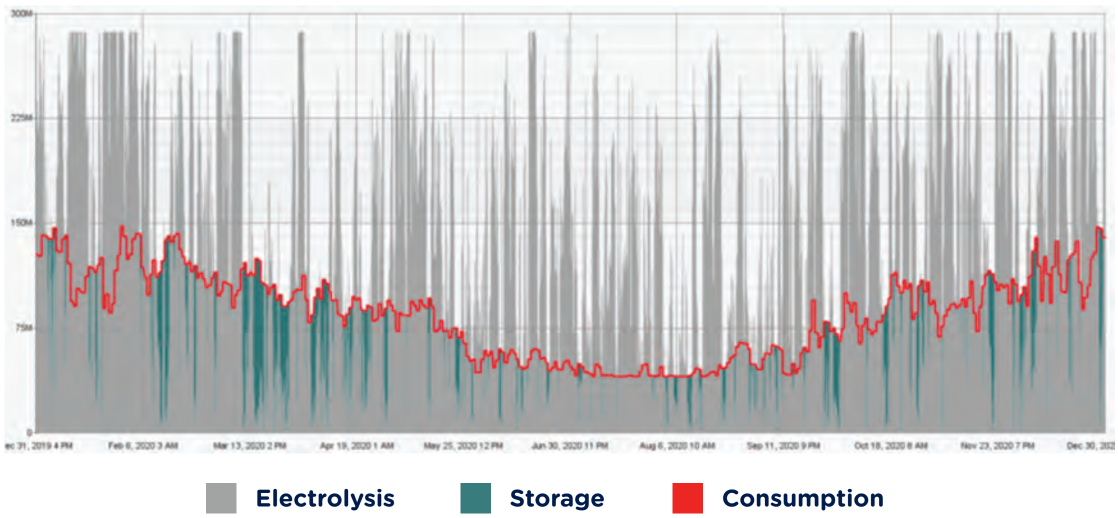


**FIGURE 28: Operation of an electrolyser with dedicated RES generation to fuel a hydrogen grid and mobility end uses combined**




Summing the mobility and heating profiles changes the correlation between low electricity prices and high hydrogen demand. This results in larger storage requirements. For a grid-connected electrolyser, producing hydrogen for both a dedicated grid and transportation, the storage needs increase to 177 GWh – i.e. 5.4 thousand tonnes of hydrogen – to satisfy the hourly demand throughout the year. For an electrolyser connected to dedicated renewables, storage needs remain low due to the high hydrogen production capacity of the electrolyser combined with the high generation output of the windfarm. However, to ensure production during low wind generation, a nominal storage capacity of 43 GWh – i.e. 1.3 thousand tonnes of hydrogen – is still required.

*Supporting customers in areas where hydrogen is introduced will be important to achieving buy-in.*

## 4.8 Avoided network costs

As discussed in section 4.1, the significant electrical interconnection capacity between our Fife and GB nodes ensured that our model showed no curtailment of generation resulting owing to constraints in the network. While avoided investment in electrical transmission and distribution capacity is frequently cited as a benefit of power-to-X, we were unable to test this hypothesis within our study in light of the lack of curtailment.

We did however undertake a high-level analysis of alternative approaches. Our analysis shows that additional large-scale deployment of offshore renewables around Fife may be restricted by the inability to connect directly into the Fife electricity network. The network capacity between Fife and the rest of GB is significant but is more restricted within Fife, particularly in the East Neuk which is more rural. These constraints and the lack of a ready local market for power in part explain why the Neart na Gaoithe offshore wind farm has been connected to the Lothian coast (see figure 29). Since the distance to shore is roughly double the shortest route to the Fife coast, we estimate that the costs avoided by making the connection in Fife rather than Lothian to be in the range £25 – 30m (based on a cost of £2,800 per MWkm as reported by the Offshore Renewable Catapult in 2016). In fact, this 2016 study shows a range of costs for offshore transmission and the avoided cost could reach £63 m at the higher end of the range (£6,600 per MW/km).

**Figure 29: Location of Neart na Gaoithe wind farm**


It should be noted that offshore production of hydrogen could be an alternative solution to bringing power ashore and producing hydrogen onshore and may be cheaper according to the analysis in the Dolphyn study.[10]

[10] *See https://www.rechargenews.com/wind/floating-wind-to-hydrogen-plan-to-heat-millions-of-uk-homes/2-1-670960*

## 4.9 Recap of main findings


- Hydrogen production, in sufficient quantities, is possible through either a grid-connected electrolyser or with a dedicated renewable generation source.
- Grid-connected systems would allow for cheaper hydrogen production but cannot guarantee 100% renewable hydrogen. Conversely, a dedicated renewables system would produce more expensive hydrogen, but it would be 100% renewable.
- Curtailed renewables will not provide enough electricity for meaningful hydrogen production in the Fife region. This is the result of a large (600 MW) Net Transfer Capacity between Fife and the rest of the UK. Therefore, curtailment in the region is not linked to needing network upgrades but rather surplus generation occurring in the entirety of the UK.
- Storage will likely be required to avoid using back-up hydrogen generation (i.e. SMR production) or ensuring low-carbon electricity use for hydrogen production.
- Electrolyser flexibility will be required to respond to either wind generation profiles (dedicated renewables) or to electricity prices (grid-connected).
- Locating electrolyser capacity in Fife could allow onshore or offshore transmission network costs to be reduced or avoided.
- Offshore transmission costs are high and avoiding these costs through the use of PtX could be attractive.


*Aerial view of Anstruther, Cellardyke and Kilrenny in the East Neuk.*

# 5 ACHIEVING THE POTENTIAL FOR HYDROGEN IN FIFE

## 5.1 Background

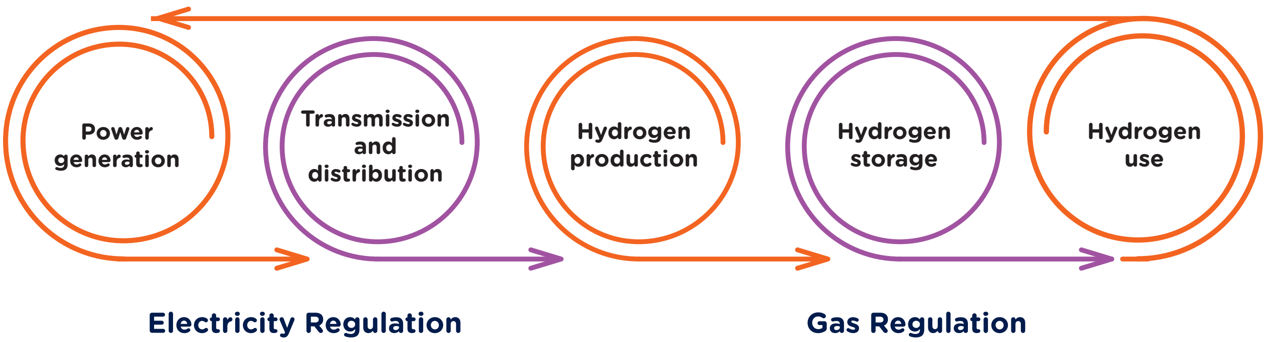
The production of hydrogen in Fife is technically feasible and the foregoing analysis suggests that it may be economically attractive under certain circumstances. However, barriers remain to the implementation of the technology required to deliver power-to-hydrogen. PtH creates an additional physical interface between the electricity and gas markets (a link that already exists owing to the use of gas in power generation) with implications for the regulatory environment. Both power and gas are unbundled but regulated markets and sector coupling has the potential to increase system complexity and create the need for changes to the regulatory arrangements. For power-to-hydrogen to be successfully implemented, a wholesale review of the market and access arrangements will be required to ensure that the overall objectives in relation to competitiveness and transparency of the market are maintained.

Our research points to a number of critical aspects in relation to the regulatory environment for PtX, which need to be taken into consideration when assessing the options available.

- PtH is currently more expensive to produce than fossil fuels and a regulatory regime that contributes to improved profitability of PtH is likely to be required if the market is to develop substantially;
- PtH can help with the integration of renewables, reducing external environmental effects, and making the case for supporting PtH stronger;
- PtH could be used to provide a number of other system services to the power grid which could have benefits for its overall performance;
- PtH has the potential to reduce energy imports and ensure better utilisation of infrastructure by providing storage capacity.

Figure 30 illustrates how power-to-hydrogen fits within the power and gas supply chains each of which has its own existing legislative framework.

FIGURE 30: Power-to-hydrogen supply chain - legislation and regulation




In the following sections we review the current network access and market arrangements and outline commercial and regulatory approaches that may be suitable for supporting power-to-hydrogen infrastructure and operations. We highlight the key issues that will need to be addressed in order to allow the implementation of power-to-hydrogen in Fife and further afield.

Our analysis concentrates on two critical aspects of the UK regulatory framework relating to PtH: the configuration, siting and ownership of hydrogen generation equipment; and the integration of the hydrogen produced into either the gas market or adjacent markets such as transport fuels.

The primary objective of the independent regulator, the Office for Gas and Electricity Markets (Ofgem), created when the UK electricity and gas markets were unbundled under the Gas Act (1986) and Electricity Act (1989), is to protect the consumer. Ofgem oversees the licencing of any organisation seeking to access the gas and electricity markets which are organised according to their role in the value chain, i.e. generation, transmission, distribution and retail[11]. Additionally, Ofgem and the electricity and gas networks have formed codes and standards that outline the regulations permitting access to and allowing participation in these markets[12].

At the time of privatisation, competition was introduced into the electricity and gas production markets as well as in retail, while transmission and distribution remain regulated monopolies. A certain amount of vertical integration exists, with companies owning generation assets and supplying retail customers (and in some cases owning distribution assets). However, competition is underpinned by a requirement for these business units to operate on an arm's length basis from one another.

Since the creation of the liberalised electricity and gas markets, an array of European legislation has been implemented which also impacts on the conduct and operation these markets. Notable are the Third Energy Package 2009 (Gas Directive and Gas Regulation)[13], the Clean Energy Package (Electricity Directive and Electricity Regulation (2019)[14] and Renewable Energy Directive (2018)[15]. A further Gas Package is planned for 2020 although the timing and content of this is yet to be agreed.

The treatment of PtX from a regulatory standpoint which largely depends on its legal classification remains unclear. Owing to its particular characteristics, PtX could be viewed as a consumer, storage provider or producer depending on the precise configuration. This is illustrated in Table 11.

**Table 11 – Treatment of PtX provider in electricity and gas markets**

| | Electricity Market | Gas Market |
|---|---|---|
| **Producer** | Under EU legislation, the reconversion of previously stored energy into electrical energy means in the electricity system energy storage and not electricity production<br>• Power to Gas is not an electricity producer under EU regulation<br>• However, under UK regulation electricity storage remains a subset of generation | No clear definition of production in the gas context<br>Analogy to the production of biogas from biomass possible<br>• Power to Gas would likely be regarded as gas production<br>• Clarification would be useful |
| **Storage** | The conversion of electrical energy into a form of energy which can be stored, the storing of such energy, and the subsequent reconversion of such energy into electrical energy or use as another energy carrier<br>• Power to gas is fully covered by this definition of energy storage | Storage facility means a facility used for the stocking of natural gas<br>Unlikely that conversion of energy from an electrical to a gaseous state falls under the "stocking of natural gas"<br>• Power to Gas is not to be regarded as gas storage<br>• However, is new definition of hydrogen storage required? |
| **Consumer** | Electricity is taken from the grid in order to carry out subsequent electrolysis<br>• Power to gas is to be regarded as an electricity consumer | Not applicable |

*Source: European Legislative and Regulatory Framework on Power-to-Gas (Veseli, 2019)*

[11] *https://www.ofgem.gov.uk/licences-industry-codes-and-standards/licences*
[12] *https://www.ofgem.gov.uk/licences-industry-codes-and-standards/industry-codes*
[13] *https://ec.europa.eu/energy/en/topics/markets-and-consumers/market-legislation/third-energy-package*
[14] *https://ec.europa.eu/energy/en/topics/energy-strategy/clean-energy-all-europeans*
[15] *https://ec.europa.eu/energy/en/topics/renewable-energy/renewable-energy-directive*

This assessment suggests that PtX would clearly be identified as an electricity consumer. All other categorisations require some further clarifications, at least in the UK context as set out below:

- There seems little doubt that PtX is also gas production but at present no clear definition of gas production (in contrast to natural gas supply) has been developed. There are some parallels with the production of biogas or biomethane but greater clarity is required.

- Similar uncertainty surrounds the treatment of PtX as gas storage, since the current definition only pertains to the storing of natural gas. If hydrogen (or synthetic methane) is produced and stored it may be logical to treat this as gas storage.

- PtX would not be treated as electricity production but some ambiguity exists over the regulation of electricity storage, at least in the UK context. Electricity storage is currently viewed as a subset of electricity generation meaning the regulatory regime pertaining to generation may apply if hydrogen produced through PtH is reconverted to electricity.

- In the context of EU regulation, power-to-hydrogen-to-power would be treated as electricity storage but in the UK no proper definition of storage exists. There are moves to clarify the definition of storage following the recent call for evidence on a smart, flexible energy system[16].

Electricity and gas market regulations also define permissible ownership arrangements for different as shown in Table 12.

**TABLE 12: Ownership by market actor type**

| | | Electricity Storage | Gas Storage | Gas Production |
|---|---|---|---|---|
| Electricity | TSO | ✘ | ? | ? |
| Electricity | DSO | ✘ | ? | ? |
| Electricity | Generator | ✔ | ✔ | ? |
| Electricity | Storage Provider | ✔ | ✔ | ? |
| Gas | TSO | ? | ✘ | ✘ |
| Gas | DSO | ? | ✘ | ✘ |
| Gas | Producer | ✔ | ✔ | ✔ |
| Gas | Storage | ✔ | ✔ | ✘ |

Certain allowable or prohibited ownership arrangements are clear, but a number remain uncertain. Once again, this ambiguity exists in part because the opportunities that PtX presents were not envisaged in the legislation.

[16] *https://www.gov.uk/government/consultations/call-for-evidence-a-smart-flexible-energy-system*

## 5.2 Gas production

### 5.2.1 Relevant legislation and regulation

The operation of the gas markets is set out in the Gas Act (Department of Energy, 1990) which allows for the separation of production, transmission, distribution and end-use with transmission and distribution remaining as regulated monopolies.

In addition to ownership arrangements, this legislation determines, among other things, the quality of natural gas supply. Gas suppliers wishing to connect to the gas network are required to meet minimum requirements regarding the quality and calorific value of the gas injected and this applies equally to fossil and non-fossil gas suppliers. Consumers are charged on an energy basis but metered according to the volume consumed. Gas specifications define a standardised calorific value, kept within a narrow range, to ensure that gas delivered to ensure that each customer is being fairly charged for the energy consumed.

While the regulation of hydrogen production through PtH could be seen to have certain parallels with the production of biogas or biomethane, establishing appropriate standards for calorific value presents complications. Hydrogen can either be injected into natural gas grid, producing a blend of natural gas and hydrogen or the grid (or sections of it) can be repurposed to use 100% hydrogen. Alternatively, new hydrogen-specific networks could be laid. Hydrogen can be injected at the transmission or distribution level, although given the scope of this project, we have only considered incorporating hydrogen integration into the distribution network.

In the case of gas blending, the volumetric proportion of hydrogen will depend on the characteristics of gas flow at the point of injection and the location of consumer offtakes in relation to the point of injection.

Large-scale injection of hydrogen or very low levels of injection (as is permissible today) could ensure that a tolerably consistent level of blend is achieved across the entire network. However, with more localised injection there may be a need for specific actions to maintain blend levels across only a sub-section of the network. This points to the need for localised gas standards which would limit the quantity of hydrogen that could be injected at a given point in time at specific locations and reflect the degree of blending allowable in a given area. In doing so, some of the benefits associated with a national network in terms of redundancy and security supply as well homogeneity would be lost but this may be the only way to ensure that customers receive gas of the agreed calorific value.

By contrast, dedicating parts of the existing grid to hydrogen or building new pure hydrogen grids would eliminate the need to control blend levels. Regulating the calorific value of hydrogen should be relatively simpler than for natural gas or biogas which can demonstrate quite wide variations in heat value according to the source of gas. Hydrogen producers would likely be required to maintain a minimum level purity but typically electrolytically produced hydrogen is of high purity.

Gas retailers and larger consumers contract directly with gas producers, including producers of green gas. Low-carbon forms of gas, such as biogas, have been incentivised through various mechanisms, including premium payments to biogas or biomethane suppliers. Key legislation relating to heat decarbonisation is now embodied in the Renewable Heat Incentive which has different features according to whether it relates to the domestic or non-domestic customers.

The Renewable Heat Incentive (RHI) is a UK-wide policy designed to promote the use of renewable heat in the domestic and commercial properties. For the domestic scheme, the technologies supported are ground source and air source heat pumps, biomass boilers and solar thermal. These attract payments from the government (tariffs) of between approximately £69 and 210 /MWhth[17]. RHI incentives are calculated on a per technology basis and the range given here is only indicative figures for the value of decarbonised heat. The upper bound here is roughly equal to the current level of support for transport under the RTFO. Heat from hydrogen is not currently supported under the scheme but this level of support for hydrogen would equate to approximately £2.3 – 7.0 /kg.

For the non-domestic scheme, a wider range of technologies is covered, and the tariff received for the decarbonised heat is also dependent on the heat capacity of the facility in terms of power delivery. Biomass CHP, geothermal, biogas combustion and biomethane injection are all added to the list of technologies under the domestic scheme (see above). Tariffs of between £12 and 110 /MWhth[18] are available, equivalent to approximately £0.4 – 3.7 /kg of hydrogen.

[17] *https://www.energysavingtrust.org.uk/scotland/grants-loans/renewables/renewable-heat-incentiv*

[18] *https://www.ofgem.gov.uk/environmental-programmes/non-domestic-rhi/contacts-guidance-and-resources/tariffs-and-payments-non-domestic-rhi*

## 5.3 Storage, Transmission and Distribution

### 5.3.1 Relevant legislation and regulation in electricity sector

Under their licence conditions, transmission and distribution network operators are precluded from owning generation or consumption assets. This includes storage assets which are, at present, treated as a subset of generation. They are similarly precluded from funding specific projects in these areas except as discussed below.

The electricity TSO has the responsibility of ensuring the balance between generation and load and that power quality conditions are met. This is achieved by provisioning supply and demand through the capacity, balancing and ancillary services markets[19]. Through the TSO's Balancing Mechanism, generators are paid to curtail their generation output if there is excess generation and/or where there are network constraints.

Renewable generators bid positive prices into the Balancing Mechanism, as curtailing their generation means a loss of revenue from both the sale of power and the subsidies received, such as the Renewables Obligation (RO) or Contracts for Differences (CfD). These 'curtailment' payments in 2018 and 2019 (up to June) were on average £71/MWh curtailed. This may represent a floor price for consumers, such as PtH operators, seeking to access curtailed generation for the production of hydrogen.

The transmission operators (TOs) and distribution network operators (DNOs) are responsible for ensuring that appropriate levels of investment in network assets are maintained, in order to allow the connection of generators and consumers, to support market development and ensure security and quality of supply. Since the fees charged by TOs and DNOs reflect the size of their regulated asset base, the level of investment is regulated through the RIIO (Revenue = Incentives + Innovation + Outputs) price control mechanism. The objective of RIIO is ensure network companies deliver innovation, reliability and investment at the lowest cost to consumers. Any investments in network or technology need to demonstrate value for money. In certain instances, innovation projects are allowed to blur the boundaries of the activities network companies are permitted to engage in, at least on a temporary basis.

No specific legislation relating to the electricity storage market exists in the UK at present. Storage providers able to take power from the grid, store it and return it to the grid (e.g. battery storage or pumped hydro) are treated as a subset of the generation market and therefore require to be licenced in the same way. They are able to operate like other generators, participating in the balancing, ancillary services and capacity markets. Recognising the limitations of such an approach, in July 2017 Ofgem and the UK Government released their initial response to the November 2016 consultation, 'A smart, flexible energy system: call for evidence'[16].

The response set out the proposed approach for incorporating flexibility and other smart technologies into the UK energy system and resulted in a number of changes to the regulatory treatment of storage, although it remains a subset of generation. It also includes proposals from Ofgem and the UK Government to address barriers that may inhibit further deployment of energy storage such as:

- grid and other network charges;
- the viability of and mechanisms for revenue stacking;
- creating a specific market definition of 'storage';
- addressing planning and installation constraints;
- application of final consumption levies;
- providing clarity in relation to colocation of storage on Renewables Obligation (RO);
- accreditation for (RO) and Feed-in Tariff (FIT);
- condition of grid connections;
- ownership of storage by network operators;
- incentivisation of appropriate technology innovation;
- small scale storage deployment; and
- health and safety and environmental issues

These are relevant issues in the context of power-to-hydrogen, especially in the event that hydrogen is used as an electricity storage medium and could form the basis of an engagement with Ofgem. However, at present the approach eschews the treatment of energy storage as a system-wide issue and as such does not seek to consider the production of hydrogen for use elsewhere in the energy system as storage (see comments below).

[19] *https://www.twobirds.com/~/media/pdfs/news/bird--bird--the-role-of-energy-storage-in-the-uk-electricity-system.pdf?la=en*

## 5.3.2 Relevant legislation and regulation in gas sector

The arrangements for gas transmission and distribution mirror the arrangements in the electricity sector with regards to meeting requirements for security of supply and network access.

Currently, natural gas storage facilities are owned by third-party companies, with transmission and distribution networks are explicitly prohibited from owning gas storage. Supply into the gas network from storage facilities is assured through contractual arrangements as required to meet demand. However, the natural gas transmission network itself represents a significant store of energy and line-pack can be used to vary the amount of gas stored according to supply and demand. This is in contrast to the electricity network which must be instantaneously in balance, limiting flexibility.

One important characteristic of PtH is that it allows coupling between the electricity and gas markets and presents the opportunity to store energy where it is most valuable. At present PtH on its own would not be treated as gas storage but if it were coupled with hydrogen storage facilities it could be considered as such.

## 5.4 Electricity consumption

Grid connected electricity consumer pay prices that are determined in part by the scale of consumption, with very large consumers able to participate in the wholesale markets. Smaller commercial or industrial consumers pay the commercial domestic electricity tariff set by retailers which would reflect annual consumption amount and patterns.

In addition, the electricity tariff paid will include network fees to the transmission and distribution networks as well charges for network balancing. Consumers requiring a new grid connection pay a connection charge to the network operator (TO or DNO) relating to the capacity of the connection. This is a one-off cost that would be paid on construction.[20] Smaller facilities, where no additional grid connection is necessitated, will pay a standardised connection fee.

Network fees and charges are paid according to the amount of energy consumed and the voltage and capacity of the connection. The larger the connection and the more energy consumed, the lower the network fees on a per energy consumed basis. Indicative network costs lie in the range £18 – 23/MWh for industrial consumers, although network fees in the UK are dependent on the location and time of consumption and the values outlined here are averages. By way of indication, an electrolyser of more than 9MW would benefit from large industrial consumer prices and pay network fees at the lower end of the range[21]. An electrolyser running from dedicated renewable generation (not connected to the electricity grid) would benefit from avoiding network fees or connection charges altogether.

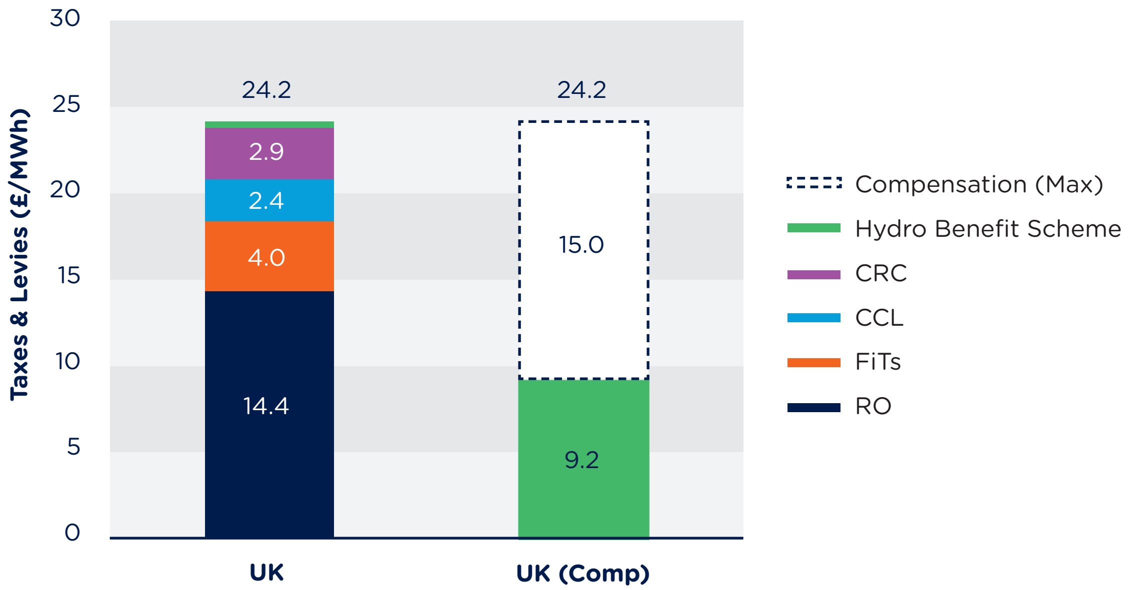
Electricity charges also incorporate taxes and levies designed to recover, amongst other things, the cost of renewable support mechanisms. These mechanisms include Feed-in Tariffs (FiTs), the Renewables Obligation (RO) and the RO's replacement, Contracts for Difference (CfDs). Also included are the Capacity Market (CM), the Climate Change Levy (CCL) and the CRC Energy Efficiency Scheme (the latter being combined with the CCL in FY 2019/2020). These charges are shown in Figure 31 and Figure 32[22].

[20] *https://www.ucl.ac.uk/bartlett/sustainable/sites/bartlett/files/uk_industrial_electricity_prices_-_competitiveness_in_a_low_carbon_world.pdf*

[21] *Calculated on the Eurostat categorisation of the largest consumer group starting at 70GWh per annum. Also assumes 90% utilisation of the grid connected electrolyser.*

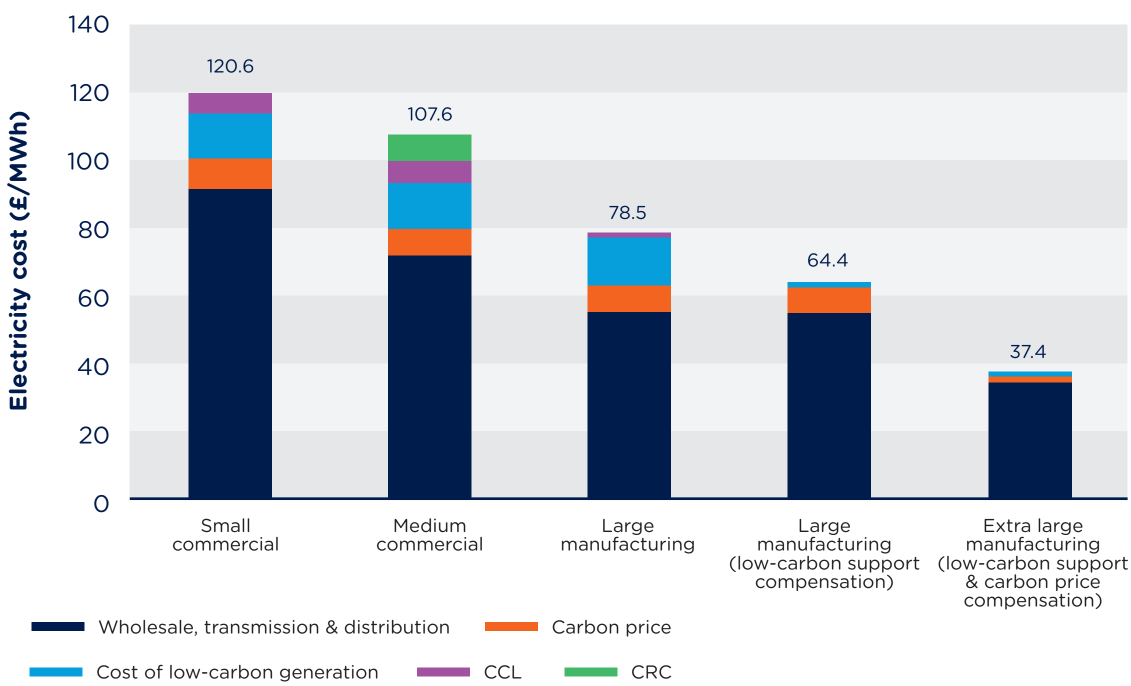
[22] *CfD and CM are not shown here as their contribution to cost was insignificant in 2016*

Figure 31: UK taxes and levies 2016 (Source: UCL)




Consumers in energy intensive sectors receive up to 85% compensation for the RO and FiT charges with this cost being recovered from non-exempt electricity consumers. They also receive 93% reduction in levies associated with the CCL. Taken together this reduces the taxes and levies applied to energy intensive consumers to approximately 10 €/MWh (in 2016). Figure 32 shows an indicative grid electricity cost for different types of consumer in the UK. This highlights the importance of the scale of PtH production in determining the cost of power.

FIGURE 32: Electricity costs with tax and levy breakdown (2016)



## 5.5 Implications for PtH

**Based on the foregoing analysis of the legislative and regulatory frameworks surrounding power, gas and PtX, we have identified a number of key implications and actions which would be required to ensure the successful deployment of PtH. These are set out below.**

### The legal status of power-to-hydrogen remains undefined

- The legal treatment of power-to-hydrogen remains uncertain.
- Power-to-hydrogen is not currently explicitly recognised as a form of energy storage in electricity sector regulation or UK Government legislation[23].
- Current updates to legislation are focusing on power-to-power energy storage, such as batteries (although hydrogen could potentially fulfil this service it is unlikely to be cost-effective).

**Action: Clarify legal status and treatment within electricity and gas (or other applicable) legislation, including that relating to storage.**

### The application of subsidies to generators supplying power to produce hydrogen may need to be reviewed

- Dedicated renewables used in the production of hydrogen would not automatically qualify for incentive payments for the electricity generated. There may be incentives paid for the hydrogen produced depending on where it is used (see later discussion) which may, in whole or part, compensate for any loss of electricity generation subsidies.
- It may be argued that incentives both for generators and hydrogen producers should both apply (double incentive), at least in the early stages of development in order to recognise the value of decarbonising non-electricity sectors.

**Action: Undertake review of applicability of generation incentives**

### Implementing PtH would not necessitate any significant changes to the legislation relating to electricity generators

- Current legislation would allow generators to contract with electrolyser operators in all the ways we have envisaged.
- We do not anticipate that there would be any restriction on a single entity owning both electrolyser and generation assets in a dedicated renewable regime (electricity consumers are permitted to own generation assets to supply their own load requirements and at the same time either sell surplus power to the grid or import power from the grid if they have a shortfall).
- If dedicated generation assets have any grid connection, then it is assumed that the Grid Code would continue to apply but an exemption would presumably apply if a grid connection was completely avoided. This could be interesting to suppliers since although the electrical assets will still require regulation, the technical requirements may not be as onerous.
- Where the electrolyser is directly connected to or co-located with the generator, electricity costs would reflect the commercial arrangements between generator and electrolyser owner. Common ownership of both assets would be feasible under current regulations as discussed with some form of transfer pricing mechanism used between the two operations.
- In a semi-dedicated system, where the electrolyser and renewable generation share a connection to the grid, the electrolyser might be expected to pay only a share of the initial connection fee and network charges.
- It is anticipated that a renewable generator co-located with an electrolyser would only pay consumption fees on that portion of its generation that is exported to the grid.
- Provisions exist for PPA agreements between large consumers and generators although this is a relatively under-developed market in the UK to allow for indirect connection between generator and PtH producer.

**Action: None envisaged**

[23] *HyLaw Database*

### Changes may be required to the way compensation payments for curtailment are administered

- There is currently no regulatory framework outlining how an electrolyser (or any other consumer) can access and utilise electricity that would otherwise be curtailed.
- A mechanism that allows renewable generators to sell power that would otherwise be curtailed to opportunistic consumers, such as electrolyser could avoid the need for curtailment payments (which have been controversial) and allow hydrogen to be produced from relatively cheap green power.

**Action: Discuss adapting payment arrangements for power being constrained off in order to incentivise the use of 'curtailed' renewables for hydrogen production.**

### Impact on market competitiveness of sector coupling unclear

- Currently, integration between the gas and electricity sector is only one way: gas-to-power and not power-to-gas-to-power.
- Closer integration of gas and electricity through PtH may result in price convergence between power and gas. This may be considered undesirable by the regulator given that power and gas are nominally competing energy sources for end-users and needs to be considered when constructing new legislation relating to PtH.
- Further coupling of the electricity and gas markets could occur if the electrolytic gas (produced from grid electricity) is used to generate electricity in gas (hydrogen or syngas) power plants, or in fuel cells.

**Action: Undertake a study to investigate the impact on pricing and develop regulation as required to ensure that it does not have a detrimental effect on consumers**

### Implementing PtH would not necessitate any significant changes to the legislative arrangements for electricity transmission and distribution

- No changes to the current regulations and legislation specific to the transmission and distribution of electricity would be needed for power-to-hydrogen to operate in any of the configurations we have envisaged.
- Since PtH can bring benefits to both the electricity and gas networks and there may be an argument for allowing networks to own such assets in order to supplement the services it already provisions through the balancing and ancillary services markets.
- In the short run this could be achieved under the innovation allowance mechanisms which permit derogations from the underlying legislation.

**Action: None envisaged**

### Electrolysers connecting to the electricity grid as a consumer are likely to be treated in the same way as other consumers

- There are no specific barriers to connecting an electrolyser to the grid as long as it is able to meet the requirements of the Grid Code etc.
- Connection is subject to pricing from the DNO (or TO if transmission-connected), although this is overseen by Ofgem.
- Under the current legislative environment, the electrolyser will be treated the same as any other large consumer; at present, there is no agreed denotation for electrolyser operators in terms the consumer category.
- Network fees and taxes would apply in the normal way to grid-connected electrolysers but would be avoided if a dedicated electricity supply is used.
- Note that in Germany fees are waived if PtH is part of an electricity storage scheme (i.e. power is converted to hydrogen and then back to power).

**Action: Undertake a review of consumer categorisation of PtH and associated fee schedule**

### Grid-connected electrolysers could be expected to participate in all ancillary markets through load adjustment

- Markets include Frequency Response (FFR and EFR), Frequency Control by Demand Management (FCDM), Demand Turn Up (DTU) and Short Term Operating Reserve (STOR) subcategory.
- Access to these ancillary markets is dependent on capacity although electrolysers could cooperate with an aggregator if too small.
- The ability of electrolysers to participate in these markets may be limited by the needs of the primary customer for hydrogen produced but this is a commercial rather than a regulatory.

**Action: None envisaged**

### Lack of recognised approach to utilisation of curtailed power is a barrier to PtH

- No framework is needed to recognise the benefit a localised electrolyser demand brings when it reduces the need for curtailment and its associated payments, as well as delaying or removing the need for network upgrade from constraint.

**Action: Investigate potential options for utilising curtailed power**

### Electrolytic hydrogen production is likely to require the development of hydrogen storage capacity and / or market

- Our analysis shows that even in Fife there would be need for a large amount of hydrogen storage to ensure effective utilisation of the electrolyser or to enable access to cheap power from the grid.
- Clarifying the regulatory arrangements relating to hydrogen storage would be a critical step in developing the PtH market.

**Action: Identify opportunities for geological or other storage capacity in the region and associated market mechanisms**

### Hydrogen injection has parallels with biomethane injection but is not fungible in the same way

- Since hydrogen is not a drop-in fuel, its use in the gas network imposes certain constraints on consumers since it implies the need for modified end-use applications (except at very low levels of hydrogen injection).
- In a domestic scheme, a switch to using hydrogen or a hydrogen blend may not be a choice as sections of the grid are converted.
- Incentivising hydrogen through the current decarbonising heat scheme could be an option to limit the price impact of any such change for the end-consumer.

**Action: Ensure that development of heat regulation and incentives effectively incorporates hydrogen**

### Moving to 100% hydrogen might reduce competition until hydrogen retailers emerge

- Moving to 100% hydrogen (and some blending scenarios) would require sections of the gas network to be systematically modified leading to different arrangements in converted and non-converted regions.
- This may result in reduced competition as a full range of suppliers may not initially be present in a converted region; consumers in the Fife region, for example, could initially find themselves subject to a monopoly supplier of hydrogen.
- Ofgem will likely seek to protect consumers from the potential lack of competition.

**Action: Undertake review of competition implications of move to 100% hydrogen and how this should be managed**

## 5.6 Legislation and regulation relative to transport applications

### 5.6.1 Current legislation and commercial arrangements

Gas market regulations do not currently incorporate the use of hydrogen in transport fuel since hydrogen transport fuel operations currently rely primarily on either the delivery of gas in tube trailers or the local production of hydrogen by electrolysis at hydrogen refuelling stations (HRS). The delivery of hydrogen to HRS via the gas network, which may be envisaged in the future, would no doubt fall at least partially under the gas market legislation, including safety standards.

The main legislative mechanism relating to the use of hydrogen as a transport fuel is the Renewable Transport Fuel Obligation (RTFO). Established in 2008, the RTFO is aimed at reducing greenhouse gas emissions from fuel supplied into transport. The RTFO defines specific levels for the proportion of renewable fuel supplied into the market. Fuel suppliers are rewarded Renewable Transport Fuel Certificates (RTFCs), for each unit of renewable fuel supplied and certificates can be traded amongst suppliers to balance any shortfall or excess. Suppliers can also 'buy-out' of their obligation at a fixed price, set to be more expensive than fulfilling the obligation.

According to the terms of the legislation, hydrogen produced from renewable electricity counts as a renewable fuel when used in transport if [25]:

1. the electricity production site is not connected to the electricity grid and is connected to the electrolyser; or
2. the electricity production site is connected directly to the electrolyser and the electricity grid, and can evidence that the annual electricity generation that would have been lost due to local grid capacity constraints has been consumed by the fuel production plant instead; or
3. the electricity production site is connected directly to the electrolyser and the electricity grid, and the fuel production plant can evidence that their consumption has been provided by the electricity production site without importing electricity from the wider grid.

Hydrogen is classed as a "development fuel" under the RTFO, so therefore attracts double the RTFCs. This means that under the RTFO hydrogen has a high financial incentive of approximately £7 /kg of hydrogen (£210 /MWh). This value is based on the size of the market for RTFCs from development fuels, and as costs reduce for other fuel processes, it is likely that the size of this incentive will reduce.


*In the short-term, transport fuel is likely to be the most attractive market for hydrogen.*

*[24] Biomass-derived electricity cannot be used to generate a RFNBO, as the energy content of a RFNBO has to come from non-bioenergy sources. Biomass-derived electricity used in a hydrogen electrolyser therefore generates a hydrogen fuel that is not a fossil fuel, not a biofuel and not a RFNBO. Similarly, nuclear fission-derived electricity cannot be used to generate a RFNBO, as nuclear power is not listed as a renewable energy source, so again, the resulting fuel would neither be a fossil fuel, nor a biofuel, nor a RFNBO.*

*[25] RFTO guidance part one*


### 5.6.2 Implications for Power-to-Hydrogen

There is currently a strong incentive under the RTFO for PtH for transport, but the power source is critical

- Highest level of incentive only available if power ‘truly green’.
- In Table 13 we have calculated the maximum delivered cost of hydrogen, based on the equivalent fuel prices paid for incumbent fuels and the financial support that is received in the sector.
- Given that over the long-term incentives will reduce, any PtH business plan predicated on the receipt of RTFO support needs to take into account the potential revenue risk.

**TABLE 13: Summary of sector price points, policy support and viable hydrogen production costs**

| | £/MWh | | | £/kg ($H_2$) | | |
|---|---|---|---|---|---|---|
| | **Transport** | **Heating** | **Power** | **Transport** | **Heating** | **Power** |
| Current equivalent fuel cost | 165 | 40 | 19 | 5.5 | 1.3 | 0.6 |
| Additional support available | 210 | 100 | 8 | 7 | 3.3 | 0.3 |
| Highest viable delivered $H_2$ cost | 375 | 140 | 27 | 12.5 | 4.7 | 0.9 |

# 6 CONCLUSIONS

## 6.1 Summary of findings

The report highlights a range of conclusions and we summarise the most important of these in this section.

- **Cheap, low-carbon power could underpin hydrogen production in Fife:** The relatively high interconnection capacity between Fife and the rest of GB (~600MW) could allow cheap renewable and nuclear generation to be used in conjunction with local constrained generation to produce hydrogen cost-effectively in Fife. Our two-node model estimates that more than 2TWh of low-carbon, low-carbon grid electricity could potentially be available for hydrogen production in Fife, more than sufficient to meet the East Neuk heat demand of approximately 400GWh. It is unlikely that locally constrained generation alone can deliver enough low-cost hydrogen to fuel a meaningful amount of heat and/or transport demand in the region. We estimate a total of 15GWh of curtailed generation would be available, which equates to approximately ~8GWh hydrogen. There may be other regions, however, where curtailed electricity may be able to offer a more compelling business case, especially as renewable penetration increases significantly.
- **Dedicated renewable generation to produce hydrogen can encourage deployment and lessen the need for network upgrades:** Our analysis shows that additional large-scale deployment of offshore renewables around Fife may be restricted by the inability to connect directly into the Fife electricity network. The network capacity between Fife and the rest of GB is significant but is more restricted within Fife, particularly in the East Neuk which is more rural. These constraints and the lack of a ready local market for power in part explain why the Neart na Gaoithe offshore wind farm has been connected to the Lothian coast (see figure below). Since the distance to shore is roughly double the shortest route to the Fife coast, we estimate that the costs avoided by making the connection in Fife rather than Lothian to be in the range £25 – 30m (based on a cost of £2,800 per MWkm as reported by the Offshore Renewable Catapult in 2016). It should be noted that offshore production of hydrogen could be an alternative solution to bringing power ashore and producing hydrogen onshore and may be cheaper according to the analysis in the Dolphyn study.

- **Low-carbon electricity is key to successful power-to-hydrogen business cases:** Electricity price is the principal determinant of the cost of electrolytic hydrogen. If we assume that electrolyser owners would be able to access wholesale prices (i.e. excluding grid fees and taxes), grid power-based electrolysis could be as low as £1.2/kg. By contrast, if the electrolyser owner pays the commercial or industrial electricity price, including transport costs and other levies, the cost of hydrogen would be considerably higher (£3.35/kg). The use of dedicated renewable power could be an attractive option, with better electrolyser load factors than can be achieved with low-carbon grid power. Hydrogen production costs would be in around £2.8/kg, which could be competitive with hydrogen produced with grid electricity at commercial or industrial power prices. In practice, the extended periods of low wholesale prices predicted by our model may be over-stated, since we use the FES 'Two Degrees' scenario as the basis of our analysis, which anticipates higher volumes of nuclear power than may credibly be achieved.

- **The optimal electrolyser configuration must weigh capital cost and utilisation:** In our modelling we sized the grid connected electrolyser injecting hydrogen into the gas grid (with no blending limit) at 300MW, reflecting the high interconnection capacity. By contrast, limiting the local proportion of hydrogen to 20% by volume in the KY8, KY9, KY10, KY15 and KY16 postcodes would restrict the optimal size of the electrolyser plant to a maximum of 35 MW. However, the optimal size will vary depending on subsidy level provided to hydrogen producers. The optimal scale for an electrolyser connected directly to a dedicated 450MW putative wind farm (at the same geographical location as Neart na Gaoithe) would be 400MW, assuming that hydrogen storage capacity is available. If the hydrogen producer were required to follow gas consumption (i.e no storage) in the East Neuk, a much smaller unit would be optimal (179MW). The wide variation illustrates the dependency on end-use application, source of power, level of support and availability of storage.

- **Access to storage will be a crucial factor for the viability of a pure hydrogen grid:** The ability to capture excess renewable generation or low-cost electricity and use it during periods of generation shortfall or high cost electricity will critically influence the cost of hydrogen and security of supply. Fully converting the gas grid in the Leven area (KY8) to hydrogen from dedicated renewables would necessitate hydrogen storage capacity of over 700 tonnes. Producing the same amount of hydrogen from grid electricity would allow the electrolyser and storage size to be better optimised according to wholesale price, resulting in lower required storage capacity (less than 5 tonnes). The counterfactual case, supplying hydrogen from an SMR plant and transporting it to Leven, is more expensive in both cases.

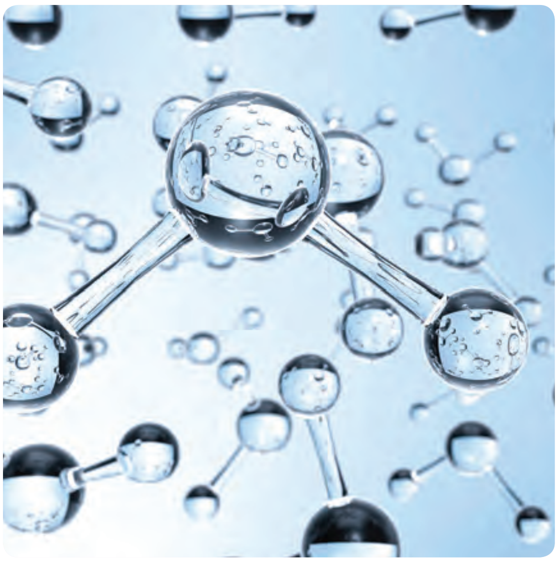
- **Transport fuel is likely to be the most attractive market in the short-term:** Our analysis supports the findings of other studies, in that the transport market is relatively insensitive to premium cost hydrogen and may represent the most attractive initial market for hydrogen. We envisage scenarios where hydrogen produced from low-cost low-carbon (or renewable) electricity could be competitive with transport fuels depending on the carbon price applied. We also show that where low-carbon, low-carbon grid power is available, injection into the gas grid could also be economically viable with subsidies of around £0.7/kg. Grid connected electrolysers could improve grid performance and a grid connection means that the electrolyser operator can offer grid services, with opportunities to generate additional revenues. "Stacking" of services in this way could improve the economic viability of delivered hydrogen.

- **The legal status and legislative arrangements surrounding power-to-hydrogen remains unclear, with potential to limit market development:** The classification of power-to-hydrogen from a legal and regulatory perspective has not been established, which creates uncertainty for parties wishing to enter the market. This could limit players entering the market and delay the development of a vibrant market environment. Clearly defined boundaries will need to be applied to areas being dedicated to 100% hydrogen with customer opt-out not being a feasible option once the decision has been taken to convert a specific region to hydrogen (unless an natural gas grid is operated in parallel). Ring-fencing will likely also be the required in a blending scenario, where blend levels will need to be carefully controlled for safety and metering purposes on a local or regional basis. Solutions which bypass existing transmission networks, e.g. through the deployment of an offshore network on the East Coast, might prove more cost effective if they can tie in offshore production and storage locations such as the one off Fife and could help.

## 6.2 Recommendations

**Based on the analysis undertaken and the overall findings from the study, we have developed a number of recommended actions in order to further the development of PtH in Fife and in the UK more generally.**

- **Increase the maximum limit on blending hydrogen:** The blending limit into natural gas should be increased once the safety case has been established. This would require the Gas Safety Management Regulation 1996 to be altered to reflect an increase from a current maximum limit of 0.1% of hydrogen in volume terms. Such a modification would improve the business case for power-to-hydrogen in the short term and represent an important step towards the establishment of pure hydrogen grids.



- **Incentivise uptake through incentives including lower electricity costs:** Creating a suitable market framework that recognises the benefits that result from dedicated renewables and supports the deployment of renewable generation in combination with electrolysis could boost investment. For example, the viability and benefits or double incentives (both for renewable generator and power-to-hydrogen provider) could ensure faster roll-out of power-to-hydrogen. The Renewable Heat Incentive (RHI) should also be reviewed and overhauled to ensure it provides adequate and effective incentives for power-to-hydrogen. One further way to incentivise hydrogen uptake is for fees and taxes to be waived on electricity used to produce hydrogen, which in turn can be directed to the decarbonisation of other sectors like heat and transport.

- **Widen the definition of green hydrogen:** The current narrow definition of green hydrogen as being 100% from dedicated renewables risks preventing the low-carbon excess power from GB contributing to low-carbon hydrogen production, allowing the perfect to be the enemy of the good. Allowing green tariffs or power-purchase agreements (PPAs) with renewable generators to qualify for green hydrogen production and including nuclear in the same definition would be a positive first step to driving down hydrogen costs. Loosening the requirement for power to be sourced from 100% renewable generation under the RTFO might encourage greater quantities of hydrogen to be produced; while the carbon savings might be somewhat less than with 100% renewable power, this approach would allow electrolyser owners to access larger quantities of low-carbon, low-carbon power. An important element of such an approach would be the ability to time-stamp green certificates in order to validate that power used in a given hour is truly low-carbon.

- **Create a market mechanism to utilise curtailed power:** Enabling power-to-hydrogen providers to bid for potentially curtailed power in a short-term market could result in a better economic scenario for all parties, supporting the business case for deployment of electrolyser capacity and reducing curtailed power (payments for which have been controversial).

- **Review interim and long-term legislative framework for power-to-hydrogen:** A rapid clarification of the legal and regulatory status of power-to-hydrogen is critical to ensuring rapid and effective deployment. This should include a review of the legal status of power-to-hydrogen and should consider how investment is encouraged while at the same time ensuring that end customers are not adversely affected by such investments. There may be a need for interim legislation and regulation during the early stages of the introduction of hydrogen (whether by injection to natural gas grids or through localised 100% hydrogen networks). Derogations from current market principles may be required to facilitate the rapid switchover of networks and to ensure consumers are not disadvantaged by the switch since they will be unable to opt-out. There may be a case, for example, for allowing distribution networks to own storage facilities, to control security of supply and or blend levels adequately. Alternatively, this responsibility could be left to the electrolyser owner-operator, or a third party. This should be discussed with Ofgem, to determine their appetite for the different options and progress towards clarity on the responsibilities of each player in the supply chain. The creation of parallel network infrastructure could be supported through the application of a regulated asset base (RAB) model which decouples infrastructure from both power and gas commodity prices and capital recovery can be amortised over a longer period. In this model the customer or GB resident is charged RAB + Maintenance, minimising price volatility.

- **Rethink ownership structures:** The increasing complexity around market convergence may require a loosening of regulations around whether network operators can own hydrogen production (for balancing) and storage to optimise market functioning. This could be especially valuable during any transition phase, where optimisation of the use of expensive assets will be critical to project viability. While this may run counter to Ofgem's long term objectives for generating competition in energy markets, a short-term derogation may boost investment while risks remain significant.

- **Create a supportive environment for customers in hydrogen regions:** There is a need to work with Ofgem to determine the best way to support customers in localised areas where a blended or H100 grid is established. This would include reviewing how gas is metered and how appliances can be modified or replaced in a cost-neutral way. Approaches to encourage the early entry of multiple retailers of hydrogen blends or 100% hydrogen, as regions are converted, should be investigated. The potential for sector coupling from power-to-hydrogen and power-to-hydrogen-to-power, especially at high levels of penetration of power-to-hydrogen, and the negative impact on competition should be explored further.

- **Prove the case for power-to-hydrogen providing grid support:** It is suggested that a demonstration should be undertaken to investigate the potential for power-to-hydrogen to support network operation in practice, potentially through a pilot project with the support of the innovation allowance.

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