North East Network & Industrial Cluster Development – Summary Report

A consolidated summary report by SGN & Wood

November 2021

Your gas. Our network.

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Glossary

Abbreviation or Term	Definition
AHP	Analytical hierarchical process
BECCS	Bioenergy with carbon capture and storage
BEIS	[UK Government Department for] Business, Energy & Industrial Strategy
BNEF	Bloomberg New Energy Finance
CaCO3	Calcium carbonate
CaO	Calcium oxide
CCC	Committee on Climate Change
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CCU	Carbon, capture and utilisation
CCUS	Carbon capture, utilisation and storage
CHP	Combined heat and power
EC	European Commission
EfW	Energy-from-waste
EIA	Environmental impact assessment
EPC	Engineering, procurement and construction
F13	[National Transmission System] feeder pipeline 13
FEED	Front-end engineering design
FEED	Front end engineering design
FES	[National Grid] Future Energy Scenarios
kTPA	Kilo-tonnes per annum
LCOE	Levelised cost of energy
LCOH	Levelized cost of hydrogen
LOHC	Liquid organic hydrogen carrier
MCDA	Multi-criteria decision analysis
MDF	Medium-density fibreboard
MTPA	Mega-tonnes per annum
MW	Megawatt
MWe	Megawatt (electrical) - electric power produced by a generator
MWth	Megawatt (thermal) - thermal power produced by a plant
NGL	Natural gas liquids
NH3	Ammonia
NTS	National Transmission System
ONE	Opportunity North East
OOM	Order of magnitude
SCM	Standard Cubic meters
SIU	Scottish Independent Undertakings
SMR	Steam methane reforming
SWOT	Strength, weakness, opportunity and threat [analysis]
TWh	Terawatt-hours

1 Executive Summary

1. Executive Summary

The Scottish Government's Climate Change Act 2019 commits Scotland to 'net-zero' emissions of all greenhouse gases (GHGs) by 2045, which means that any residual GHG will need to be balanced by activities that take CO_2 out of the atmosphere. This is likely to require carbon capture and storage (CCS) on all major emitters, and the conversion of fossil fuel systems to hydrogen is likely to play a major part in reducing emissions from sectors such as domestic heating and transport. The Scottish Government's Energy Strategy[1] published in 2017 sets a target of 50% of the energy for Scotland's heat, transport and electricity consumption to come from renewable sources by 2030. It recognises the important role that hydrogen could play in meeting this and future targets. Additionally, hydrogen can be deployed to reach the Scottish Government's target to decarbonise the heat demand of one million homes by 2030 as part of the government's Heat in Buildings Strategy[2] which outlines the steps required to reduce greenhouse gas emissions from Scotland's homes.

Scotland is excellently placed to pursue an energy transition programme which would see existing hydrocarbon infrastructure repurposed to facilitate a change to low and zero carbon energy. Scotland's abundant renewable energy resources (which include ~25% of Europe's offshore wind and tidal resource) along with well-developed onshore and offshore oil and gas infrastructure, and presence of offshore geological stores for carbon sequestration, lend themselves well to SGN's proposed gas network reconfiguration concept.

The concept proposed by SGN would allow existing natural gas infrastructure to be re-purposed to provide customers with new utility services that would result in SGN playing a major role in achieving the Scottish Government's 2045 net-zero target. Switching a large proportion of all gas grid users to low carbon hydrogen would provide a substantial contribution to meeting Scotland's ambitious 2030 and 2045 climate targets.

Figure 1-1 Project Area

Wood was appointed by SGN to provide consultancy services for the North East Network & Industrial Cluster Development project (the Project). This constitutes a feasibility study of the Project Area as demarcated in Figure 1-1 and investigating the potential to reconfigure SGN's gas distribution network in the north east and east coast of Scotland, to separately transport hydrogen to end users and captured carbon dioxide (CO_2) to geological stores.

The extent of the Project Area offers a significant opportunity for substantial decarbonisation of Scottish industry and commercial and domestic heat demand. The proposed reconfiguration solution caters for expansion of hydrogen into new markets in transport and exports.

[1] https://www.gov.scot/publications/scottish-energy-strategy-future-energy-scotland-9781788515276/pages/3/

[2] https://www.gov.scot/publications/heat-buildings-strategy-achieving-net-zero-emissions-scotlands-buildings-consultation/

It is anticipated that hydrogen produced from renewably powered electrolysis ('green') and hydrogen produced from the reformation of natural gas with CCS ('blue') will both play important roles in the overall network solution. The proposed reconfiguration solution allows both green and blue hydrogen producers to be connected to the network.

System Reconfiguration Options Appraisal

The Project has included an extensive optioneering exercise to determine the optimal reconfiguration of SGN's gas network taking into account various aspects pertaining to potential hydrogen opportunities and CO_2 generation within the Project Area.

The exercise utilised a robust, multi-stage and multi-criteria methodology for shortlisting the proposed options to support the Project.

All the options considered would contribute towards achieving the Scottish Government's commitment to making Scotland net-zero by 2045. A range of technically feasible options were initially developed based on different potential blue and green hydrogen configurations, each one capable of addressing the strategic objectives of the Project. Each of the options were scored using professional judgement and supporting data against an agreed set of criteria developed by the Project.

Weightings were generated for each criterion using an analytical hierarchical process (AHP). Weighted scores of the options, against each criterion, were subsequently fed into Wood's in-house DecisionVue software (Figure 1-2) to generate a hierarchy of options, which was subject to further sensitivity analysis.

Figure 1-2 Example DecisionVue Sunburst Plot

The option ultimately selected for further development comprised a distributed blue hydrogen production model and onshore hydrogen transmission system with offshore CO_2 transmission (see Figure 1-3 below).

The dispersed production of blue and green hydrogen adopted by this option has the advantage of greater resilience to disruption and therefore a more reliable gas supply. When compared with a centralised option, multiple sites can spread economic benefits whilst providing more opportunities for early adopters and offering flexibility about where to build first.

The onshore hydrogen transmission pipeline offers opportunities to connect early adopters and fits well with current project plans for the Aberdeen area, including the Acorn project and future plans at Peterhead Power Station. Onshore hydrogen transmission also offers more opportunities for supplying the marine, road and aviation transport sectors.

The offshore CO_2 pipeline system does not offer many opportunities to re-use existing infrastructure but has the important advantage of being inherently safer than onshore, due to more limited threat to public exposure to CO_2 in the event of a leak. SGN considers that planning consent for such a system would be more likely to be secured.

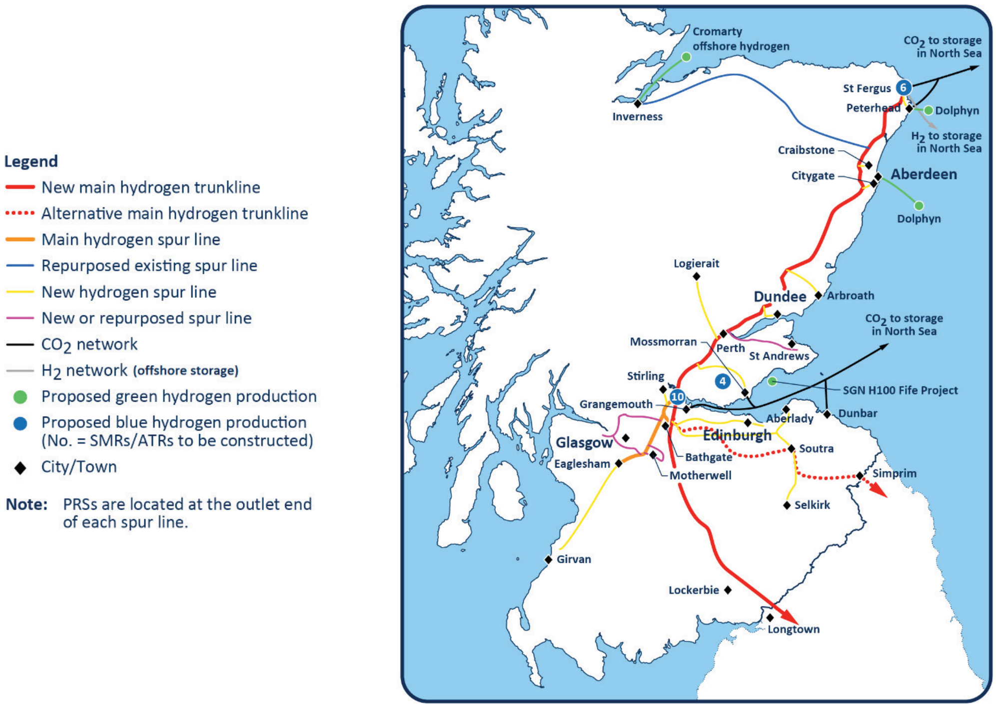


Figure 1-3 Chosen System Option

The perceived benefits of an onshore hydrogen transmission system with offshore CO_2 removal are summarised as follows:

- The build-out is expected to start with early supply of green hydrogen from the Dolphyn project to the south of Aberdeen which will eventually integrate into the wider onshore blue hydrogen transmission system proposed.
- Future green hydrogen generation at Peterhead will have access to the proposed hydrogen transmission system.
- Avoids having to build a separate hydrogen pipeline from St Fergus to Kinknockie to supply Peterhead.
- Onshore hydrogen solutions may favour transport hub connections or options to compress and transport hydrogen to remote areas.
- Future expansion of offshore hydrogen can be integrated into the new system.
- Offers opportunities for import and export of hydrogen i.e., suitable locations for shipping.
- Offers flexibility that can more easily help in construction phasing and future access to funding.
- Likely to stimulate faster hydrogen uptake amongst end users, helping to decarbonise the heat demand of one million homes by 2030 in line with the Scottish Government's target.

Hydrogen Demand

Hydrogen can be a key vector for the decarbonisation of power and heating systems that are currently fuelled by natural gas. Where the requisite hydrogen is produced from low carbon sources (e.g., blue hydrogen with 90% of the carbon captured and stored) this can be considered a lower carbon solution to the reduction in natural gas use. This Project also considers wider applications for hydrogen in sectors such as transport, power and agriculture.

The following chart summarises the estimated demand profile, by sector, for the Project Area, including a 10% allowance for the export of hydrogen in addition to the sum of all other sectors. This demand profile has been modelled in conjunction with input from local stakeholders who engaged with the Project.

The Project has identified opportunities in the Project Area to supply hydrogen to SGN's existing customer base and also new markets in the transport, industrial, power generation and export sectors.

The selected Project system reconfiguration option allows for early adopters and producers of hydrogen to be connected, thus integrating the various complementary hydrogen initiatives already underway in Scotland such as the Dolphyn and Acorn projects.

The Project has the potential to provide a route to market for green hydrogen producers operating in the Project Area with network infrastructure in place to supply into.

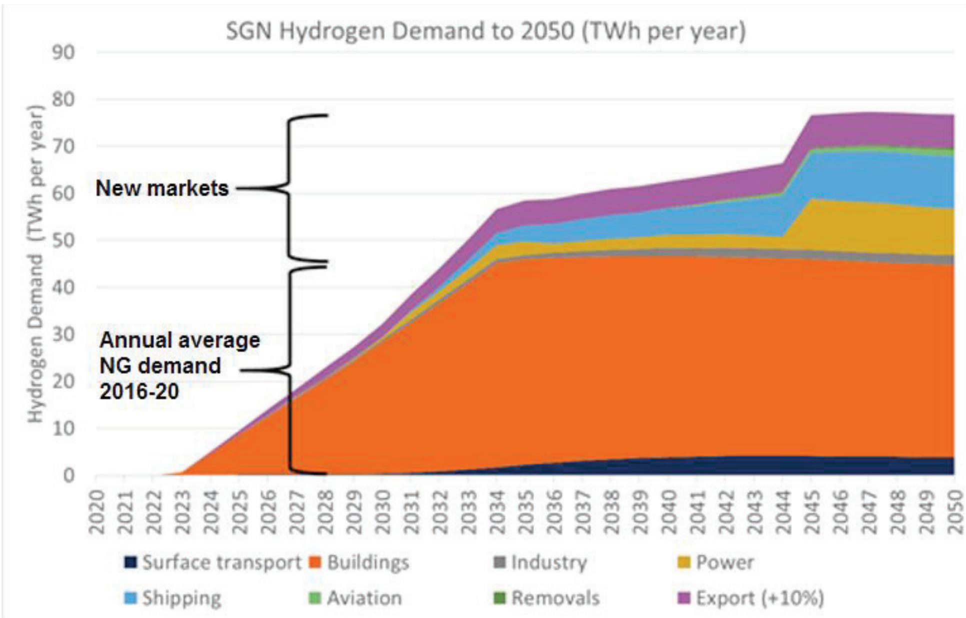


Figure 1-4 Hydrogen Demand for the Project Area

Network: Blending and Conversion

Industry consensus suggests gas appliances can operate safely and efficiently on blends of up to 20% hydrogen by volume, but they require modifications to operate beyond this level up to 100% hydrogen. A conversion programme would be required with a transition to 100% hydrogen networks.

Conversion of an area from natural gas to 100% hydrogen requires, *inter alia*, the following key activities:

- Industrial and commercial plant sensitivity assessments.
- Planned sectorisation of the Project Area that ensures minimal disruption and costs associated with additional connections and strategically placed valves.
- Disconnection, isolation and purging of the local natural gas system.
- Conversion of burners and appliances to operate with 100% hydrogen.
- Any additional changes to customers' gas systems.
- Any additional network reinforcement or upgrades to district governors and/or removal of material that is not suitable for hydrogen.
- Purging of the pipework system
- Connection to the local hydrogen system.

This process requires customers to be without gas during the conversion process, and most likely carried out during periods of low demand (March to October). The conversion process requires on average one person-day per customer. The sectorisation plans would involve sub-sectors of the network being supplied with a temporary hydrogen supply until such time several sub-sectors can be commissioned as one complete sector.

If the conversion process takes place from March to October over a period of 11 years from 2024 to 2034:

- There will be 2,772 days available (assuming seven days a week and 4.5 weeks per month).
- 649 customers can be converted per day (assuming one day per customer to convert).
- This would require a field workforce of approximately 1,300 dedicated to customer changeover, plus additional staff to support preparatory activities, and provide supervision and support.

This means that the local grids will need to be sectionalised to allow areas to be individually isolated and changed to 100% hydrogen. The aim would be to reduce disruption to the network and customers.

Hydrogen Storage

Gas demand varies across the year from summer to winter (inter-seasonal), and also within the day (diurnal). Therefore, some form of hydrogen storage would be required where the supply is not being delivered by hydrogen generated on-demand from natural gas. Our analysis shows the storage requirement in the entire geographical area for the winter of 2017-18 was approximately 3.6 billion scm of hydrogen equivalent.

For seasonal storage of gaseous hydrogen there are 2 main options, salt cavern storage and porous rock formations (aquifers and depleted natural gas reservoirs). As discussed in Section 7, none of these options are considered available to, or technically achievable for, the Project at present. However, it is assumed that hydrogen storage in porous rock formations becomes available by 2045.

Liquefaction and storage of hydrogen is likely to be prohibitively expensive, due to the very low boiling point of hydrogen (-253 °C). There is some potential for using liquid organic hydrogen carriers (LOHCs) for storage of hydrogen.

The proposed solution for managing the seasonal peak in gas demand is therefore to construct additional reformers to cover the peak demand, and to use some modulation of reformers to adjust hydrogen production to demand. Suitable business models with governmental support would be required to operate these commercially; however, it is recognised that these reformers could also support an export market whilst allowing early conversions to take place.

Management of the winter peak would also include some demand management. For the peak in hydrogen demand, compression to high pressure storage for transport applications can be applied in order to free capacity for heating demands. Transport demands are projected to account for approximately 18% of overall demand. Transport hubs are likely to have a degree of on-site storage that would be beneficial to smoothing out peak daily demand when required.

The proposed Project roadmap includes some flexibility: if storage in local porous rock formations becomes technically feasible earlier than expected (e.g., by 2030), it would be possible to reduce the number of reformers that are built and rely on storage to cover the winter peak in demand. If large scale storage in porous rock formations becomes available at a later date, the additional blue hydrogen reformer capacity that is freed up would be available to provide low-carbon hydrogen for export.

Existing Assets within the Project Area

The proposed hydrogen pipeline routing has been developed with reference to the existing SGN network. The proposed hydrogen pipeline layout for the Project, illustrated in Figure 1-3 above, indicates where pipelines are new assets or whether existing assets can be re-purposed.

Section 10.1 presents the peak and average flow rates used for the hydrogen network analysis which was undertaken together with estimated pipeline lengths. Also presented are the selected line sizes established by the analysis.

Early options appraisal by the Project team on the re-purposing of National Transmission System (NTS) feeder pipeline ‘F13’ could reduce incurred capital costs through re-use of this existing asset. Additionally, there may be a saving on construction emissions from re-using this existing pipeline; however, at this level of engineering design it is not possible to quantify this against construction of a new pipeline.

F13, was constructed in 1982 and thus incurs a risk of increased maintenance and shorter design life. These trade-offs have been considered within our optioneering assessment. At the time of this report publication the suitability of re-using F13 for transport of 100% hydrogen has not been proven and is the subject for ongoing research and development.

The selected configuration proposed is based on achieving full transition of the gas network by 2045 and supporting a net-zero emissions compliant Scotland. A significant advantage of an offshore CO_2 storage route is that it would be able to collect CO_2 from major existing emitters at Grangemouth, Mossmorran and Dunbar and it opens up a variety of potential CO_2 storage sites in the North Sea, supporting long term CCS.

For early adopters there is potential to re-use Feeder 10 (F10) for transport of CO_2 from the Central Belt to St. Fergus (this is being considered as part of the Acorn project), where booster compressors would then increase the pressure to send it to the storage pipeline.

System Configuration – Hydrogen Infrastructure

The hydrogen system capacity sizing and number of reformers required has been calculated to meet the modelled gas network demand for winter peak conditions.

The basis for this profile is to meet the Scottish Government’s target to convert one million homes to low carbon heating by 2030. There are challenges associated with this deployment rate in terms of the construction schedule. A steep ramp-up in hydrogen production would be needed starting in 2024 in order to meet the 2030 target.

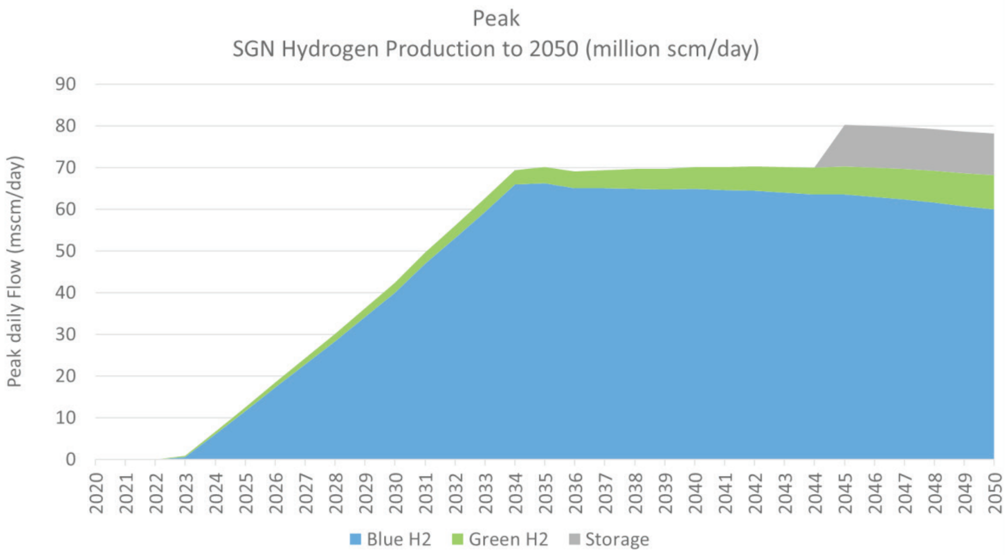


Figure 1-5 Supply Profile at Winter Peak

A supply profile based on annual average demand (e.g., with average green and blue production) is shown in Figure 1-5 to illustrate the different green and blue supply ratio compared to winter peak conditions (e.g. maximum blue hydrogen production with green production output reduced by 50% to take account of annual variable wind conditions).

As shown in grey, storage capacity is anticipated to become available around 2045. Over the course of the average year the hydrogen stores would be drawn down and filled, smoothing out the peaks and troughs. The peak in blue hydrogen production in 2045 is a result of the expectation that the existing reformers will ramp up production during winter in order to fill the storage, which is then drawn down for power generation at Peterhead Power Station during the winter.

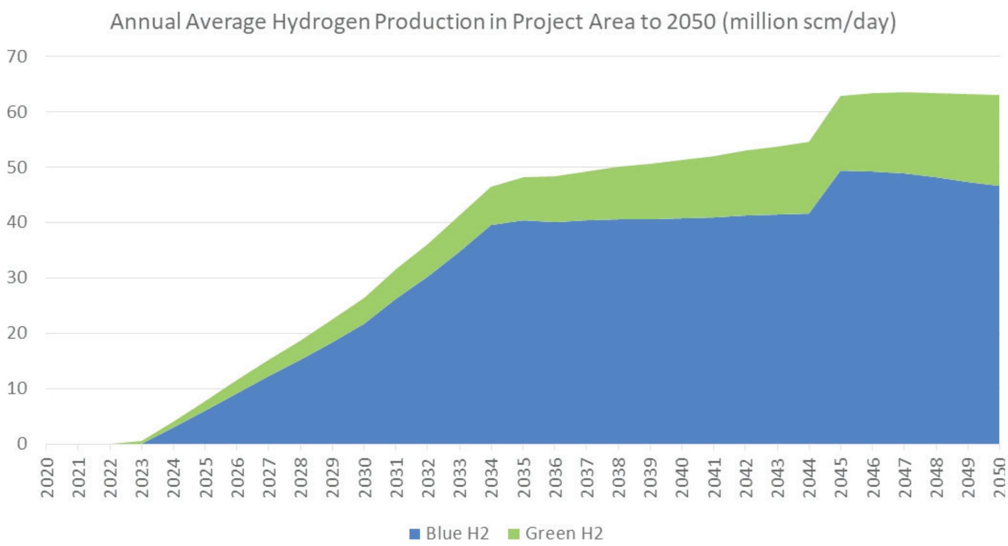


Figure 1-6 Supply Profile at Average Annual Demand

A supply profile made up of blue and green hydrogen has been developed to align with the anticipated demand profile. This is shown in previous Figure 1-6. The following key observations are made on the supply profile:

- The supply includes a gradual increase in annual green hydrogen use to 20 TWh per year in 2050[3], which is equivalent to an average green hydrogen flowrate of 16.4 million scm/day.
- Because green hydrogen production is subject to intermittency (where no storage is available) the supply profile has been designed so that blue hydrogen can be called upon to meet almost all of the overall peak demand if required. The green hydrogen supply shown represents a situation where green hydrogen production is below average due to low wind speed periods.
- The allowance taken for green hydrogen generation is 50% of normal generation, reflecting a load factor of about 0.25, because the peak in heating demand could correspond to a period of high electricity demand.
- Increasing green hydrogen supply penetration over time will allow for the export of hydrogen outside of the Project Area, thus maintaining the overall number of reformers in operation.
- When the anticipated hydrogen demand reaches its expected peak at around 2035, hydrogen production at peak would be dominated by blue hydrogen generation, with 20 reformers (capacity 140,000 Nm3/h H_2 each rated at 500 MWth thermal/hydrogen output) being needed to meet the peak. Blue hydrogen production has been sized based on meeting the overall anticipated demand minus the anticipated contribution from green hydrogen sources.
- After 2035, there is an anticipated reduction in peak hydrogen demand due to expected gradual improvements in domestic appliance and insulation efficiency assumed as part of the Project, but average yearly demand will continue to grow due to new markets in the transport sector.

In 2045, the curve shows an increase in demand due to the use of hydrogen for large-scale power generation at Peterhead. This demand is assumed to be met by stored hydrogen, so will not affect the peak number of reformers planned.

Green hydrogen plant/electrolyser build-out rates are likely to be the main constraint for scale-up of green hydrogen production. Generation of 20 TWh per year of green hydrogen in Scotland is assumed by 2050[4] .

Initially green hydrogen production is expected to be small to medium scale, up to circa 200 MW per unit, primarily using onshore wind or solar PV. This production would likely be co-located or near to end users. It is unlikely that renewable electricity resources will be the limiting factor in green hydrogen production as there could be significant offshore wind resource available that could meet the demand for green hydrogen.

Blue hydrogen generation is expected to be located at existing industrial sites. The system configuration chosen for the Project requires 20 reformers (assuming a capacity of 140,000 Nm3/h H_2 each), with 10 of these intended to be located at Grangemouth, six at St Fergus and four at Mossmorran.

The number of reformers has been selected to cover the winter peak in demand for gas heating without storage. This is due to current limitations in storage capacity, which is described in Section 7.

Figure 1-3 shows the proposed final hydrogen transmission system envisioned to be in place by 2045 that would include interconnectivity with the north of England. The figure also shows the location of blue hydrogen generation, indicated by blue dots. The figures within the blue dots indicates the number of reformers proposed for each location.

[3] This 2050 target is based on scaling 50 TWh of green hydrogen production in the UK to the Project Area as assumed by the Offshore Renewable Energy Catapult Wind and Hydrogen report.

[4] ORE Catapult Offshore Wind and Hydrogen report

This main hydrogen pipeline would link St Fergus and Grangemouth and would link up the existing natural gas national offtakes. An export pipeline would extend the main hydrogen pipeline south to connect with the future hydrogen system in England. This study has selected a base case route from Grangemouth to Longtown, following the routing of the existing SGN pipelines. Longtown has been provisionally selected as this is the existing interface of natural gas networks. It is, however, subject to further study, including consultation with studies for development of hydrogen networks in England.

Spur lines operating at the same pressure as the main hydrogen pipeline would take hydrogen to pressure reduction stations (PRSs) to lower the pressure to 7 bar to bring hydrogen into the existing local distribution zones to facilitate sectionalisation and changeover of users to 100% hydrogen.

The 7 bar systems are not included within the scope of this study and it is noted that, to complete the system there will be the requirement to install new 7 bar pipelines to extend the hydrogen system into user areas and allow staged conversion to hydrogen use.

System Configuration – CO_2 Infrastructure

The key locations in Scotland for dispatching captured carbon to offshore geological storage are from the north-east of Scotland and from the Firth of Forth. Existing emitters in the north-east and Central Belt area (e.g. at Grangemouth, Mossmorran, Dunbar and biomass emitters) are mainly at coastal locations therefore most of the CCS plants should be located near the coast.

The north-east CO_2 collection and transport system proposed as part of the Project would serve two sites: St Fergus Gas Terminal and Peterhead power station. At St. Fergus, six blue hydrogen reformers would be constructed and the CO_2 from these (produced at 20 barg) would be combined with CO_2 collected by post combustion processes at the gas terminal. At Peterhead, post-combustion CCS is assumed to be implemented on the power station from 2026 onwards.

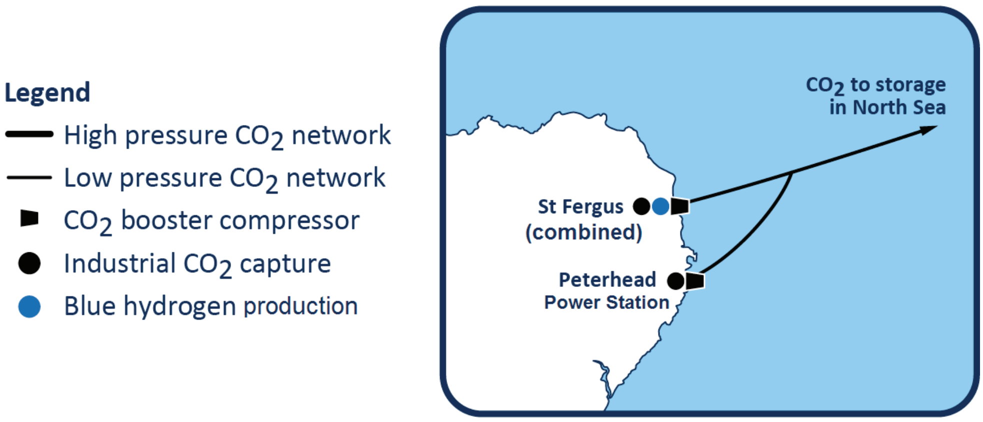


Figure 1-7 CO_2 Capture and Transport in the North East (2030 Onwards)

The main emitters of CO_2 in the Central Belt are from the Grangemouth industrial cluster, which is therefore likely to be the starting point for CO_2 capture in the area.

For the Project timeline, CO_2 capture is assumed to start at Grangemouth in 2025, with the proposed new CO_2 pipeline becoming operational. The need for carbon capture and storage at Grangemouth is driven by the need to decarbonise the Grangemouth cluster and reformers nearby will help support and reduce the costs of the CO_2 gathering infrastructure and pipeline overall requirements.

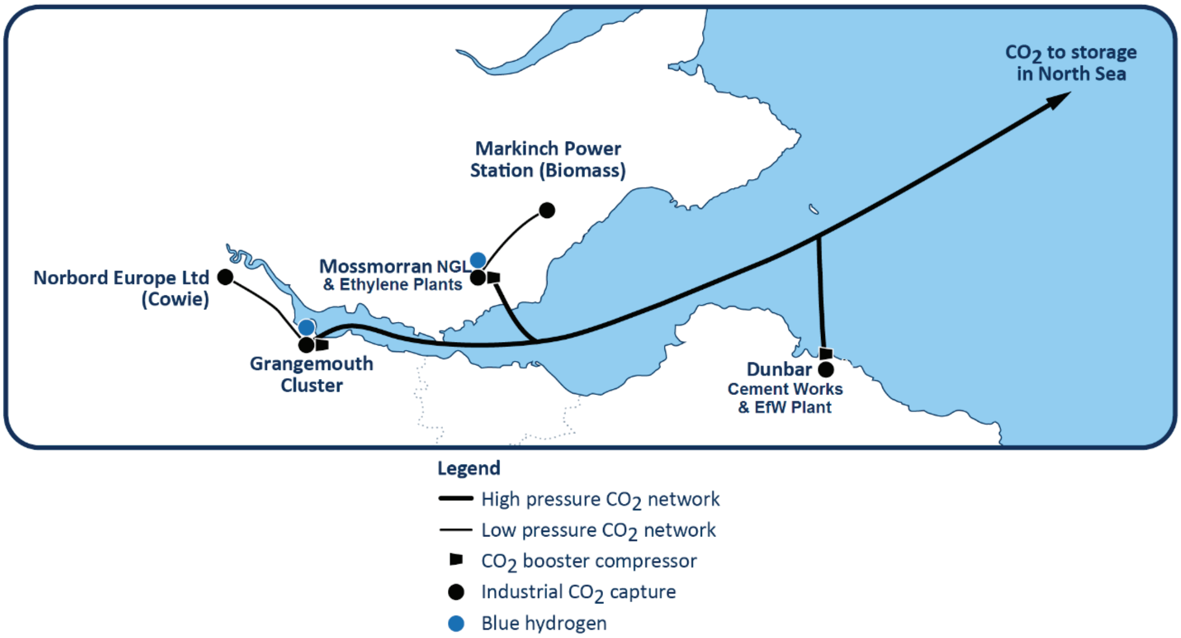


Figure 1-8 CO_2 Capture and Transport in the Central Belt (2040 Onwards)

The installation of this pipeline will enable construction of the proposed blue hydrogen reformers to commence in parallel. The reformers could share the CO_2 compression and transport infrastructure with the existing industrial cluster emitters proposed to be connected. The main CO_2 pipeline would run along the Firth of Forth and would include tie-in points for connections for CO_2 from Mossmorran and the Dunbar cement works.

CO_2 capture at Mossmorran is assumed to start around 2029/2030, with capture from the furnaces at the ethylene cracker, and CO_2 capture from major emitters at the adjacent Cowdenbeath Gas Terminal. With this in place, blue hydrogen production could start at the Mossmorran site.

The UK target for the cement industry envisages cement production being zero-emission by 2040, therefore CO_2 capture would need to be installed on the Dunbar cement plant by 2040. The adjacent energy from waste (EfW) plant is assumed to implement CCS at the same time, and the combined CO_2 from the two plants would use a common booster compressor to send high pressure CO_2 offshore via a pipeline which would join the main CO_2 line via a subsea pipeline.

The Central Belt CO_2 system has the potential to facilitate negative CO_2 emissions by connecting to two facilities in the area that emit significant amounts of CO_2 originating from biomass: the Markinch biomass power station and the Norbord factory at Cowie that can be used to offset any reformer inefficacies.

The Norbord factory at Cowie emits 0.3 million t/year CO_2 of which 60% originates from biomass. The area between Cowie and Grangemouth is mainly farmland, which is likely to be suitable for a low-pressure CO_2 gas connection to Grangemouth. Depending on the proportion of biomass in their fuel feedstock, there may be additional negative emissions associated with the cement plant and EfW plant at Dunbar.

Project Roadmap

A three-phase approach to the proposed system reconfiguration is anticipated for the hydrogen infrastructure, mainly based around hydrogen production locations:

- Hydrogen deployment phase 1 (2024 construction) – Aberdeen and St Fergus.
- Hydrogen deployment phase 2 (2025 construction) – Central Belt.
- Hydrogen deployment phase 3 (2026/7 construction) – East Coast.

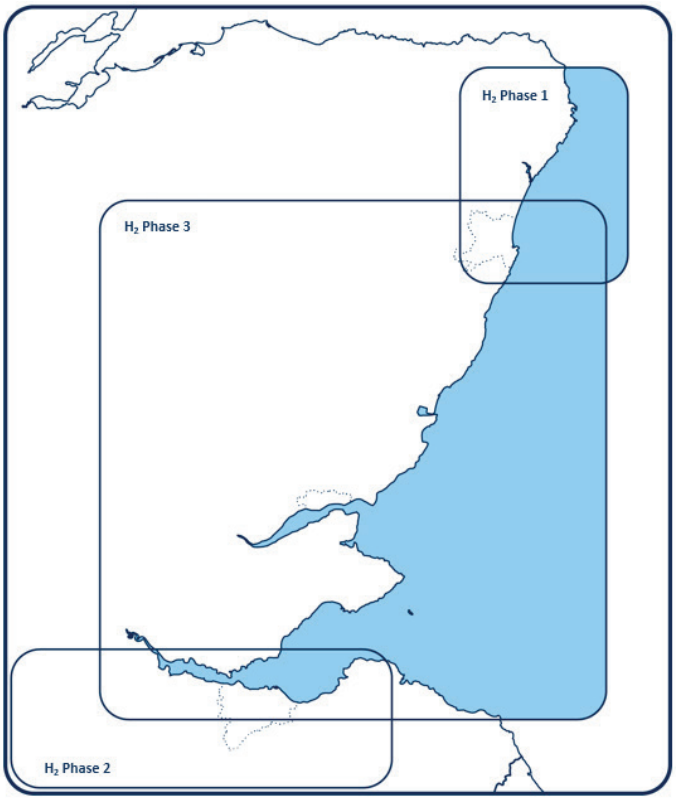


Figure 1-9 Hydrogen Infrastructure Phasing

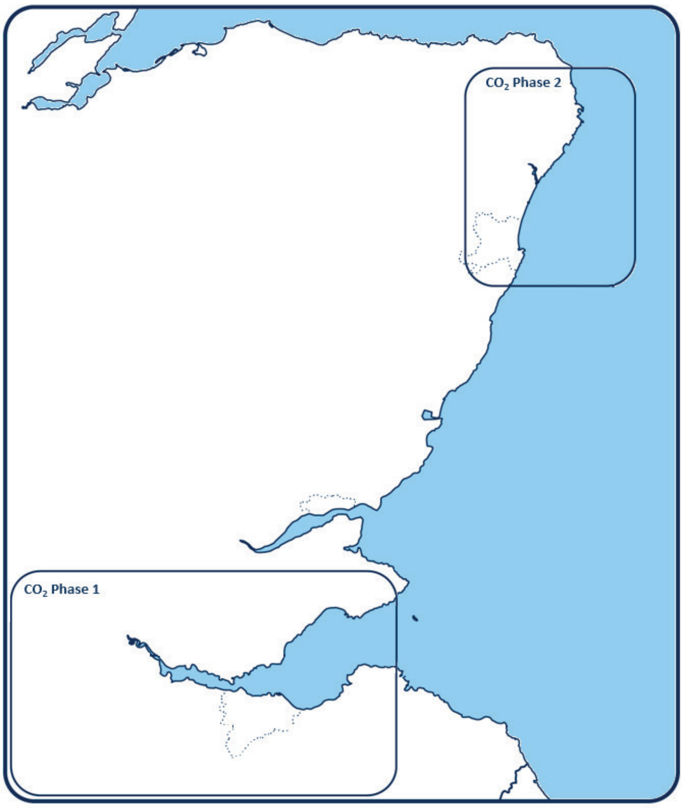


Figure 1-10 CO_2 Infrastructure Phasing

The proposed CO_2 collection and transport infrastructure would be deployed in two strategic areas:

- CO_2 deployment Phase 1 (2025 operational) – Central Belt.
- CO_2 deployment Phase 2 (2026 operational) – North east.

Deployment of complementary CO_2 infrastructure is expected at St Fergus as part of the Acorn CCS project.

Figure 1-11 below illustrates the required deployment of hydrogen production assets necessary to meet the proposed system reconfiguration objectives of decarbonising one million homes by 2030. Reformers (numbering 12 by 2030) would supply the bulk of the hydrogen supply though complemented by green production from early green hydrogen projects running in parallel such as Dolphyn.

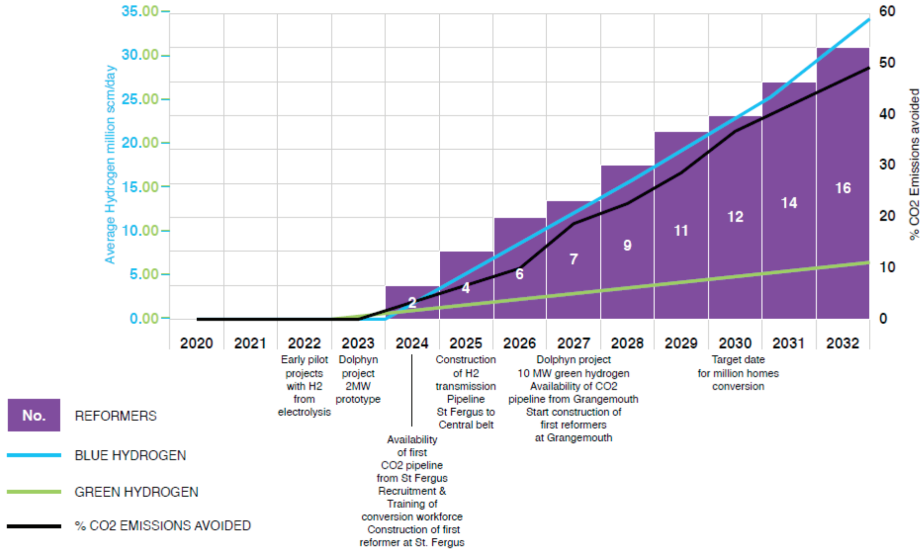


Figure 1-11 Roadmap to 2030

Figure 1-11 Roadmap to 2030

Figure 1-12 below illustrates the required deployment of hydrogen production assets necessary to support the Scottish Government's 2045 net-zero target. It is anticipated that 20 reformers would be required by 2034 to supply the bulk of hydrogen up to 2045, with a gradual increase in green hydrogen up to and beyond this date. This hydrogen capacity will meet the demand for the modelled sectors within the Project Area (see Figure 1-4). This includes hydrogen for fuel-switched domestic customers, new markets in the transport sector and exports. Hydrogen storage in porous rock formations is assumed to become available from 2045. The proposed Project roadmap includes flexibility: if storage in local porous rock formations becomes technically feasible earlier than expected (e.g., by 2030), it would be possible to reduce the numbers of reformers that are built and rely on storage to cover the winter peak in demand (see section 7 for further information).

The 20 reformers planned can be turned up to full utilisation with the additional output used to support hydrogen-based power production. It is anticipated that an increasing share of green hydrogen supplied beyond 2045 would displace blue hydrogen consumption in the Project Area over time. However, maintaining the number of reformers will allow for exports of blue hydrogen.

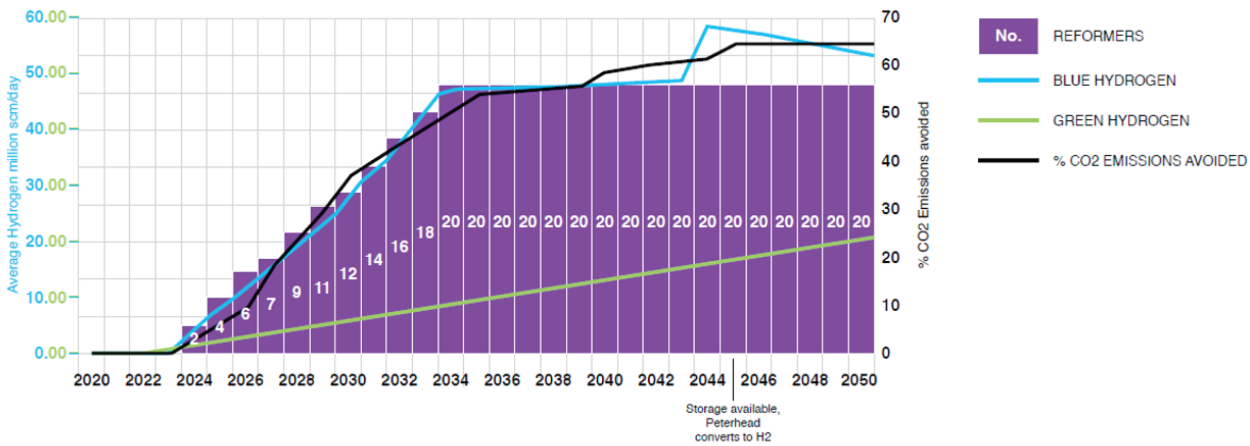


Figure 1-12 Roadmap to 2050

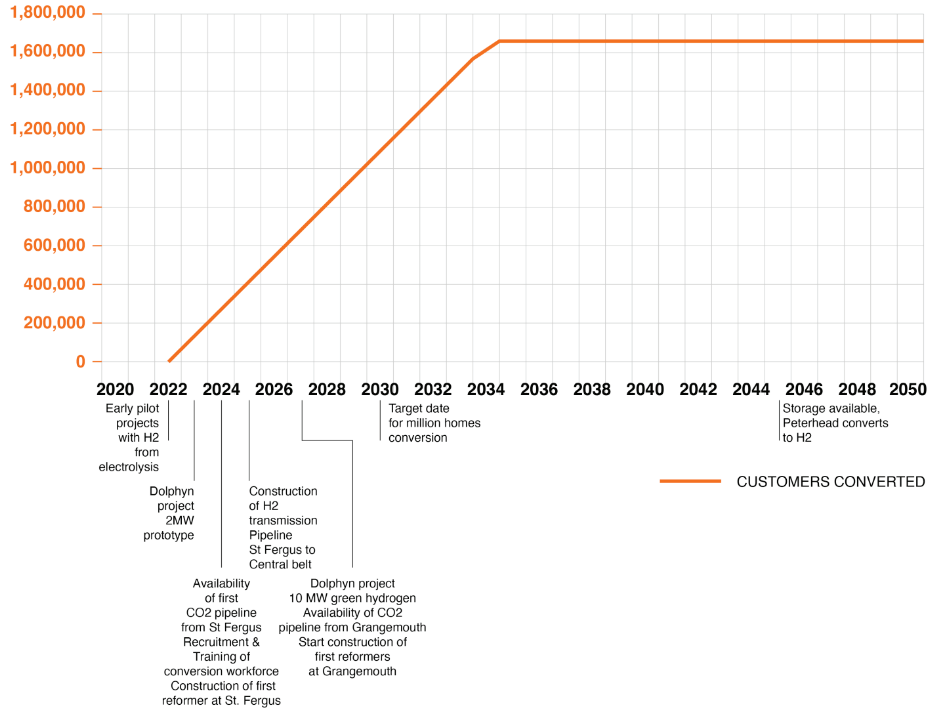


Figure 1-13 Customers Converted

Figure 1-12 shows the major contribution that the combination of CCS on existing emitters and decarbonisation of the grid (with blue and green hydrogen) could make to the decarbonisation of Scotland. These technologies can together avoid around 60% of Scotland's current CO2 emissions. The remaining 40% covers emissions outside the scope of the Project including:

- Geographical areas outside the Project Area (gas customers and industrial emitters) for example CO_2 emissions from hydrocarbon processing in Orkney and Shetland.
- Transport such as cars, where decarbonisation is assumed to involve electrification.
- Domestic and commercial premises not connected to SGN's gas distribution network.
- Domestic and commercial premises connected to independent town gas grids (statutory independent undertakings or SIUs) operated by SGN.
- Emissions from agriculture.

The CO_2 emission capture profile is based on the following dates for anticipated CO_2 capture:

Year	Event
2024	CO_2 capture at St Fergus, blue hydrogen production starts at St Fergus.
2024-2034	Ramp-up in blue hydrogen production.
2024-2050	Ramp-up in green hydrogen production.
2025	CO_2 capture starts at the Grangemouth cluster, ramping up over three years, blue hydrogen production starts at Grangemouth.
2030	CO_2 capture from Fife ethylene cracker and blue hydrogen production at Mossmorran.
2035	Bioenergy with carbon capture and storage (BECCS) at Norbord Cowie and Markinch power station.
2040	CO_2 capture at Dunbar cement plant.

Table 1-1 CO_2 Capture Events

The initial steep ramp-up to meet the 2030 target to decarbonise the heat demand in one million homes is challenging and is dependent on early construction at the Grangemouth cluster and at St Fergus. It will also require early availability of CO_2 pipelines from these locations to support blue hydrogen production otherwise alternative CO_2 sequestration options would need to be employed.

The profile for the CO_2 captured and stored is shown in Figure 1-14. This includes sites where CO_2 is generated as part of the process, and therefore cannot be mitigated by fuel switching. Figure 1-15 shows the CO_2 that would be abated through the use of green hydrogen: this is the amount of CO_2 which would have been emitted if natural gas were used instead of green hydrogen.

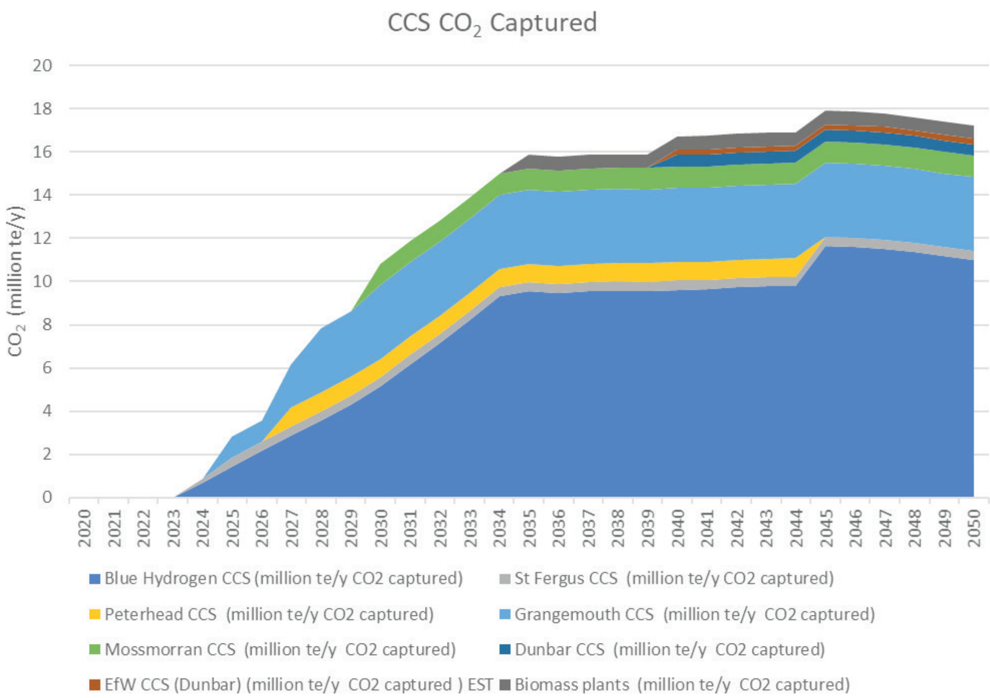


Figure 1-14 CO_2 Capture Profile

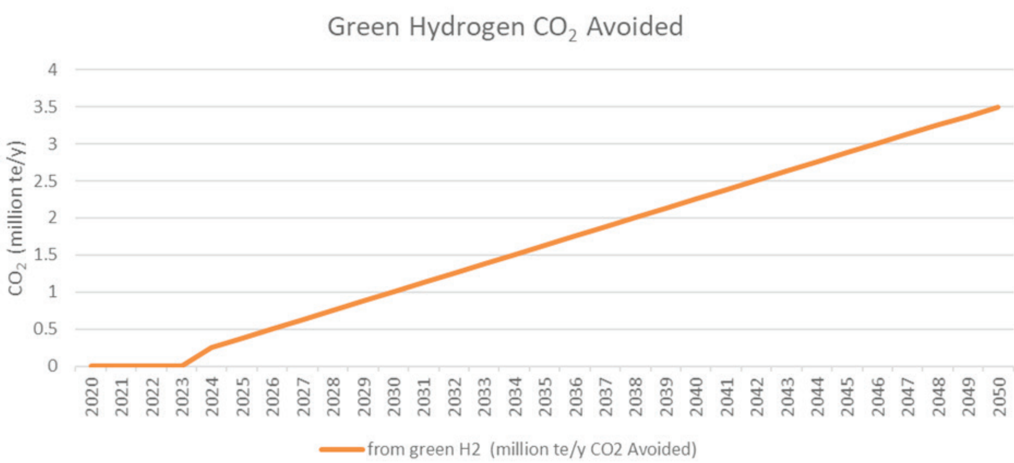


Figure 1-15 CO_2 Emissions Avoided due to Green Hydrogen Use

Financial Analysis

The capex estimate for the Project is based on the system re-configuration selected and is an order of magnitude (OOM) estimate, with a typical accuracy of ±50%, reflecting an instantaneous cost level of Q1 2021. The base estimate has been taken up to 'Project subtotal' level, which includes direct, indirect and service costs.

In Figure 1-16 below, the costs have been broken down into two categories:

1. The hydrogen system, covering the production, generation and transmission of green and blue hydrogen (and associated CO_2 transport for blue).

2. The CO_2 system serving industry, covering the transport (pipelines and booster compressors) of CO_2 from industries (not including CO_2 from blue production).

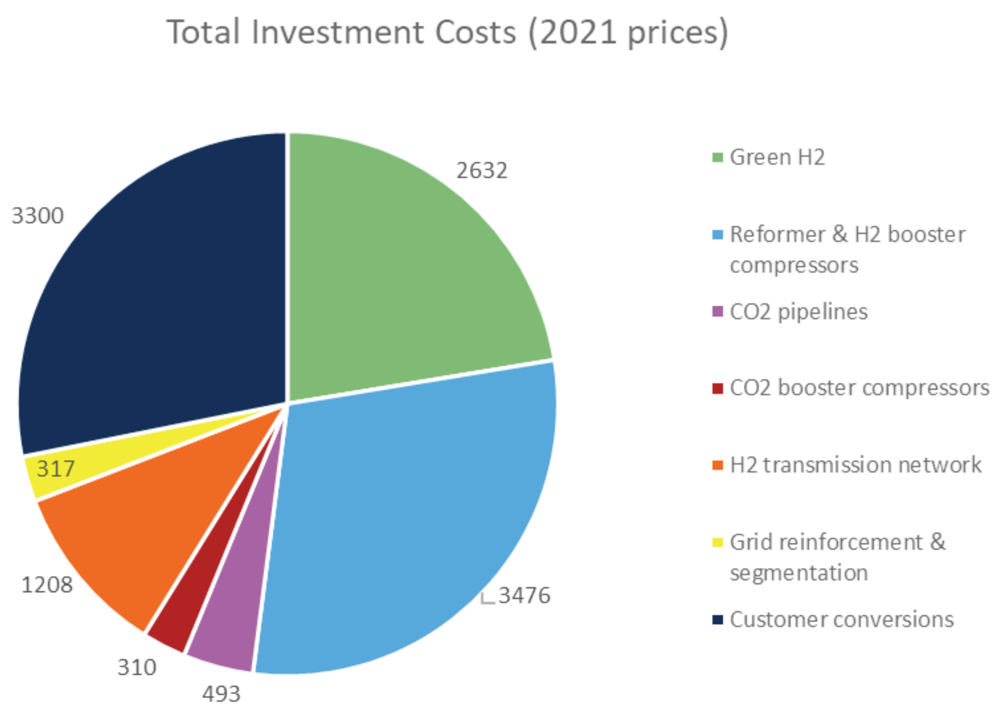


Figure 1-16 Total Investment Costs (£M)

The breakdown shows that the most significant costs are customer conversions to 100% hydrogen, and the hydrogen reformers. Green hydrogen generation accounts for a relatively high proportion of the cost as it has a higher cost uncertainty than the blue hydrogen components. This is because costs are forecast to change rapidly over the next 30 years.

If green hydrogen costs turn out to be higher than forecast, then less green hydrogen generation is likely to be built. Nevertheless, the peak demand in gas is met by blue hydrogen production, and as such the reformers and pipeline systems represent a low-regret investment. If green hydrogen costs come down more than forecast, more green hydrogen capacity is likely to be built, and the blue hydrogen reformer capacity could be used to increase hydrogen export to other regions.

The Project has developed an events timeline which drives the anticipated investment profile (Figure 1-17) for the proposed system reconfiguration as detailed in Section 14.2.

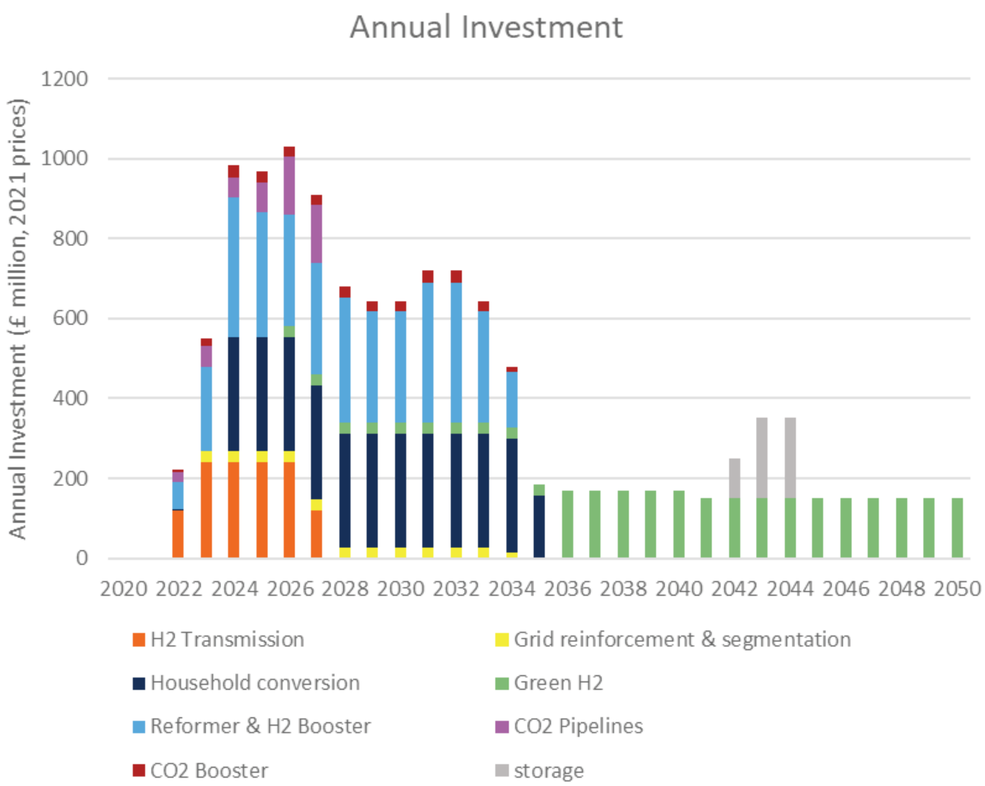


Figure 1-17 Investment Profile 2020-2050

From 2035 onwards enough reformers would have been constructed to be able to cover peak hydrogen demands. Investment in green hydrogen would continue, and could increase in pace after 2050, as costs come down.

If hydrogen geological storage becomes available post-2045, this is likely to support additional green hydrogen generation. A typical cost for a large geological storage facility has been included in the profile as an illustration (but this is not included in the total cost as it is not certain exactly when and if hydrogen storage would be constructed).

Hydrogen Production Costs Relative to Natural Gas Plus Carbon

Figure 1-18 below illustrates the data compiled from a number of sources to compare the projected cost of blue and green hydrogen production with a fully loaded carbon cost from the unabated burning of natural gas.

As governments have galvanised their commitments to a net-zero greenhouse gas emissions-based economy by 2050, removing unabated natural gas from the energy mix will be required. Traditionally, spatial heating with natural gas has typically been lower cost than electrical heating equivalent. A sustainable alternative is the use of low and zero carbon hydrogen for spatial heating.

Consequently, the ability to use natural gas on a distributed basis will require conversion to a renewable-based molecule in the form of green hydrogen. It is probable that blue hydrogen will provide a significant role in the energy mix due its ability to reach scale quickly combined with dispatchable energy delivery without the need for storage systems.

With ever decreasing carbon budgets the prospective cost of greenhouse gas emissions is expected to make the burning of unabated natural gas less uneconomic relative to blue and green hydrogen. Therefore, the role of green hydrogen in the mix is likely to play an important and affordable form of carbon abatement to reach net zero targets by 2045.

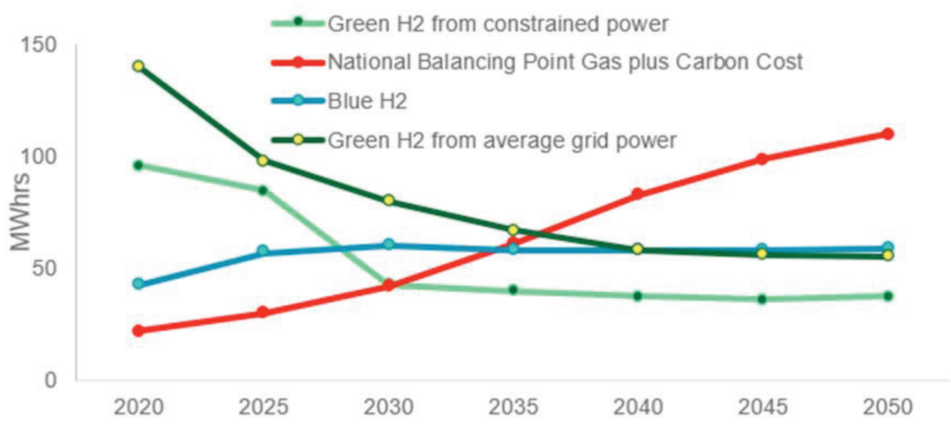


Figure 1-18 Levelised Cost of H_2 versus Natural Gas Plus Carbon

Source data: BEIS, BNEF, Element Energy, IRENA, H_2 Council, Navigant, National Grid FES, DNV-GL

Policy Alignment

The project has set out a roadmap and overview of how implementation of the Project would substantially contribute to a range of climate targets, policies and ambitions from a variety of applicable sources.

The Scottish Government has a number of relevant policies, such as the Climate Change Plan 2018-2032 and draft Heat in Buildings Strategy. The final assessment of the Project shows good alignment with the majority of UK and Scottish government goals with our detailed assessment presented in Section 15.5.

Recommendations and Next Steps

As a key next step, a detailed construction timeline should be produced based on the outline timeline provided, aligning with the Project objectives. The timing and availability of blue and green hydrogen should be established to ensure commitments and schedule can be met. Where possible, pipeline route corridors and proposed locations for reformers, pressure let-down stations, tie-ins/pigging facilities should also be established.

The detailed timeline could be developed in collaboration with key stakeholders and complementary hydrogen initiatives such as the Dolphyn and Acorn projects, or those arising from other offshore wind projects such as the recent ScotWind offshore wind leasing auction[5], which could be incorporated into Project deployment.

A detailed construction programme developed in conjunction with a network analysis/sectorisation for all phases would allow for the early identification of risks and opportunities and produce a set of early actions required to maintain the overall schedule. This would allow for detailed planning of workforce training and recruitment, requisite land acquisitions, planning and environmental consents, procurement of materials including long-lead and critical items, etc.

The production of a detailed construction programme would benefit from a degree of policy and regulatory certainty to ensure adequate alignment with the proposed technical reconfiguration of SGN's network. Until such certainty can be delivered by other actors, including the UK Government Department for Business, Energy & Industrial Strategy (BEIS) who are currently developing business models to support a future hydrogen economy, a number of steps can be taken to ensure SGN can maintain a pro-active approach in anticipation of greater policy clarity.

[5] https://www.crownestatescotland.com/our-projects/scotwind

This Project demonstrates that there is a decarbonisation option for the Project Area using hydrogen and CCS which is both technically and economically viable, with appropriate support. The adoption of the proposed Project roadmap could play a significant part in contributing towards Scottish and wider UK net zero targets. Providing a potential pathway to decarbonisation of the Project Area can help retain existing jobs, as well as create further permanent jobs in the long-term and construction work in the near-term.

These may include:

- Examine all industrial and commercial appliances within a designated conversion area as soon as possible to determine convertibility and readiness for initial blending and 100% hydrogen, ensuring that the supply chain has sufficient time, resources and incentives to develop hydrogen ready appliances where required.
- Assisting in the development of a streamlined approach to local planning could ensure a timely build-out programme. The distributed model of blue hydrogen production proposed would involve multiple local authorities with limited experience of hydrogen infrastructure planning applications.
- Continue to work with other stakeholder groups and local authorities to continually review and update total anticipated hydrogen demand and identify any new areas / locations for hydrogen applications.
- Advocating for hydrogen ready appliances to be mandated as soon as they become available to support the conversion programme in a timely manner.
- Developing a public engagement strategy which is comprehensive and widespread in its coverage as early as possible.
- Planning for workforce recruitment and training which will be essential to the successful delivery of the reconfiguration. The workforce will require specific hydrogen training in preparation for conversion.
- Monitoring progress with hydrogen geological storage initiatives such as HyStorPor which are investigating the potential for hydrogen storage in porous rock formations and HyScale project on LOHC solutions to storage.
- Sharing of robust and comprehensive evidence of hydrogen networks with policy makers such BEIS, the Scottish Government and Ofgem and captured as part of Ofgem's 'RIIO-3' business plan development.

2 Project Background

2. Project Background

North East Network & Industrial Cluster Development project constitutes a feasibility study investigating the potential to reconfigure SGN's gas distribution network in the north east and east coast of Scotland to separately transport hydrogen to end users and captured carbon dioxide (CO_2) to geological stores.

The Project consisted of four sequential feasibility phases:

Phase 1 Background and literature review.

Phase 2 Hydrogen use and carbon dioxide generation; system optioneering.

Phase 3 System configuration.

Phase 4 Analysis and conclusion.

This report summarises the findings of all phases of the Project and contains information on the activities undertaken.

The report provided details on the hydrogen generation, distribution and storage infrastructure along with the CO_2 capture, collection, transportation and storage infrastructure required to re-purpose SGN's network and meet several policy drivers. These include meeting the Scottish Government's target to convert 1 million homes to low carbon heating by 2030[6] and contributing to the government's 2045 target committing the country to 'net-zero' emissions of GHGs.

It is necessary to make certain assumptions during the study. Assumptions and external references used have been documented separately in the Project Terms of Reference document[7].

[6] Scottish Government - Draft Heat in Buildings Strategy

[7] X.19.00472.GLA.R.013 - Terms of Reference

3 Stakeholder Engagement

3. Stakeholder Engagement

The table below documents the activities and interactions undertaken as part of stakeholder engagement from project commencement to date. This table incorporates updates following the issue of our Phase 2 report to SGN. These engagements have primarily taken the form of one-to-one sessions.

The project originally sought to develop a 'bottom up' approach to estimating future hydrogen demand in the Project Area by canvassing stakeholders and collating their expected individual needs. Due to lack of requisite information from stakeholders it was determined that this approach was not viable, and an alternative method was adopted as described in Section 4.

On completion of the Project it is intended that relevant stakeholders will be engaged for a final briefing on the findings of this study which can feed into complementary initiatives being led by organisations such as NECCUS and ONE.

Next steps for stakeholder engagement can be found in Section 16.

Table 3-1 Stakeholder Engagement Organisation Type Notes

Organisation	Type	Notes
Aberdeenshire Council	Policy	Meeting held on 17 August 2020. Information exchange agreed and further combined local authority meetings agreed. Update meeting held on 14 December 2020.
Crown Estate Scotland	Policy	Meeting held on 21 September 2020. Interest in offshore super-grid work.
Diageo	Industry	Meeting held on the 28 of October 2020.
DNV GL	Industry	Part of joint progress update with Petroineos and SGN on 25 February 2021.
Energy Systems Catapult	Policy	Meeting held on 28 August 2020.
ERM / Dolphyn	Industry	Meeting held on 24 September 2020. Follow-up meeting held on 27 November 2020.
Falkirk Council	Policy	Meeting held on 11 September 2020.
Fife Council	Policy	Meeting held on 10 August 2020.
Food & Drink Federation	Industry	Meeting held on 11 September 2020.
Forth Ports	Industry	Meeting held on 16 October 2020.
Ineos	Industry	Meeting held on 08 October 2020.
National Grid	Industry	Meeting held on 25 August 2020. Part of joint progress update meeting with Pale Blue Dot and SGN on 24 February 2021.

Organisation	Type	Notes
NECCUS	Industry	Meeting held on 12 August 2020 (joint with Scottish Enterprise). Follow-up meeting held on 04 December 2020 (joint with Scottish Enterprise). Follow-up meeting held on 22 January 2021 (joint with Scottish Enterprise and SHFCA).
Oil & Gas Technology Centre (OGTC)	Industry	Meeting held on 04 of December 2020.
ORION	Industry	Meeting held on 14 December 2020.
Pale Blue Dot	Industry	Meeting held on 27 August 2020. Update meeting held on 25 November 2020. Part of joint progress update meeting with National Grid and SGN on 24 February 2021.
Petroineos	Industry	Meeting held on 15 September 2020. Participated in joint progress update with DNV and SGN 25 February 2021.
Scott Pollock Transport	Industry	Meeting held on 17 August 2020.
Scottish Carbon Capture & Storage	Industry	Meeting held on 30 September 2020. Information on HyStorPor project provided.
Scottish Enterprise	Policy	Meetings held on 12 August 2020, 04 December 2020, and 22 January 2021 (joint with NECCUS).
Scottish Hydrogen and Fuel Cell Association	Industry	Meeting held on 14 August 2020.
Scottish Maritime Cluster	Policy	Meeting held on 19 February 2021 to discuss marine fuel consumption.
Scottish Water	Policy	Meetings held on 05 November 2020, 16 December 2020, and 11 January 2021.
Scottish Whisky Association	Industry	Meeting held on 21 August 2020.
SSE	Industry	Meeting held on 11 September 2020.
Tarmac	Industry	Meeting held on 11 January 2021.
Transport Scotland	Policy	Meeting held on 01 October 2020.
Cities Alliance		

4 System Reconfiguration Options Appraisal

4. System Reconfiguration Options Appraisal

An extensive optioneering exercise was undertaken to determine the optimal reconfiguration of SGN's gas network, taking into account the various aspects pertaining to potential hydrogen opportunities and CO_2 generation within the Project Area as discussed in Section 8 and Section 4.2 respectively.

Wood's previous experience has shown that assessments that are outcome focused and evidence based are the most robust. Wood has therefore utilised a robust, multi-stage and multi-criteria methodology for shortlisting the proposed options to support the Project. Options refers to different schemes which have been developed by the Project team and validated by SGN for transporting hydrogen to end users and captured CO_2 to geological stores.

This methodology, illustrated in Figure 3-1 below, utilised multi-criteria decision analysis (MCDA), following established UK Government standards[8] and best practice; using an industry recognised multi-criteria decision-making process to facilitate the identification and assessment of options. All options considered contribute towards achieving the Scottish Government's commitment to making Scotland net-zero by 2045. It was essential that the evidence basis supporting the MCDA analysis was robust and transparent in order to ensure both quality and reliability of the assessment outcomes. As such, all aspects of the evidence basis have been provided and peer reviewed.

The options assessment that forms a central part of the methodology was used to identify a hierarchy of options that will be progressed to Phase 3 of the project. A robust options assessment process built around MCDA has been implemented to inform the development of the Project. This approach is based on the following key steps:

- Identification of a comprehensive long list of options.
- Definition of minimum requirements.
- Screening of options using minimum requirements.
- Development and definition of assessment criteria.
- Development of criteria weighting schemes.
- Detailed options assessment using Wood's in-house DecisionVue[9] software platform; and
- Production of the robust options hierarchy tested through sensitivity analysis.

These steps were informed, developed and subsequently refined using information and feedback received from members of the Project team and SGN. Internal peer review and SGN feedback was sought at each stage in the process to ensure a robust approach. Figure 4-1 presents an overview of these key steps.

[8] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/191506/Mult-crisis_analysis_a_manual.pdf

[9] Wood's DecisionVue platform is based on Multi Criteria Decision Analysis (MCDA) and Robust-Utility Analysis (RUA), a quantitative decision making under uncertainty evaluation technique, which compares options or strategies based on their performance and robustness across a range of possible futures.

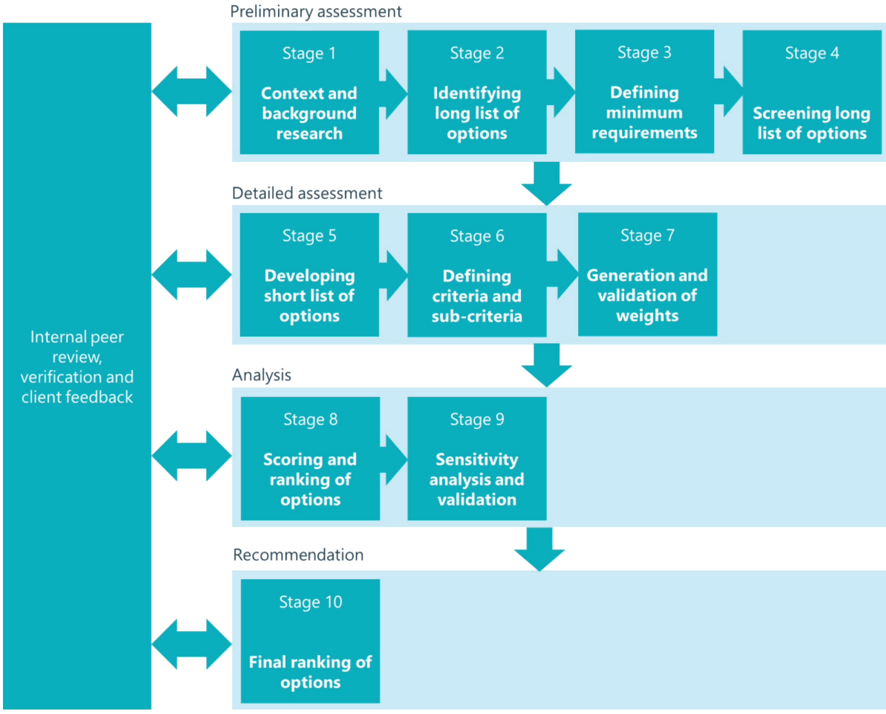


Figure 4-1 Option Appraisal Process inc. Internal Peer Review and SGN Validation

The review of relevant background information established the context for the assessment and identified key factors that have the potential to influence decision making. The options assessment was undertaken in stages which enabled the team to progressively refine the list of options over time in response to new evidence.

The preliminary assessment stages involved the identification and screening of options. The objective of this stage was to identify a comprehensive list of technically and economically feasible solutions. Absolute minimum requirements (hard constraints) were then used to screen out those options that would not satisfy the Project objectives or impeded by other Project constraints such as consenting risks and financial or technological constraints.

Further detail relating to the optioneering appraisal methodology can be found in the Project Phase 2 report[10].

4.1 Options Assessment

A range of technically feasible options were initially developed based on different potential blue and green hydrogen configurations, each one capable of addressing the strategic objectives of the Project. A list of eight options were subsequently identified and screened against the hard constraints identified during the first joint workshop. This exercise revealed that while all eight options satisfied the minimum requirements, subsequent discussions between members of the Project team and SGN highlighted several potential gaps in terms of different configurations of the planned hydrogen pipeline. As a result, a further five options were added to the initial list of options producing 13 shortlisted options which would be subject to the full MCDA assessment. These 13 options are summarised in Table 4-1 below. Illustrations of the optioneering cases described above can be found in Appendix A of the Project Phase 2 report.

[10] X.19.00472.GLA.R.022 - Phase 2 Report

The additional five options were identified from a combination of observations and assumptions made by members of the Project team during the first joint workshop covering the reuse of existing facilities and infrastructure including National Transmission System (NTS) feeder pipeline 'F13'. Use of this particular pipeline could reduce incurred capital costs through reuse of an existing asset. Additionally, there may be a saving on construction emissions from re-using this existing pipeline; however, at this level of engineering design it is not possible to quantify this against construction of a new pipeline.

F13 was constructed in 1982 and thus incurs a risk of increased maintenance and shorter design life. These trade-offs were considered within this particular assessment and reflected in the resilience and constructability criteria. At the time of this report publication the suitability of re-using F13 for transport of 100% hydrogen has not been proven and is the subject for ongoing research and development. This uncertainty is reflected in the disadvantages listed in Table 4-1 below

Table 4-1 Summary of Optioneering Cases and Descriptions, and their Advantages and Disadvantages

Case ID	Description	Blue H_2 Production	Blue H_2 Location	H_2 Transmission Pipeline	Main Advantages	Main Disadvantages
C(SF)L	Blue hydrogen production centralised at St. Fergus with Onshore Hydrogen transmission pipeline.	Centralised	St. Fergus	Onshore (Land)	Onshore hydrogen system offers more opportunities for early adopters and faster decarbonisation.	Centralised location less resilient against disruption (e.g. natural disaster).
C(SF)S	Blue hydrogen production centralised at St. Fergus with Offshore Hydrogen transmission pipeline.	Centralised	St. Fergus	Offshore (Sea)	Long term potential to connect to offshore hydrogen generation.	Centralised location less resilient against disruption (e.g. natural disaster).
C(CB)L	Blue hydrogen production centralised at a single location in the Central Belt with Onshore Hydrogen transmission pipeline.	Centralised	Central Belt	Onshore (Land)	Onshore hydrogen system offers more opportunities for early adopters and faster decarbonisation.	Centralised location less resilient against disruption (e.g. natural disaster).
C(CB)S	Blue hydrogen production centralised at a single location in the Central Belt with Offshore Hydrogen transmission pipeline.	Centralised	Central Belt	Offshore (Sea)	Long term potential to connect to offshore hydrogen generation.	Centralised location less resilient against disruption (e.g. natural disaster).

Case ID	Description	Blue H_2 Production	Blue H_2 Location	H_2 Transmission Pipeline	Main Advantages	Main Disadvantages
DL	Blue hydrogen production distributed at several locations with Onshore Hydrogen transmission pipeline.	Distributed	Distributed	Onshore (Land)	Dispersed production of blue H_2 gives better resilience of gas supply. Multiple sites give opportunities of early adopters and faster change. Flexible about where to build first Multiple sites spread economic benefit and jobs. Onshore H_2 transmission gives more opportunities for early adopters. Opportunities for H_2 export from ports.	Onshore H_2 transmission more difficult to connect to offshore green H_2 (long term).
DS	Blue hydrogen production distributed at several locations with Offshore Hydrogen transmission pipeline.	Distributed	Distributed	Offshore (Sea)	Distributed location more resilient against disruption (e.g. natural disaster). Multiple sites give opportunities for early adopters and faster change. Flexible about where to build first. Multiple sites spread economic benefit and jobs. Long term potential to connect to offshore hydrogen generation. Long term potential to connect to offshore hydrogen storage facilities.	Offshore H_2 pipeline offers fewer opportunities to reuse existing infrastructure. Offshore hydrogen transmission more difficult to tie into, especially for early projects around Aberdeen.

Case ID	Description	Blue H_2 Production	Blue H_2 Location	H_2 Transmission Pipeline	Main Advantages	Main Disadvantages
C(SF)LA	As C(SF)L but reusing Feeder 13 for Hydrogen transport.	Centralised	St. Fergus	Onshore (Land) reusing F13 (A)	Avoids delays associated with permitting and constructing a new pipeline. 40” line should give plenty of capacity. Capex saving of approx. £360 million. Could blend to 20% at St. Fergus and transport to Aberdeen as 20% H_2.	F13 was constructed in 1982, therefore risk of increased maintenance and shorter design life. Metallurgy might not be suitable for 100% H_2 service. Metallurgy might not provide the assurance of safety that a new pipeline would, reating difficulty with consent and public perception. Limited to maximum allowable operating pressure (MAWP) of existing pipeline. Reduces capacity of NTS between St. Fergus and Aberdeen.
DLA	As DL but reusing Feeder 13 for Hydrogen Transport.	Distributed	Distributed	Onshore (Land) reusing F13 (A)		
C(SF)LB	As C(SF)L but part reusing Feeder 13 for Hydrogen transport.	Centralised	St. Fergus	Onshore (Land) part reusing F13 (B)	Avoids delays associated with permitting and constructing a new pipeline. 40” line should give plenty of capacity. Capex saving of approx. £50 million. Could blend to 20% at St. Fergus and transport to Aberdeen as 20% H_2.	F13 was constructed in 1982, therefore risk of increased maintenance and shorter design life. Metallurgy might not be suitable for 100% H_2 service. Metallurgy might not provide the assurance of safety that a new pipeline would, creating difficulty with consent and public perception. Limited to MAWP of existing pipeline. Reduces capacity of NTS between St. Fergus and Aberdeen.
C(CB)LB	As C(CB)L but part reusing Feeder 13 for Hydrogen transport.	Centralised	Central Belt	Onshore (Land) part reusing F13 (B)		
C(CB)SB	As C(CB)S but part reusing Feeder 13 for Hydrogen transport.	Centralised	Central Belt	Offshore (Sea) part reusing F13 (B)		
DLB	As DL but part reusing Feeder 13 for Hydrogen Transport.	Distributed	Distributed	Onshore (Land) part reusing F13 (B)		
DSB	As DS but part reusing Feeder 13 for Hydrogen Transport.	Distributed	Distributed	Offshore (Sea) part reusing F13 (B)		

Case ID	Description	Blue H_2 Production	Blue H_2 Location	H_2 Transmission Pipeline	Main Advantages	Main Disadvantages
Onshore CO_2 Pipeline	Onshore pipeline for captured CO_2 running from Central Belt to St. Fergus, then offshore to storage.	N/A	N/A	N/A	Easier to tie-in additional CO_2 sources. Potential to re-use existing infrastructure.	Inherent safety not as good as offshore option. Potentially more difficult to consent.
Offshore CO_2 Pipeline	Offshore pipeline for captured CO_2 running from Central Belt to St. Fergus, then offshore to storage.	N/A	N/A	N/A	Better inherent safety than onshore (little public exposure to risk). Easier to consent. More resilient (less exposure to damage or disruption). Potentially faster construction enabling faster decarbonisation.	

4.2 Assessment Criteria

Each of the options were scored using professional judgement and supporting data against an agreed set of criteria developed during the project. Weightings were generated and applied to the scored options using Wood's DecisionVue software to support detailed assessment. DecisionVue was used to undertake rapid sensitivity analysis and explore the robustness of the outcomes as well identify model sensitivities that could impact the preferred solution for the Project. Twenty-three discrete sub-criteria were developed under the following seven main criteria:

Criterion	Description
Impact	The effect on decarbonisation, safety and consumer price of the scheme.
Transition	How the sector will be converted from natural gas to blended natural gas and hydrogen, then to 100% hydrogen, and how blue hydrogen will transition to green hydrogen.
Infrastructure	Reuse of existing facilities, and reliability and constructability of the system.
Network	How hydrogen is distributed through the network, including the number of injection nodes and PRSs.
Security of Supply and Storage	How the system can cope with changes in future demand.
Levelised cost of energy (LCOE)	The financial cost/viability of scheme.
Barriers	Describes barriers such as public perception and regulatory factors.

Table 4-2 Main Assessment Criteria

The full list and definitions of criteria, sub-criteria, and referenced low and high scoring options can be found in Section 6.2 of the Project Phase 2 report.

Each of these criteria were developed following extended consultation and discussions during Project team meetings, ensuring that each element of the decision and any factors which could impact the future viability of the scheme were adequately captured and assessed. It was critical that each criterion was sufficiently discrete, clearly defined and could be used to assess the performance of each option in an objective and semi-quantitative manner (i.e. using a 1-9 numerical scale informed using professional judgement), following best practice.

To ensure this, internal peer review and validation as well as additional quality assurance checks were undertaken by members of the Project team. Additionally, criteria and sub-criteria were assessed against the following MCDA principles and questions, consistent with UK Governmental guidance and best practice:

- **Completeness:** have all important criteria been included?
- **Redundancy:** are there criteria included which are unnecessary?
- **Operationality:** can each option be judged against each criterion?
- **Mutual independence of preferences:** can preference scores be assigned to one option based on one criterion without knowing what the options' preference scores are on any other criteria?
- **Double counting:** have all criteria which could result in double-counting been removed?
- **Size:** does the value tree contain an excessive number of criteria leading to extra analytical effort and deterioration in input data?
- **Impacts occurring over time:** is time included as an explicit function? This can be modelled as a separate criterion, with a non-linear value function.

4.3 Criteria Scoring

Weighting were generated for each criterion using an analytical hierarchical process (AHP). This particular method comprised a series of simultaneous pairwise comparisons to rank the relative importance of each criteria (against every other criteria) as well as additional validation checks. The criteria and weightings were then digitised in DecisionVue creating a sunburst plot with the relative size of each wedge indicating its overall importance of a particular criterion to the decision outcome. Further details of the AHP method and example pairwise comparisons can be found in Section 6.4 of the Phase 2 report.

Criterion	Weight
Impact	35.84%
Transition	5.15%
Infrastructure	5.43%
Network	5.59%
Security of Supply & Storage	30.55%
Cost	9.65%
Barriers	7.79%

Table 4-3 Generated Weights from AHP Pairwise Comparison

Weighted scores of the options, against each criterion, were subsequently fed into DecisionVue to generate a hierarchy of options, which was subject to further sensitivity analysis. This involved scaling the original weights by a factor and recording the equivalent change in option rank and score.

An example sunburst plot, showing the relative weighting of each criterion (based on the size of wedge) is shown in Figure 3-2 below. The sunburst plot illustrates different criteria and sub-criteria according to colour, with relative weightings represented by segment sizes.

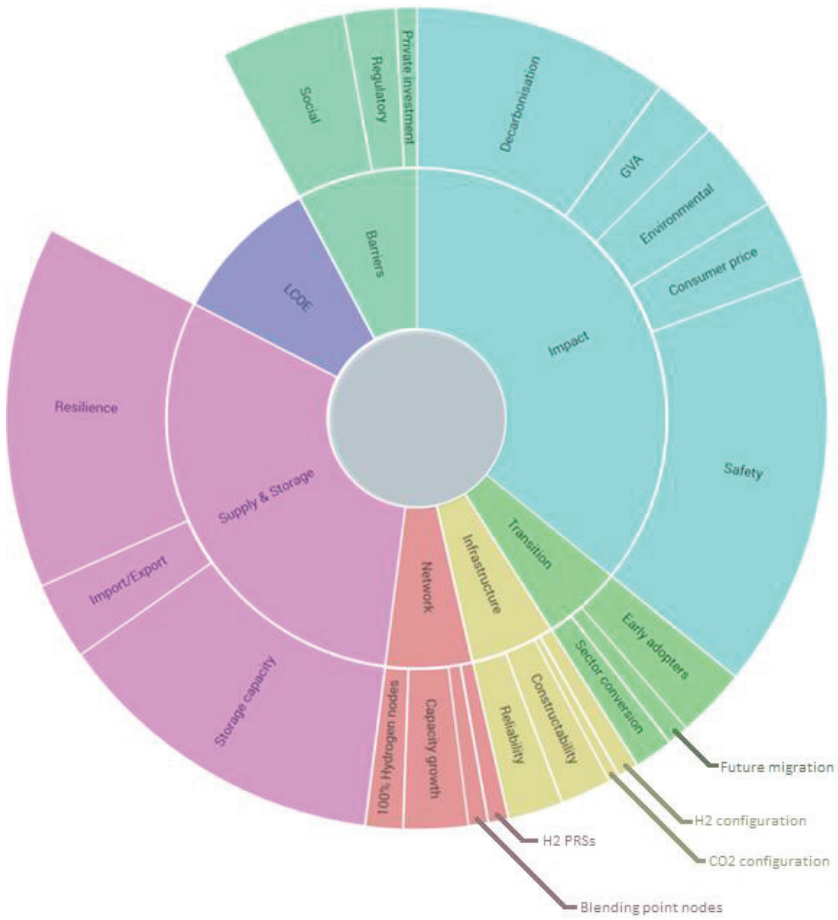


Figure 4-2 Example DecisionVue Sunburst Plot

Following the detailed assessment, several low performing options (n=7) were eliminated from further analysis. Those options scoring more highly (n=6) were developed further, creating an equivalent CO_2 onshore transmission (n=6) and CO_2 offshore transmission (n=6) configuration for each option (i.e., 12 options total). These new option iterations were then re-scored using the above methodology using the previously defined weighting scheme. The detailed assessment produced a provisional ranking of options. This ranking was then subject to further verification by SGN and extended peer review and challenge.

4.4 Options Ranking

As shown in Figure 4-3 and Table 4-4, the ranked options were split into four groups comprising (i) High Priority; (ii) Medium Priority; (iii) Low Priority and (iv) Eliminated options. These groups of options have been determined based on their total weighted score. The total score for each option is shown below in Table 4-4 together with the relative score for each criterion. Generally, options which scored more highly, tended to also perform well across all criteria.

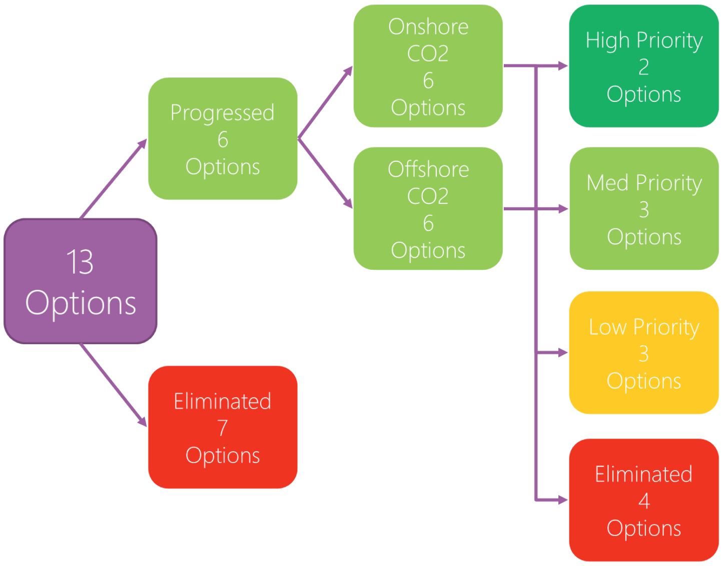


Figure 4-3 Option Ranking and Elimination Process

Options Performances			
High priority	**Medium priority**	**Low priority**	**Eliminated**
DL - Offshore CO_2 DS - Offshore CO_2	C(CB)S - Offshore CO_2 DL - Onshore CO_2 DS - Onshore CO_2	DLB - Offshore CO_2 C(CB)L - Offshore CO_2 DLA - Offshore CO_2	C(CB)S - Onshore CO_2 DLB - Onshore CO_2 C(CB)L - Onshore CO_2 DLA - Onshore CO_2
Options Descriptions			
C(SF)L	Blue hydrogen production centralised at St. Fergus with onshore hydrogen transmission pipeline.		
C(SF)S	Blue hydrogen production centralised at St. Fergus with offshore hydrogen transmission pipeline.		
C(CB)L	Blue hydrogen production centralised at a single location in the Central Belt with onshore hydrogen transmission pipeline.		
C(CB)S	Blue hydrogen production centralised at a single location in the Central Belt with offshore hydrogen transmission pipeline.		
DL	Blue hydrogen production distributed at several locations with onshore hydrogen transmission pipeline.		
DS	Blue hydrogen production distributed at several locations with offshore hydrogen transmission pipeline.		
C(SF)LA	As C(SF)L but reusing Feeder 13 for hydrogen transport.		
DLA	As DL but reusing Feeder 13 for hydrogen transport.		
C(SF)LB	As C(SF)L but part reusing Feeder 13 for hydrogen transport.		
C(CB)LB	As C(CB)L but part reusing Feeder 13 for hydrogen transport.		
C(CB)SB	As C(CB)S but part reusing Feeder 13 for hydrogen transport.		
DLB	As DL but part reusing Feeder 13 for hydrogen transport.		
DSB	As DS but part reusing Feeder 13 for hydrogen transport.		
Onshore CO_2 (Pipeline)	Onshore pipeline for captured CO_2 running from Central Belt to St. Fergus, then offshore to storage.		
Offshore CO_2 (Pipeline)	Offshore pipeline for captured CO_2 running from Central Belt to St. Fergus, then offshore to storage.		

Table 4-4 Option Groupings Based on Relative Performance

Sensitivity analysis revealed that the options formed clustered groups comprising:

- High performing;
- Middling performance; and
- Those which performed poorly.

Varying the weighting of individual criteria resulted in limited re-ranking of options; however, this rarely resulted in significant changes to the composition of these groups (i.e. options moving between groups) suggesting that they provide a reasonably robust characterisation of the option prioritisation.

The options groups were found to be largely insensitive to variations in the proposed weighting scheme. Some re-ranking of options was apparent within option groups when subject to extended sensitive analysis (i.e. varying the weight of individual criteria by a stated multiplier). However, this did not result in a material change in terms of the top ranked options.

While the AHP exercise revealed some differences in proposed weightings across individual experts, this did not result in a significant difference in terms of the ordering of options, with all experts largely agreeing on the preferred course of actions, despite some individuals occasionally favouring one criterion over another. Sensitivity analysis was conducted on both weights and scores and the ordering of options was found to be relatively robust across different assumption sets.

The following option from the high-performance group was ultimately selected for further development:

- Preferred option (1st ranked) 'DL - Offshore CO_2' - Distributed blue hydrogen production and onshore hydrogen transmission with offshore CO2 transmission (illustrated in Figure 4-4 below).

- The dispersed production of blue and green hydrogen adopted by this option has the advantage of greater resilience to disruption and therefore a more reliable gas supply, when compared with a centralised option, with multiple sites spreading economic benefits whilst providing more opportunities for early adopters and offering flexibility with respect to the order of deployment.

The onshore hydrogen transmission pipeline offers opportunities to connect early adopters and fits well with current project plans for the Aberdeen area, including the Acorn project and future plans at Peterhead Power Station. Onshore hydrogen transmission also offers more opportunities for supplying the marine, road and aviation transport sectors.

The offshore CO_2 pipeline system does not offer many opportunities to re-use existing infrastructure, but has the important advantage of being inherently safer than onshore, due to reduced threat to public exposure to CO_2 in the event of a leak and considers such a system to be more likely to be secured.

Figure 4-4 Option 'DL - CO_2'

Legend

- New main hydrogen trunkline
- Alternative main hydrogen trunkline
- Main hydrogen spur line
- Repurposed existing spur line
- New hydrogen spur line
- New or repurposed spur line
- CO_2 network
- H_2 network **(offshore storage)**
- Proposed green hydrogen production
- Proposed blue hydrogen production (No. = SMRs/ATRs to be constructed)
- City/Town

Note: PRSs are located at the outlet end of each spur line.

A summary sunburst plot was produced for the top scoring option ('DL - Offshore CO_2') using DecisionVue (Figure 3-5). This plot shows the relative performance for individual criteria (compared with other options) as well as potential trade-offs where the reference option scores more highly for one criterion at the expense of another.

The project has progressed option DL - Offshore CO_2 to further development. This decision was taken as this particular option scored significantly better than all others and was found to be relatively robust to changing assumptions.

Additional rationale for the selection of option DL - Offshore CO_2 as the preferred scheme was also provided and reconfirmed by SGN. The perceived benefits of an onshore hydrogen transmission system with offshore CO_2 removal are summarised as:

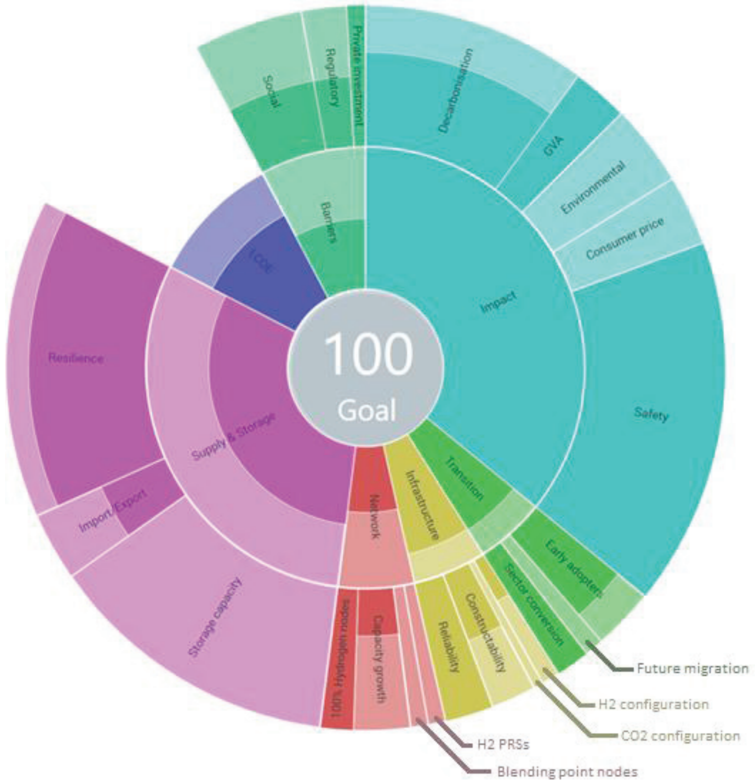
- The build-out is expected to start with early supply of green hydrogen from the Dolphyn project[11] to the south of Aberdeen which will eventually integrate into the wider onshore blue hydrogen transmission system proposed.
- Future green hydrogen generation at Peterhead will have access to the proposed hydrogen transmission system.
- Avoids having to build a separate hydrogen pipeline from St Fergus to Kinknockie to supply Peterhead.
- Onshore hydrogen solutions may favour transport hub connections or options to compress and transport hydrogen to remote areas.
- Future expansion of offshore hydrogen can be integrated into the new system.
- Offers opportunities for import and export of hydrogen i.e. suitable locations for shipping.
- Offers flexibility that can more easily help in construction phasing and future access to funding.
- Likely to stimulate faster hydrogen uptake amongst end users, helping to decarbonise the heat demand of one million homes by 2030 in line with the Scottish Government's target[2].

Conversely, the perceived drawbacks to an opposing shortlisted option comprising offshore hydrogen transmission were considered as follows:

- An offshore transmission system that lands north of Aberdeen makes it more complicated to distribute hydrogen to locations proposed for Aberdeen.
- Offshore hydrogen producing wind farms will likely incur at least the same downtime and maintenance issues as conventional offshore wind assets and therefore less resilient than a system built around an onshore supply of blue hydrogen produced from natural gas reformation.

[11] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/866375/Phase_1_-_ERM_-_Dolphyn.pdf

Figure 4-5 Summary Plot of Primary Preferred Option



DL - Offshore CO_2 - Distributed Blue H_2 production and onshore hydrogen transmission with offshore CO_2 transmission.

Total Score: 100%

Summary:

Dispersed blue H_2 production improves resilience and supply reliability, and onshore H_2 transmission provides opportunities for early adopters. Offshore CO_2 pipeline assumed safer and therefore easier to consent.

#	Criteria	Score
	Impact	100
	Transition	80
	Infrastructure	79
	Network	46
	Security of Supply & Storage	56
	LCOE	67
	Barriers	50

4.5 Conclusion

SGN has completed an assessment of the hydrogen opportunities available with potential demand modelling, alongside an assessment of CO_2 removal requirements within the Project Area. This has allowed for a variety of system re-configuration options to be proposed that would convert SGN's network to provide hydrogen (both pure and blended) streams to end users and provide a CO_2 removal service for existing point source emitters and blue hydrogen producing gas reformation plants. These options also anticipate import and export of these services by pipeline and/or shipping.

SGN has used multi-criteria decision analysis, following established UK Government standards and best practice; using an industry recognised multi-criteria decision-making process to facilitate the identification and assessment of options. This process has allowed for the ranking of all of the options considered based on a range of weighted criteria developed in close collaboration with SGN. The results of this process indicate that, of the scenarios considers, a distributed blue hydrogen configuration is optimal; specifically, option 'DL Offshore CO_2' – distributed blue hydrogen production with onshore transmission system and offshore CO_2 transmission to geological storage. This option is illustrated above in Figure 4-5.

5 Hydrogen Demand

5. Hydrogen Demand

Hydrogen can be a key vector for the decarbonisation of power and heating systems that are currently fuelled by natural gas. Where the requisite hydrogen is produced from low carbon sources (e.g., blue hydrogen with 90% of the carbon captured and stored) this can be considered a lower carbon solution to the reduction in natural gas use. This Project also considers wider applications for hydrogen in sectors such as transport, power and agriculture. This section provides a high-level assessment of the future primary uses for low-carbon hydrogen, including an assessment of where potential demands are located within the Project Area.

5.1 Industrial

Hydrogen is used at large scale within the refining and chemicals industries, which currently represents the majority of global use of hydrogen. Grangemouth Refinery is no exception to this; it currently meets its own needs for hydrogen with onsite oil and gas-fed processes including a steam methane reforming unit. Hydrogen production from oil and gas feedstocks results in large emissions of CO_2, therefore switching to a green hydrogen source or applying carbon capture to these hydrogen production units would have an impact on the carbon footprint of these industries.

Hydrogen can also be used as an alternative fuel to decarbonise the very significant emissions that are generated through the provision of process heat and power in industries which currently use either natural gas or coal as a fuel.

Potential industrial hydrogen users for decarbonisation purposes can be broadly grouped into two categories:

- Small, distributed users who currently use natural gas to fire boilers or meet other high temperature process needs, such as distilleries and pulp and paper manufacturers.
- Large single point users, who are in general, currently large single point emitters of CO_2, such as Grangemouth Refinery and Tarmac Cement in Dunbar.

5.1.1 Small Distributed Potential Users

Smaller industrial facilities which currently use natural gas are largely fed from the low-pressure distribution network and are hard to identify as a distinct group, separate from residential and other commercial customers of SGN. However, they can be identified in the detail of the UK national emissions to air database, which, for example, shows that the 60 distilleries, maltings and associated warehouses with the highest CO_2 emissions in the Project Area together contributed just under 300 kilo-tonnes per annum (kTPA) of CO_2 emissions in 2017.

Using the quantity of CO_2 emitted as an indicator of the quantity of natural gas burned allows us to estimate the amount of heat energy used by each of these industries and subsequently estimate the amount of hydrogen they may require.

Smaller potential users are dominated by distilleries, which are many in number but with just three sites contributing a substantial proportion of emissions. These three sites would therefore be good candidates for fuel-switching to hydrogen:

- United Distillers & Vintners Blackgrange site, near Stirling (41 kTPA CO_2, circa 10 MW hydrogen).
- North British Distillery, near Edinburgh (37 kTPA CO_2, circa 9 MW hydrogen).
- Diageo's Cameronbridge site, in Leven (31 kTPA CO_2, circa 7.5 MW hydrogen).

The above estimates are derived from 2017 annual CO_2 emissions so may differ from the actual fuel demand at maximum plant output.

If all of the distilleries in the Project Area were to fuel-switch to hydrogen by 2040 (in line with the recently announced target of the Scottish Whisky Association) and use a similar amount of fuel heat input to their current usage, this would equate to approximately 0.6 TWh annual hydrogen usage (70 MW production capacity).

5.1.2 Large Potential Users

National predictions of decarbonisation pathways for the UK in the National Grid Future Energy Scenarios (FES) and the Committee on Climate Change (CCC) 6th Carbon Budget assume a very substantial role for hydrogen fuel-switching in industrial applications with between 20 and 30% of all hydrogen produced in 2050 to be used for this purpose. However, taking a closer look at the specific large industrial heat users in the Project Area indicates that this does not appear likely for many of these sites.

5.1.2.1 Grangemouth Industrial Area

The Grangemouth industrial area consists of Grangemouth Refinery (Petroineos), the chemical plant (Ineos), Kinneil gas terminal and utilities and smaller connected sites which are inter-dependent for services, feedstocks, intermediates and products. For example, the chemicals complex depends on refinery products for some of its feedstocks and these two sites provide the main demand for the heat and power plant.

It is difficult to say what the future will hold for this interconnected group of sites, but many options are available for decarbonisation including hydrogen fuel-switching and carbon capture and storage. It is widely anticipated that the largest principal products from the refinery, which are road transport fuels, will not have a market in a net-zero compliant Scotland in 2045, but that others are expected to maintain their market, such as jet fuel and chemical feedstocks. It also seems likely that the largest feedstock to the area, crude oil, will continue to see depressed value due to reduced demand for fossil derived fuels the closer the world gets to net-zero.

This group of industries already meets its own hydrogen needs and could be reconfigured to produce little or no transport fuels, without major site modifications, focussing instead on production of low-carbon hydrogen and chemicals feedstocks. Thus, this seems unlikely to be a site which will become a major importer of hydrogen, even if it switched a number of its high heat demands to hydrogen firing. Based on the limited evidence available at this time, it is currently anticipated that this group of industries will have very limited (if any) hydrogen demand from an SGN operated system.

5.1.2.2 Mossmorran Industrial Area

The Mossmorran industrial site includes ExxonMobil's ethylene cracker, which takes heavier components of natural gas and produces chemical feedstocks, and Shell's natural gas liquids (NGL) plant, which predominantly supplies feedstock to ExxonMobil, plus smaller sales of butane and propane. Hydrogen is produced as a normal by-product of the cracking process and some of this is used internally, but the portion which exceeds the site's internal demand is vented to the atmosphere or flared. Since Mossmorran already has an excess of hydrogen that it produces itself, this site is also assumed to result in zero demand for hydrogen from a future SGN system.

5.1.2.3 Dunbar Cement Works

Among the next largest current CO_2 emissions sources are Dunbar Cement works, Viridor's energy-from-waste (EfW) facility in the same location and Markinch biomass fired heat and power plant. To achieve the near-zero[12] emissions target for the cement industry, currently recommended as 2040 by the CCC, Dunbar, which already partially mitigates its emissions by using some renewable fuels, would need to adopt post combustion carbon capture. Once this form of CCS is fitted, reducing the carbon content of the fuels used becomes ineffective as a decarbonisation strategy.

[12] The CCC recommendations of "near-zero" is to allow for plants to apply just CCS if needed and not offset residual emissions when firing with biofuels.

5.1.2.4 Energy from Waste Plants

The CCC also recommends that application of CCS be mandated to EfW plants, from 2045, therefore Viridor's EfW plant's co-location with the cement plant facing a similar mandate makes it a very likely site for carbon capture. Also, EfW plants in the UK tend to operate with safe destruction of waste as the primary function and generation of low carbon power is somewhat less crucial.

Dundee also has an energy-from-waste plant emitting small but significant quantities of CO_2, however, while important for CO_2 transportation sizing, this site would not require hydrogen for refuelling.

5.1.2.5 Markinch Biomass Plant

The Markinch site is also a substantial CO_2 emitter, but in this case the feedstock is biomass and decarbonisation of the site may not be essential to achieve net-zero. It does of course have the potential for negative carbon emission CO_2 production if capture were fitted. Either way, hydrogen fuel-switching for this site is not applicable.

5.1.2.6 Gas Terminals

There are two operating gas terminals located at St. Fergus which emit a significant amount of CO_2 both from the process of removing CO_2 from natural gas as well as further emissions from high temperature heat demands. While the high temperature heat demand could be refuelled with hydrogen, the process emissions cannot be mitigated in this way. These particular plants form the CO_2 source for the Acorn CCS project which is vital to demonstrating the CO_2 transportation and storage for the first phase of Scotland's CO_2 storage infrastructure deployment.

Therefore, at least some CCS will be deployed at the St. Fergus gas terminals, although it is not public domain information how much of this would be process CO_2 and how much might be mitigated via hydrogen fuel-switching.

Further engagement with Pale Blue Dot may enable SGN to determine the hydrogen demand at St. Fergus, if such is being considered. At this stage, fired equipment at St. Fergus is assumed not to contribute to the hydrogen demand of SGN's future system. The scale of CO_2 emissions at St. Fergus in the 2017 UK database are such that if 100% of this CO_2 were due to fired equipment, the equivalent hydrogen demand would be of the order of 110 MW. Therefore, all we can conclude at this stage is that the hydrogen demand here will be somewhere between zero and 110 MW (1 TWh per year).

5.1.2.7 Norbord Europe Ltd Cowie

Norbord's Cowie medium-density fibreboard (MDF) factory, near Stirling, is a substantial emitter of CO_2 with 300 kTPA of reported emissions in 2017, however, 57% of these result from combustion of biomass. Assuming the fossil declared emissions arise from the combustion of natural gas for high temperature processes then this site would have an estimated hydrogen demand of 22 MW, or 0.2 TWh per year on average to refuel with hydrogen. Depending on the relative incentives which become available in the next few years this site might prefer to take advantage of the potential for a negative emissions income stream by fitting CCS. For the purposes of demand estimate for this study we have assumed that this site will fuel-switch to hydrogen.

5.1.2.8 Alloa Glass Plant

The glass plant in Alloa is a significantly sized industrial site where high temperature heat is essential to its process. Natural gas substitution with hydrogen for glass manufacture is being developed as one of the early adopters in the HyNet industrial cluster project in north-west England. However, it is unclear if this scheme, or adding post-combustion CO_2 capture, would achieve lower levels of residual emissions since a small portion of the chemistry of glass making gives rise to CO_2 emissions, although at much smaller levels than those seen in cement manufacture. This site recorded 137 kTPA of fossil CO_2 emissions in 2017, therefore using this as an approximate guide, refuelling this site with hydrogen would require 0.3 TWh per year, around 33 MW.

5.1.2.9 Compressor Stations

There are two natural gas grid compression stations within the Project Area, at Bathgate and Aberdeen each emitting 90 kTPA of CO_2 from gas fired compressor turbine drives. These could be replaced with electric drives, but since both are co-located with expected locations where hydrogen would be added to the grid it is far more likely that the hydrogen fuel-switching option would be selected. Initial estimates, again based on the CO_2 emissions from these sites, place the hydrogen demand for these at approximately 22 MW (0.2 TWh) each.

5.1.2.10 Pulp and Paper Industry

In the pulp and paper industry there are two locations which currently report significant fossil emissions, one much larger than the other. The larger site is Arjo Wiggins' Stoneywood Mill near Aberdeen and the smaller is Fourstones Paper Mill in Leslie which emit 74 and 14 kTPA of fossil CO_2 emissions respectively. Replacement of natural gas to these sites with hydrogen would require around 18 MW and 3.5 MW respectively.

5.1.2.11 Remaining Sites

The only remaining sites in the list of the largest CO_2 emitters in the Project Area are Michelin Tyres (which closed in 2020), large NHS hospitals, university campuses and the RAF bases at Lossiemouth and Kinloss.

Hospitals often have high temperature special waste incineration requirements which should ideally include heat recovery and be integrated with heat and power generation. It is likely that such a site will continue to require gas to provide the high temperature heat needed to safely dispose of the special waste. The 10 largest hospitals in the Project Area would require between 1 and 6 MW of hydrogen each, and 28 MW (0.25 TWh) in total, based on their historic CO_2 emissions with Aberdeen Grampian, Ninewells in Dundee and South Glasgow the largest users, all above 4 MW.

There are seven university campuses emitting more than 30 kTPA of CO_2 each year, assuming that these sites convert to hydrogen would provide an additional hydrogen demand of approximately 14 MW. The RAF bases at Lossiemouth and Kinloss would add a further 2.3 MW if they converted to hydrogen.

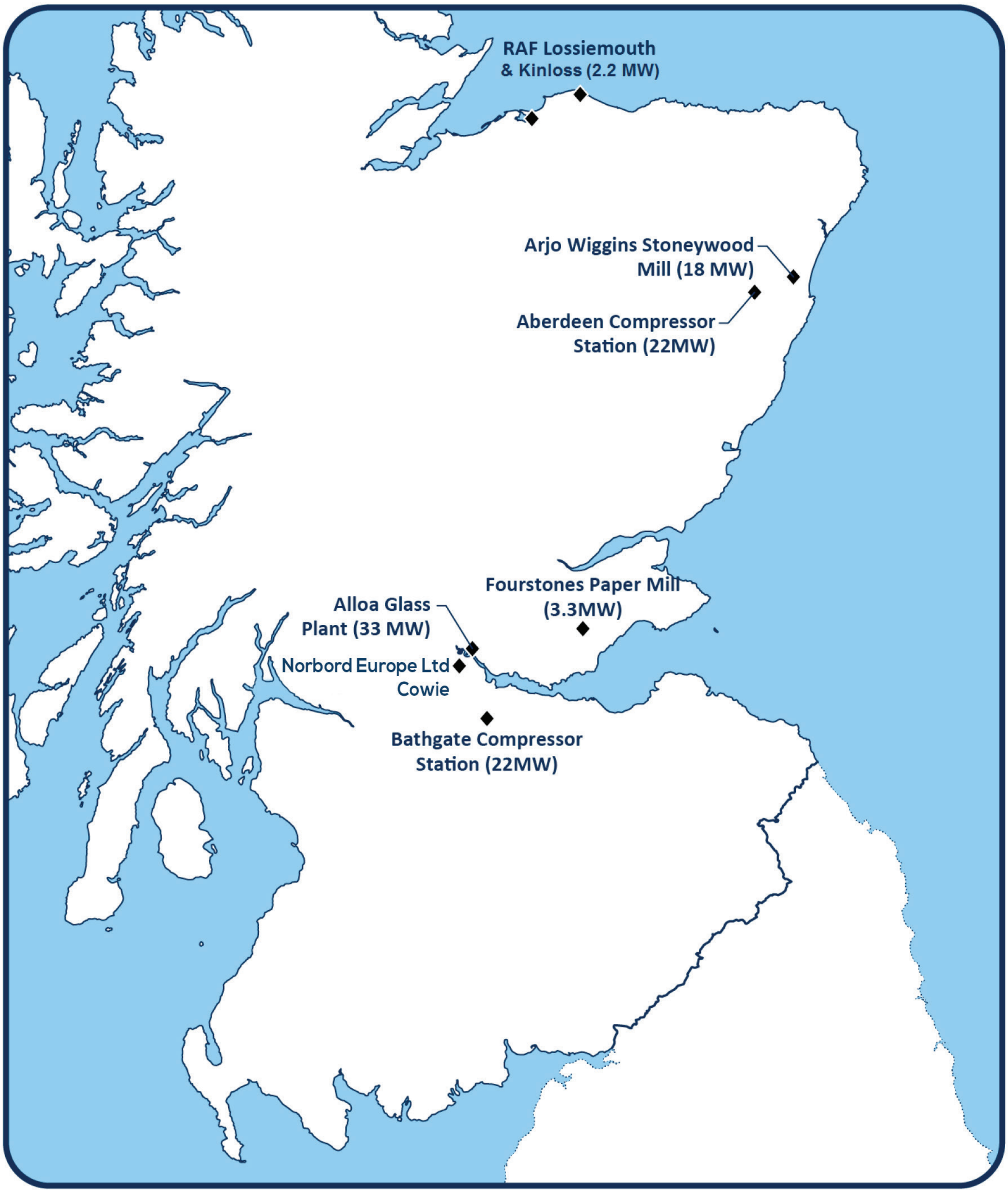
Crematoria were also investigated since they have a high temperature heat requirement similar to that of hospitals. Although there are a huge number of these, adding them all together across the whole of Scotland resulted in such small historic CO_2 emissions (less than 1 kTPA) that these can be neglected at this stage.

5.1.3 Industrial Hydrogen Demand Summary

In general, it has been found that although a huge amount of hydrogen demand is projected nationally for fuel-switching in industry, our bottom-up evaluation has shown that this prediction does not seem to be appropriate for the industries currently operating in the Project Area as many are not appropriate for hydrogen fuel-switching. Those industries which are viewed as likely to adopt hydrogen include the following, with key sites demarcated on Figure 5-1 below:

- Distilleries (72 MW across 60+ sites).
- Norbord's Cowie MDF factory (22 MW).
- Alloa Glass Plant (33 MW).
- Aberdeen and Bathgate Compression stations (22 MW each).
- Arjo Wiggins Stoneywood Mill (18 MW).
- Fourstones Paper Mill in Leslie (3.3 MW).
- Hospitals (28 MW across 10 largest hospitals)
- University Campuses (14 MW across 7 sites)
- RAF Lossiemouth and Kinloss (2 MW).
- Potential Total Industrial Demand: 234.6 MW

Figure 5-1 Potential Hydrogen Users



Less likely, but possible other adopters of hydrogen for industrial refuelling include the gas terminals at St. Fergus and Kinneil which would require a maximum of 110 MW and 90 MW respectively. These figures are a significant over-estimate as they are based on the total CO_2 emissions from these sites, including process emissions.

5.2 Transport

5.2.1 Surface Transport

Estimates for hydrogen demand for use in surface transport have been based on national predictions as this is likely to be driven by national and regional policy as well as by technology constraints and costs.

UK and Scottish government policy currently include targets which would result in quite gradual transition away from fossil surface transport fuels, such as cessation of sales of new petrol and diesel cars and vans by 2025 in Scotland. However, the uptake of hydrogen versus electric vehicles is still very difficult to predict at this time, although initial studies predict that heavier vehicles are more likely to use hydrogen due to battery weight constraints making electrification challenging.

The national predictions vary significantly from almost no hydrogen use in surface transport in some scenarios, up to 54 TWh national demand in 2050, this is circa 6 GW of hydrogen production capacity. This highest figure is reported in the System Transformation scenario in the National Grid FES 2020 report[13] and represents the assumption that 40% of all energy used for surface transport will be used in the form of hydrogen.

This national demand estimate can be scaled down to apply to the Project Area based on:

- The surface transport CO_2 emissions in Scotland versus UK surface transport emissions.
- Population of Scotland that falls within the Project Area.

Using the System Transformation scenario, the Project Area would require 3.85 TWh of hydrogen per year by 2050 for surface transport. It is important to consider how soon significant amounts of hydrogen would be required, and again, there is disagreement between the national predictions. The CCC 6th Carbon Budget report[14] anticipates that hydrogen use for surface transport will reach its highest level by 2040 and remain flat from 2040 to 2050 while the National Grid FES report has a more gradual increase up to 2050.

At this time, an additional allowance has not been included for potential hydrogen demand for rail due to the substantial rail electrification plans already in progress for the Central Belt and extending up the east coast. In addition to this, rail fuel use accounts for a surprisingly small proportion of overall transport sector emissions, at around 1%, therefore can be assumed to represent a very small fuel demand compared to other forms of transport.

5.2.2 Shipping

In 2017, the Scottish shipping sector (both domestic and international) contributed the second largest amount of CO_2 for any type of transport (after cars) at near 19%. This contrasts with the UK as a whole, in which only 8% of transport CO_2 emissions came from shipping.

Electrification is much more challenging for shipping than it is for light vehicles such as cars and vans due to the weight of batteries that would be needed to cover the long distances often carrying heavy loads in addition to the weight of the vessel itself. All of the national prediction scenarios therefore anticipate a very significant amount of hydrogen to be required for decarbonisation of the shipping sector, whether this is used directly as hydrogen or with chemical carriers e.g. in the form of ammonia.

A prediction for hydrogen demand in the Project Area was developed using the same methodology as that used for surface transport, i.e. scaling UK predicted hydrogen demand down to a Scottish demand based on relative CO_2 emissions in the shipping sectors, then down further to 80% of Scottish demand on the basis of 80% of the Scottish population living in the Project Area.

This method results in an estimate of 11.3 TWh of hydrogen required by the shipping sector in 2050 with an approximately linear increase from less than 1 TWh in 2032 to 9.8 TWh by 2045 then a more gradual rise for the last 5 years up to 2050.

[13] Future Energy Scenarios 2020 Documents
[14] CCC 6th Carbon Budget Report

It is recognised that shipping hydrogen demand will be less directly tied to population than road transport (which is dominated by cars belonging to individuals), however, this sector is quite diverse, encompassing fishing fleets, to offshore infrastructure service vessels to ferries to international cargo ships, which makes development of a more granular estimate for the Project Area challenging.

Since the anticipated hydrogen demand for shipping is large (11.3 TWh) compared to other demands reported above (total industrial users at less than 2 TWh and surface transport at less than 4 TWh) we recommend that further investigation be undertaken to better define how much of anticipated shipping demand for hydrogen is likely to be required from an SGN operated system in parallel to the next phase of this project.

5.2.3 Aviation

Aviation is excluded from the National Grid Future Energy Scenarios, therefore the generally more hydrogen conservative CCC scenarios must be used as a basis. Within the CCC scenarios are two cases in which 30 TWh of hydrogen are used for aviation, three times the amount predicted in the Balanced scenario. Therefore, the profile of hydrogen demand growth from the CCC 'Balanced' scenario has been scaled up by a factor of three before being scaled down again to apportion this for Scotland from the national demand prediction.

In the case of aviation, the anticipated demand for Scotland, which can be estimated from the historic CO_2 emissions for Scotland compared to the UK as a whole, has not been scaled down any further for the Project Area. This is because the Project Area includes Scotland's major airports, both for international and domestic travel, with only small airports outside. the Project Area.

The Scottish Government has a target of zero emissions from domestic aviation by 2040, therefore the proportion of aviation emissions that are attributable to domestic aviation have been assumed to be converted to hydrogen by this date. This shifts the anticipated uptake of hydrogen forward from the CCC prediction to see ramp up beginning in 2031 and achieving the anticipated 2050 figure of 1.3 TWh by 2042.

It should be noted that all of the scenarios anticipate that aviation will be the only remaining sector to still use fossil-based transport fuels in 2050, which is a contributor to the need for negative emissions to balance this out. If trials of hydrogen use in aviation go well, this figure could therefore be expected to be higher. The HyFlyer project, currently undertaking demonstration flights with a hydrogen powered aircraft, is seeking to prove the viability of hydrogen in the aviation sector 15.

5.3 Agriculture

Agriculture is one of the most challenging sectors to consider decarbonisation from an engineering solutions viewpoint as the largest impacts are related to natural processes such as the digestion of ruminants. The carbon footprint of agricultural vehicles is very small in comparison. However, there are two areas which could very likely adopt hydrogen as a strategy to reduce greenhouse gas emission:

- Fuel use, for vehicles and equipment.
- Fertiliser production.

Although it is not entirely clear, agricultural vehicles seem to be included in the "other" section of transport CO_2 emissions (along with military vehicles). These make up just 0.4% of UK transport emissions and 0.3% of Scottish transport emissions. Interrogation of the detailed emissions figures available to the UK as a whole, by sector, shows that just under 10% of direct greenhouse gas emissions (as MTPA of CO_2 equivalent) from agriculture arise from fuel use.

Direct emissions from agriculture are accounted separately to figures for land use, land use change and forestry. These figures include emissions from burning biomass, converting land to cropland and settlements but do not include figures for fossil fuels used in the sector. It could be argued that these are included in line items such as harvested wood, which reports a net negative CO_2 emission as a line item.

[15] https://www.zeroavia.com/

For the purposes of this study, we can therefore conclude that agricultural demands for hydrogen as a transport fuel are very small and can be considered to be included in the surface transport hydrogen demand.

Hydrogen is already a key component in the production of ammonia-based fertiliser and is usually made by reforming natural gas as one step of an integrated facility with subsequent reaction of the hydrogen with nitrogen to produce ammonia (NH3). This process results in production of pure CO_2, which is either sold for food, beverage and chemicals use, or is vented. An additional stream of CO_2 is contained in the flue gas from the hydrogen production unit.

The carbon footprint of ammonia-based fertiliser production should be included under industrial emissions rather than emissions from agriculture. This is because the CO_2 emissions are generated at the time of the ammonia production (i.e. in an industrial process) as opposed to when it is used in an agricultural setting. This argument could also be applied to the hydrogen demand for fertiliser production, however, there may be a mid-term market for low-carbon footprint ammonia fertilisers which include blue hydrogen which should be considered (perhaps called blue ammonia).

5.4 Power Generation

For low carbon baseload power generation from natural gas, it has been shown in many years of comparative study, that it is both more thermally efficient and more cost effective to fit post-combustion CO_2 capture to a combined cycle gas turbine (CCGT) power plant than to reform natural gas to hydrogen and feed the resulting decarbonised fuel stream to a hydrogen compatible CCGT. However, as the anticipated utilisation of a power plant decreases from baseload towards peak power generation, and as technologies continue to develop further, the case for large scale power generation using the hydrogen route is expected to improve.

The only large natural gas fired power plant in Scotland is SSE's plant at Peterhead. This plant has been the subject of a number of key decarbonisation projects, including two front-end engineering design (FEED) studies for retrofitting carbon capture, one based on the hydrogen route, and one based on the post-combustion route.

Bearing in mind the cost and efficiency benefit of selecting the post combustion route for Peterhead in the medium term, along with the anticipated requirement for at least some baseload power to be retained (in the absence of large-scale energy storage on the grid), SGN anticipates that post-combustion will be the selected decarbonisation route up to 2045. This assumption is far from firm, with many factors which could influence the choice over the next 12 to 24 months, but on balance, SGN judges that this route is somewhat more likely than the hydrogen route based on evidence available.

From 2045 onwards, it is expected that there will be a significant proportion of green hydrogen generation, with zero residual carbon emissions, which will drive the technology use at Peterhead from post combustion CO_2 capture (anticipated residual emissions of circa 5%) towards the hydrogen route. For our analysis, Wood has therefore assumed that Peterhead will switch from post-combustion carbon capture to full hydrogen firing in 2045, which translates to 8.5 TWh hydrogen demand per year if the plant operates on average for 66% of the time.

A much smaller amount of hydrogen is predicted to be required for distributed power generation for balancing supply and demand on the electricity grid. An estimate for the amount of hydrogen used for this purpose has been developed by scaling the total hydrogen demand for power generation down from the national predictions. This might entail a certain amount of double-counting since the national predictions cover both large- and small-scale power generation. However, the quantity of hydrogen expected to be used for this is very small when scaled down to the Project Area (using the same methodology as that used for surface transport). This method predicts 3 TWh of hydrogen use for small scale power generation in 2040, dropping back to 1.3 TWh in 2050.

5.5 Export / Import Market

The CCC Balanced Pathway estimates that around 10 to 20% of hydrogen used in the UK in 2050 will be imported, across all scenarios, which is a contrast from the National Grid 'System Transformation' scenario, the most hydrogen ambitious scenario, which does not anticipate any imported hydrogen. Since a key aim of this study is to determine the amount of hydrogen which should be generated in order to meet demand in the Project Area as well as for export, it is therefore assumed that there will be zero imported hydrogen for the purposes of this Project.

The UK has an interconnected natural gas grid which also supplies gas to Ireland. From Scotland the grid is largely supplied from St. Fergus and is connected by feeder pipelines which go south into northern England, with St. Fergus supplying an average of approximately 35% of UK natural gas.

At this point in time, before the hydrogen economy has really begun and projects across the UK and northern Europe are scoping their designs, it is difficult to say whether any one region will develop production capacity beyond its own needs in order to export, or whether each region will meet their own needs. For example Germany has announced policy which assumes significant imports of green hydrogen, whereas the UK are considering exports.

In order to arrive at a suitable design point for our study, in terms of an allowance for export of hydrogen from the Project Area into northern England, it has been proposed to calculate the line size that is required to move hydrogen around the Project Area, then increase the line size to the next standard line size up. The final figures for this line size and resulting margin allowed for export to England will be confirmed during the next phase of the Project when the line size, and number and location of hydrogen production sites, will be determined.

The European Union and a number of individual nations have announced ambitious plans for hydrogen to be used to decarbonise their economies. However, a significant amount of these targets are specifically for green hydrogen:

- Germany – 5 GW installed capacity by 2030, 10 GW by 2035 and 15 GW by 2040.
- France – 6.5 GW installed capacity by 2030.
- EU – 40 GW installed capacity within the EU and a further 40 GW on EU borders to be imported into the EU.

The 2030 target announced in the UK Government November 2020 10-point plan[16] of having 5GW of low carbon hydrogen production capacity in the UK does not specific a production technique (i.e. neither green nor blue) and as such is neutral on the question of how the low carbon hydrogen should be produced

There are not similar targets announced further into the future, but such figures for generation by 2030 are very ambitious for green hydrogen.

The EU expectation of 40 GW green hydrogen capacity to be installed outside the EU for import into the EU market is a very interesting one for this project as the UK would be an ideal location, should there be a connection to provide that hydrogen to the EU. 40 GW of green hydrogen capacity would be equivalent to more than five times the expected hydrogen demand of the Project Area by 2050. This would indicate a nearly unlimited market to export green hydrogen from the Project Area to the EU, depending on competition with others also planning to export green hydrogen.

[16] UK Government 2020 10-point Plan

5.6 Domestic and Commercial Buildings

It is possible to generate an estimate of the hydrogen demand predicted for the Project Area for use in domestic and commercial buildings based on the national profiles in the same way as for surface transport – which is based on population of the Project Area. Using the FES System Transformation case as a hydrogen uptake guide, this method predicts that 24 TWh of hydrogen will be required in 2050 with growth beginning slowly in the 2030s, rapid growth from 2040 to 2045 followed by slower growth again to 2050.

The System Transformation case assumes that 80% of domestic heat is provided by hydrogen, but also anticipates a drop in total energy used for heating in homes in 2050 to 57% of the current usage. This is expected to be due to efficiency improvements in appliances as well as increased uptake of insulation and double/triple glazing.

The FES analysis also includes for a growth in the expected number of customers by around 12.5%. This is higher than the expected growth in the number of households predicted by National Records of Scotland, which predicts an average growth across all authority areas of 5%.

An alternative approach would be to take the known amount of gas currently delivered by the SGN system in the areas covered by this study as a basis for residential and commercial users who would convert to hydrogen and include for anticipated reduction in total heat required due to increased efficiencies as that used in the FES Systems Transformation Case. There is a possibility that this may include a small amount of double counting for those industrial customers currently supplied by SGN who have already been included in the industrial demand figures. However, it is important not to underestimate these industrial users, who will have a higher likelihood of selecting hydrogen, and for whom we would not anticipate significant future demand reduction.

Using this method, we arrive at an estimate of 49.8 TWh of hydrogen demand required in 2050 for residential and commercial buildings – twice the FES prediction (24 TWh). Using this prediction would assume that demand for each household is reduced to 88% of current demand, and that 100% of current customers convert to hydrogen. By inference this also assumes that no new customers are connected to a hydrogen grid, or that the number of new customers is approximately balanced by the number of current customers switching to electrified heat supply.

For the purposes of this study, it is therefore recommended to use the 2050 figure (32.2 TWh) generated based on real data from SGN for the Project Area and roll out profile based on conversion to 100% hydrogen steadily over the period from 2025 to 2050.

5.7 CO_2 Removals and Others

The CCC 6th Carbon Budget includes two other sectors not considered above, CO_2 removals (technologies with net negative carbon emissions) and “others”.

The CO_2 removals sector is a group of technologies which result in net removal of CO_2 from the atmosphere. While the majority of negative emissions are likely to be achieved from biomass power plants with CCS, some technologies utilising CO_2 also require a hydrogen feed stream, such as synthetic fuels or plastics production.

Scaling the CCC’s predicted national hydrogen demand for this sector down to the Project Area results in a hydrogen demand by 2050 of around 0.6 TWh, growing gradually from 2040 onwards.

Despite thorough review of the CCC 6th Carbon Budget report, data files and supporting reports, the definition of “others” in terms of hydrogen demand is not stated. Scaling the national prediction to the Project Area would result in small but significant hydrogen demand; however, at 1 TWh per year, a similar scale to that anticipated for aviation. Since we could not find a definition for this sector, it has not been included in the development of this project.

5.8 Hydrogen Demand Summary

The following chart summarises the estimated demand profile, by sector, for the Project Area as discussed in the preceding sections, including a 10% allowance for the export of hydrogen in addition to the sum of all other sectors. This demand profile has been modelled by the project in conjunction with input from local stakeholders who engaged with the Project.

The Project has identified opportunities in the Project Area to supply hydrogen to SGN's existing customer base and also new markets in the transport, industrial, power generation and export sectors.

The selected Project system reconfiguration option allows for early adopters and producers of hydrogen to be connected, thus integrating the various complementary hydrogen initiatives already underway in Scotland (such as the Dolphyn and Acorn projects).

The Project has the potential to provide a route to market for green hydrogen producers operating in the Project Area with network infrastructure in place to supply into.

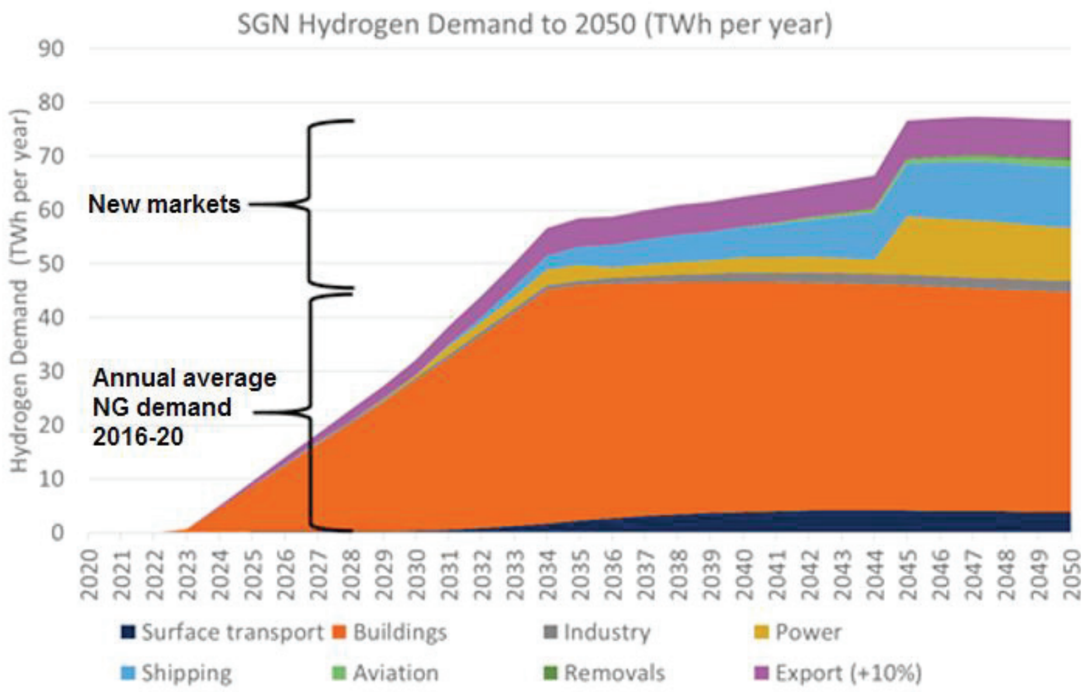


Figure 5-2 Hydrogen Demand for the Project Area

6 Network: Blending and Conversion

6. Network: Blending and Conversion

Industry consensus suggests gas appliances can operate safely and efficiently on blends of up to 20% hydrogen by volume[17], but they require modifications to operate beyond this level. A conversion programme would be required with a transition to 100% hydrogen networks. Methods to increase the proposed rate of conversions per day that ensure minimal disruption to customers at all times would be sought. The conversion programme would seek to minimise disruption and is discussed further below.

Conversion of an area from natural gas to 100% hydrogen requires, inter alia, the following key activities:

- Industrial and commercial plant sensitivity assessments.
- Planned sectorisation of the Project Area that ensures minimal disruption and costs associated with additional connections and strategically placed valves.
- Disconnection, isolation and purging of the local natural gas system.
- Conversion of burners and appliances to operate with 100% hydrogen.
- Any additional changes to customers' gas systems.
- Any additional network reinforcement or upgrades to district governors and/or removal of material that is not suitable for hydrogen.
- Purging of the pipework system.
- Connection to the local hydrogen system.

This process requires customers to be without gas during the conversion process, and most likely carried out during periods of low demand (March to October). The conversion process requires on average one person-day per customer[18]. The sectorisation plans would involve sub-sectors of the network being supplied with a temporary hydrogen supply until such time several sub-sectors can be commissioned as one complete sector.

If the conversion process takes place from March to October over a period of 11 years from 2024 to 2034:

- There will be 2,772 days available (assuming seven days a week and 4.5 weeks per month).
- 649 customers can be converted per day (assuming one day per customer to convert).
- This would require a field workforce of approximately 1,300 dedicated to customer changeover, plus additional staff to support preparatory activities, and provide supervision and support.

This means that the local grids will need to be sectionalised to allow areas to be individually isolated and changed to 100% hydrogen. The aim would be to reduce disruption to the network and customers.

During winter periods, when network conversion work may be restricted, resource teams could be diverted on to the installation of hydrogen ready boilers in properties in readiness for summer conversions. This would reduce the conversion time per customer and enable larger sectors to be converted.

[17] https://www.hse.gov.uk/research/rrpdf/rr1047.pdf
[18] F.-N. Consultancy, "Logistics of Domestic Hydrogen Conversion," Prepared for the Department of BEIS, 2018

6.1 Case Study: Aberdeen City

In the Aberdeen area the major pressure reduction stations (PRSs) are:

- Aberdeen City Gate (41,318 customers)[19].
- Craibstone (51,593 customers).

Smaller PRSs in the area are:

- Peterculter (7,473 customers).
- Maryculter (4,718 customers).
- Westhill (3,494).

For the two smallest PRSs (Westhill and Maryculter) it may well be possible to convert the corresponding local gas grid all at once, but the grid supplied by the larger PRSs will need to be sectionalised. The size of the sectors would be based on minimising disruption: Figure 6-1 gives an illustration of how this might be done for the Aberdeen area with 60 sectors. Figure 6-2 illustrates a close-up of the same conversion around the Craibston PRS.

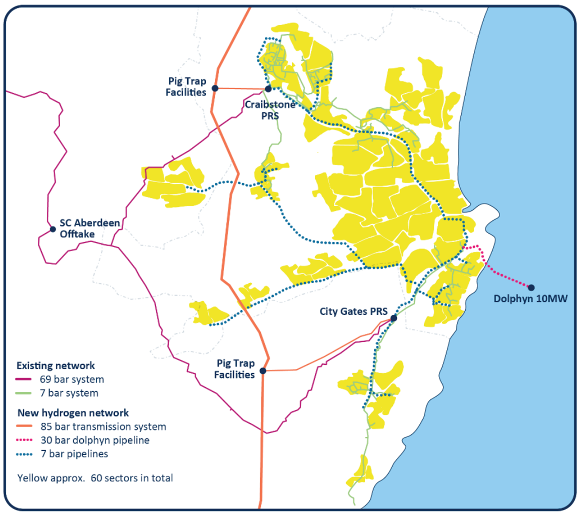


Figure 6-1 Segmentation of Local Grids in the Aberdeen Area

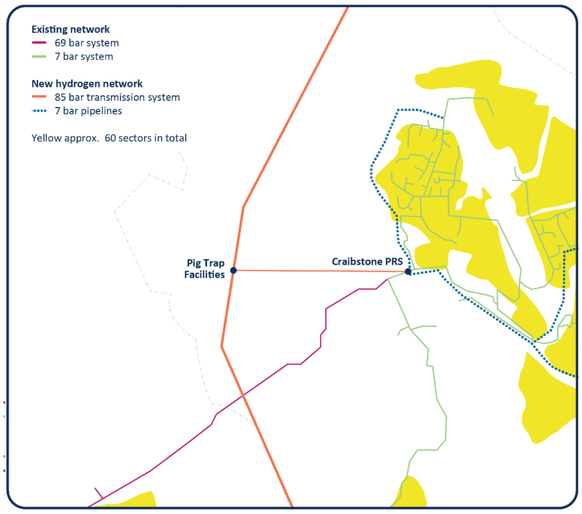


Figure 6-2 Segmentation of Local Grids in the Aberdeen Area (Craibstone PRS)

Focussing on Aberdeen City Gate PRS as an example, a new 7 bar hydrogen line (18-20”) would be installed running in parallel to the existing 7 bar natural gas grid. Once conversion is complete, the old lines can be left in hydrogen service (if suitable) which would help to improve network flexibility, minimise pressure drop in the system (and hence compressor power) and potentially offer additional line packing storage.

Conversion of the whole of the Aberdeen city area would need at least 24 weeks to convert the 108,596 customers to 100% hydrogen.

[19] GN, “Operations Report,” SGN Internal , 2020/21

7 Hydrogen Storage

7. Hydrogen Storage

Gas demand varies across the year from summer to winter (inter-seasonal), and also within the day (diurnal). Therefore, some form of hydrogen storage would be required where the supply is not being delivered by hydrogen generated on-demand from natural gas.

In the current natural gas system, inter-seasonal variation is met by imports, salt cavern storage and liquified natural gas (LNG). Diurnal variation is met by line packing. In the past, other natural gas storage technologies have been used, such as storage in porous rock formations (for instance the Rough field storage facility) and gasometers/gas holders.

Operation of the gas networks with hydrogen would present an additional challenge for storage, because of the low energy density of hydrogen, which holds about one third of the energy content of natural gas per unit volume. Figure 7-1 below shows the seasonal variation in gas demand over the 2016-20 period. The data are obtained from the National Grid website and cover the following offtakes serving the Project Area:

North east Offtakes:

- Aberdeen
- Burnhervie
- Careston
- Balgray
- St Fergus
- Kinknockie

Central Belt Offtakes:

- Glenmavis
- Broxburn
- Bathgate
- Drum
- Armadale
- Soutra[20]

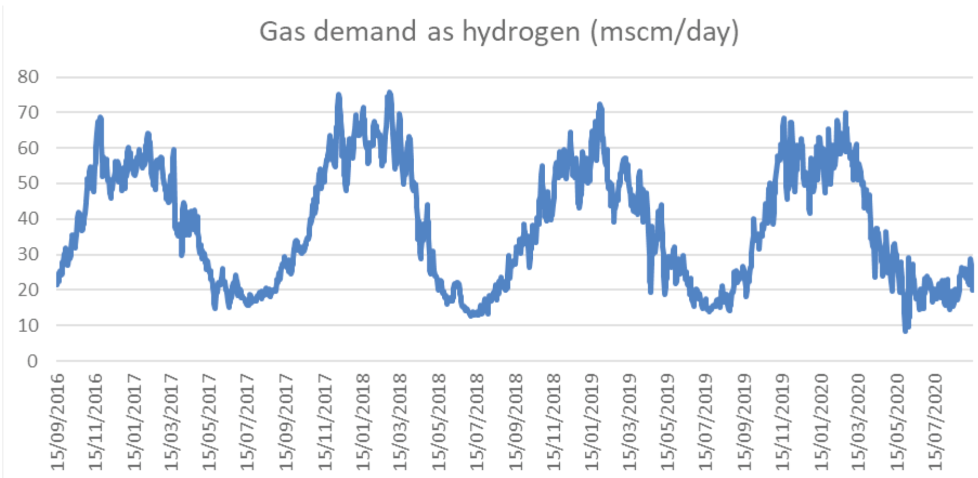


Figure 7-1 Annual Variation in Gas Demand for the Project Area (2016-20)

[20] Soutra national offtake is included because the Soutra, Broxburn and Armadale national offtakes are interlinked and work together to supply the south Edinburgh area.

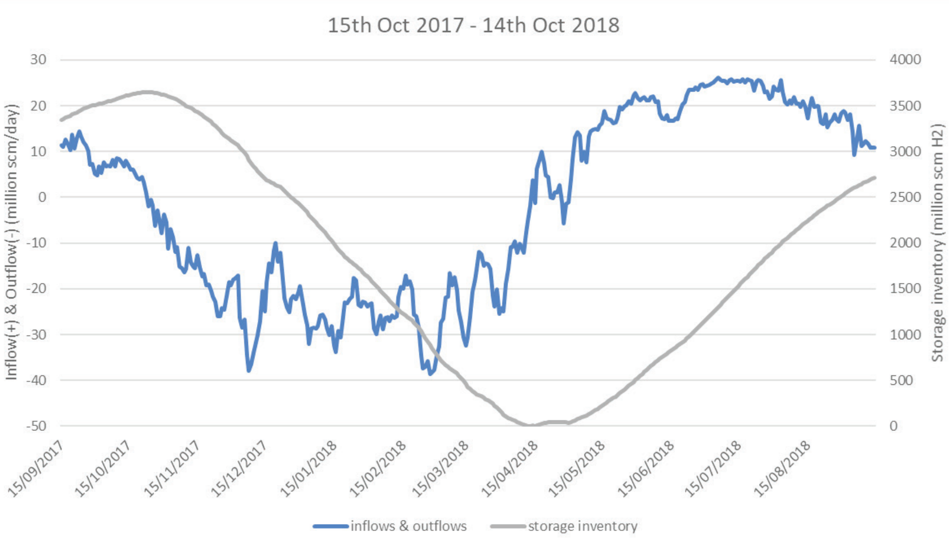


Figure 7-2 Storage Requirement for Winter 2017-18

The analysis in Figure 7-2 above shows the requirement for inter-seasonal storage for the Project Area, based on generating hydrogen at a constant rate (which requires 9 off 500MW reformers), and using the storage capacity to meet the additional demand in winter. The storage requirement for the winter of 2017-18, which included the extended 'Beast from the East' cold weather event and had a relatively high demand for gas, was approximately 3.6 billion scm of hydrogen equivalent.

For seasonal storage of gaseous hydrogen there are three main options:

Salt cavern storage, porous rock formations (aquifers and depleted natural gas reservoirs), and depleted oil and gas reservoirs.

Salt cavern storage: Has been extensively used for storage of natural gas and other gases but requires suitable geology with thick strata of rock salt at suitable depth. The nearest areas to Scotland with suitable geology are Teesside, Humberside and Cheshire. Salt cavern storage can be expensive: the Stublach facility in Cheshire, constructed from 2013-2018 cost approximately £500 million and has a total storage capacity of 400 million scm of natural gas. The project includes of 28 caverns at a depth of 600m plus injection facilities, water treatment, gas processing, compression and drying 21. The equivalent of six such facilities would be needed to meet the seasonal storage for the Project Area, which could be prohibitively expensive.

Porous rock formations: At present, large-scale hydrogen storage in porous rock formations is not a proven technology. Research is ongoing, and in the long-term it is likely that storage of hydrogen in porous rock formations could be available by the mid-2040s. Porous rock formations could have the capacity to be able to meet the required storage capacity. The Rough storage facility had a capacity of 3.3 billion scm of gas, which is similar to the requirements for the Project Area. However, at present, large-scale hydrogen storage in porous rock formations (such as aquifers or depleted gas fields) is not a proven technology. Technological uncertainties include:

- Preventing leakage and migration of hydrogen.
- Controlling microbial growth (which could convert hydrogen to methane).
- Controlling contaminants (such as hydrocarbons).
- Management of water, operation of the reservoir, filling and withdrawal rates.
- Management of the cushion gas water, operation of the reservoir, filling and withdrawal rates. Controlling contaminants (such as hydrocarbons).

[21] https://www.hydrocarbons-technology.com/projects/stublach-gas-storage-project/

Research is ongoing, and in the long-term it is likely that storage of hydrogen in porous rock formations could be available by the mid-2040s.

Onshore oil and gas fields: The Balgonie field is currently the subject of investigation on their ability to store hydrogen, with the latter estimated to be able to hold 700 tonnes of hydrogen.

Liquefaction and storage of hydrogen is likely to be prohibitively expensive, due to the very low boiling point of hydrogen (-253 °C). There is some potential for using liquid organic hydrogen carriers (LOHCs) for storage of hydrogen, but again this is not yet fully developed technology.

The proposed solution for managing the seasonal peak in gas demand is therefore to construct additional reformers to cover the peak demand, and to use some modulation of reformers to adjust hydrogen production to demand. Suitable business models with governmental support would be required to operate these commercially; however, it is recognised that these reformers could also support an export market whilst allowing early conversions to take place.

Management of the winter peak would also include some demand management. For the peak in hydrogen demand, compression to high pressure storage for transport applications can be applied in order to free capacity for heating demands. Transport demands are projected to account for approximately 18% of overall demand. Transport hubs are likely to have a degree of on-site storage that would be beneficial to smoothing out peak daily demand when required.

The proposed Project roadmap includes some flexibility: if storage in local porous rock formations becomes technically feasible earlier than expected (e.g. by 2030), it would be possible to reduce the numbers of reformers that are built and rely on storage to cover the winter peak in demand. If large scale storage in porous rock formations becomes available at a later date, the additional blue hydrogen reformer capacity that is freed up would be available to provide low-carbon hydrogen for export.

Storage in porous rock formations is assumed to be available from 2045, to support hydrogen-based power generation. Power generation from hydrogen requires storage of low-cost green hydrogen so that it is available to generate electricity at times of peak electricity demand. If storage is not available, there would be no benefit in converting electricity to hydrogen in the electrolysers whilst simultaneously converting the hydrogen back to electricity in a power station.

8 Carbon Capture Utilisation and Storage

8. Carbon Capture Utilisation and Storage

8.1 General

In 2017, point source emitters in Scotland, including those burning biomass, accounted for 11.1 million t/year of carbon dioxide (as CO_2). If point source emitters burning biomass are not included, the total is 9.7 million t/year CO_2. This accounts for 33% of Scotland's net CO_2 emissions and 24% of net greenhouse gas emissions.

The scale and location of the primary sources of CO_2 generation has been assessed based on the information gathered in the Phase 1 report[22].

8.2 Industrial

Table 8-1 lists the main Industrial emitters which emit greater than 50,000 tonnes of CO_2 per annum in Scotland. For this table, combined heat and power (CHP) plants associated with the Grangemouth refinery and petrochemicals site are listed as power plants in Table 8-2. Table 8-1 lists only emitters over 50,000 t/year – a longer list is included in the Phase 1 report. These emitters are also illustrated below in Figure 8-1 and Figure 8-2.

Table 8-1 List of CO_2 Emitters in Scotland (>50,000 TPA, 2017 data)

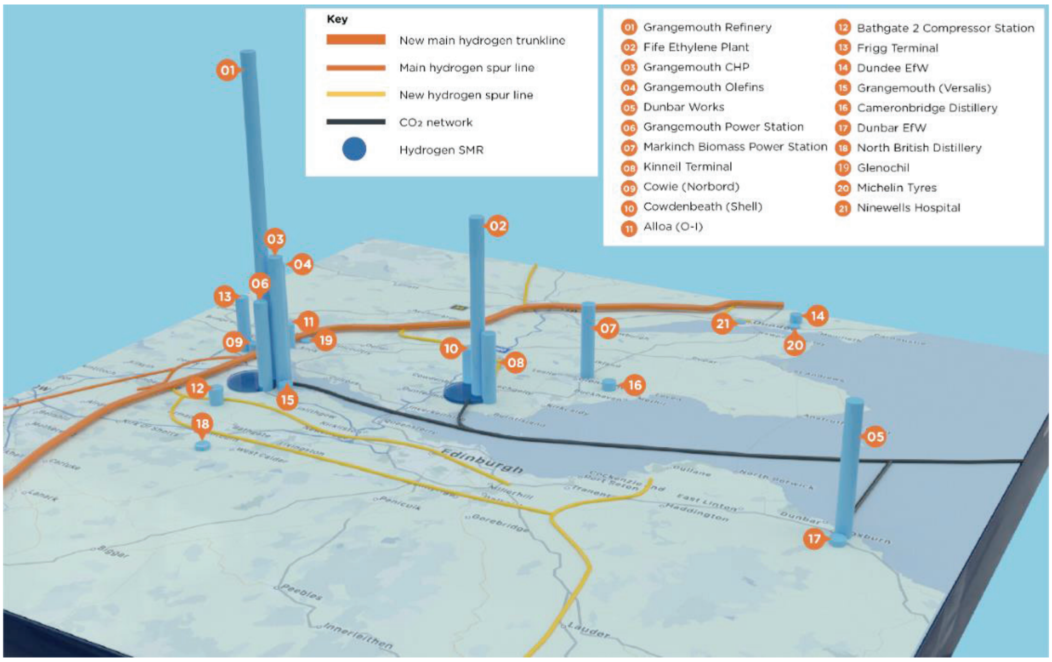
Site	Postcode	Operator	Non-biomass CO_2 (t/year)	Biomass CO_2 (t/year)	Total CO_2 (t/year)
Inside Project Area					
Grangemouth Refinery	FK3 9XH	Petroineos Manufacturing Scotland	1,638,305	0	1,638,305
Fife Ethylene Plant	KY4 8EP	ExxonMobil Chemical	892,964	0	892,964
Grangemouth Olefins	FK3 9XH	INEOS Chemicals Grangemouth	612,321	0	612,321
Dunbar Works	EH42 1SL	Tarmac Cement and Lime	587,824	0	587,824
St Fergus (combined)	AB42 3EP	Shell UK, Apache, National Grid Gas, Total	468,938	0	468,938
Kinneil Terminal	FK3 9XE	BP Exploration Operating Co	364,789	0	364,789
Cowie	FK7 7BQ	Norbord Europe	89,722	209,352	299,074
Mossmorran	KY4 8EL	Shell UK (NGL Plant)	197,089	0	197,089
Alloa	FK10 1PD	O-I Manufacturing UK	137,284	0	137,284
Aberdeen Compressor	AB32 6UR	National Grid Gas (compressor station)	90,385	0	90,385
Bathgate 2 Compressor	FK1 2JY	National Grid Gas (compressor station)	89,935	0	89,935
Stoneywood Mill	AB21 9AB	Arjo Wiggins Fine Papers	73,595	0	73,595
Grangemouth	FK3 9XE	Versalis UK	55,618	0	55,618 SUB
TOTAL (PROJECT AREA)			**5,298,769**	**209,352**	**5,508,121**

[22] X.19.00472.GLA.R.004 - Phase 1 Report

Site	Postcode	Operator	Non-biomass CO_2 (t/year)	Biomass CO_2 (t/year)	Total CO_2 (t/year)
Outside Project Area					
Sullom Voe	ZE2 9QR	BP Exploration Operating Co	310,192	0	310,192
Irvine	KA11 5AT	UPM-Kymmene (UK)	11,309	271,412	82,721
Shetland	ZE2 9QR	Total E&P UK Gas Plant	239,203	0	239,203
Flotta	KW16 3NP	Talisman Sinopec Energy UK	148,107	0	148,107
Dalry	KA24 5JJ	DSM Nutritional Products (UK)	116,397	0	116,397
Morayhill	IV2 7QJ	Norbord Europe	4,725	89,772	94,497
Lochaber	PH33 9TH	Liberty Aluminium Lochaber	70,709	0	70,709
Irvine	KA12 8JA	Ardagh Glass	67,310	0	67,310
Girvan Distillery	KA26 9PT	William Grant & Sons Distillers	62,498	0	62,498
SUB-TOTAL (OUTSIDE PROJECT AREA)			**1,030,450**	**361,184**	**1,391,634**
TOTAL (SCOTLAND)			**6,329,219**	**570,536**	**6,899,755**

Figure 8-1 Industrial Emitters (North East)

Figure 8-2 Industrial Emitters (Central Belt)



The six largest industrial point source emitters are all located in the project area. Three are associated with the Grangemouth complex: Grangemouth Refinery, the Grangemouth Olefins plant and the Kinneil Terminal. These are supported by CHP plants (included in Table 8-2), and together with the Versalis plant, the Grangemouth complex emitted 3.8 million tonnes CO_2 in 2017. This complex is a strong candidate for CCS due to its size and geographical concentration. Co-locating blue hydrogen production would give opportunities to share CO_2 compression facilities and pipelines.

As demand for road fuels reduces, Grangemouth Refinery is likely to see a change in its product slate to produce more petrochemical feedstocks and jet fuel, rather than gasoline and diesel, and there will likely be some reduction in throughput. The Grangemouth Olefins plant operates on imported ethane and CO_2 emissions are mainly from the process, so mitigation would involve post combustion capture rather than fuel switching. Continuing demand for petrochemicals will mean that emissions from the site are likely to continue into the middle of the century.

The Fife Ethylene Plant at Mossmorran is the third largest point source emitter in Scotland, with 0.9 million t/year in 2017, with the adjacent Cowdenbeath Terminal accounting for a further 0.2 million t/year. Again, CO_2 emissions come from combustion of gas produced during the cracking process, so mitigation would involve post combustion capture rather than fuel switching.

The Dunbar cement plant emitted approx. 0.6 million tonnes in 2017. Most of the CO_2 originates form the calcination part of the cement process, in which calcium carbonate (CaCO3) is converted to calcium oxide (CaO) + CO_2, and the plant already makes use of biomass to help fuel its kiln. Post combustion capture would be the best way of mitigating these emissions (rather than fuel switching to hydrogen). There are also likely to be synergies with the adjacent, newly commissioned EfW plant operated by Viridor. The cement plant's location is further away from the main emitters in the Central Belt, but a CCS project at the plant could tie into a CO_2 pipeline from the Grangemouth cluster.

The largest industrial emitter outside the Central Belt is the St. Fergus Gas Terminal. St. Fergus has different processing trains with multiple operators who report their CO_2 emissions separately. In 2017, the total emissions from all trains at the terminal were 0.47 million tonnes CO_2. Decarbonisation plans at St. Fergus are considering a combination of fuel switching and CCS.

The oil and gas terminals in Orkney and Shetland (Sullom Voe, Shetland Gas Plant and Flotta) fall outside the geographical scope of the project, but there might be potential to capture and liquefy the CO_2 from these sites and ship it to St. Fergus for geological storage.

The natural gas NTS has two natural gas compressor stations in the project area: Aberdeen and Bathgate. These use the natural gas in the pipeline to drive gas turbines to run the compressors, producing significant CO_2 emissions. Both compressor stations are located at national offtakes, and it is likely that hydrogen will be routed to these offtakes to convert the gas grid to hydrogen. The availability of hydrogen at these locations would offer an opportunity to decarbonise the compression stations by fuel-switching to hydrogen (see Section 5.1).

Other manufacturing industries include Norbord Europe Ltd at Cowie, which produces engineered wood products, and emits about 0.3 million te/year CO_2, mostly from biomass combustion. Its location relatively close to Grangemouth means that it could be a candidate to use bioenergy with carbon capture and storage (BECCS) and tie into a Central Belt CCS cluster. Other industries such as glass product manufacture (O-I Manufacturing UK Ltd at Alloa) and distilleries, and smaller incinerators such as hospitals are likely to favour fuel switching, because applying smaller scale CCS plants to these sites would be disproportionately expensive, so fuel switching to hydrogen is likely to be favoured (see Section 5.1.3).

8.3 Power Generation

Table 8-2 lists the main power plants (including CHP plants associated with the Grangemouth refinery and petrochemicals site) that emit over 20,000 tonnes/y CO_2.

Location	Postcode	Operator	Non-biomass CO_2 (t/year)	Biomass CO_2 (t/year)	Total CO_2 (t/year)	Type
Inside Project Area						
Peterhead Power Station	AB42 3BZ	SSE Generation	950,298	0	950,298	CCGT power Station
Grangemouth CHP	FK3 9XB	Grangemouth CHP	680,626	0	680,626	Site CHP plant
Grangemouth Power Station	FK3 9XB	INEOS Infrastructure	462,146	0	462,146	Site CHP plant
Markinch Biomass	KY7 6GU	RWE Markinch	7,819	383,155	390,974	Power station
Dundee EfW	DD4 0NS	Dundee Energy Recycling	58,247	0	58,247	EfW
SUBTOTAL (INSIDE PROJECT AREA)			**2,159,136**	**383,155**	**2,542,291**	
Outside Project Area						
Steven's Croft	DG11 1HD	E.On-UK	6,572	322,013	328,585	Biomass (wood) power station
Lerwick Power Station	ZE1 0PS	SSE Generation	77,509	0	77,509	Diesel generator
SUBTOTAL (OUTSIDE PROJECT AREA)			**84,081**	**322,013**	**406,094**	
TOTAL			**2,243,217**	**705,168**	**2,948,385**	

Table 8-2 List of Power Plant CO_2 Emitters in Scotland (>20,000 TPA, 2017 data)

The table of power station emitters shows that power sector emitters are dominated by the Peterhead Power Station, and the CHP plants supporting the refinery and petrochemicals complex at Grangemouth. These are all candidates for CCS and / or fuel switching to hydrogen.

As noted in the Phase 1 report, the load factor for Peterhead varies from year-to-year, and in some years, it is the largest point source emitter in Scotland. The Peterhead power station is expected to continue in operation because it provides dispatchable power to help balance the variability of the increasing amount of renewable electricity on the grid. Peterhead has several pathways to decarbonisation, this could include the following: it could install new gas turbines to burn hydrogen, or continue operating on natural gas with post-combustion capture, before fuel switching to hydrogen when the cost of residual CO_2 emissions becomes too high (probably towards the middle of the century).

The Markinch Power Station in Glenrothes is integrated with a paper mill and uses wood and paper by-products as its biomass feedstock. It is therefore not suitable for fuel switching with hydrogen, but potentially could use BECCS technology to achieve negative emissions. If the challenge of its urban location can be overcome, it could tie into a wider Central Belt CO_2 collection system.

Viridor has recently commissioned an EfW facility at Dunbar, which is not included in the 2017 data. Most of the CO_2 emissions from this plant will come from burning waste, and this plant could be a good candidate for CCS because it could have synergies with CCS at the adjacent Dunbar cement works.

9 Carbon Export, Import and Utilisation

9. Carbon Export, Import and Utilisation

Although there is interest in utilisation of CO_2, at a large-scale, CO_2 is a waste product rather than a resource. It is possible, for a fee, to send CO_2 to another country for storage and/or utilisation. For the Project, this is termed export of CO_2 with the country that receives the CO_2 also receiving a payment for providing the service of storage.

9.1 Export

It is possible that companies in Scotland could pay to export CO_2 for disposal by geological storage. Primary candidates for export include:

- Other parts of the UK (northern England, Northern Ireland).
- Ireland.
- Continental Europe (e.g. Germany, the Netherlands, Denmark).
- Norway (via Northern Lights project).

Scotland has considerable geological storage potential. For large-scale projects, exporting CO_2 outside of Scotland would require significant infrastructure development and therefore not seen to be economically attractive.

Early-stage smaller-scale CO_2 projects could make use of shipping liquid CO_2. The Northern Lights project has been developed to facilitate CCS projects in Norway. It involves shipping liquid CO_2 from capture plants in the Oslo area to a CO_2 liquid terminal on the west coast of Norway, from where the CO_2 will be sent via pipeline to an offshore geological storage facility. The project is designed to be able to receive liquid CO_2 from third parties, which means that CO_2 capture projects at coastal locations in Scotland could liquefy their CO_2 and send it to Norway. This might be an opportunity to implement CO_2 capture at more remote locations, or for CCS projects in Scotland to start capturing CO_2 before local geological storage and pipelines are ready.

9.2 Import

The east coast of Scotland has access to considerable resources for geological storage and could potentially receive income from importing CO_2 for storage. Pale Blue Dot has included a liquid CO_2 reception facility at Peterhead within the preliminary design of the Acorn export system. The nearest potential CCS clusters are the proposed Teesside and Humberside clusters. However these are large clusters and are likely to rely on pipelines to local storage in depleted gas fields and saline aquifers in the North Sea, which are much closer than Scotland.

The Teesside and Humberside clusters are also nearer to each other than they are to Scotland so are more likely to connect to each other than connect to the central Scotland cluster.

9.3 Utilisation

Carbon capture and utilisation (CCU) is receiving much interest as an alternative to geological storage which may have economic benefits, however it is expected that the quantity of CO_2 emitted in the Project Area will significantly exceed practical usage routes. CO_2 is already used at a scale of roughly 1 million tonnes per year across the UK. This would roughly equate to 60,000 tonnes per year in the Project Area.

Further information on the forms of CO_2 utilisation can be found in the Project Phase 2 report[23].

[23]X.19.00472.GLA.R.022 - Phase 2 Report

10 Existing Assets: Project Area

10. Existing Assets: Project Area

10.1 Hydrogen Re-purposing

The proposed hydrogen pipeline routing (as discussed in Section 11.1) has been developed with reference to the existing SGN network. The Scotland network schematic[24] identifies the location of key points of the routes and supply outlets of the existing network.

Table 10-1 details the proposed hydrogen pipeline layout for the Project (illustrated in Figure 11-4 on page 81) indicates where new pipelines are required and existing assets can be re-purposed. Google Earth has been used to assess pipeline lengths presented.

The figures given in Table 10-1 present the peak and average flow rates used for the hydrogen network analysis which was undertaken together with estimated pipeline lengths. Also presented are the selected line sizes established by the analysis

Table 10-1 Input Data and Analysis Results

Pipeline	Length (km)	Nominal Diameter (in)	Peak Flow (MM scm/h)	Average Flow (MM scm/h)(1)
Main Trunkline St Fergus to Longtown (New)	359	36	1.67(2)	1.67(2)
St Fergus to Peterhead (New)	11	8	0.065	0.0325
Main Trunkline to Inverness (Connection of existing 10.7-inch pipeline to Main Trunkline required)	Existing pipeline to Inverness to be repurposed to allow top up of hydrogen supplies to be produced at Inverness.			
Main Trunkline to Craibstone (New)	1	12	0.18	0.09
Main Trunkline to Citygate (New)	5	12	0.18	0.09
Kirriemuir to Arbroath (New)	27	8	0.063	0.0316
Main Trunkline to Dundee (New)	25	12	0.276	0.138
Main Trunkline to St Andrews (New or connection to existing 10.75-inch pipeline)	31	12	0.189	0.0945
Main Trunkline to Logierait (New)	39	12	0.189	0.0945
Drum to Mossmorran (New)	21	12	1.11(3)	0.5556
Longannet to Stirling (New)	18	10	0.139	0.0696
Bathgate to Edinburgh (New)	48	30	0.6	0.3
Bathgate to Soutra (New)	66	24	0.447	0.2235
Soutra to Aberlady (New)	24	16	0.2235(4)	0.1118
Soutra to Selkirk (New)	27	16	0.2235(4)	0.1118
Longannet to Eaglesham Major Spurline (New)	62.5	24	1.14	1.07
Main Spur line to Glasgow North (New or connection to existing 18-inch pipeline)	75	24	0.57(5)	0.2852
Main Spur line to Bathgate (New)	4	12	0.1428(6)	0.0714
Main Spur line to Motherwell North (New or connection to existing 10.75-inch pipeline)	9	12	0.1428(6)	0.0714
Main Spur line to Motherwell South (New or connection to existing 10.75-inch pipeline)	9	12	0.1428(6)	0.0714
Main Spur line to Glasgow South (New or connection to existing 18-inch pipeline)	40	24	0.57(5)	0.2852
Eaglesham to Girvan (New)	55	16	0.57(7)	0.2852

[24] 2019 - 20 Scotland Operations Plan - Online Version'

Notes:

(1) The average flow rate is assumed to be 50% of peak flow rate for the analyses unless noted otherwise.

(2) This is the peak inlet flow from 6 reformers located at St Fergus and is assumed consistent for purposes of the analyses.

(3) This flow is based upon an H_2 injection source from 4 reformers located between Drum and Mossmorran

(4) Assumed even distribution between Aberlady and Selkirk.

(5) Assumed 50% distribution of flow from Longannet to Eaglesham Major Spur line into each of the pipelines routed to the north and south of Glasgow.

(6) Assumed that 1/8th of the flow from the Longannet to Eaglesham Major Spurline flows through the pipelines to Bathgate and Motherwell.

(7) Assumed 50% of flow from Longannet to Eaglesham Major Spurline.

10.1.1 NTS Feeder 13

Early options appraisal by the Project team on the re-purposing of National Transmission System feeder pipeline 'F13' could reduce incurred capital costs through re-use of this existing asset. Additionally, there may be a saving on construction emissions from re-using this existing pipeline; however, at this level of engineering design it is not possible to quantify this against construction of a new pipeline.

F13, was constructed in 1982 and thus incurs a risk of increased maintenance and shorter design life. These trade-offs have been considered within the optioneering assessment documented in Section 6 of the Project Phase 2 report. At the time of this report publication the suitability of re-using F13 for transport of 100% hydrogen has not been proven and is the subject for ongoing research and development. This uncertainty is reflected in the disadvantages documented in the optioneering assessment.

10.2 CO_2 Re-purposing

The selected configuration proposed is based on achieving full transition of the gas network by 2045 and supporting a net-zero emissions compliant Scotland. An advantage of an offshore CO_2 storage route is that it is able to collect CO_2 from Mossmorran and Dunbar, as well as Grangemouth and it opens up a variety of potential CO_2 storage sites in the North Sea, supporting long term CCS. The proposed offshore CO_2 pipeline would be designed and constructed to operate in dense phase supercritical mode.

For early adopters there is potential to re-use Feeder 10 (F10) for transport of CO_2 from the Central Belt to St. Fergus (this is being considered as part of the Acorn project), where booster compressors would then increase the pressure to send it to the storage pipeline. The maximum allowable pressure of Feeder 10 ranges from 70 to 85 barg, so it would need to be operated in the gas phase, rather than the supercritical dense phase[25].

[25] F.-N. Consultancy, "Logistics of Domestic Hydrogen Conversion," Prepared for the Department of Business, Energy and Industrial Strategy, 2018

11 System Configuration

11. System Configuration

11.1 Hydrogen Infrastructure

The demand for hydrogen over the course of the Project period has been discussed previously in Section 5.8, with the modelled overall demand (including an assumption on likely exports) used as the basis for the quantities of hydrogen required for the Project.

The system capacity sizing and number of reformers has been calculated to meet this gas network demand for winter peak conditions[26]. To reduce the overall gas network peak demand, it is assumed that at times of peak demand a combination of demand management and local high pressure gas storage can be used to reduce compression of hydrogen for use for transport (air, rail, and heavy road transport). As an alternative approach, additional reformers could be employed to meet both heat and transport peak hydrogen demand without deferring transport sector production.

For example, in 2035, if there were no reductions, transport users would account for 3.6 million scm/day out of a total of 72 million scm/day. Using demand management to temporarily reduce the amount of hydrogen being compressed for transport uses is assumed to bring the transport demand down to 0.9 million scm/day. This reduces the total gas network peak demand to 69.4 and saves a reformer. The peak winter demand profile (taking into account of demand management for transport) is shown in Figure 11-1 below.

The basis for this profile is to meet the Scottish Government's target to convert one million homes to low carbon heating by 2030[27]. There are challenges associated with this deployment rate in terms of the construction schedule. A steep ramp-up in hydrogen production would be needed starting in 2024 in order to meet the 2030 target.

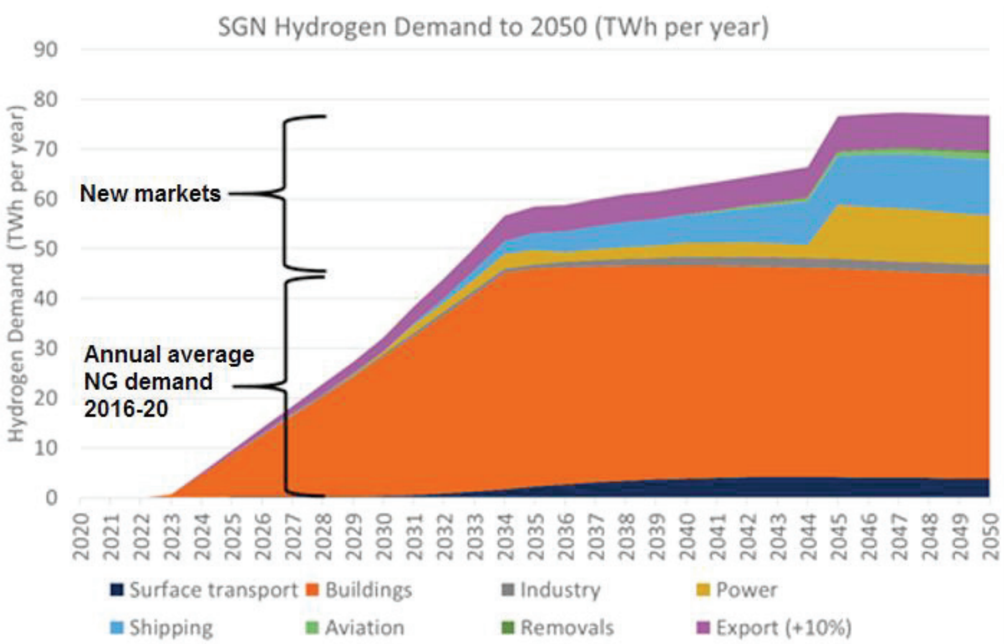


Figure 11-1 Hydrogen Demand for the Project Area

[26] Data provided by SGN from '2019 - 20 Scotland Operations Plan' (see X.19.00472.GLA.R.013 – ToR)
[27] Scottish Government - Draft Heat in Buildings Strategy

A supply profile made up of blue and green hydrogen has been developed to align with the anticipated demand profile. This is shown in Figure 11-2. The following key observations are made on the supply profile:

- The supply includes a gradual increase in annual green hydrogen use to 20 TWh per year in 2050, which is equivalent to an average green hydrogen flowrate of 16.4 million scm/day.
- Because green hydrogen production is subject to intermittency (where no storage is available) the supply profile has been designed so that blue hydrogen can be called upon to meet almost all of the overall peak demand if required. The green hydrogen supply shown represents a situation where green hydrogen production is below average due to low wind speed periods.
- The allowance taken for green hydrogen generation is 50% of normal generation, reflecting a load factor of about 0.25, because the peak in heating demand could correspond to a period of high electricity demand.
- Increasing green hydrogen supply penetration over time could allow for the export of hydrogen outwith the Project Area, thus maintaining the overall number of reformers in operation.
- When the anticipated hydrogen demand reaches its expected peak at around 2035, hydrogen production at peak would be dominated by blue hydrogen generation, with 20 reformers (capacity 140,000 Nm3/h H_2 each rated at 500 MWth thermal/hydrogen output) being needed to meet the peak. Blue hydrogen production has been sized based on meeting the overall anticipated demand minus the anticipated contribution from green hydrogen sources.
- After 2035, there is an anticipated reduction in peak hydrogen demand due to expected gradual improvements in domestic appliance and insulation efficiency assumed as part of the Project, but average yearly demand will continue to grow due to new markets in transport. In 2045, the curve shows an increase in demand due to the use of hydrogen for large-scale power generation at Peterhead. This demand is assumed to be met by stored hydrogen, so will not affect the peak number of reformers planned.

The generation, distribution and storage of the hydrogen is discussed in further detail in the following subsections.

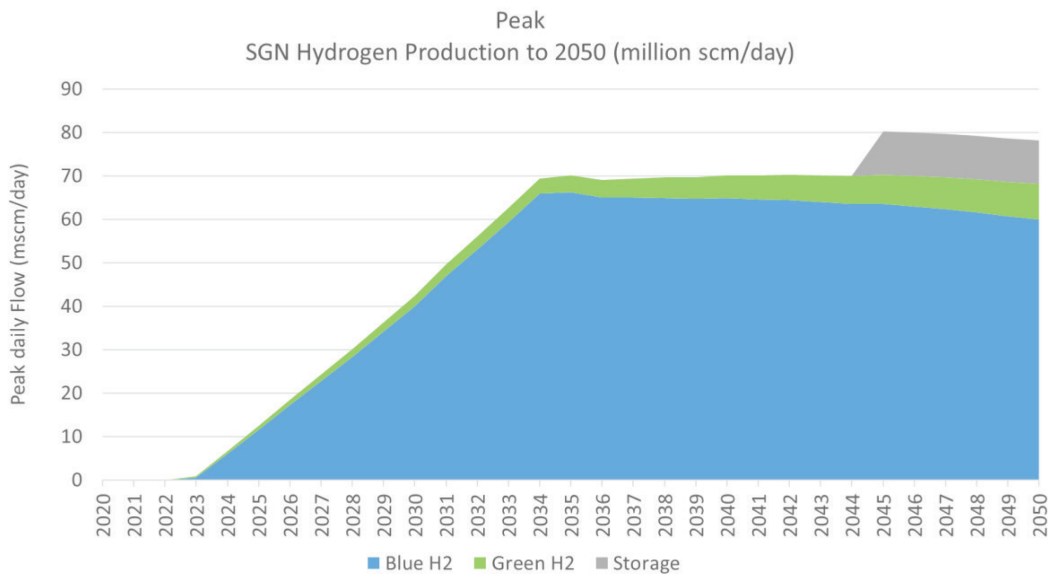


Figure 11-2 Supply Profile at Winter Peak

A supply profile based on annual average demand (e.g., with average green and blue production) is shown below in Figure 11-3 to illustrate the different green and blue supply ratio compared to winter peak conditions (e.g., maximum blue hydrogen production and green production reduced by 50% due to the possibility of poor wind conditions).

As shown above, storage capacity is anticipated to become available around 2045. Over the course of the average year the hydrogen stores would be drawn down and filled, smoothing out the peaks and troughs. The peak in blue hydrogen production in 2045 is a result of the expectation that the existing reformers will ramp up production during winter in order to fill the storage, which is then drawn down for power generation at Peterhead Power Station during the winter.

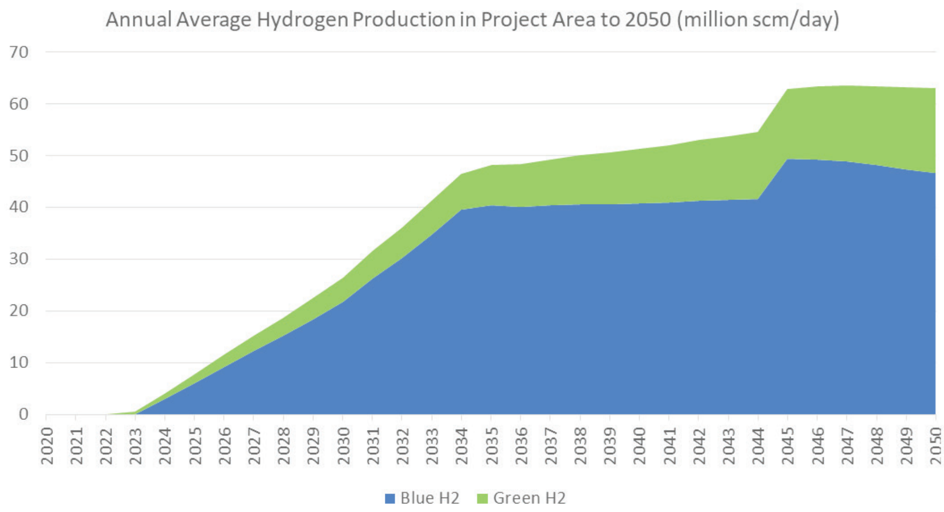


Figure 11-3 Supply Profile at Average Annual Demand

11.1.1 Green Hydrogen Generation

Green hydrogen plant/electrolyser build-out rates are likely to be the main constraint for scale-up of green hydrogen production. Generation of 20 TWh per year of green hydrogen in Scotland is assumed by 2050, based on the aforementioned Offshore Wind and Hydrogen report[28].

Initially green hydrogen production is expected to be small to medium scale, up to circa 200 MW per unit, primarily using onshore wind or solar PV. This production would likely be co-located or near to end users. It is unlikely that renewable electricity resources will be the limiting factor in green hydrogen production as there is more than sufficient offshore wind resource already available to meet the demand for green hydrogen.

11.1.2 Blue Hydrogen Generation

Blue hydrogen generation is expected to be located at existing industrial sites, which have a number of advantages:

- Availability of skilled workforces.
- Availability of infrastructure.
- Greater acceptability for new process plant, compared with a greenfield site.
- The opportunity to share CO_2 capture infrastructure, thus reducing costs.

The system configuration chosen for the Project requires 20 reformers (assuming a capacity of 140,000 Nm3/h H_2 each), with 10 of these intended to be located at Grangemouth, six at St Fergus and four at Mossmorran. Reformer sizes vary, but for the basis of this study we have used a size that is typical for large refinery applications (equivalent to 500 MWth).

The number of reformers has been selected to cover the winter peak in demand for gas heating without storage. This is due to current limitations in storage capacity, which is described in Section 7.

[28] ORE Catapult Offshore Wind and Hydrogen report

There are a number of viable routes to generation of blue hydrogen, although at this time, only CO_2 capture from the process gases (circa 50% of the total carbon emitted) is demonstrated in industrial practice at demonstration facilities including the Shell Quest project in Canada, Air Products' Port Arthur hydrogen plant in Texas and the Tomakomai project in Japan.

It is feasible to apply conventional post combustion CO_2 capture processes, such as proprietary amine solvent technologies, to hydrogen unit reformer flue gases in order to capture around 95% of the total CO_2 emitted by the hydrogen production process. This option can be applied to retrofit existing plants. However, more advanced technologies have been developed for new build plants which have an inherently smaller footprint, capital cost and energy penalty, these include:

- Auto-thermal reforming with gas heated reformer.
- Steam methane reforming with gas heated reformer.
- Partial oxidation.

All three of these technologies are closely competing in terms of techno-economic performance and it is expected that all three will see substantial deployment.

For the purposes of this study the project has specified steam methane reforming with gas heated reformers at a scale of 140,000 Nm3/h H_2 per unit. This is a typical scale and will give rise to capital and operating costs, natural gas, CO_2 and hydrogen flows which will be broadly representative of any of the three competing technologies.

Each blue hydrogen reformer would have its own booster compressor to raise the hydrogen to pipeline pressure, assumed to be 80 barg.

The use of blue hydrogen will lead to an increase in peak demand for natural gas in the National Transmission System (NTS), to compensate for the energy losses in the reformers and to meet the additional demand for sectors such as transport. Currently in Scotland the quantity of gas available exceeds demand, so the system would need to be re-balanced.

11.1.3 H_2 Distribution – Final Configuration (2045 Onwards)

Figure 10-4 below shows the proposed final hydrogen transmission system envisioned to be in place by 2045 that would include interconnectivity with the north of England. The figure also shows the location of blue hydrogen generation, indicated by blue dots. The figures within the blue dots indicates the number of reformers proposed for each location.

This main hydrogen pipeline would link St Fergus and Grangemouth, and would link up the existing natural gas national offtakes. An export pipeline would extend the main hydrogen pipeline south to connect with the future hydrogen system in England. This study has selected a base case route from Grangemouth to Longtown, following the routing of the existing SGN pipelines.

Longtown has been provisionally selected as this is the existing interface of natural gas networks. It is, however, subject to further study, including consultation with studies for development of hydrogen networks in England. An alternative option is to route the main hydrogen pipeline from Grangemouth to Simprim via Soutra, indicated as a dashed line in Figure 10-4.

Spur lines will operate at the same pressure as the main hydrogen pipeline would take hydrogen to PRS's to lower the pressure to 7 bar to bring hydrogen into the existing local distribution zones to facilitate sectionalisation and changeover of users to 100% hydrogen. The 7 bar systems are not included within the scope of this study and it is noted that, to complete the system there will be the requirement to install new 7 bar pipelines to extend the hydrogen system into user areas and allow staged conversion to hydrogen use.

As described in Section 7, technology for hydrogen storage in porous rock formations is assumed to be available by 2045 and would be used to support power generation at Peterhead.

Estimated sizes for the proposed hydrogen transmission system pipelines are shown in Table 10-1.

Figure 11-4 Generation and Distribution (2045)

Legend

- New main hydrogen trunkline
- Alternative main hydrogen trunkline
- Main hydrogen spur line
- Repurposed existing spur line
- New hydrogen spur line
- New or repurposed spur line
- CO_2 network
- H_2 network **(offshore storage)**
- Proposed green hydrogen production
- Proposed blue hydrogen production (No. = SMRs/ATRs to be constructed)
- City/Town

Note: PRSs are located at the outlet end of each spur line.

11.2 CO_2 Infrastructure

The key locations in Scotland for dispatching captured carbon to offshore geological storage are from the north-east of Scotland and from the Firth of Forth. Existing emitters in the north-east and Central Belt area (e.g. at Grangemouth, Mossmorran, Dunbar and biomass emitters) are mainly at coastal locations therefore most of the CCS plants should be located near the coast.

11.2.1 CO_2 Collection and Transportation – North East

The north-east CO_2 collection and transport system proposed as part of the Project and illustrated below in Figure 11-5, would serve two sites: St Fergus Gas Terminal and Peterhead power station. At St. Fergus, six blue hydrogen reformers would be constructed and the CO_2 from these (produced at 20 barg) would be combined with CO_2 collected by post combustion processes at the gas terminal. A common booster compressor (two trains) would be used to export CO_2 at 135 barg via a pipeline. This approach would complement the Acorn project and could use the same CO_2 stores and infrastructure.

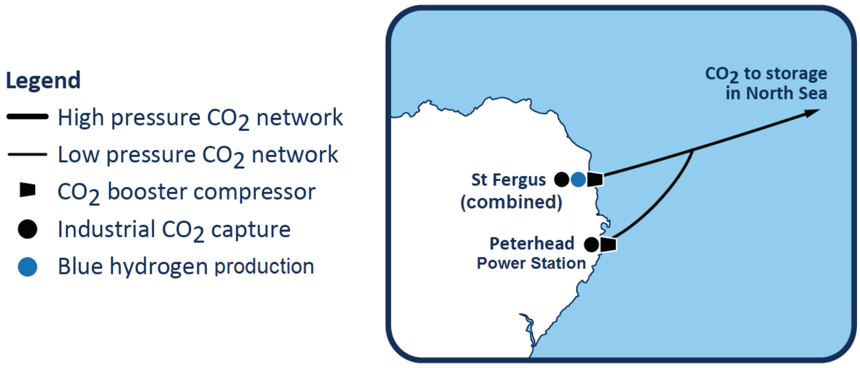


Figure 11-5 CO_2 Capture and Transport in the North East (2030 Onwards)

At Peterhead, post-combustion CCS is assumed to be implemented on the power station from 2026 onwards (see Project Phase 2 report for further details). A booster compressor at the Peterhead site would compress the CO_2 to supercritical dense phase and will be sent offshore directly, possibly connecting to the main line from St Fergus with a subsea tie-in, as developed for the Shell Peterhead FEED project.

Typical costs for the industrial CO_2 capture plants have been calculated using an in-house tool developed by Wood. These are shown in Table 11-1 below.

Location	CO_2 Captured (TPA)	Design Flow Captured (te/h)	Capture Unit Capex (£M)	LP Compression and Drying Capex (£M)
St Fergus Terminal	324,000	39	63	15
SAGE - St Fergus	117,000	14	47	14
Frigg Terminal Phase II (St Fergus)	56,000	7	15	5
Peterhead Power Station	903,000	206	117	17
TOTAL	**1,400,000**	**266**	**243**	**50**

Table 11-1 Estimated Costs for Industrial CO_2 Capture Plants in the North East

Table 11-2 Estimated Performance of CO_2 Booster Compressor (North East)

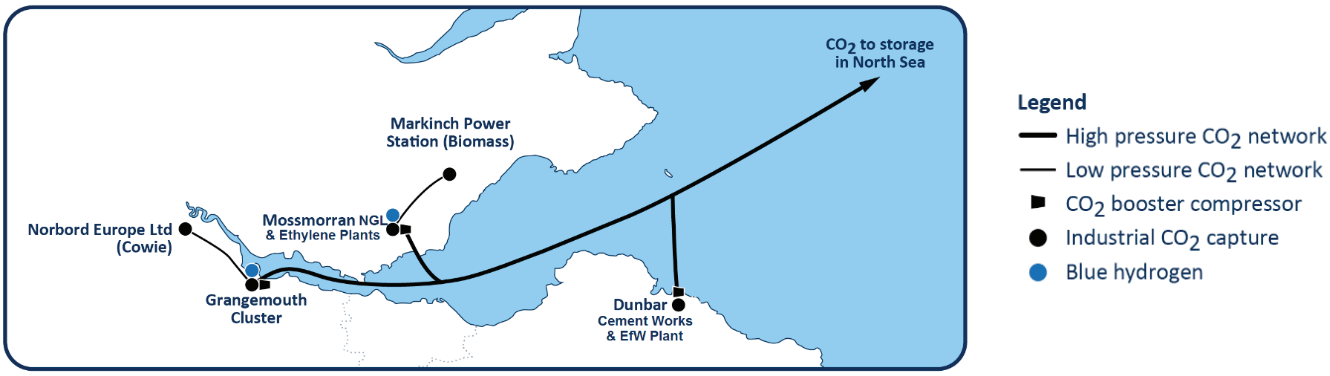
Location	Compression Range	Total Flow (te/h)	Total Power (MW)	No of trains
St Fergus	12 to 135 barg	680	29	2
Peterhead	12 to 135 barg	107	5	1

11.2.2 CO_2 Collection and Transportation – Central Belt

The main emitters of CO_2 in the Central Belt are from the Grangemouth industrial cluster, which is therefore likely to be the starting point for CO_2 capture in the area as shown below in Figure 11-6. For the Project timeline, CO_2 capture is assumed to start at Grangemouth in 2025, with the proposed new CO_2 pipeline becoming operational. The need for CCS at Grangemouth is driven by the need to decarbonise the Grangemouth cluster and reformers nearby will help support and reduce the costs of the CO_2 gathering infrastructure and pipeline overall requirements.

The installation of this pipeline will enable construction of the proposed blue hydrogen reformers to commence in parallel. The reformers could share the CO_2 compression and transport infrastructure with the existing industrial cluster emitters proposed to be connected. The main CO_2 pipeline would run down the Firth of Forth and would include tie-in points for connections for the CO_2 from Mossmorran and the CO_2 from the cement works at Dunbar.

Figure 11-6 CO_2 Capture and Transport in the Central Belt (2040 Onwards)



CO_2 capture at Mossmorran is assumed to start around 2029/2030, with capture from the furnaces at the ethylene cracker, and CO_2 capture from major emitters at the adjacent Cowdenbeath Gas Terminal. With this in place, blue hydrogen production could start at the Mossmorran site, with the blue hydrogen and cracker CCS plant using a common booster compressor. The high-pressure CO_2 pipeline has 4 km to run to the sea: as this can run through a rural area, with lower risk profile than for some more built-up areas, the CO_2 booster compressor is assumed to be located at the Mossmorran site, rather than a separate site near the coast.

The UK target for the cement industry envisages cement production being zero-emission by 2040, therefore CO_2 capture would need to be installed on the Dunbar cement plant by 2040. The adjacent energy from waste (EfW) plant is assumed to implement CCS at the same time, and the combined CO_2 from the two plants would use a common booster compressor to send high pressure CO_2 offshore via a pipeline which would join the main CO_2 line via a subsea pipeline.

The Central Belt CO_2 system has the potential to facilitate negative CO_2 emissions by connecting to two facilities in the area that emit significant amounts of CO_2 originating from biomass: the Markinch biomass power station and the Norbord factory at Cowie that can be used to offset any reformer inefficacies.

The CO_2 pipelines for these would be in low pressure gas service, to avoid the hazards and consenting issues associated with onshore high-pressure CO_2 pipelines. For Markinch, the plant is located in a relatively built-up area near Glenrothes, but there is potential for a pipeline to run westwards, crossing farmland for approx. 18 km to connect to the proposed Mossmorran booster compressor.

The Norbord factory at Cowie emits 0.3 million te/y CO_2 of which 60% originates from biomass. The area between Cowie and Grangemouth is mainly farmland, which is likely to be suitable for a low-pressure CO_2 gas connection to Grangemouth.

Depending on the proportion of biomass in their fuel feedstock, there may be additional negative emissions associated with the cement plant and EfW plant at Dunbar.

Table 11-3 Estimated Costs for Industrial CO_2 Capture Plants in the Central Belt

Location	CO_2 Captured (TPA)	Design Flow Captured (te/h)	Capture Unit Capex (£M)	LP Compression and Drying Capex (£M)
Petroineos Manufacturing Scotland Ltd	1,638,000	187	118	19
Grangemouth CHP Ltd	681,000	78	81	16
INEOS Chemicals Grangemouth Ltd	612,000	70	87	16
BP Exploration Operating Company Limited (Kinneil terminal, Grangemouth)	365,000	42	65	15
INEOS Infrastructure (Grangemouth) Ltd	462,000	53	86	15
Norbord Europe Ltd Cowie	299,000	34	59	15
Versalis UK Ltd Grangemouth	56,000	6	15	4
ExxonMobil Chemical Ltd	893,000	102	102	17
Shell U.K. Limited, Cowdenbeath Terminal	197,000	22	54	14
RWE Markinch Ltd	391,000	45	64	15
Tarmac Cement and Lime Ltd, Dunbar	588,000	67	80	16
Viridor EfW, Dunbar (Estimated)	285,000	33	60	15
TOTAL	**6,143,000**	**738**	**869**	**177**

Table 11-4 Estimated Performance of CO_2 Booster Compressors (Central Belt)

Location	Compression Range	Total Flow (te/h)	Total Power (MW)	No of trains
Grangemouth	12 to 136 barg	1470	63	5
Mossmorran	12 to 136 barg	540	23	2
Dunbar	12 to 136 barg	98	4	1

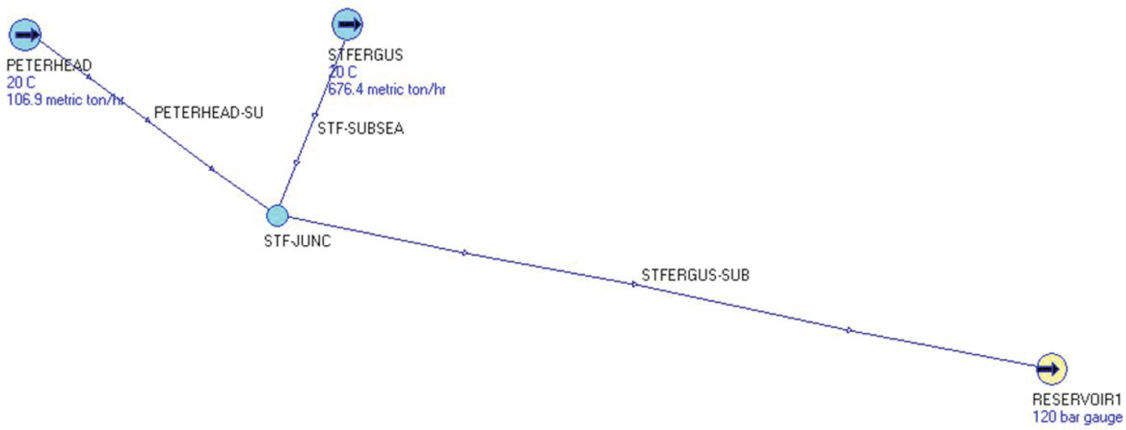
11.2.3 CO_2 Pipelines

For this Project, the pressure of the CO_2 sent offshore to storage would be boosted to supercritical pressure. A typical CO_2 pressure of 135 barg is assumed. In the Central Belt, the main offshore CO_2 line would also tie into the CO_2 pipelines coming from the Mossmorran site and from Dunbar. The locations for blue hydrogen generation have been selected to be able to share the CO_2 collection and transport infrastructure with other major emitters. There are two separate CO_2 sequestration pipelines running from the mainland to offshore locations. These pipelines would transfer CO_2 in the dense phase. Two key assumptions have been made:

1. **Seabed depth at injection location is 100m for both locations.**
2. **Pressure at the injection location at the pipeline outlet is 120 barg.**

The first system proposed is from both St Fergus and Peterhead to the offshore reservoir and is illustrated in Figure 11-7 below.

Figure 11-7 St Fergus / Peterhead CO_2 Pipeline Schematic



The second system proposed comprises CO_2 from Grangemouth and Mossmorran. There is also a flow from Dunbar, the facilities and pipeline for which is outside of the scope of this study but has been included for sizing of the pipeline from the Dunbar Junction to Reservoir 2. This system is illustrated in Figure 11-8 below.

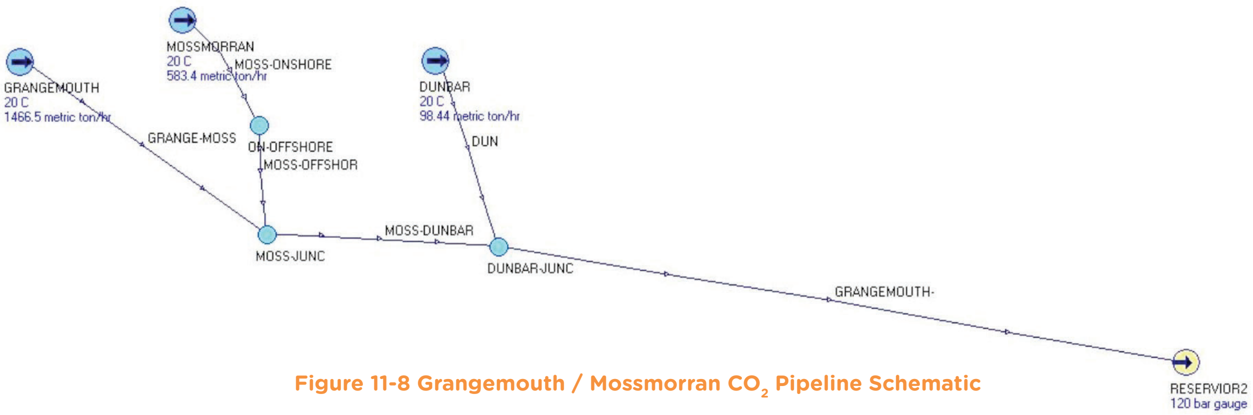


Figure 11-8 Grangemouth / Mossmorran CO_2 Pipeline Schematic

During the calculations to determine the line sizes, checks were made to ensure that the fluid velocity will not exceed the erosional velocity limit as specified in API 14E (~4.0 m/s) and that the pipeline inlet pressures were around 135 barg.

Further information on flow analysis including resultant pressures and velocities can be found in Section 4.4 of the Phase 3 Project report.

12 Green Hydrogen Projected Costs

12. Green Hydrogen Projected Costs

As the proposed system reconfiguration is ultimately intended to facilitate large-scale green hydrogen delivery to end users, an analysis of the cost of green hydrogen production has been undertaken and described below. This analysis looks at the relative merits of both green and blue hydrogen with respect to natural gas and the price of energy.

12.1 Policy Drivers

The European Commission's (EC) new hydrogen strategy[29] involves an estimated $550 billion capital commitment by 2030. The UK has announced its commitment to develop 5 GW of hydrogen production[30] with plans for 20% (by volume) natural gas blending by 2030. The EC's hydrogen policy is likely to exert the greatest influence for cost reduction in the near term.

The EC's hydrogen strategy is an essential component of the European Union's pledge to reach carbon neutrality by 2050. The key aims of the strategy include the following targets set by 2030:

- Focus on green hydrogen production (as opposed to fossil fuel-based).
- Circa 40 GW of installed electrolysis powered by renewables.
    - Interim 2024 target of circa 6 GW electrolyser capacity.
- Circa 40 GW of additional demand side green hydrogen from neighbouring non-EU countries.
- Euro denominated traded market in green hydrogen for purchasing and hedging fuel contracts.
- 10 million tons of green hydrogen production.
- Circa 80 to 120 GW of additional wind and solar installed capacity.

Today, green and blue are not currently price competitive with unabated methane reforming production techniques. The current cost of unabated natural gas fed hydrogen is circa £0.60 to £2.00/kg (which is price sensitive to feedstock cost) versus circa £2.50 from localised CCS entrapment (like-for-like natural gas price). The current cost of green hydrogen is in the region of £2.00 to £8.20/kg with capex, power costs and utilisation driving price variation.

With 40 GW of electrolyser installations by 2030 (a 55-fold increase in global installed capacity) some market commentators expect that economies of scale and learning will deliver green hydrogen at prices comparable to unabated hydrogen production prices.

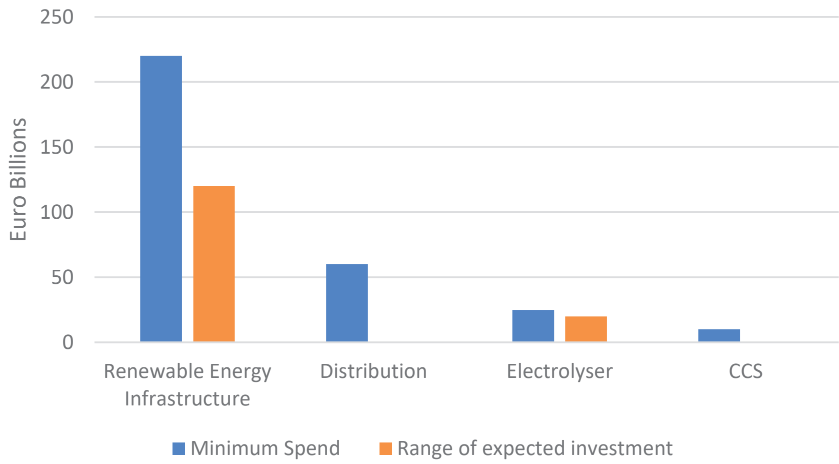
In Figure 12-1 it is illustrated where the proposed investment will be allocated which involves building circa 80-120 GW of solar and wind capacity specifically for green hydrogen production. The planned investment is largely targeted at subsidising renewable power cost to electrolysers and therefore lowering operating costs for powering the electrochemical process.

Seven EU countries have made giga-watt scale electrolyser capacity pledges. However, to date there is uncertainty that national level policies will achieve targets set by the EC. It is expected that carbon costs combined with national level policies will drive investment towards the use of green hydrogen where electrification is not possible or economically attractive relative to hydrogen.

While there will be some funding and policy support available to meet the hydrogen targets, the EU will require significant buy-in and budgetary support from member state governments to realise its hydrogen ambition. To date, the EU has installed wind capacity of 230 GW and circa 171 GW of solar and this will also need to increase considerably.

[29] https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf
[30] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/936567/10_POINT_PLAN_BOOKLET.pdf

Figure 12-1 EU Green Hydrogen Funding to 2030

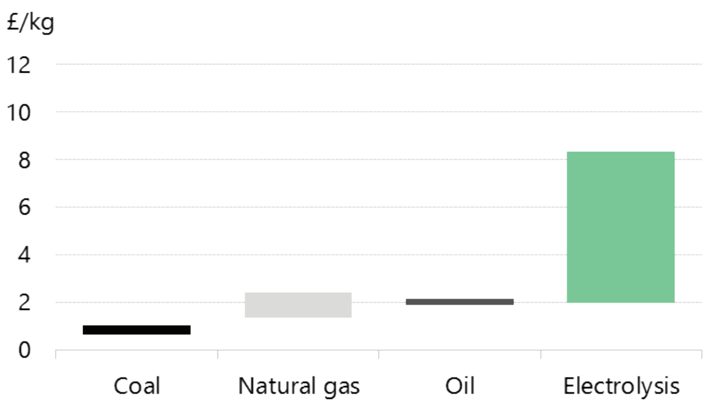


12.2 Current Cost of Hydrogen Production

Figure 12-2 below illustrates the current cost of producing hydrogen from energy sources including coal, oil and gas, which range between £0.60-2.40/kg. Steam methane reforming (SMR) is the main technology used to convert natural gas to hydrogen, and coal gasification is the main technology for coal-based production. Production costs vary primarily with fuel price. The costs indicated assume highly efficient large-scale producers utilising low-cost fossil fuels with no carbon costs.

These estimates are at the lower bound of benchmarks in other literature reviewed during the project. However, to assess the competitive merits of green hydrogen, it is prudent to consider these estimates as a credible competitive cost comparison.

Figure 12-2 Current Cost Range of H_2 Production



12.3 Hydrogen Projected Production Costs

To provide an indication of the projected hydrogen costs, Bloomberg New Energy Finance (BNEF) data for the levelized cost of hydrogen (LCOH) for large scale projects has been analysed and projected, with the key contributors to the levelized cost illustrated.

The figures provided were only available for the time periods of 2019, 2030 and 2050, therefore, it was assumed that a linear change between the time periods will occur, allowing values for more time periods to be presented. The value for 2019 was £3.29/kg. The data used provides prices in terms of 2019 value of money, thus will not take into account the effect of inflation over time.

Some of the figures arrived at by BNEF, in their conservative case detailed in Table 12-1 below, appear to be lower than typically expected. BNEF do not divulge all of the assumptions made in their figures, however it is expected that the assessment takes advantage of favourable assumptions with respect to reducing electricity price, project size and capacity factor. It is important to note the cost of hydrogen will be project specific and the figures below should only be used as an indicator of potential price movement.

Table 12-1 Green Hydrogen LCOH Figures (Conservative Case)

	2023	2026	2029	2035	2045	2050
Electricity Cost (£/kg H_2)	1.46	1.21	0.97	0.79	0.61	0.52
Equipment Cost (£/kg H_2)	1.40	1.32	1.23	0.96	0.48	0.24
Total Cost (£/kg H_2)	**2.86**	**2.53**	**2.20**	**1.75**	**1.09**	**0.76**

The figures provided above represent the conservative approach taken by BNEF. To provide an idea of potential range and variation in these figures, the optimistic figures can be found in the Appendix A of the Project Phase 4 report [31].

12.4 Hydrogen Production Costs Relative to Natural Gas Plus Carbon

Figure 12-3 below illustrates the data compiled from a number of sources to compare the projected cost of blue and green hydrogen production with a fully loaded carbon cost from the unabated burning of natural gas.

As governments have galvanised their commitments to a net-zero greenhouse gas emissions based economy by 2050, removing unabated natural gas from the energy mix will be required. Traditionally, spatial heating with natural gas has typically been lower cost than electrical heating equivalent. A sustainable alternative is the use of low and zero carbon hydrogen for spatial heating.

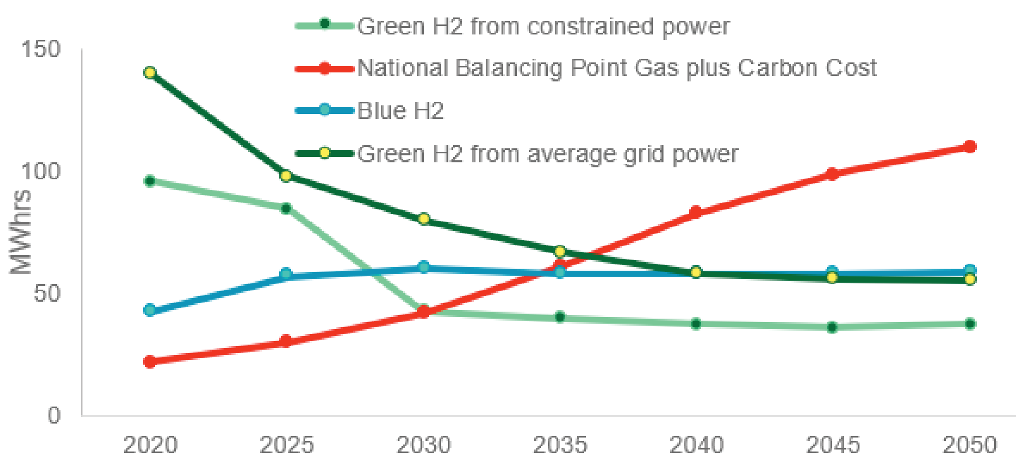
Consequently, the ability to use natural gas on a distributed basis will require conversion to a renewable-based molecule in the form of green hydrogen. It is probable that blue hydrogen will provide a role in the energy mix due its ability to reach scale quickly combined with dispatchable energy delivery without the need for expensive storage systems.

Additionally, the forecast cost for blue hydrogen is expected to be lower than the green equivalent in the period leading up to 2030 (see Figure 12-3). Therefore, it is credible that blue hydrogen will play an important role as a bridge fuel and/or acting as a method to balance lower utilisation water electrolysis powered by surplus renewables power production (as evidenced green hydrogen from constrained power). In the long run grid-tied power which has been heavily decarbonised with the benefit of time-shift storage (stationary battery systems plus electric vehicles) is expected to deliver a progressively increased proportion of the green power used to energise grid-tied high capacity water electrolysis.

With ever decreasing carbon budgets the prospective cost of greenhouse gas emissions is expected to make the burning of unabated natural gas less uneconomic relative to blue and green hydrogen. Therefore, the role of green hydrogen in the mix is likely to play an important and affordable form of carbon abatement to reach net zero targets by 2045.

Figure 12-3 Levelised Costs of H_2 versus National Gas Plus Carbon

Source data: BEIS, BNEF, Element Energy, IRENA, H_2 Council, Navigant, National Grid FES, DNV-GL



13 Project Roadmap

13. Project Roadmap

13.1 Construction Programme and Funding Route

A three-phase approach to the proposed system reconfiguration is anticipated for the hydrogen infrastructure, mainly based around the locations where hydrogen will be produced:

- Hydrogen deployment phase 1 (2024 construction) – Aberdeen and St Fergus.
- Hydrogen deployment phase 2 (2025 construction) – Central Belt.
- Hydrogen deployment phase 3 (2026/7 construction) – East Coast.

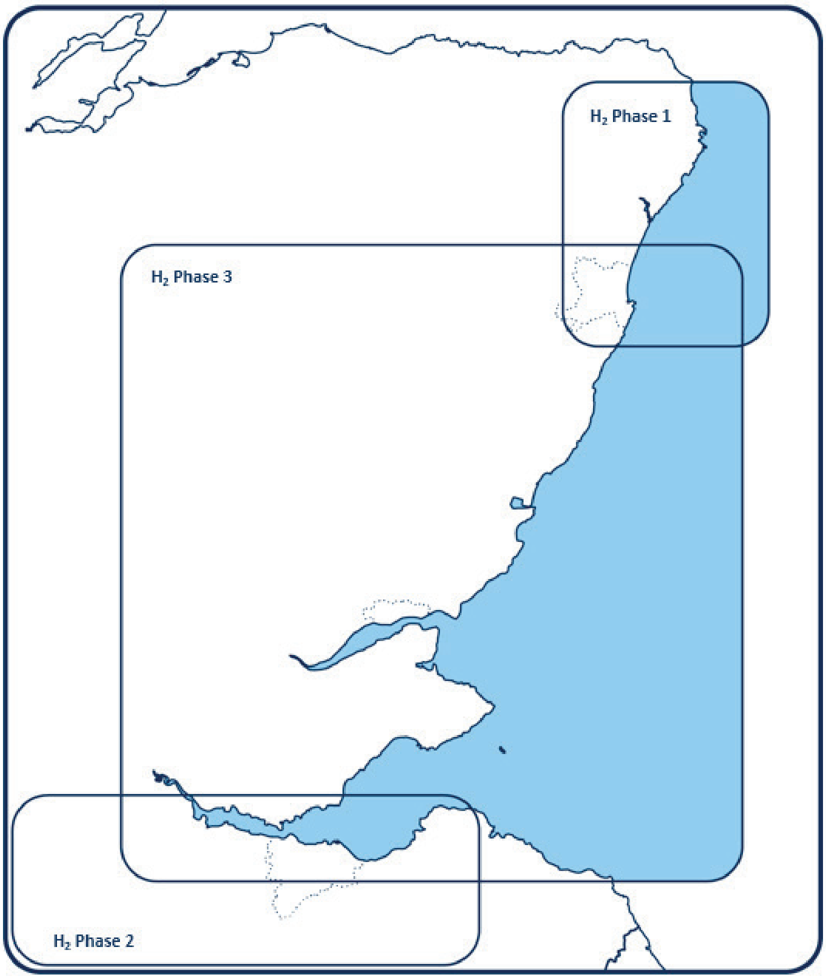


Figure 13-1 Hydrogen Infrastructure Phasing

See Section 13.2.1 for the deployment of the local hydrogen transmission and distribution systems for further details.

The proposed CO_2 collection and transport infrastructure would be deployed in two strategic areas:

- CO_2 deployment Phase 1 (2025 operational) – Central Belt.
- CO_2 deployment Phase 1 (2026 operational) – North east.

Deployment of complementary CO_2 infrastructure is expected at St Fergus as part of the Acorn CCS project

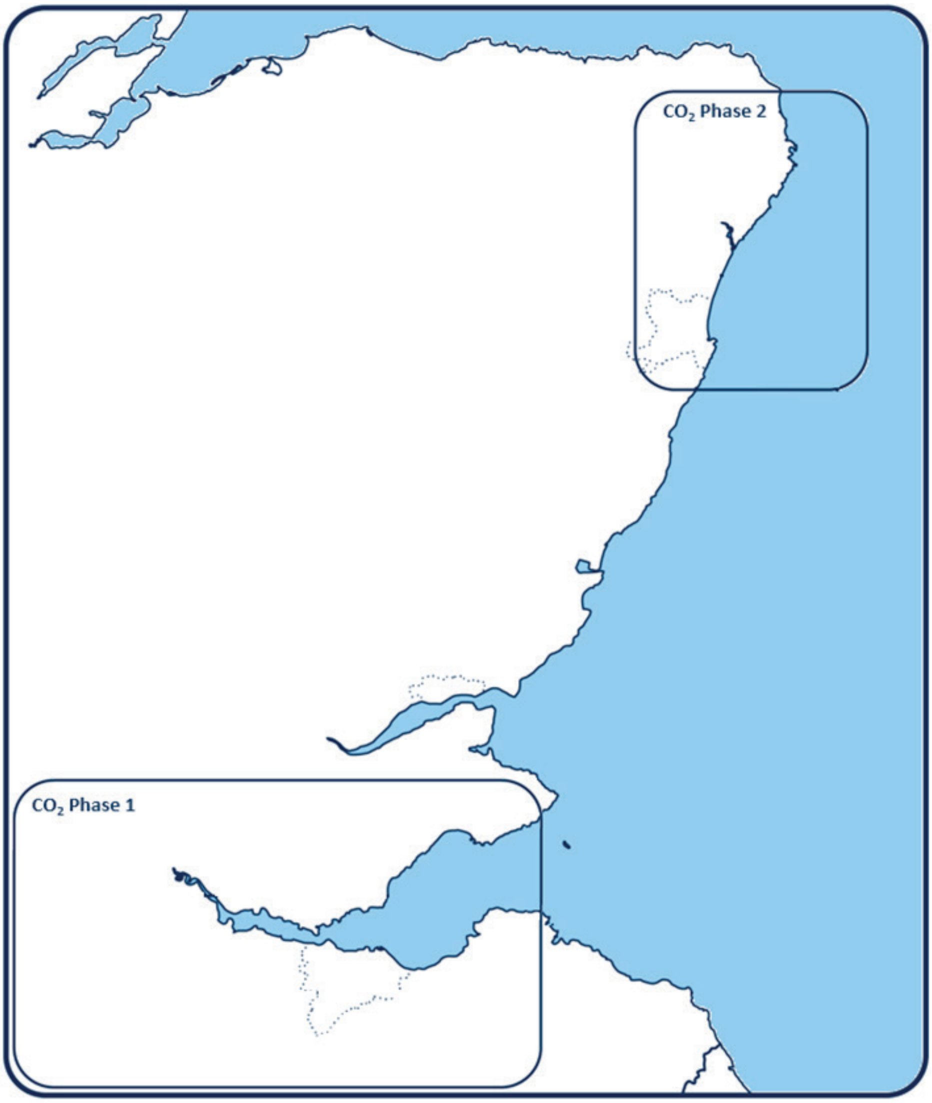


Figure 13-2 CO_2 Infrastructure Phasing

See Section 13.2.2 for detail the CO_2 infrastructure phasing for the north east and Central Belt areas.

13.1.1 Roadmap to 2030

Figure 13-3 below illustrates the required deployment of hydrogen production assets necessary to meet the proposed system reconfiguration objectives of decarbonising 1 million homes by 2030. Reformers (numbering 12 by 2030) would supply the bulk of the hydrogen supply though complemented by green production from early green hydrogen projects running in parallel such as Dolphyn.

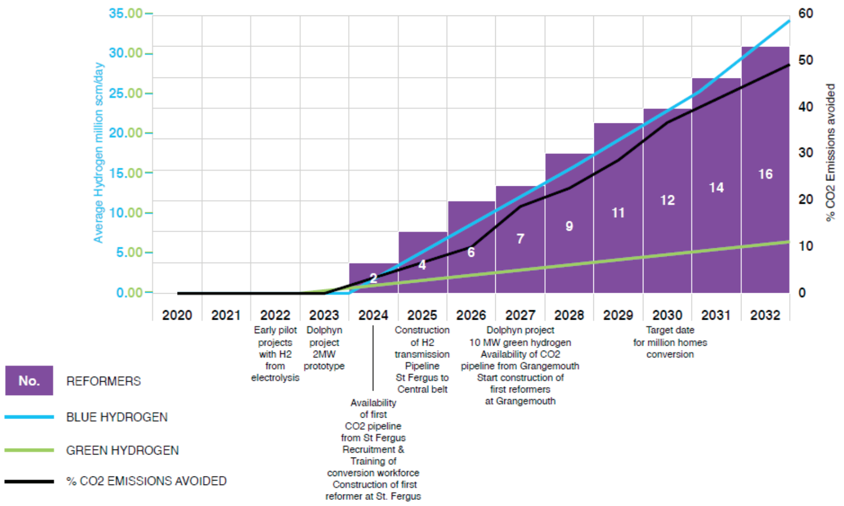


Figure 13-3 Roadmap to 2030

13.1.2 Roadmap to 2050

Figure 13-4 below illustrates the required deployment of hydrogen production assets necessary to support the Scottish Government's 2045 net-zero target. It is anticipated that 20 reformers would be required by 2034 to supply the bulk of hydrogen up to 2045, with a gradual increase in green hydrogen up to and beyond this date. This hydrogen capacity will meet the demand for the modelled sectors within the Project Area. This includes hydrogen for fuel-switched domestic customers, new markets in the transport sector and exports. Hydrogen storage in porous rock formations is assumed to become available from 2045. The proposed Project roadmap includes flexibility: if storage in local porous rock formations becomes technically feasible earlier than expected (e.g., by 2030), it would be possible to reduce the numbers of reformers that are built and rely on storage to cover the winter peak in demand (see Section 7 for further information). The 20 reformers planned can be turned up to full utilisation with the additional output used to support hydrogen-based power production. It is anticipated that an increasing share of green hydrogen supplied beyond 2045 would displace blue hydrogen consumption in the Project Area over time. However, maintaining the number of reformers will allow for exports of blue hydrogen.

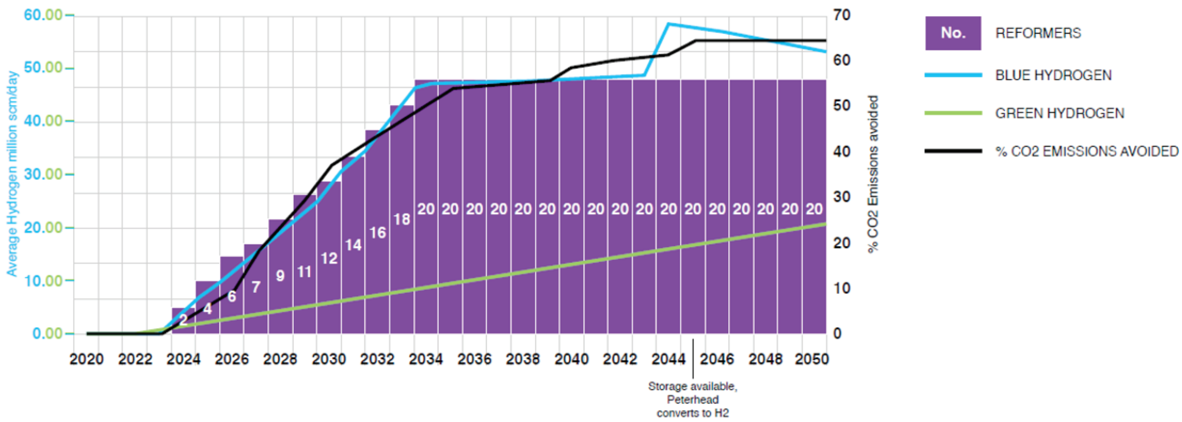


Figure 13-4 Roadmap to 2050

The graph above (Figure 13-4) shows the major contribution that the combination of CCS on existing emitters and decarbonisation of the grid (with blue and green hydrogen) could make to the decarbonisation of Scotland. These technologies can together avoid around 60% of Scotland's current CO_2 emissions. The remaining 40% covers emissions outside the scope of the Project including:

- Geographical areas outside the Project Area (gas customers and industrial emitters) for example CO_2 emissions from hydrocarbon processing in Orkney and Shetland.
- Transport such as cars, where decarbonisation is assumed to involve electrification.
- Domestic and commercial premises not connected to SGN's gas distribution network.
- Domestic and commercial premises connected to independent town gas grids (statutory independent undertakings or SIUs) operated by SGN.
- Emissions from agriculture.

Figure 13-5 below illustrates the number of existing gas customers would be converted to hydrogen up to 2050

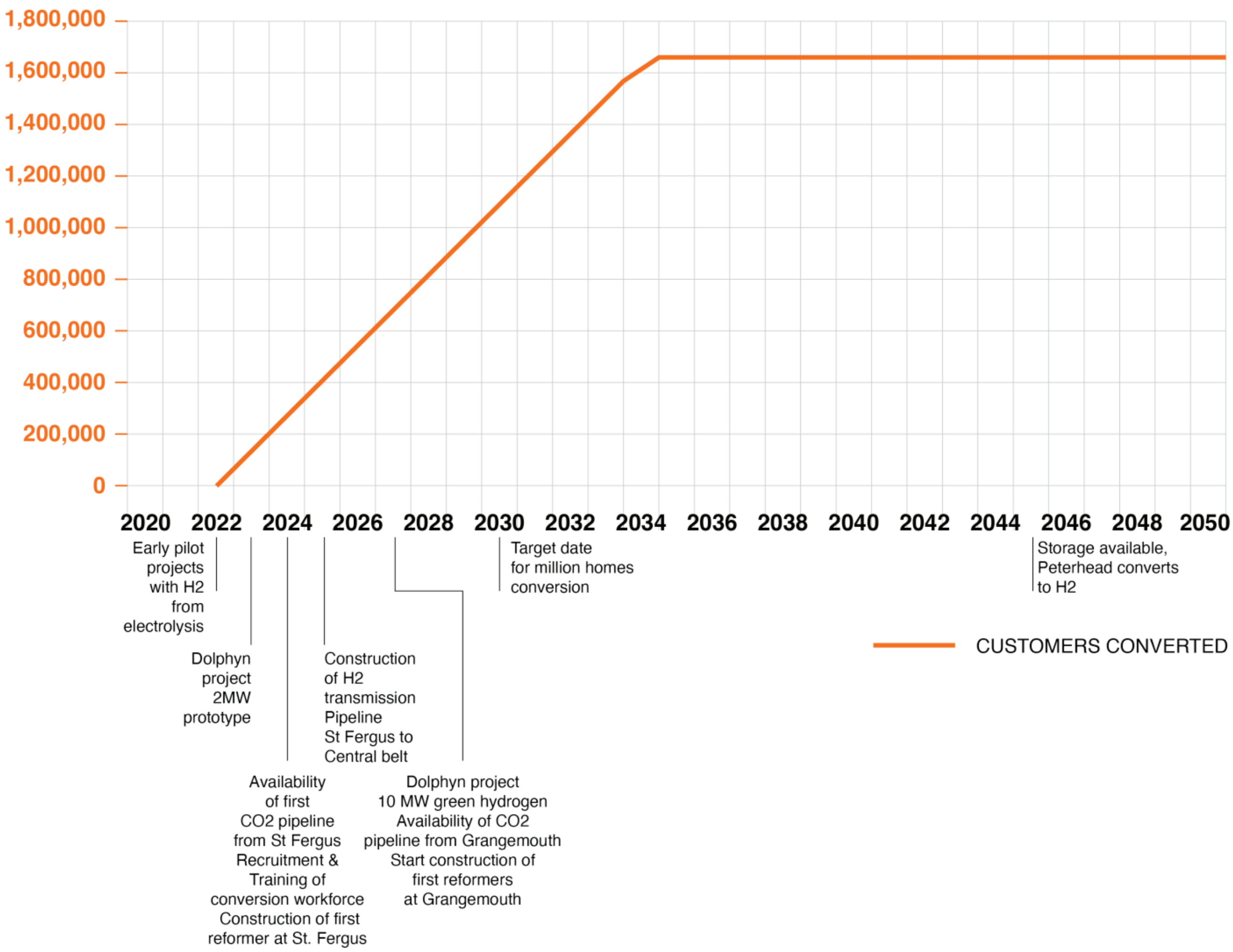


Figure 13-5 Customers Converted

13.2 Deployment Phasing

13.2.1 Hydrogen Infrastructure Phasing

13.2.1.1 Phase 1

Phase 1, as illustrated below in Figure 13-6, would commence in the Aberdeen area. This is planned due to complementary, separate hydrogen initiatives such as the Acorn (carbon capture and blue hydrogen production) and Dolphyn (offshore green hydrogen production) projects being already under development in the region.

The Project proposes blue hydrogen reformers (initially one or two units) would be constructed at the St Fergus site (aligning with the Acorn project's plans). The first phase of the hydrogen supply line would be used to supply Aberdeen, with the process of conversion to 100% hydrogen proposed to start immediately. The initial phase of the Dolphyn project is also intended to supply Aberdeen.

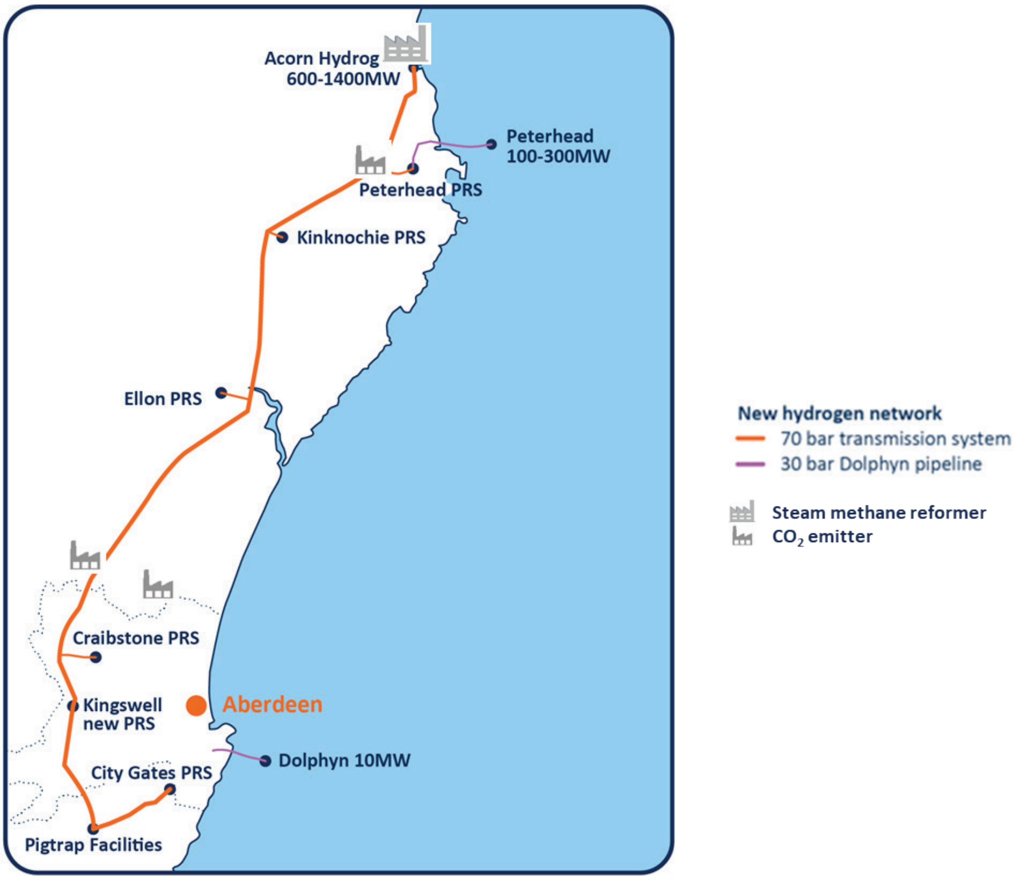


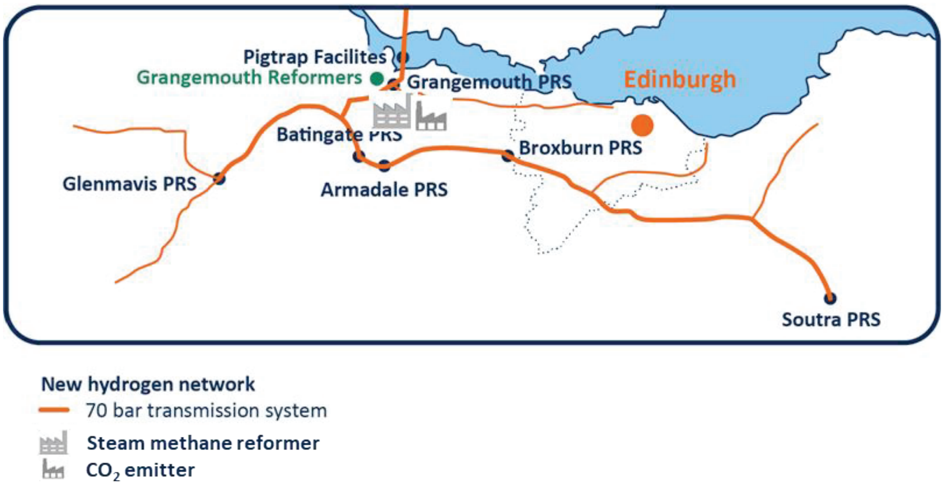
Figure 13-6 Phase 1 - Construction 2024

13.2.1.2 Phase 2

In Phase 2 of the Project, as illustrated in Figure 13-7 below, construction would move to the Central Belt with the deployment of blue hydrogen production at Grangemouth. This would enable hydrogen to be sent to the major national offtakes in the Central Belt (Glenmavis, Bathgate, Armadale, Broxburn and Soutra) for blending 20% hydrogen into the natural gas supplies at these locations.

Availability of CO_2 transport for the Grangemouth cluster would be needed: this could be via a new pipeline from Grangemouth to a store in the North Sea, as assumed for this Project (refer to Section 11.2) or could re-use National Grid's Feeder 10 (F10) pipeline to transport CO_2 to St Fergus as envisaged in the Acorn project. At the same time, conversion of customers in the Central Belt can start.

Figure 13-7 Phase 2 - Construction 2025



13.2.1.3 Phase 3

In Phase 3, the hydrogen line between Aberdeen and Grangemouth would be constructed. This would permit additional blending, for example at the Careston, Balgray and Drum national offtakes. It would also provide synergies with other early green hydrogen projects and enable the expansion of the Dolphyn project which could connect into the main hydrogen pipeline, as well as SGN's planned H100 hydrogen demonstration project on the Fife coast[32].

This phase could have an opportunity to re-purpose National Grid's F13 pipeline for hydrogen transport. At the time of this report publication, this pipeline has not yet been proven to be suitable; however, National Grid are seeking to confirm its suitability for re-purposing. This work is ongoing and has not been completed in the time frame of this report. The size of F13 (40") should be adequate for the expected hydrogen flowrates. The maximum allowable pressure of Feeder 10 ranges from 70 to 85 barg, so it would need to be operated in the gas phase, rather than the supercritical dense phase[33].

Figure 13-8 Construction 2026/27

[32] https://www.sgn.co.uk/H100Fife
[33] https://dokumen.tips/documents/project-act-acorn-feasibility-study-acorn-feeder-10-act-acorn-project-271500.html

13.2.2 CO_2 Infrastructure Phasing

The CO_2 emission capture profile is based on the following dates for anticipated CO_2 capture:

Table 13-1 CO_2 Capture Events Year Event

Year	Event
2024	CO_2 capture at St Fergus, blue hydrogen production starts at St Fergus.
2024-2034	Ramp-up in blue hydrogen production.
2024-2050	Ramp-up in green hydrogen production.
2025	CO_2 capture starts at the Grangemouth cluster, ramping up over three years, blue hydrogen production starts at Grangemouth.
2030	CO_2 Capture from Fife ethylene cracker and blue hydrogen production at Mossmorran.
2035	Bioenergy with carbon capture and storage (BECCS) at Norbord Cowie and Markinch power station.
2040	CO_2 capture at Dunbar cement plant.

The initial steep ramp-up to meet the 2030 target to decarbonise the heat demand in one million homes is challenging and is dependent on early construction at the Grangemouth cluster and at St Fergus. It will also require early availability of CO_2 pipelines from these locations to support blue hydrogen production otherwise alternative CO_2 sequestration options would need to be employed.

The profile for the CO_2 captured and stored is shown in Figure 13-9. This includes sites where CO_2 is generated as part of the process, and therefore cannot be mitigated by fuel switching. Figure 12-10 shows the CO_2 that would be abated through the use of green hydrogen: this is the amount of CO_2 which would have been emitted if natural gas were used instead of green hydrogen.

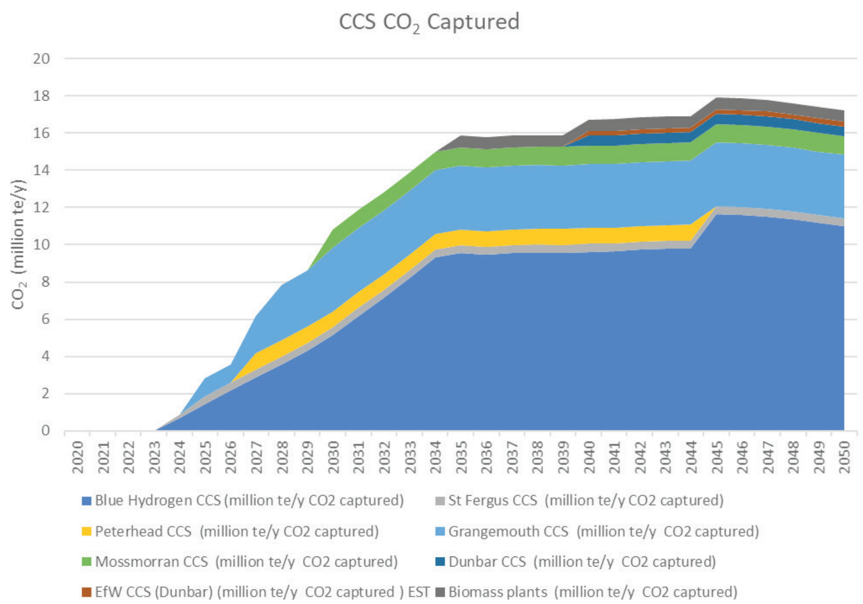


Figure 13-9 CO_2 Capture Profile

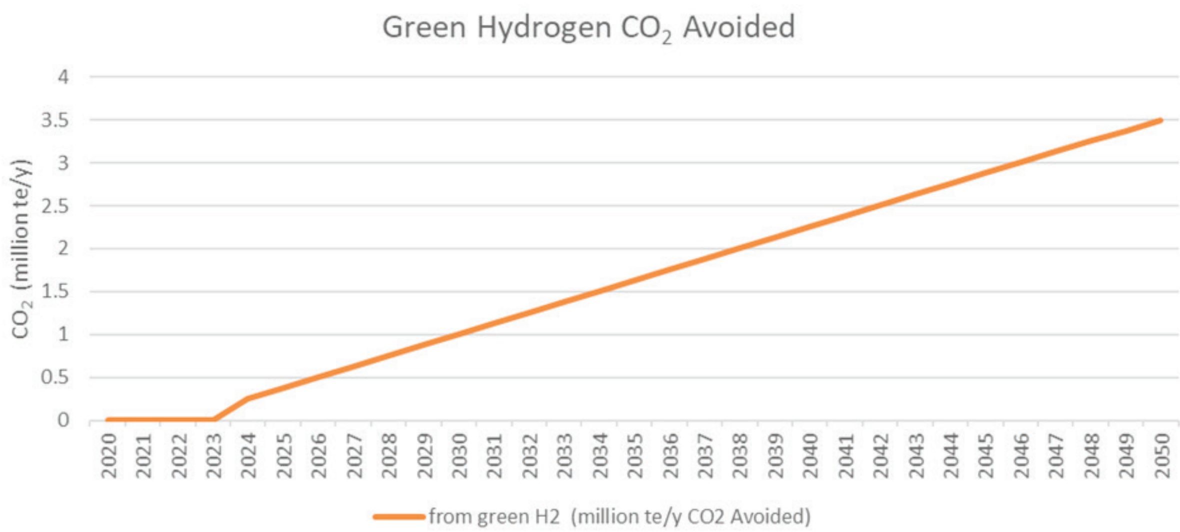


Figure 13-10 CO_2 Emissions Avoided due to Green Hydrogen Use

13.2.3 Construction Timetable & Funding Sources

Figure 13-11 below details the kick-off dates for the envisioned construction phases for the proposed system, associated potential funding streams relating to the elements under SGN's purview, and other relevant events. It is anticipated that pre-FEED work for each phase would be funded under the Ofgem's Network Innovation Allowance (NIA) with FEED and construction work funded via Ofgem's Net Zero (NZ) and Re-opener Development allowance.

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
No. Reformers		0	0	0	0	2	4	6	7	9	11	12
Event	**Funding Mechanism**											
Dolphyn 10 MW prototype	Dolphyn project											
Phase 1 pre-FEED	NIA											
Phase 1 FEED	NZ pre-construction											
Phase 1 construction	NZ re-opener											
Phase 2 pre-FEED	NIA											
Phase 2 FEED	NZ pre-construction											
Phase 2 construction	NZ re-opener											
Phase 3 pre-FEED	NIA											
Phase 3 FEED	NZ pre-construction											
Phase 3 construction	NZ re-opener											
Conversion workforce recruitment & training	SGN											
Target date for 1 million homes conversion	n/a											

Figure 13-11 Construction Timetable (Kick-off Dates) & Funding Sources

14 Financial Analysis

14. Financial Analysis

14.1 Capital Cost

The capex estimate for the Project is based on the system re-configuration selected and described in phases 2 and 3. It is an order of magnitude (OOM) estimate, with a typical accuracy of 350%, and reflects an instantaneous cost level of Q1 2021.

The base estimate has been taken up to 'Project subtotal' level, which includes the following aspects:

- Direct costs:
    - Direct materials (including spare parts, third party inspection and shipping / freight).
    - Labour only subcontracts.
    - Material and labour subcontracts.
- Indirect costs
    - Engineering, procurement and construction (EPC) contractor.
    - Temporary construction facilities and laydown areas.
    - Heavy lift equipment (>100 tonne).
    - Vendors engineering support.
- Services costs:
    - EPC contractor detailed design, procurement and home office construction services.
    - EPC contractor site supervision.
    - EPC contractor commissioning team.
- The following items are considered as 'below the line' items and are not included in the estimate at this stage. These items can typically add an additional 30 – 50% to the Project subtotal (depending on the extent of forward escalation required).
    - EPC contractor's profit.
    - Contingency.
    - Owners costs.
    - Forward escalation.
    - Acquisition of land (this will be an important factor for the pipelines).
    - Project development including Pre-FEED, FEED, environmental impact assessment (EIA) and permitting and consenting.

Note: These cost elements may not be applicable to all scope items, for example, the allowance included for modifications to domestic appliances.

Order of magnitude equipment costs have been determined as follows:

- For blue hydrogen production, reformer costs have been scaled from a separate assessment of blue hydrogen reformer costs that Wood has previously undertaken for the UK Government Department for Business, Energy & Industrial Strategy (BEIS)[34].
    - A typical cost has been allowed for flare systems based on experience with similar plants. An estimate for the hydrogen booster compressor to take the hydrogen to pipeline pressure was based on a sized equipment list and historic cost data.

[34] Wood plc, "Hydrogen Supply Programme – Novel Steam Methane / Gas Heated Reformer," BEIS, 2020.

- Green hydrogen costs were initially determined by scaling from a recent (2020) design developed by Wood, which was costed based on vendor quotation data.
    - If this cost is scaled-up, the capital cost would be £8,400 million. At present, the high price of electrolysers is due to low manufacturing capacity relative to the immediate demand forecast. Similar to cost reductions seen in mass-produced energy technologies, such as solar panels, hydrogen electrolyser systems are expected to see major reductions in price in the near future due to economies of scale, automation and other improvements in manufacturing, and technology improvements [35].
    - Capital cost reductions of over 80% are forecast for electrolyser systems. In particular, factory automation is expected to lead to a step change reduction in costs[25].
    - The green hydrogen electrolyser cost has therefore been corrected to take account of this mprovement by assuming that most of the electrolysers are constructed when costs have reduced:
    - 4% of electrolyser capacity installed at 80% of 2020 prices.
    - 16% of electrolyser capacity installed at 60% of 2020 prices.
    - 80% of electrolyser capacity installed at 20% of 2020 prices.
    - Leading to an overall cost of 29% of 2020 prices.
- The hydrogen transmission system has been costed by estimating pipeline construction costs for the proposed main hydrogen trunkline between St Fergus and the Central Belt (and the extension towards northern England), plus the cost of the proposed spur lines.
- The cost of the grid reinforcement and modifications required to provide sectionalisation and convert local grids to 100% hydrogen has been calculated by using the analysis of conversion of Edinburgh in the H21 Strategic Modelling Major Urban Centres report[36] where converting the grids for 205,565 customers required an investment of £39.5 million.
    - This has been extrapolated to the rest of the grids, assuming that for more rural areas the longer distances are compensated for by less congested construction access therefore overall costs are similar.
- Appliance modification costs have been estimated at an average of £1,000 labour per customer per conversion to 100% hydrogen [37]. An additional £1,000 per average customer has been assumed for parts. 1.65 million customers have been assumed, covering the offtakes in the Project Area (total SGN customers are 1.8 million [38])
- CO_2 transport costs have been obtained by scaling from recent project cost data for CO_2 booster compressor systems and estimating offshore CO_2 pipeline costs.

In Table 14-1 and Figure 14-1 below, the costs have been broken down into two categories:

1. The hydrogen system, covering the production, generation and transmission of green and blue hydrogen (and associated CO_2 transport for the latter production method).
2. The CO_2 system serving industry, covering the transport (pipelines and booster compressors) of CO_2 from industries (not including CO_2 from blue hydrogen production).

Where facilities (for example a pipeline) handle CO_2 produced from blue hydrogen production and CO_2 produced from industrial capture, the cost is split pro-rata based on flowrate. The overall cost is dominated by the hydrogen system, with the proportion of cost attributed to industrial CO_2 being relatively small (2%).

[35] RENA (International Renewable Energy Agency), "Green Hydrogen Cost Reduction: Scaling up Electrolysers to meet the 1.5°C Climate Goal," IRENA, 2020.

[36] H21, "H21 Strategic Modelling Major Urban Centres," H21.

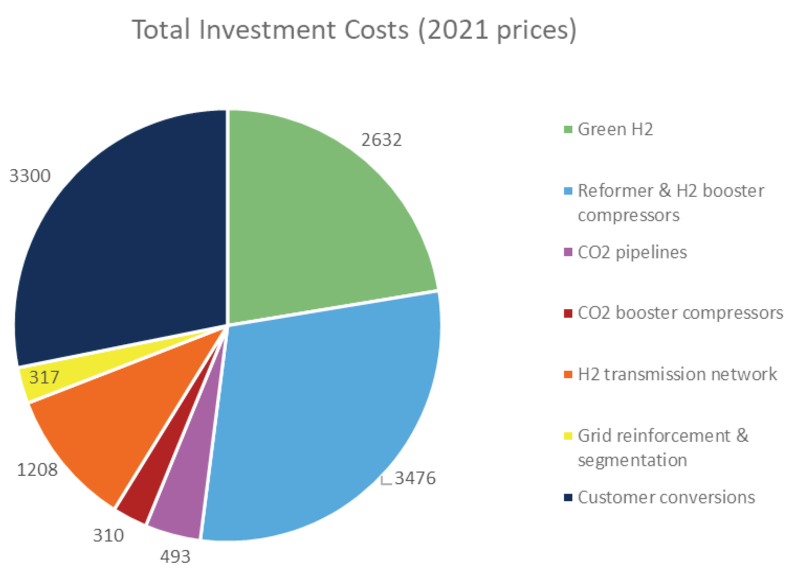
[37] F. N. Consultancy, "Logistics of Domestic Hydrogen Conversion FNC 57239/47448R," BEIS, 2018.

[38] SGN, "Operations Report Winter 2020/21".

Table 14-1 Summary of Capex to 2050

Item	Description	Quantity	Cost (Hydrogen system) (£M)	Cost (Industrial CO_2 System) (£M)	Total Cost (£M)
Blue hydrogen generation (new assets, non-retrofit)	Blue hydrogen reformers (140,000 Nm3/h H_2 / 500 MWth)	20	3,068	0	3,068
	Hydrogen flare systems	3	24	0	24
	Hydrogen booster compressors (140,000 Nm3/h, 80 barg outlet pressure)	20	384	0	384
Green hydrogen generation	Electrolysis (total)	2,850 MWe	2,421	0	2,421
	Green hydrogen booster compressors	20	216	0	216
Hydrogen transmission system	Main trunk line (St Fergus to Grangemouth with connection to England)	359 km	500	0	500
	Spur lines	43 km	580	0	580
Hydrogen grid	Reinforcement, segmentation and modifications	1.65 million customers	317	0	317
Appliance modification	Conversion of appliances to 100% hydrogen	1.65 million customers	3,300	0	3,300
CO_2 booster compressors	Grangemouth boosters	5	101	42	143
	Mossmorran boosters	2	45	13	58
	St Fergus boosters	2	58	5	63
	Dunbar boosters	1	0	23	23
	Peterhead boosters	1	0	24	24
CO_2 pipeline system	CO_2 pipeline system (NE)	132 km	103	27	130
	CO_2 pipeline system (Central Belt)	290 km	246	117	363
TOTAL			**11,363**	**251**	**11,614**

Figure 14-1 Total Investment Costs (£M)



The breakdown shows that the most significant costs are customer conversions to 100% hydrogen, and the hydrogen reformers. Green hydrogen generation accounts for a relatively high proportion of the cost as it has a higher cost uncertainty than the blue hydrogen components. This is because costs are forecast to change rapidly over the next 30 years.

If green hydrogen costs turn out to be higher than forecast, then less green hydrogen generation is likely to be built. Nevertheless, as shown in the Project Phase 3 report [39], the peak demand in gas is met by blue hydrogen production, and as such the reformers and pipeline systems represent a low-regret investment. If green hydrogen costs come down more than forecast, more green hydrogen capacity is likely to be built, and the blue hydrogen reformer capacity could be used to increase hydrogen export to other regions.

14.2 Investment Profile

Table 14-2 below outlines the events timeline anticipated that would drive the investment profile for the proposed system.

Table 14-2 Reconfiguration Events Year Event

Year	Event
2023	Training for workforce for conversion to 100% hydrogen.
2024	CO_2 capture and blue hydrogen production starts at St Fergus. Home conversions begin.
2024-2034	Ramp-up in blue hydrogen production.
2024-2050	Ramp-up in green hydrogen production.
2025	CO_2 capture starts at the Grangemouth cluster, ramping up over three years. Blue hydrogen production starts at Grangemouth.
2030	CO_2 capture starts at the Fife ethylene cracker. Blue hydrogen production starts at Mossmorran.
2035	Bioenergy with carbon capture and storage (BECCS) starts at Norbord Cowie and Markinch power station.
2040	CO_2 capture starts at Dunbar cement plant.
2045	Underground geological storage implemented to support power generation using hydrogen.

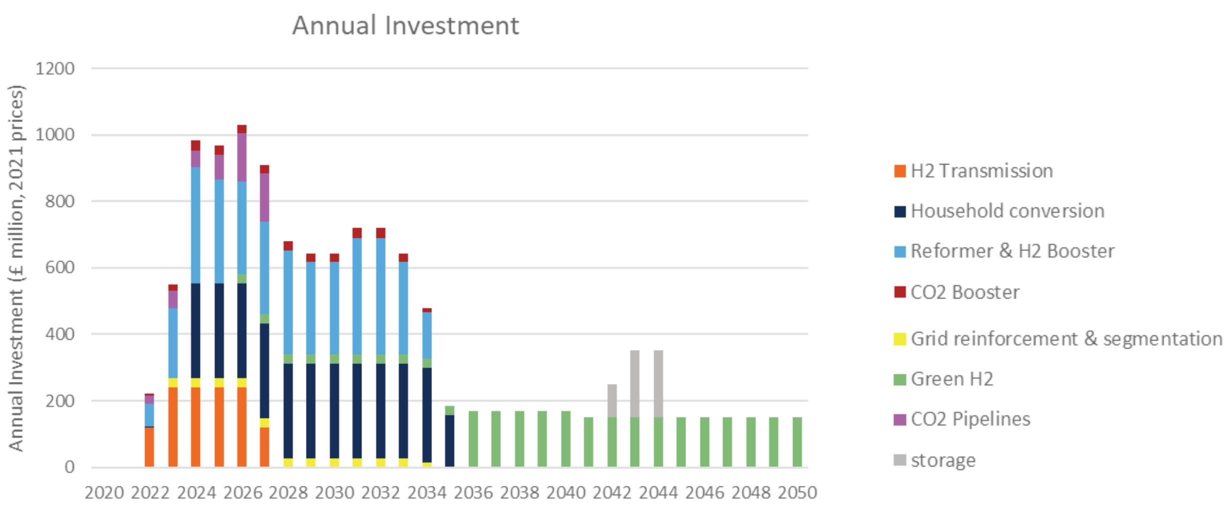
[39] X.19.00472.GLA.R.023 - Phase 3 Report

For a typical investment (for example a blue hydrogen reformer), it is assumed that if the reformer is completed in Year 3, expenditure is distributed as follows:

- **Year 1: 20%**
- **Year 2: 40%**
- **Year 3: 40%**

For the process of converting customers to 100% hydrogen, expenditure for staff training is allowed in the year before this process would commence.

Figure 14-2 Investment Profile 2020-2050



From 2035 onwards enough reformers would have been constructed to be able to cover peak hydrogen demands. Investment in green hydrogen would continue, and could increase in pace after 2050, as costs come down.

If geological storage of hydrogen becomes available post-2045, this is likely to support additional green hydrogen generation. A typical cost for a large geological storage facility has been included in the profile as an illustration (but this is not included in the total cost as it is not certain exactly when and if hydrogen storage would be constructed).

SGN's share of the proposed investment would mainly be in the hydrogen transmission system (£1,080 million), grid reinforcement and segmentation (£317 million), and potentially in customer conversion (£3,300 million). As illustrated below in Figure 14-3 investment is envisioned to take place mainly in the period 2023-2035.

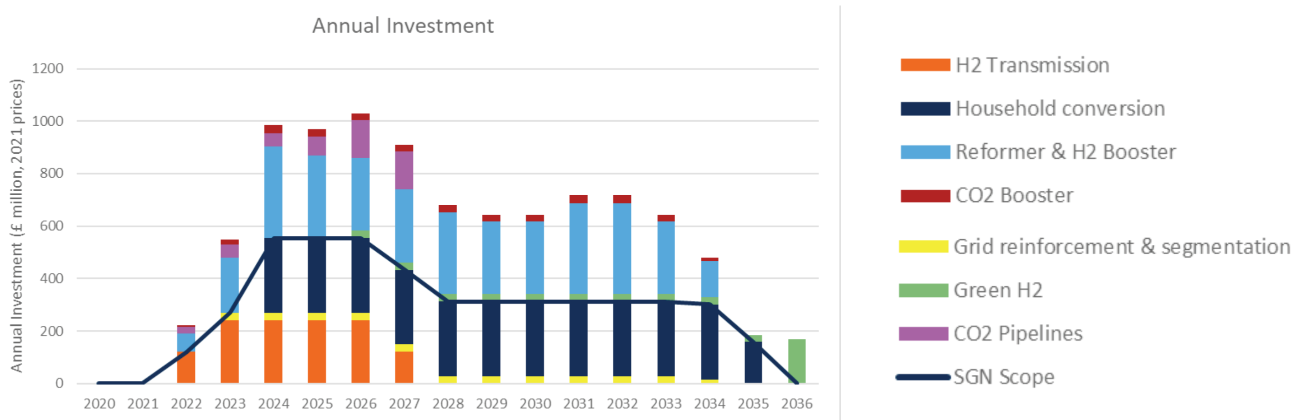


Figure 14-3 Investment Profile 2020-2036 Showing Probable SGN Scope

15 Project Analysis

15. Project Analysis

A strength, weakness, opportunity and threat (SWOT) analysis of the proposed system reconfiguration option selected by the Project was undertaken. The reconfiguration option selected in Phase 2 of the Project was chosen following a multi-criteria decision analysis (MCDA) process following UK Government standards and best practice and has previously been subjected to a rigorous industry standard multi-criteria decision-making process. The system reconfiguration option selected following this optioneering process is a distributed model of blue hydrogen production supported by an onshore local transmission system with a parallel network for CO_2 collection and offshore transmission to geological storage.

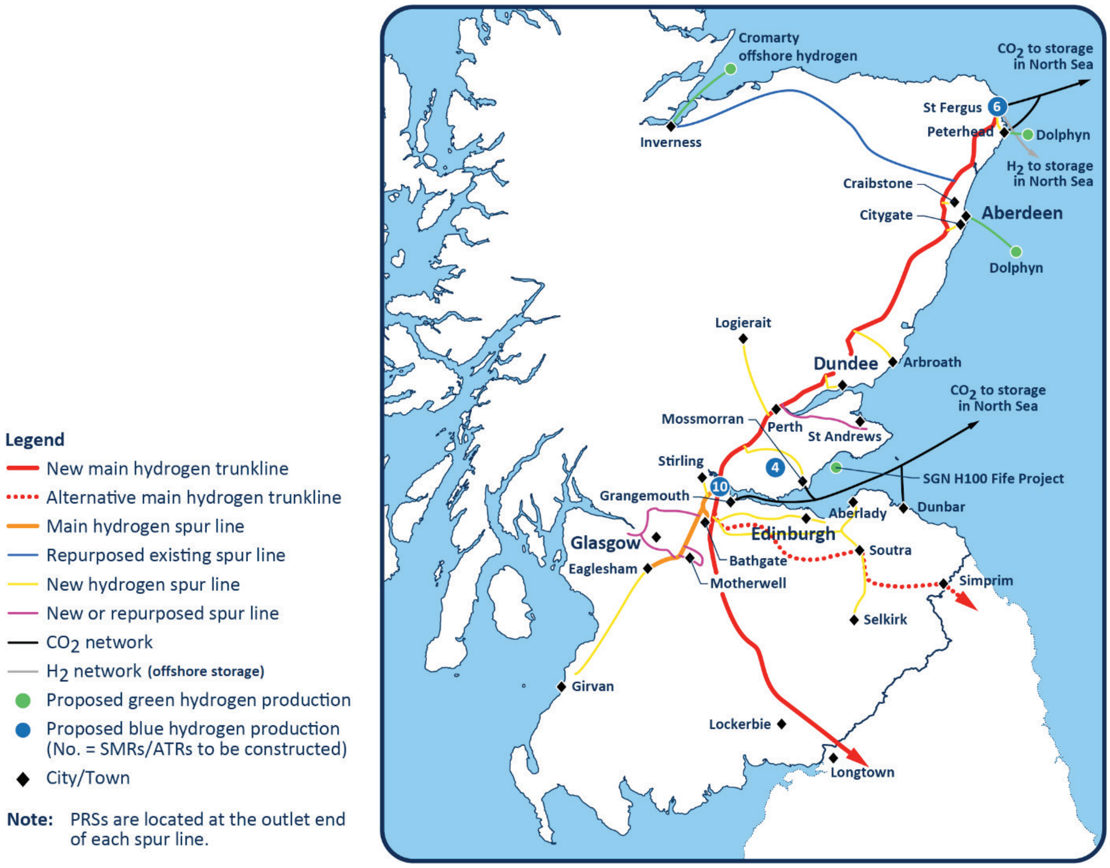


Figure 15-1 Option DL Offshore CO_2

The assessment criteria and sub-criteria used to appraise the options in the MCDA are detailed in the Project Phase 2 report.

Each of the sub-criteria developed for the MCDA were scored for each option with weightings applied to each top-level criterion. Following this process, it was agreed to progress option DL - Offshore CO_2 to further development in Phase 3. This decision was taken as this particular option scored significantly better than all other others and was found to be relatively robust to changing assumptions.

The following non-exhaustive lists of strengths, weaknesses, opportunities and threats have been identified.

15.1 Strengths

The perceived strengths of the proposed system reconfiguration are as follows:

- The build-out is expected to start with early supply of green hydrogen from the Dolphyn project[40] to the south of Aberdeen which will eventually integrate into the wider onshore blue hydrogen transmission system proposed.
- Anticipated future green hydrogen generation at Peterhead will have access to the proposed hydrogen transmission system.
- Avoids having to build a separate hydrogen pipeline from St Fergus to Kinknockie to supply Peterhead.
- Onshore hydrogen solutions may favour transport hub connections or options to compress and transport hydrogen to remote areas.
- Future expansion of offshore green hydrogen can be integrated into the new system. Offers opportunities for import and export of hydrogen i.e., suitable locations for shipping.
- Offers flexibility that can more easily help in construction phasing and future access to funding.
- Likely to stimulate faster hydrogen uptake amongst end users, helping to decarbonise of the heat demand of one million homes by 2030 in line with the Scottish Government's target
- New pipelines designed for purpose provide for increased safety.
- Potential to develop local hydrogen hubs for transport applications.
- Provides resilience against disruption in supply from external factors.
- Ability to decarbonise heat for difficult-to-decarbonise buildings such as apartments and historic buildings.

15.2 Weaknesses

The perceived weaknesses of the proposed system reconfiguration are as follows:

- Onshore hydrogen pipelines may be more difficult to consent than offshore from an environmental consenting perspective due to multiple environmental and associated constraints. On a distributed rather than centralised model for blue hydrogen production (different locations for SMR deployment) there are more sites for consenting.
- Due to the unavailability of local salt caverns for geological storage of hydrogen (the nearest suitable sites are located in the Teesside / Humberside area) additional SMRs are required to ensure adequate hydrogen supply and thus increasing costs.
- Perception that hydrogen would be viewed negatively by the public based on new technology and concerns around the safety case. This would be more of an issue with a distributed model as there are more sites and likely more people affected.
- Geography of chosen solution means an increase in overall length of pipelines required to facilitate distributed blue hydrogen production and thus costs.
- Development dependent on the growth of carbon capture and storage in the North Sea as blue hydrogen cannot start being produced without operational storage sites for captured CO_2. Transporting CO_2 to alternative European stores, should they be available when required, may offer suitable mitigation.

[40] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/866375/Phase_1_-_ERM_-_Dolphyn.pdf

15.3 Opportunities

The perceived opportunities available to the proposed system reconfiguration are as follows:

- The selected system does not currently envision the re-use existing NTS feeder pipelines 'F10' or 'F13'. If the evidence base can be established proving their viability to carry CO_2 and/or hydrogen these assets may be available for re-use and could reduce costs.
- With blue hydrogen production proposed in different locations there could be multiple work-fronts for quick expansion of 100% converted users and early adoption of industrial users across the Project Area.
- Multiple blue hydrogen production sites would create more job and investment opportunities across a wider area than with a centralised model.
- Potential to diversify products for companies based at Grangemouth and Mossmorran.
- Proposed system can facility a greater degree of green hydrogen inclusion should these costs decrease faster than anticipated.

15.4 Threats

The perceived threats to the proposed system reconfiguration are as follows:

- Should there be a delay in CO_2 pipelines and/or storage sites becoming operational to facilitate blue hydrogen production there may be a delay in delivering hydrogen to early adopters.
- Competition from more advanced projects may set the future agenda for hydrogen deployment in the Project Area and deter broader engagement and/or investment.
- Future policy and/or regulatory drivers from local government, the Scottish Government and/or the UK Government may be contrary to the Project proposition. E.g. future policy favouring an electrification route to heat decarbonisation.
- Inadequate funding mechanisms to develop the Project. E.g. the right incentives may not be in place for developers to invest in production assets.
- Delays in requisite land acquisition may delay the 2030 one million homes heat decarbonisation target.
- Delays in recruitment and/or training of conversion workforce may delay the 2030 one million homes heat decarbonisation target.
- Green electricity prices may fall below those than anticipated in the future making electrification of heat and other energy demands appear more attractive than using hydrogen.
- The price of natural gas may increase above those anticipated thus raising the cost of blue hydrogen production.

15.5 Policy Alignment

The project set out a roadmap and overview of how implementation of the Project would substantially contribute to a range of climate targets, policies and ambitions from a variety of applicable sources (see Table 15-1).

The Scottish Government has a number of relevant policies, such as the Climate Change Plan 2018-2032 and draft Heat in Buildings Strategy. The final assessment of the Project shows good alignment with the majority of UK and Scottish government goals with our detailed assessment presented in Table 15-2 below.

Table 15-1 Policy Alignment

Authority	Policy	Colour Code
Scottish Government	Update to the Climate Change Plan 2018 – 2032	
	Local Energy Policy Statement	
	Hydrogen Policy Statement	
	Heat Policy Statement	
	Draft Heat in Buildings Strategy	
Climate Change Committee	Sixth Carbon Budget	
International Maritime Organisation (IMO)	Decarbonisation and shipping: International Maritime Organization ambitions and measures	
National Grid	Future Energy Scenarios (FES) 2020	
European Commission	Hydrogen Strategy for a Climate-neutral Europe	
n/a		

Table 15-2 Policy Alignment Timeline

Date	Target/ Ambition/ Scenario/ Project		Jurisdiction	Category	Alignment
2024	10 MW hydrogen generation by ERM Dolyphyn by end of 2024.	Project	Scotland	Hydrogen Generation	Allows integration of Dolphyn project.
2024	The majority of new buses purchased are zero emission.	Target	Scotland	Transport	Distributed hydrogen network configuration will facilitate multiple complementary hydrogen transport nodes.
2024	All new homes and buildings consented from 2024 will use zero emissions heating and be highly energy efficient.	Target	Scotland	Buildings	Project can provide a customer option within the Project Area of a supply of hydrogen to new build homes depending on network conversion progress.
2025	As a minimum, the rate of zero missions heat installations in new and existing homes and buildings double every year out to 2025.	Target	Scotland	Buildings	
2025	At least 64,000 homes install low and zero emission heating systems per year by 2025.		Scotland	Buildings	Project supports the delivery of this objective.
2025	New gas fired power plants are properly CCS and/or hydrogen ready by 2025 at the latest.	Target	UK	Industry	Project supports these objectives by providing a CO_2 collection network to facilitate carbon capture from power stations for transport and storage.
2025	Shipped import of CO_2 via Peterhead Port from Scotland's industrial Central Belt, other UK regions and European nations.	Ambition	Scotland	Industry	
2025	Phase out the need for new petrol and diesel light commercial vehicles.	Target	Scotland	Transport	Distributed hydrogen network configuration can facilitate multiple complementary hydrogen transport nodes.
2025	200 MW Acorn Hydrogen project (hydrogen production with CCS).	Project	Scotland		Allows integration of the Acorn project.
2026	ERM Dolphyn 200 MW at Peterhead.	Project	Scotland		Allows integration of the Dolphyn project.
2026	Phase out of new sales of oil boilers in commercial properties by 2025 – 2026.	Target	UK		Project supports targets by providing a customer option for hydrogen.
2028	Phase out of new sales of oil boilers in residential homes by 2028.	Target	UK		

Date	Target/ Ambition/ Scenario/ Project		Jurisdiction	Category	Alignment
2029	Low and zero emissions heat installations in Scottish homes expected to peak at over 200,000 new systems per annum in the late-2020s.	Ambition	Scotland	Buildings	Project supports these objectives by delivering 2030 target to decarbonise the heat demand of one million households and can support progressive conversion targets. Project can facilitate conversion of over 100,000 homes per year in the Project Area in the 2025 – 2030 timescale.
2030	Around 50% of homes (over 1 million households) to convert to a low or zero carbon heating system.	Target	Scotland Scotland	Buildings	
2030	Rapidly accelerate heating system conversions during this decade, from the current rate of around 0.1% of homes converting per year to a rate in the region of 5-10% (over a hundred thousand) homes per year up to 2030.	Target	Scotland	Buildings	
2030	50% (50,000 premises) of non-domestic buildings will need to be converted to low and zero emissions heating.	Target	Scotland Scotland	Buildings	
2030	Emissions for homes and non-domestic buildings combined will have to fall by 68% by 2030 as compared to 2020 (from 8 to 2.6 $MtCO_2e$).	Ambition / Guide	Scotland	Buildings	Project shall contribute significantly to this objective by approximately 50% reduction.
2030	5 GW of low-carbon hydrogen production capacity.	Ambition	Scotland	Hydrogen Generation	Allows integration of hydrogen production.
2030	40 GW installed capacity of green hydrogen within the EU and 40 GW on EU borders to be imported into the EU.	Target	European Union	Hydrogen Generation	Project proposes a hydrogen network with export capabilities to allow green hydrogen to be imported and exported.
2030	75% reduction in Scotland reenhouse gas emissions (compared to 1990).	Target	Scotland Scotland	General	Project shall contribute significantly to this objective.
2030	By 2030, the government would like at least 20% of the volume of the gas in the gas grid to be green gas.	Ambition	Scotland	General	>50% of the gas in the gas grid will be low carbon gas. Project could facilitate use of green hydrogen and facilitate injection of hydrogen.

Date	Target/ Ambition/ Scenario/ Project		Jurisdiction	Category	Alignment
2030	The Scottish Government delivered the Offshore Wind Policy Statement published in October 2020 which supports the development of between 8 and 11 GW of offshore wind capacity by 2030.	Ambition	Scotland	Electricity Generation	Project would allow integration of green hydrogen production from new offshore wind capacity.
2030	50% of all energy to come from renewables.	Target	Scotland	Electricity Generation	Project would facilitate green hydrogen production as a route to market for new or existing renewable energy projects within the Project Area.
2030	2 GW of community / locally owned renewables.	Target	Scotland	Electricity Generation	
2030	Phase out the need for all new petrol and diesel vehicles in Scotland's public sector fleet.	Target	Scotland	Transport	Distributed hydrogen network configuration can facilitate multiple complementary hydrogen transport nodes.
2030	Reduce the carbon intensity of international shipping compared to 2008 levels by 40%.	Target	Global	Transport	Project would provide a supply of hydrogen to port locations within the Project Area to facilitate the decarbonisation of shipping.
2030	Phase out the need for new petrol and diesel cars and vans.	Target	Scotland	Transport	Distributed hydrogen network configuration will facilitate multiple complementary hydrogen transport nodes.
2030	No new unabated gas plants should be built after 2030.	Target	UK	Industry	Project would provide a CO_2 collection network to facilitate CCS at any new gas plants within the Project Area.
2030	Between 7,000 and 45,000 UK jobs could ultimately be associated with Scotland securing 40% of the carbon storage element of a European CO_2 management market.	Ambition	Scotland / UK	Economic	Project would allow for the import of CO_2 for dispatch to offshore geological storage.
2032	43% reduction on 2018 emission levels whilst Scottish industry remains globally sustainable and competitive.	Target	Scotland	Industry	Project would position Scotland as a world-leader in the use of hydrogen for decarbonisation.
2032	Expect to see renewable generation increase to between 11 and 16 GW of capacity helping to decarbonise transport and heating energy demand.	Ambition	Scotland	Electricity Generation	Project facilitates green hydrogen production as a route to market for new or existing renewable energy projects within the Project Area.

Date	Target/ Ambition/ Scenario/ Project		Jurisdiction	Category	Alignment
2032	Low emissions solutions will be widely adopted at Scottish ports.	Ambition	Scotland	Transport	Project would provide a supply of hydrogen to port locations within the Project Area to facilitate the decarbonisation of shipping.
2032	Have 35% of heat for domestic buildings and 70% of heat and ooling for non-domestic buildings upplied using low carbon heat technologies, where technically easible.	Target	Scotland	Buildings	Project aims to decarbonise >50% of domestic properties' heat demand by 2030.
2033	Phase out (of new sales) of gas boilers in commercial properties by 2030 – 2033 with the exception of hydrogen-ready gas boilers.	Target	UK	Buildings	This target aligns with Project plans.
2033	Phase out (of new sales) of gas boilers in residential homes by 2033 with the exception of hydrogen-ready gas boilers.	Target	UK	Buildings	
2035	78% reduction in UK greenhouse gas emissions (compared to 1990).	Target	UK	General	Project significantly contributes to this target.
2035	The burning of unabated natural gas for electricity generation should be phased out entirely by 2035.	Target	UK	Electricity Generation	Project supports this target by providing a decarbonisation route to existing unabated natural gas plants in the Project Area.
2035	30 TWh of power generation comes from gas CCS, meeting 6% of demand.	Scenario	UK	Electricity Generation	Project aligns with these objectives by providing a CO_2 collection network for existing emitters and biomass power stations within the Project Area to transport captured CO_2 to offshore geological storage.
2035	Bioenergy with carbon capture and storage (BECCS) plants provide 3% of generation by 2035.	Ambition	UK	Electricity Generation	
2035	Hydrogen gas plants provide 20 TWh of power generation, meeting 5% of demand. Hydrogen can provide a flexible form of dispatchable generation similar to unabated gas.	Target	UK	Hydrogen Generation	Project can align with this target from 2045 onwards once hydrogen storage in geological formations in Scotland can be implemented.
2035	Reduce emissions in the freight sector through removing the need for new petrol and diesel heavy vehicles.	Target	Scotland	Transport	Distributed hydrogen network configuration can facilitate multiple complementary hydrogen transport nodes.

Date	Target/ Ambition/ Scenario/ Project		Jurisdiction	Category	Alignment
2035	Scotland's rail services decarbonised.	Target	Scotland	Transport	Project assumes rail decarbonisation via electrification but will also provide hydrogen transport nodes which could offer supplies of hydrogen to other rail routes connecting the Project Area.
2035	Deploy at least 50 TWh of low carbon dispatchable and flexible generation (e.g. gas CCS, hydrogen) to help balance a system driven by renewables at low emissions.[41]	Target	UK	Industry	Project aligns with these objectives by providing a CO_2 collection network for existing emitters and biomass power stations in the Project Area to transport captured CO_2 to offshore geological storage.
2040's	Potential to build a pipeline for hydrogen export, connecting the country to mainland Europe.	Ambition	Scotland	Hydrogen Generation	Project proposes a hydrogen network with export capabilities to allow green hydrogen to be imported and exported.
2040	The Carbon Trust's Floating Wind Joint Industry Project forecasts 70 GW of floating wind could be installed by 2040.	Ambition	Scotland	Electricity Generation	Project would facilitate green hydrogen production as a route to market for new floating wind renewable energy projects within the Project Area.
2040	Scheduled flights within Scotland will be decarbonised.	Target	Scotland	Transport	Project Area incorporates all of Scotland's major airports and it is assumed by the Project that domestic aviation shall be decarbonised via hydrogen.
2040	All cement production near-zero emissions.	Target	UK	Industry	Project supports decarbonisation of Dunbar cement works via the proposed CO_2 collection network.
2040	No more than 5% of households in fuel poverty and no more than 1% in extreme fuel poverty.	Target	Scotland	Target	Project is a systems transformation that can support a 'just transition' for customers.
2040	90% reduction in Scotland greenhouse gas emissions (compared to 1990).	Target	Scotland Scotland	General	Project shall contribute significantly to this objective.
2045	Scotland to reach net zero emissions.	Target	Scotland	General	Project aims to reach net-zero for the customers within the Project Area by this date and is a portable solution to areas outwith the Project Area.
2045	25 GW of low-carbon hydrogen production capacity.	Ambition	Scotland	Hydrogen Generation	Project supports these ambitions by providing the necessary infrastructure.
2045	Production potential for 126 TWh/year of renewable hydrogen.	Ambition	Scotland	Hydrogen Generation	

[41] Policy recommendation as opposed to a target.

Date	Target/ Ambition/ Scenario/ Project		Jurisdiction	Category	Alignment
2045	94 TWh/year of renewable hydrogen produced for export.	Ambition	Scotland	Hydrogen Generation	Project supports these ambitions by providing the necessary infrastructure.
2045	Emissions from heating all buildings across Scotland need to reach zero.	Target	Scotland Scotland	Buildings	Project shall contribute significantly to this objective and can be rolled out across other geographical areas.
2045	Change in type of heating used in over two million homes and 100,000 non-domestic buildings, moving from high emissions heating systems to low and zero emissions systems such as hydrogen.	Target	Scotland	Buildings	Project shall contribute significantly to this objective.
2045	The gross impact from the production of hydrogen is in the main due to future export demand from the UK and Europe. Across three scenarios modelled range from 70,000 to over 300,000 jobs protected or created and GVA impacts of between £5 billion and £25 billion.	Ambition	Scotland	Ambition	Project shall contribute significantly to this objective.
2050	Energy demand – demand falls by 85% for oil and 70% for natural gas.	Scenario	UK	General	Project aims to provide significantly decarbonised energy to end users via conversion to hydrogen and use of CCS as appropriate.
2050	Net zero emissions achieved by 2050.	Target	UK	General	Project shall contribute significantly to this objective and is targeting the 2045 Scottish net-zero year.
2050	To meet the UK target of net zero by 2050, requires an average annual reduction in UK emissions of 15 MtCO2e.	Ambition	UK	General	Project shall contribute significantly to this objective.
2050	An expansion of variable renewables, so that it provides 80% of generation by 2050.	Target	UK	Electricity Generation	Project would facilitate green hydrogen production as a route to market for new renewable energy projects within the Project Area.
2050	At least 190 TWh of energy for hydrogen production is required for net zero in all scenarios examined by FES 2020.	Target	UK	Hydrogen Generation	Project aligns with this target.
2050	Reduce the carbon intensity of international shipping compared to 2008 levels by 70%.	Target	Global	Transport	Project shall contribute significantly to these objectives. Project would provide a supply of hydrogen to port locations within the Project Area to facilitate the decarbonisation of shipping.

Date	Target/ Ambition/ Scenario/ Project		Jurisdiction	Category	Alignment
2050	Reduce GHG emissions from international shipping, compared to 2008 levels, by at least 50%.	Target	Global	Transport	Project shall contribute significantly to these objectives. Project would provide a supply of hydrogen to port locations within the Project Area to facilitate the decarbonisation of shipping.
2050	Between 22,000 and 105,000 UK jobs could ultimately be associated with Scotland securing 40% of the carbon storage element of a European CO_2 management market.	Ambition	Scotland /UK	Ambition	Project shall contribute significantly to this objective. Project would allow for the import of CO_2 for dispatch to offshore geological storage.
<2100	Achieve zero GHG emissions from international shipping as soon as possible within this century.	Target	Global	Transport	
On-going	To meet the sixth Carbon Budget (78% reduction from 1990 UK GHG emissions by 2035), requires an average annual reduction in UK emissions of 21 $MtCO_2e$, similar to those achieved since 2012 (19 $MtCO_2e$).	Ambition	UK	General	Project shall contribute significantly to this objective.
Cont-inuous	Overall estimates that as many as 24,000 jobs could be supported each year in Scotland by the roll out of low and zero emissions heat.	Ambition	Scotland	Ambition	Project supports a significant workforce for conversion plus support work and construction.

16 Recommendations and Next Steps

16. Recommendations and Next Steps

An initial outline of a construction programme was produced (see Section 13.1). This outline programme details a phased approach to implementing the proposed system reconfiguration including green and blue hydrogen production rates required up to 2050 to enable the Scottish Government's one million homes decarbonisation target to be met by 2030.

As a key next step, a detailed construction timeline should be produced based on the initial timeline outlined provided, aligning with the Project objectives. The timing and availability of blue and green hydrogen should be established to ensure commitments and schedule can be met. Where possible, pipeline route corridors and proposed locations for reformers, pressure let-down stations, tie-ins/pigging facilities should also be established.

The detailed timeline could be developed in collaboration with key stakeholders and complementary hydrogen initiatives such as the Dolphyn and Acorn projects, or those arising from other offshore wind projects such as the recent ScotWind offshore wind leasing auction[42], which could be incorporated into Project deployment.

A detailed construction programme developed in conjunction with a network analysis/sectorisation for all phases would allow for the early identification of risks and opportunities and produce a set of early actions required to maintain the overall schedule. This would allow for detailed planning of workforce training and recruitment, requisite land acquisitions, planning and environmental consents, procurement of materials including long-lead and critical items, etc.

The production of a detailed construction programme would benefit from a degree of policy and regulatory certainty to ensure adequate alignment with the proposed technical reconfiguration of SGN's network. Until such certainty can be delivered by other actors, including the UK Government Department for Business, Energy & Industrial Strategy (BEIS) who are currently developing business models to support a future hydrogen economy, a number of steps can be taken to ensure SGN can maintain a pro-active approach in anticipation of greater policy clarity.

This Project demonstrates that there is a decarbonisation solution for the Project Area using hydrogen and CCS which is both technically and economically viable, with appropriate support. The adoption of the proposed Project roadmap could play a significant part in contributing towards Scottish and wider UK net zero targets. Providing a potential pathway to decarbonisation of the Project Area can both help retain existing jobs, as well as create further permanent jobs in the long-term and construction work in the near-term.

[42] https://www.crownestatescotland.com/our-projects/scotwind

These may include:

- Identifying sites for blue hydrogen production and liaising with owners.
- Undertaking detailed conversion planning to identify all gas appliances within an area and ensure that there are decarbonisation options available at the point of conversion.
- Examine all industrial and commercial appliances within a designated conversion area as soon as possible to determine convertibility and readiness for initial blending and 100% hydrogen, ensuring that the supply chain has sufficient time, resources and incentives to develop hydrogen ready appliances where required.
- Assisting in the development of a streamlined approach to local planning could ensure a timely build-out programme. The distributed model of blue hydrogen production proposed would involve multiple local authorities with limited experience of hydrogen infrastructure planning applications.
- Continue to work with other stakeholder groups and local authorities to continually review and update total anticipated hydrogen demand and identify any new areas / locations for hydrogen applications.
- Advocating for hydrogen ready appliances to be mandated as soon as they become available to support the conversion programme in a timely manner.
- Developing a public engagement strategy which is comprehensive and widespread in its coverage as early as possible.
- Planning for workforce recruitment and training which will be essential to the successful delivery of the reconfiguration. The workforce will require specific hydrogen training in preparation for conversion.
- Monitoring progress with hydrogen geological storage initiatives such as HyStorPor which are investigating the potential for hydrogen storage in porous rock formations and HyScale project on LOHC solutions to storage.
- Sharing of robust and comprehensive evidence of hydrogen networks with policy makers such BEIS, the Scottish Government and Ofgem and captured as part of Ofgem's 'RIIO-3' business plan development.

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