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RHODE RENEWABLE HYDROGEN FEASIBILITY STUDY

Final Report

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GLOSSARY

Term	Definition
AGI	Above ground installation
AGIG	Australian Gas Infrastructure Group
ALK	Alkaline
BNM	Bord na Móna
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CEF	Connecting Europe Facility
CEN	Comité Européen de Normalisation (European Committee for Standardisation)
CNG	Compressed Natural Gas
CO_2	Carbon Dioxide
DVLA	Driver and Vehicle Licensing Agency
ECOH	Estimated Cost of Hydrogen. ECOH is the average minimum price at which hydrogen can be sold in order to offset the costs of its production (CAPEX and annual OPEX <u>including</u> the cost of electricity for running the electrolyser) over the project lifetime (assumed to be 20 years).
EN	European Norm (standard)
ETS	Emissions Trading Systems
EU	European Union
FC	Fuel Cell
FCEV	Fuel Cell Electric Vehicle
GHG	Greenhouse Gas
GNI	Gas Networks Ireland
H_2	Hydrogen
HCL	Hydrochloric Acid
HCNG	Hydrogen Compressed Natural Gas
HGV	Heavy Goods Vehicle
HMI	Hydrogen Mobility Ireland
JTF	Just Transition Fund
LCOH	Levelised Cost of Hydrogen. LCOH is the average minimum price at which hydrogen can be sold in order to offset the costs of its production (CAPEX and annual OPEX <u>excluding</u> the cost of electricity for running the electrolyser) over the project lifetime (assumed to be 20 years).
NG	Natural Gas
NPV	Net Present Value
OCC	Offaly County Council

OCGT	Open Cycle Gas Turbine
OPEX	Operating Expenditure
PACA	Provence-Alpes-Côte d'Azur
PEM	Polymer Exchange Membrane
RD&D	Research Development & Demonstration
REACT-EU	Recovery Assistance for Cohesion and the Territories of Europe
ROI	Republic of Ireland
SEAI	Sustainable Energy Authority of Ireland
UCD	University College Dublin
UK	United Kingdom
UN	United Nations

TECHNICAL DEFINITIONS

Term	Meaning
Capacity Factor	Unitless ratio of actual electrical energy over the theoretical continuous maximum electrical energy output.
Carbon Capture and Storage	Technology used to capture CO_2 emitted from the combustion or processing of fossil-based fuels to that it is removed from the atmosphere and can be sequestered permanently in suitable geological formations which can include depleted gas fields.
Constrained	Dispatch-down of wind generation for localised network reasons (where only a subset of wind generators can contribute to alleviating the problem).
Curtailed	Dispatch-down of wind for system-wide reasons (where the reduction of any or all wind generators would alleviate the problem).
Demonstration Hub	A site in which the operation of a system is explained in detail. In the case of hydrogen production, a demonstration hub will provide evidence of reliable, useful and safe operation and application.
Dispatch down	The deliberate reduction in output below what could have been produced in order to balance energy supply and demand or due to transmission constraints.
Electrolyser	Produces hydrogen by separating water into its hydrogen and oxygen molecules through a chemical process.
Gas Distribution Network	A system of pipelines (typically Poly Ethylene (PE)) used to transport natural gas at pressures below 16bar.
Gas Transmission Network	A system of steel pipelines used to transport gas at high pressures (>16bar).
Renewable hydrogen	Hydrogen that is produced from renewable energy sources and has a carbon footprint that is below 18 g CO_2 equiv./MJ.
Just Transition	An EU-wide fund established to alleviate the socio-economic impact of transitioning from fossil fuel energy economies to clean energy economies.
Renewable Energy	Energy collected from renewable sources.

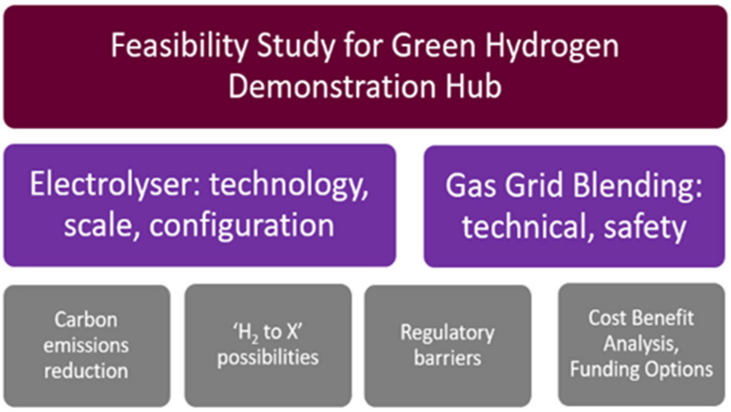
EXECUTIVE SUMMARY

Project Overview and Team

- This feasibility study examines the potential of creating a renewable hydrogen demonstration hub at Rhode Green Energy Park (RGEP), County Offaly. The project was commissioned by North Offaly Development Fund Ltd. and Offaly County Council, with co-funding by SSE Renewables and Bord na Móna. The study is also funded by the Gas Networks Ireland Gas Innovation Fund.

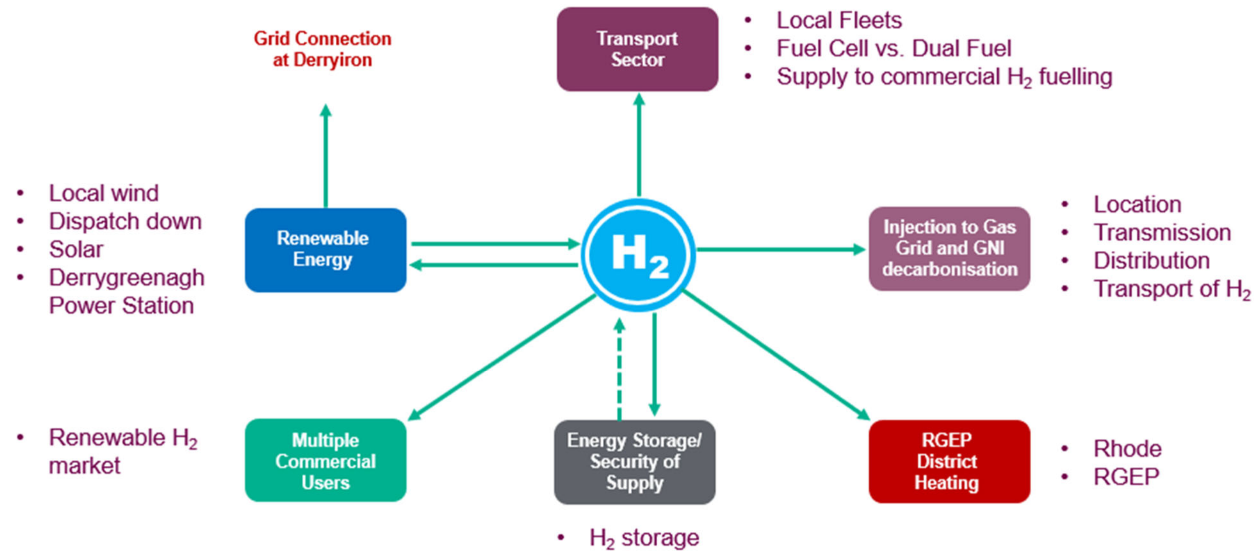
  The project team comprises:

  - RPS Consulting Engineers Limited (RPS) – study lead and project management.
  - University of Galway (UoG) (formerly NUIG) – hydrogen generation.
  - University College Dublin (UCD) – gas network integration.



Location of Related Activity

- Rhode Green Energy Park is strategically located in the Irish Midlands, close to the M6 motorway. There is a convergence of electricity grid, renewables and gas infrastructure at Rhode.
  - An opportunity assessment report by RPS (November 2020) identified the potential for an energy innovation hub at Rhode, leading to an Eco-Industrial Park.
  - RGEP has attracted €800,000 in Government of Ireland Just Transition funding for Energy Park infrastructure.
  - Siemens were appointed in March 2022 to conduct a feasibility study "Exploring Data Centre Integration with Renewable Energy & Renewable Hydrogen in the Midlands"
- Adjacent to Rhode, Bord Na Móna is advancing plans for an Energy Park – incorporating renewables, hydrogen, and industry. A renewable hydrogen electrolyser (2 MW) at Mount Lucas wind farm (9km distant) is part of this plan. The presence of another hydrogen electrolyser in Offaly will be complementary to the proposed Rhode demonstrator. There may be shared opportunities. Each also has the potential to act as back-up to the other. Together with other similar proposals they can build a hydrogen presence in the county. This is very much in line with the overall objectives of the Rhode Green Energy Park concept.
- This feasibility study explores a number of options for availing of the hydrogen opportunity at Rhode. These are summarised graphically below.



Systems Integration – Gas Network Potential

- Gas Networks Ireland (GNI) has identified injection of hydrogen into the gas network as one measure for decarbonising the natural gas system. At present there is no injection of renewable hydrogen taking place in Ireland and regulatory approval will be needed to allow this to happen.
- The injection of renewable hydrogen into gas networks is a developing area and there are various technical and safety challenges involved. However, it is widely agreed that hydrogen can be safely injected into the gas network at rates up to 20% by volume. There is also growing confidence among industrial plant manufacturers and energy end users that higher proportions of hydrogen can be safely used. Many sections of the network can support 100% hydrogen. Over time, it is envisaged that some sections will be transitioned to 100% hydrogen.
- Hydrogen can be injected into the Irish gas transmission network (high pressure (70bar – 85bar) and high flow rate) or the gas distribution network (medium pressure (4bar) and lower flow rates). Injection of hydrogen into a discrete section of the gas distribution network will facilitate the necessary preparations and careful monitoring of end user experiences as the proportion of hydrogen injected is increased. At this stage of development of the technology in Ireland, this is considered to be the most appropriate approach. It is understood that a pilot project for injection of renewable hydrogen into a section of the gas distribution network is planned by GNI. Lessons learned from the pilot project will help to pave the way for increased rates of injection across the distribution network in the future.
- The nearest nodes on the natural gas network to Rhode is Gaybrook Above Ground Installation (AGI) to the north of Rhode (supplying the gas distribution network in Mullingar) and Gneevekeel AGI to the west (supplying the gas distribution network of Tullamore / Clara). Both AGIs are locations where hydrogen could potentially be injected into the gas transmission (85bar pressure) and / or gas distribution (4bar pressure) networks.
- Renewable hydrogen produced by an electrolyser at Rhode could be transported to Gaybrook AGI or Gneevekeel AGI by road in a ‘virtual pipeline’ system (using trucks and specialised (tube) trailers). An underground physical pipeline could also be constructed for this purpose to either location. However, the relative lengths of pipeline for Mullingar and Tullamore / Clara would be approximately 18km and 33km respectively.
- Options considered by this study for delivering hydrogen from Rhode into the gas distribution network were:
    - A 4bar, 18.1km, 150mm diameter polyethylene (PE) pipeline from Rhode to Gaybrook AGI. This transport option has a relatively high CAPEX (estimated to be approximately €2.6m), but relatively low annual OPEX (approximately €135k).

- A virtual pipeline comprising a fleet of 3 tube trailers and 1 tractor unit. This option has a relatively low CAPEX (estimated to be approximately €1m), but a relatively high annual OPEX (approximately €270k).

- It is considered that for the initial phase of a demonstrator electrolyser at Rhode, the most appropriate transportation option would be the virtual pipeline. Over time, as the project develops and is potentially expanded, the pipeline option could be developed.
- If a new gas transmission pipeline connection to Derrygreenagh Power Station is constructed, there may be opportunities for significant savings in the cost of a 4bar hydrogen pipeline from Rhode to Gaybrook AGI. This would be if the 4bar pipeline could be constructed in parallel with the gas transmission pipeline. (The same hydrogen pipeline would of course in this scenario also be capable of supplying hydrogen to the new power station via a spur line).

Transport Fuel Potential

- Renewable hydrogen can also be used as a transportation fuel, at 100% replacement of conventional fuel for fuel cell vehicles, or in modified vehicles in blends that replace approximately 30% of conventional fuel. Technologies in the transportation area are continually developing.
- A fuelling station could be located adjacent to an electrolyser at Rhode to serve local transportation fleets. Alternatively, it could be located remotely, with hydrogen delivered via pipeline or 'virtual' pipeline (as for the gas network injection option). There could be potential for such a facility on the M4/M6 motorway, particularly if these routes were to become part of the TEN-T network.

District Heating

- A renewable hydrogen fuelled district heating network could be developed for Rhode Green Energy Park, and potentially extended to Rhode. The system could be combined with other sources of renewable heat including geothermal and biomass. Further detailed study would be required to explore this option.
- Using renewable hydrogen in this way would reduce the regulatory and safety challenges associated with a hydrogen gas network reaching into consumer premises. It would also rank highly among the options considered in this study in terms of its potential to reduce greenhouse gases.

Techno-Economic Modelling

- Techno-economic models (each examining multiple defined scenarios including electrolysers between 1MW and 50MW) were developed to examine the following options:
  - Injection to the gas **transmission** network.
  - Injection to the gas **distribution** network.
  - Using hydrogen as a **transportation fuel**.
- Other industrial users could also be considered as potential outlets for renewable hydrogen produced at Rhode. This could include a retailer of gas products such as BOC. These were not modelled in the study.
- The techno-economic modelling was based on maximising the use of potentially available constrained / curtailed ('dispatch down') power. This arises when the collective output of local generation exceeds the capacity of the local grid infrastructure. Above this level, scenarios were modelled for a number of combinations of dispatch down, wind power and power sourced from the grid (made up from renewable and non-renewable sources). A combination of curtailed wind power and other wind power (either prioritising hydrogen production or wind power above defined threshold values), offers the best outcome for a demonstrator electrolyser.
- The techno-economic model does not include the cost of electricity for running the electrolyser. Therefore, the outputs should be interpreted as showing the relative costs of producing hydrogen for each scenario excluding the cost of power to the electrolyser. This information has however been useful in developing a high-level investment case for a proposed demonstrator project which does include the cost of power for running the electrolyser (see further below).
- The modelling has also shown that the modelled Levelised Cost of Hydrogen (LCOH) ranges from €3.06/kg H_2 to approximately €30/kg H_2. The highest modelled values for LCOH relate to scenarios relying only on curtailed wind power. For these scenarios, the electrolyser utilisation is low and the required storage capacity is high. As electrolyser scale increases, the demand for power compared to

the quantity of curtailed power available results in lower electrolyser utilisation which further increases LCOH.

- Injection of hydrogen into the gas transmission network at a variable rate means that 'alternative hydrogen' does not need to be sourced (at potentially very high cost) to make up any shortfalls in output relative to a fixed demand. In these scenarios, the electrolyser has the highest utilisation (capacity factor) and continues to produce renewable hydrogen (with the minimum grid related carbon footprint). This arrangement also reduces the required hydrogen storage capacity with consequently reduced CAPEX. The net result is a lower Levelised Cost of Hydrogen (LCOH).
- The modelled LCOH for one supply scenario based on injection of hydrogen into the gas transmission network (Scenario S10, 1MW) is €3.94/kg H_2 (equivalent to approximately 11.82c/kWh). This value for LCOH depends on achieving a high capacity factor for the electrolyser. As stated above, the cost of power for running the electrolyser is not included. However, it is still a useful reference point for developing the 'Estimated Cost of Hydrogen' (ECOH) i.e. *including* the cost of power, for the end use options of most interest to this feasibility study and the proposed demonstrator project (see further below).

Demonstrator-Scale Electrolyser

- It has been concluded that the most suitable size for a demonstrator-scale electrolyser at Rhode is 1MW. A 1MW unit is large enough to generate useful quantities of renewable hydrogen and to learn key lessons around energy integration. A 1MW electrolyser could be expanded in a modular way as lessons are learned and the market develops. It could become an exemplar for other similar rural communities.
- The potential hydrogen output of a 1MW electrolyser is summarised below:

1MW Electrolyser	Annual	Daily
Hydrogen Output	150t/annum	480kg/day
	1.8 million m^3/annum	5,800 m^3/day
Natural Gas Equivalent	0.5 million m^3/annum	1,600 m^3/day
Diesel Fuel Equivalent	465,000 litres/annum	1,500 litres/day

- Every 1kg of hydrogen has the same energy content as 3.1litres of diesel. In cost terms, this means that a price for hydrogen that would be competitive with diesel, if used in commercial transportation and sold to end users (at today's prices for diesel of €1.87/l) is approximately €5.80/kg H_2 or 17.4c/kWh). By way of comparison, the current price for natural gas is approximately 9.5c/kWh.
- For every 1MW of electrolyser capacity, there would be potential to fuel approximately 40 Fuel Cell HGVs, approximately 60 Fuel Cell Light Commercial Vehicles (LCVs), or various combinations of these depending on fleet make up.
- Dual fuel hydrogen / diesel vehicles displace approximately 30% of the diesel fuel that would be consumed by an unconverted vehicle. The number of dual fuel vehicles that could consume the hydrogen output of a 1MW electrolyser would be approximately 140 converted HGVs, approximately 200 converted LCVs, or various combinations of these depending on fleet make up.
- The estimated CAPEX and OPEX figures for a 1MW electrolyser configured for different end uses (hydrogen injection or vehicle fuelling) are summarised as follows:

1MW Electrolyser	CAPEX (€)	OPEX (€/annum)
Electrolyser & Hydrogen transport by Road	2.0m	1.49m
Electrolyser & Hydrogen Transport by 4bar Pipeline	3.8m	1.35m
Electrolyser & Hydrogen Transport by 4bar Pipeline to Derrygreenagh Power Station	2.1m	1.35m
Electrolyser & Local Vehicle Fuelling Station	1.8m	1.43m
Electrolyser & Remote Vehicle Fuelling Station with Virtual Pipeline	4.2m	1.57m
Electrolyser & District Heating Network in Rhode	4.7m	1.36m

Notes:

1. *CAPEX values are exclusive of VAT*
2. *OPEX figures include the cost of purchasing electricity to power the electrolyser*

- An estimation for the annual revenue and cost of renewable hydrogen produced by a 1MW electrolyser producing 150 tonnes of renewable hydrogen per annum is outlined in the following table.

1MW Electrolyser	Estimated Annual Revenue[1] (€/annum)	Estimated Cost of Hydrogen[2] (ECOH) (€/kg)	Estimated Cost of Hydrogen[2] (ECOH) (c/kWh)
Electrolyser & Hydrogen transport by Road	1.63m	10.90	32.70
Electrolyser & Hydrogen Transport by 4bar Pipeline	1.63m	10.85	32.57
Electrolyser & Hydrogen Transport by 4bar Pipeline to Derrygreenagh Power Station	1.51m	10.05	30.16
Electrolyser & Local Vehicle Fuelling Station	1.56m	10.38	31.14
Electrolyser & Remote Vehicle Fuelling Station with Virtual Pipeline	1.89m	12.58	37.73
Electrolyser & District Heating Network in Rhode	1.71m	11.38	34.13

Notes:
1. *Estimated annual revenue required to achieve an NPV of zero at Year 20. Cost of power for running the electrolyser is included.*
2. *The Estimated Cost of Hydrogen (ECOH) includes the price for purchasing electricity for the electrolyser*

Proposed Demonstrator Project

- On the basis of the foregoing, a proposed demonstrator project has been defined which has the following features:
  - 1MW PEM electrolyser located at Rhode Green Energy Park producing hydrogen that meets the EU classification of Renewable Hydrogen. A modular design is envisaged which will facilitate expansion in the future as the renewable hydrogen economy develops in Ireland.
  - Use of curtailed / constrained wind power (approximately 21% of all power consumed), supplemented by additional wind and solar power.
  - One outlet for renewable hydrogen produced (48%) would be injection into the gas distribution network of Tullamore / Clara via GNI's gas transmission network node at Gneevekeel AGI. The system will be capable of meeting the requirements for hydrogen injection into this network of up to 10%.
  - Another outlet for renewable hydrogen (52%) will be in a local transport fleet converted for dual fuel (hydrogen / diesel) commercial vehicles.
  - Any renewable hydrogen produced that is surplus can be sold to industrial users / retailers.
  - Transportation of renewable hydrogen via road in a 'virtual pipeline' system to the hydrogen injection point and / or alternative outlets.
  - The system should be designed and configured to facilitate recovery of waste heat from the electrolyser and potentially use of renewable hydrogen in a local district heating network within Rhode Green Energy Park.
  - Estimated CAPEX: €2.88m ex VAT
  - Estimated OPEX: €1.52m ex VAT
  - Net `Present Value (CAPEX and OPEX costs combined over 20 years and discounted at 4% per annum): Approximately €23.5m.
  - Estimated Cost of Hydrogen (ECOH): €11.54/kg H_2 / 34.63 c/kWh (depending on achieving a high utilisation (capacity factor) of 91.2%)
  - Estimated annual CO_2 emissions savings: 1,173 tonnes.

Regulatory and Funding

- The Hydrogen Strategy for Ireland published in July, 2023 outlines how the Irish Government sees hydrogen development taking place in the future in Ireland. Action 2 of the Strategy is to establish an Early Hydrogen Innovation Fund to provide co-funding supports for demonstration projects across the hydrogen value chain. This action of the National Hydrogen Strategy has a timeline of 2023 – 2027. Details of the Fund will be published in the near future. The proposed Rhode Hydrogen Demonstrator project appears to be well aligned with the objectives of the Fund. It is also sufficiently well developed at this stage to facilitate a focussed funding application to the Early Hydrogen Innovation fund when it is possible to do so.
- A number of emerging hydrogen-related strategies are expected to be published during 2023:
  - A policy / regulatory roadmap for renewable hydrogen use within the electricity sector is due to be published in early 2023. Issues such as recovering curtailed renewable electricity via hydrogen production are expected to be addressed.
  - The recent EU announcement of the Alternative Fuel Infrastructure Regulation (AFIR) means that hydrogen refuelling stations will be required every 100km on the main road networks.
  - A north-south project on the safety regulation and interoperability of renewable hydrogen refuelling on the island of Ireland is expected to be completed in 2023.
- Funding in relation to hydrogen is available in the areas of Energy, Transport, Innovation and Research and Development at both EU and National Level. As part of the Midland's region of Ireland, renewable hydrogen innovation at Rhode can avail of Just Transition financial mechanisms to deliver socio economic dividends relating to the transition away from peat combustion and towards green energy. Funding of the demonstrator project has the potential to significantly reduce unit cost for hydrogen produced and the overall economic feasibility of the project.
- The process for nominating routes on the TEN-T network should be reviewed by Offaly County Council. with the view to making the case for the inclusion of the M4 and M6 motorways.

Next Steps

- A modular development of electrolyser capacity is recommended, enabling both the gas grid integration and transport energy opportunities to be developed and expanded progressively.
- The energy systems integration opportunity in Offaly can be best advanced through Gas Networks Ireland by selecting Tullamore / Clara as the test bed for renewable hydrogen injection into the distribution network. This is a suitable location to demonstrate carbon reduction for gas customers through renewable hydrogen injection. Technical development of this option could potentially be funded via the GNI Innovation Fund.
- The transport fuel opportunity can best be advanced in the first instance by Offaly County Council and/or a commercial fleet operator (such as BNM). This can be advanced in two stages: initially by conversion of existing diesel HGVs to dual fuel operation, followed by a transition to fuel cell HGV fleet. As renewable hydrogen generation is scaled up, Rhode is ideally located to supply renewable hydrogen to an M6/ M4 refuelling site.
- Identify a local industry which could potentially benefit from using hydrogen, for example, one using an energy intensive industrial process which would be otherwise difficult to decarbonise. This will help to ensure the hydrogen produced will be directed towards an end use (or uses) which offsets the greatest amount of carbon emissions.
- Identify, align and collaborate with other hydrogen refuelling station (HRS) projects to start the build out of the HRS network in Ireland. Rhode is ideally positioned for this.
- Rhode Green Energy Park can be developed with a small district heating network or the individual buildings on the site designed to be compatible with a future district heating network. The system could be designed to be compatible with hydrogen and other sources of renewable / recovered heat. This option is a good example of energy integration that can be replicated elsewhere and has potential to be expanded to Rhode.
- The project can be advanced by further defining technical requirements, identifying a site, advancing planning consent, and securing project funding. North Offaly Development Fund and Offaly County Council will ultimately benefit by selecting a project partner (or partners) who can manage the commercial and operational aspects.

- Explore opportunities for funding under the Early Hydrogen Innovation Fund to be established following the National Hydrogen Strategy. The proposed Rhode Hydrogen Demonstrator described in this Feasibility Study can be the basis of a future possible application for this funding as it aligns well with the objectives of the National Hydrogen Strategy.

1 INTRODUCTION

1.1 Background

North Offaly has been central to Ireland's energy provision for the last 70 years. With the phasing out of peat powered electricity generation there is an opportunity for Offaly to remain a strategic source of energy and lead the way in low carbon renewable energy generation.

The site of the former peat fired power station (now demolished) at Rhode, Co. Offaly is located close to a number of renewable generation facilities (wind, solar, battery, biomass) and a 110kV electricity substation. It is approximately 7.5km from the M6 motorway and approximately 13km from the gas transmission grid. There is therefore a convergence of electricity, renewables and gas infrastructure in this location. It is also well served by transportation and communications infrastructure.

Offaly County Council. has been proactive in developing infrastructure at the Rhode site to support local enterprise and employment. The site's unique context has great potential as a centre for clean energy innovation and employment. RPS was appointed by Offaly County Council to carry out an Opportunity Assessment Report for developing 'Rhode Green Energy Park' (RGEP). The report, which was completed in November 2020 highlighted the potential for the phased development of an energy innovation hub at Rhode, leading to an Eco-Industrial Park and Centre of Education.

The RGEP project aims to put Offaly and the Midlands at the centre of a new era of sustainable energy exploitation. Low-carbon energy is attractive to companies looking to reduce their carbon footprint. The Green Energy Park aims to demonstrate the benefit of a planned approach to energy and industry co-location. It has the potential to become a leader in Ireland's transition away from fossil fuels, to sustainable, secure energy and energy innovation.

There will also be significant benefits to the local community with the development of Rhode Green Energy Park and the production of renewable hydrogen there. These would include opportunities for local employment and also opportunities to benefit directly from the green energy produced. The local community would enjoy greater energy security and lower carbon emissions in the area.

The RGEP project is part of the Just Transition, creating enterprise and employment in an area affected by closure of peat harvesting and peat based power generation. Just Transition funding to the value of €800,000 has been awarded to RGEP.

Among the opportunities identified for RGEP was the production of renewable hydrogen from renewable power at demonstrator-scale.

1.2 Why Renewable ('Green') Hydrogen?

Climate change poses an imminent threat to our current way of life. In an Irish context, achieving 'net zero' will mean:

- Using mainly solar and wind power, rather than coal, oil, or natural gas, for power generation
- Changing our vehicles so they no longer use fossil fuels (petrol or diesel)
- Modifying industrial processes so that they don't require fossil fuels as feedstocks
- Heating our homes without fossil fuels.

At present, about 80% of energy is derived from conventional fossil / carbon-based energy (1). With Ireland setting targets of 7% annual reduction in CO_2 emissions by 2030 and net zero carbon emissions by 2050, it is necessary to reduce emissions and move towards clean, renewable sources of energy. This requires finding an alternative energy source which does not emit harmful pollutants, is a powerful fuel, and can be implemented in many different sectors.

While it is the most abundant element, the basic hydrogen molecule (H_2) exists only in trace quantities in the Earth's atmosphere. Water (H_2O) and organic compounds (C_xH_x) are where most hydrogen can be found on earth. However, the hydrogen within these compounds is 'locked up' and processing is required to release it as H_2.

Hydrogen is highly combustible and has great potential as a fuel that can displace conventional fossil fuels. When hydrogen is combusted with oxygen, the only output is water. This can be a major advantage for hydrogen - depending on how it is sourced. (If water is used to produce hydrogen, oxygen (O_2) is also released in the process).

The carbon footprint of the hydrogen produced depends on the feedstock material (e.g. water, gas, oil etc.) and the source of energy used in the process. An established, if informal colour system is used widely to differentiate hydrogen produced by different methods in terms of the carbon footprint of the process involved. However, the EU Commission and Parliament are moving away from the colour scheme to better defined classifications of 'renewable hydrogen' and 'low-carbon' hydrogen. Rules for renewable hydrogen were published in 2023 which are summarised below.

- Renewable hydrogen must derive its energy from renewable sources with a carbon intensity of less than 18g CO_2/MJ or the proportion of renewable power used to generate the hydrogen exceeds 90%. This definition also ensures that renewable hydrogen achieves a reduction in GHG emissions compared to fossil fuels or at least 70%.
- Low-carbon hydrogen is defined as hydrogen production whose energy content is derived from a non-renewable source, but meets a GHG emission reduction of 70% compared to fossil based hydrogen.

Table 1-1 below compares the colour classification for hydrogen with the EU definitions for renewable and low-carbon hydrogen. It will be noted that 'Green Hydrogen' is equivalent to 'Renewable Hydrogen'. Therefore, anywhere the term 'Green Hydrogen' is used in this report, the reader should also take this to mean 'Renewable Hydrogen'.

Table 1-1: Established colour classifications for Hydrogen and new EU classifications (2)

Hydrogen Colour	EU Classification
Green Hydrogen (Generated by electrolysis using renewable electricity) This is the process envisaged for the Rhode hydrogen demonstrator.	**Renewable Hydrogen** (sometimes also referred to as clean hydrogen) • Carbon intensity lower than 18g CO_2/MJ • Proportion of renewable power > 90% (Also means that a minimum GHG reduction of 70% is achieved)
Blue Hydrogen (sourced from natural gas and used in conjunction with Carbon Capture & Storage (CCS)	**Low- Carbon Hydrogen** (with CCS) • Minimum 70% Green House Gas (GHG) reduction
Grey hydrogen (sourced from natural gas and without CCS), Brown hydrogen (sourced from brown coal and without CCS), Black hydrogen (sourced from black coal and without CCS)	**Fossil-based Hydrogen** (without CCS)

The recent EU rules also stipulate that hydrogen must be generated using 'additional' renewable electricity that would otherwise not be used. Proof will be required that renewable hydrogen is produced only when the sufficient amount of renewable energy is available (periods of imbalance). Otherwise taking renewable energy from the grid would result in an overall loss of the amount of renewable power being used. The 'additional' renewable energy label also applies to the construction of dedicated sources of renewable energy with a direct connection to an electrolyser.

Renewable energy sources such as wind and solar are dependent on atmospheric conditions and are therefore variable. This variability does not always match demand - which is also variable. In 2020, over 12% of Ireland's renewable energy was 'turned off' or curtailed due to oversupply (3). If it could be captured, this equates to approximately 500MW of renewable electricity. There is currently no means in place for storing this amount of curtailed electricity.

Battery storage is one way of capturing curtailed wind energy. However, battery storage is limited by its capacity and accessing this stored energy must be via the electricity grid.

Hydrogen can be used in various ways in the energy market including electricity generation, blending with natural gas within the gas network, blending with transportation fuels and as a heating or transportation fuel in its own right. Hydrogen is therefore a flexible source of primary energy. The production of hydrogen is also less limited by its storage capacity than battery storage when matched with a constant demand. This is because there are more possibilities of outlets for any surplus hydrogen compared to battery storage which is linked only to the electricity grid.

A renewable hydrogen production facility based on capturing curtailed renewable electricity can of course also use other renewable electricity i.e. from generation that is not constrained or even new generation capacity. The overall output of such a facility can therefore be increased to meet a greater demand – subject to commercial feasibility.

In summary, renewable hydrogen is a focus of this study because:

1. It can contribute to lowering overall carbon emissions
2. It has the potential to capture significant quantities of curtailed renewable electricity
3. Access to the gas network or transportation uses means that hydrogen produced in this way can capture more curtailed renewable electricity than would be practical for battery storage
4. The output of renewable hydrogen from a production facility can also be increased to meet greater demands

1.3 Why Renewable Hydrogen at Rhode Green Energy Park?

Rhode Power Station was commissioned in 1960 as part of the peat development programme. It was decommissioned in 2003 and subsequently demolished in 2004. However, the electricity grid infrastructure, notably the 110kV Derryiron electricity substation remained. This has since supported the development of a large amount of renewable power generation in the area.

The following attributes have made this location attractive to energy development companies in the past decade:

- **Energy sector experience** in the Midlands means there is a diverse and talented workforce with skills potentially adaptable to energy sector opportunities
- **Renewable energy potential**
  - Wind and solar resource
  - Favourable settlement pattern - Sparsely populated area creating fewer constraints for renewable energy farms.
  - Deep geothermal resource in north Midlands with high potential as a renewable heat source
- **Proximity to Dublin** – creates accessibility and connectivity to the main population and energy load on the energy grid
- **Excellent connectivity to the motorway network**
- **Electricity grid connectivity**: access available through the 110kV Derryiron substation
- **Gas grid and fibre connectivity potential**
- **Wider agricultural hinterland** – the central and well-connected nature of the site enables opportunities for biomass, energy crops, and bioeconomy

Energy generation at Rhode has continued in the form of backup power from a peaking plant currently run by SSE Thermal. Other energy generation projects are establishing themselves in proximity to the Business Park such as the Schwungrad Energie Ltd. Flywheel Battery Storage technology, which operated between 2016 and 2018. Planning permissions have been granted for Clonin North (16246) and Srah Solar Farms (20494), Yellow River Wind farm (ABP-312876-22), and the Biomass Gasification Plant proposed by Newleaf Energy Limited/Biotricity (15366). Planning has also been granted for the 110kv substation (ABP-309441-21).

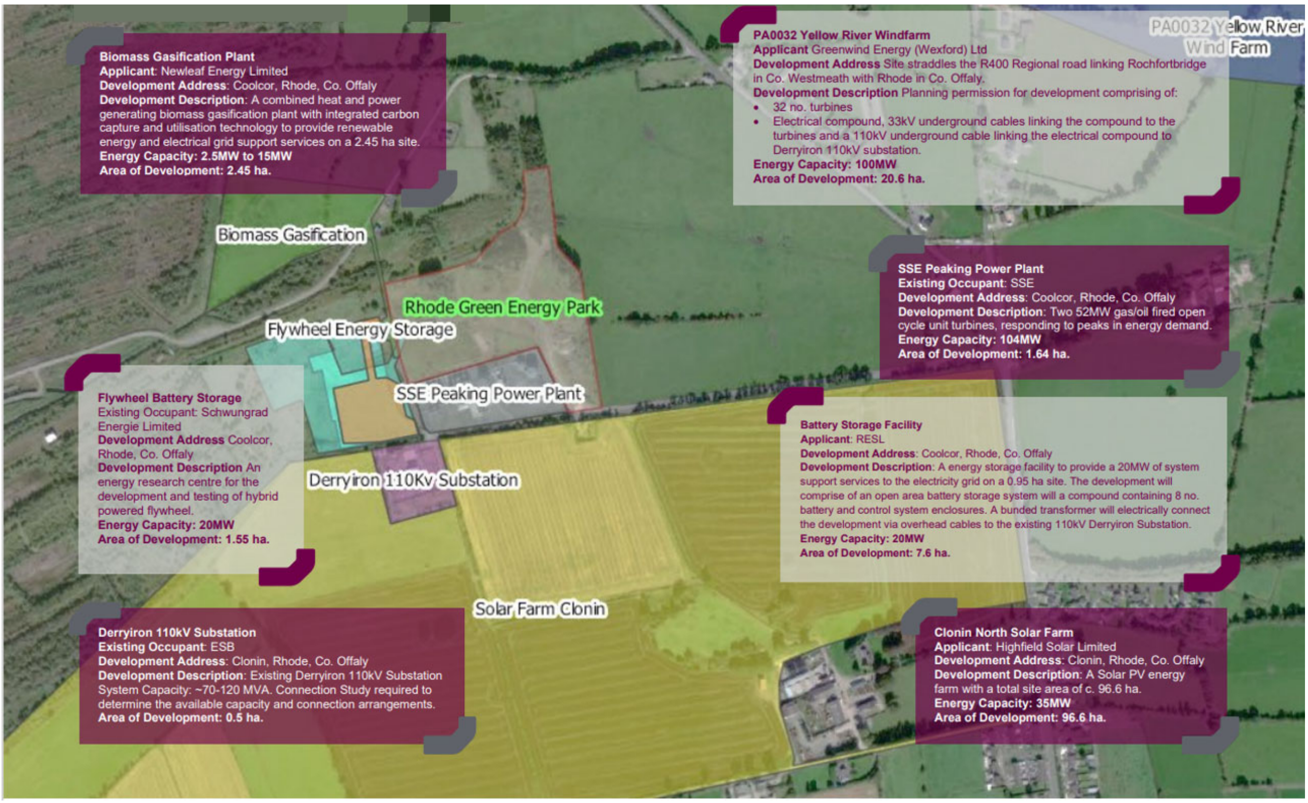


Figure 1-1: Current Energy Infrastructure and Proposals at Rhode

Given the components already available at Rhode – renewable energy, land, grid connectivity and energy innovation companies – Rhode is a unique location to test and demonstrate an electrolyser system, operating flexibly to harvest maximum renewable power. An electrolyser at Rhode could use 'dispatch down' electricity from the surrounding wind and solar farms when supply exceeds demand.

1.4 Hydrogen Demonstrator Feasibility Study at RGEP

1.4.1 Summary Description

This feasibility study examines the potential of creating a renewable hydrogen demonstration hub at RGEP. The potential for renewable hydrogen to enable a larger amount of renewable energy to be utilised from the existing electricity system is analysed. The facility would integrate energy produced from renewable electricity with the gas network. The study also aims to contribute to technical knowledge, policy / regulatory development, and confidence building.

1.4.2 Scope

The feasibility study will address:

1. Optimal technology type and scale for the electrolyser, and relationship between electrolyser, renewables (wind, solar, biomass, battery) and grid
2. Optimum means for bringing the hydrogen to gas consumers via the nearby AGI
3. Opportunities for use of hydrogen and oxygen locally (e.g. transport)
4. Carbon emissions reduction

5. Cost benefit of the preferred configuration
6. Funding opportunities, and regulatory/policy gaps
7. Dissemination of findings

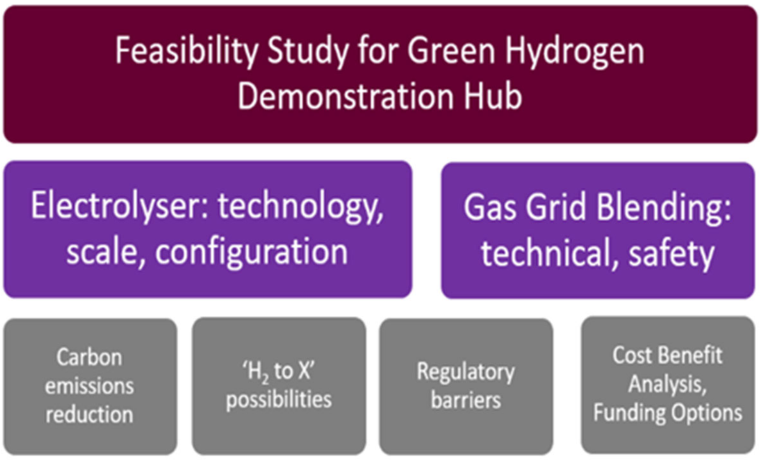


Figure 1-2: Feasibility Study Scope

1.4.3 Objectives

The study aims to investigate the potential for scalable renewable hydrogen production at Rhode Green Energy Park and to contribute to achieving a Net Zero Carbon Emission Gas Network. Table 1-2 below outlines the four primary objectives of the study and where they are addressed in this report.

Table 1-2: Project Objectives

Project Objective	Location in Report where this is addressed
Objective 1: Demonstrate energy system integration; linking the Irish electricity grid and gas network and quantifying the decarbonisation benefits, identifying challenges and funding requirements.	Chapter 5: Energy Profiles at Rhode Chapter 6: Techno-Economic Models of Gas Injection Chapter 9: CO_2 Emissions Reduction Potential Appendix A: Gas Transmission Profile Data Appendix B: Gas Transmission Injection Modelling Scenarios Appendix C: Results of Techno-Economic Modelling
Objective 2: Provide a clear roadmap for delivery of the demonstrator project, moving to a specific and feasible project, whose implications, costs, and benefits are clear.	Chapter 10: Proposed Demonstrator Project Appendix D: Investment Case Figures
Objective 3: Advance the decarbonisation journey for Irish gas grid, linking the energy transition with the Just Transition.	Chapter 1: Introduction Chapter 2: Legislation & Policy Context Chapter 11: Funding Opportunities Chapter 12: Recommendations
Objective 4: Exploring other 'Hydrogen to X' applications.	Chapter 3: Hydrogen Production Chapter 4: Relevant end use options for hydrogen Chapter 7: Transport Fleet Option for Rhode Chapter 8: District Heating Option for Rhode

1.4.4 Project Partners

There are four project partners involved in the inception and support of this feasibility study as follows:

North Offaly Development Fund Ltd. was established in 2004. Its principal objective is the creation of new employment opportunities North Offaly. The Board of Directors is made up from representatives from the following:

- ESB (1)
- Offaly County Council (1)
- Elected members from Edenderry Electoral area (6)
- Offaly Local Development Company (1)
- Local Enterprise Office (1)
- Bord na Móna (1)
- Rhode Community (2)

SSE Renewables is a renewable energy subsidiary of SSE plc, which develops and operates onshore and offshore wind farms and hydroelectric generation in the United Kingdom and Ireland. SSE Renewables has the largest offshore wind development pipeline in the UK and Ireland at over 6GW and has an onshore wind pipeline across both markets in excess of 1GW.

Bord na Móna (BNM) is a semi-state climate solutions company in Ireland with the aim to provide economic benefit for Irish Midland communities and achieve security of energy supply. BNM owns and operates over 200MW of wind power in Ireland and has multiple wind projects under development. It is a major developer of renewable energy in the Midlands Region including Co, Offaly.

Gas Networks Ireland (GNI) is responsible for the management of access to the Irish natural gas pipeline system. GNI operates and maintains Ireland's €2.7bn, 14,617km national gas network, which is considered one of the safest and most modern gas networks in the world.

1.4.5 Project Team

The Feasibility Study team comprises:

- RPS Consulting Engineers Limited (RPS). RPS was appointed as project manager by North Offaly Development Fund (NODF)
- University of Galway (UoG) (Formerly NUIG)
- University College Dublin (UCD)

2 LEGISLATIVE & POLICY CONTEXT

2.1 Policy

2.1.1 Paris Agreement

The United Nations Framework Convention on Climate Change (UNFCCC) was adopted in 1992. In 2015, the Conference of the Parties (COP) (to this convention) took place and it was there that the Paris Agreement was made. The Paris Agreement includes the key target of reducing global average temperature to 1.5°C above pre-industrial levels. Article 7 includes the requirement for parties to the agreement to engage in adaptation planning processes. Accordingly, Member Parties are responsible for submitting Nationally Determined Contributions (NDCs) that they intend to make towards achieving the 1.5°C target. These NDCs must be communicated to the UNFCCC, maintained and up-dated every 5 years.

2.1.2 EU Nationally Determined Contribution (NDC)

The EU ratified the Paris Agreement in 2016. The most recent NDC submitted by the EU is dated December, 2020. It states that '*the EU and its Member States, acting jointly, are committed to a binding target of a net domestic reduction of at least 55% in greenhouse gas emissions by 2030 compared to 1990*'. The EU has the further objective achieving climate neutrality by 2050, i.e. 'Net Zero' which was agreed within the EU in 2019.

The EU NDC is a joint submission on behalf of all Member States. Regulation (EU) 2018/1999 on the Governance of the Energy Union and Climate Action, established an EU-wide reporting and monitoring framework for the period 2021 - 2030. Member States are responsible for preparing integrated National Energy and Climate Plans for the same period including Member States' individual NDCs and other commitments under the Paris Agreement.

2.1.3 Programme for Government

In accordance with the Paris Agreement and the EU's NDC submission to the UNFCCC, Ireland's Programme for Government contains targets for an average reduction in overall Irish greenhouse gases of 7% per year from 2021 to 2030 and achieving net zero emissions by 2050.

Renewable hydrogen is referenced as a zero-emission energy source and the importance of researching and developing it is also recognised.

2.1.4 Climate Action Plan

A Climate Action Plan (CAP) was first published by the Government in 2019. It has been built on and updated through the publication of subsequent Climate Action Plans in 2021 and 2023. Necessarily, the Plan has a very broad scope covering at some level every sector and aspect of life in Ireland. This ranges from organisational and how the public sector can show leadership in responding to the challenge of climate change, through various sectors including energy, transport, building and agriculture to land use and sustainable development. The Plan contains nearly 500 specific actions which provide a clear focus across sectors for meeting carbon emissions abatement targets.

Production of renewable hydrogen by electrolysis is recognised in CAP2021 as having a potential role in carbon emissions abatement but also that the technology is still in development and costs are currently relatively high. Section 11.3.5 of the CAP identifies opportunities for further measures to achieve carbon emissions savings to reach the lower end of the 2030 range for electricity emissions including '*methods to incentivise electrolyser production and grid connection of hydrogen from renewable energy to fuel zero emission dispatchable generation*' and '*co-location of electrolysis with renewable energy production infrastructure*'.

2.1.4.1 Climate Action Plan 2023

The latest annual update of the Plan is Climate Action Plan 2023 (CAP23). This update was prepared under the Climate Action and Low Carbon Development (Amendment) Act 2021. It implements economy-wide carbon budgets and sectoral emissions ceilings that were first introduced in 2022. Overall objectives of the

Government's Climate Action Plan are to reduce Ireland's carbon emissions by 50% by 2030 and to reach net zero emissions by 2050.

CAP23 recognises the potential for renewable hydrogen to *'play a significant role in the* [electricity] *sector coupling (the increased integration of energy supply and end-use sectors), and in minimising the overall cost of decarbonisation across sectors'*.

Specific metrics identified in the Plan for objectives in carbon abatement in electricity are:

- Renewable hydrogen from surplus renewable electricity will be in production by 2030
- Zero emission gas fired generation from biomethane and hydrogen should be commenced by 2030
- 2GW of offshore wind specifically for renewable hydrogen generation should be in place in the period 2031 – 2035

Market incentives will also be developed to match electricity demand with renewable energy generation. This will include incentivising those customers whose demand can be flexible so that the system can facilitate hydrogen production among other appropriate 'non-firm' demand.

Section 12.3.4 of CAP23 outlines further measures to support the third carbon budget (2031 – 2035). These may include developing policies that '*ensure that zero carbon gases, like hydrogen, are utilised in the electricity sector to provide zero carbon dispatchable electricity at sufficient scale'* and policies to '*support the development of inter seasonal storage of hydrogen*'. These measures appear to be focussed on large-scale generation based on 100% hydrogen, with large storage capacity (potentially sub-surface / geological).

CAP23 recognises that hydrogen will also play a role in the decarbonisation of industry. However, it is also clearly stated that defining specific measures for advancing renewable hydrogen requires work in the areas of regulatory policy.

A specific action for 2023 (EN/23/7) is that the Department of Environment, Climate and Communications (DECC) will therefore '*develop a policy and regulatory roadmap for renewable hydrogen as part of the Hydrogen Strategy for Ireland. Renewable hydrogen will be reserved for use when alternative energy sources are not feasible'*.

Section 8 of CAP23 describes how a Just Transition can be delivered in the Midlands Region. There are 3 actions relating to this section of CAP23 that are potentially of relevance to a demonstrator-scale electrolyser in Rhode.

- JM/23/1 - Coordinate regional and local strategic partnerships in the Midlands region to support the transition to a low-carbon economy
- JM/23/2 - Support delivery of projects under the National Just Transition Fund 2020
- JM/23/3 - Deliver European Innovation Partnership projects in the Midlands Region

2.1.5 Energy Security Framework

A National Energy Security Framework was published by DECC in April, 2022. This was prompted by geopolitical events in February, 2022. It sets out the specific EU and in particular, the National responses for addressing issues of security of supply.

The European Commission published the REPowerEU plan, which among other measures, identifies diversifying of gas supplies via greater use of Liquified Natural Gas, sourcing natural gas from non-Russian suppliers and increasing the use of biomethane and renewable hydrogen.

2.1.6 Hydrogen Strategy for Ireland

The EU developed its hydrogen strategy 'A Hydrogen Strategy for a Climate Neutral Europe' in July, 2020. It recognises that there can be a role for renewable hydrogen in particular for meeting net zero carbon emissions by 2050. In response, the Hydrogen Strategy for Ireland (4) was published by the Department of Environment, Climate and Communications (DECC) in July, 2023. This sets out a roadmap for the production and scaling up of renewable hydrogen in Ireland. The Strategy presents a high-level development timeline from now to 2050 and lists 21 specific actions. Actions of particular relevance to the Rhode Hydrogen Demonstrator project are presented on Table 2-1 below.

Table 2-1: National Hydrogen Strategy Actions of particular relevance to the Rhode hydrogen Demonstrator

Action No.	National H_2 Strategy Action	Timeline	Relevance to Rhode
Action 2	Establish an early hydrogen innovation fund to provide co-funding supports for demonstration projects across the hydrogen value chain.	2023 – 2027	A proposed demonstrator could be eligible for co-funding supports.
Action 6	Undertake further work to assess the role that integrated energy parks could play in our future energy system, including their potential benefits and the possible barriers (market, legal or other) that may exist.	2023 – 2025	The Green Energy Park at Rhode is an ideal location to carry out this further work with its culmination of innovative renewable energies.
Action 7	Publish the draft National Policy Framework on Alternative Fuels Infrastructure, and support the roll-out of hydrogen powered heavy duty vehicles and refuelling infratructure in line with EU requirements set out in the recast Renewable Energy Directive and Alternative Fuel Infrastructure Regulation.	2024 – 2023	The production of renewable hydrogen for use by HGVs is a potentially feasible option for a demonstrator project based in Rhode.
Action 11	Continue work to prove the technical capabilities of the gas network to transport hydrogen through the network and closely work with the network operators in neighbouring jurisdictions in respect of interoperability between the networks.	2023 - 2028	Injecting renewable hydrogen produced at Rhode into the nearby gas network would help to further prove the technical capabilities of the gas network for hydrogen transportation
Action 12	Develop a plan for transitioning the gas network to hydrogen over time, taking due consideratuion of a number of factors including: d. How existing end users can transition from natural gas to hydrogen, or to alternative energy solutions such as electric heating. e. The potential use of hydrogen blends during a transition phase, the costs associated and how the transition from blending can occur.	2023 - 2026	Injecting renewable hydrogen into a local gas distribution network could become a test bed for examining the effects on end users using different blends of hydrogen. It can become an important part of the transition to achieving 100% hydrogen over time.
Action 13	Progress work to identify and support the development of strategic hydrogen clusters.	2024 - 2026	A hydrogen cluster is possible in the Rhode area. Already BNM has plans to develop a 2MW electrolyser approximately 8km away at Mount Lucas.
Action 14	Commence a review of current approaches to energy systems planning and make recommendations to support a more integrated long-term approach to planning across the network operators including electricity, natural gas, hydrogen and water.	2024 - 2026	The envisaged hydrogen demonstrator will be fully integrated with renewable energy systems, with an emphasis on sharing knowledge gained for replication elsewhere.
Action 17	Undertake a review across the entire hydrogen value chain to identify any other gaps within our spatial planning, environmental permitting and licensing regimes.	2024 - 2026	Progressing the feasibility study to detailed design, planning and construction will quickly reveal any gaps in the legislation referenced

The National Hydrogen Strategy indicates that there will be an emphasis on the use of hydrogen in areas which would otherwise be more difficult to decarbonise and where direct electrification is not feasible. Examples include heavy transport and energy intensive industry. However, there is also a clear focus on developing a plan for transitioning the gas network to hydrogen. This includes blending of renewable hydrogen in the natural gas network.

The Strategy recommends that a small number of demonstrator projects be developed to help understand the technology, business models and alleviate potential barriers for future projects.

2.1.7 Alternative Fuels Infrastructure for Transport (AFIT)

European Directive 2014/94/EU on the deployment of alternative fuels infrastructure focusses on a number of alternative fuels including hydrogen. This Directive has been the subject of a detailed review and there is now a proposed replacement regulation.

Article 6 of the proposed replacement of European Directive 2014/94/EU specifies requirements of Member States in relation to having hydrogen refuelling stations in place along the Trans European Transport Network (TEN-T) networks by the end of 2030. Hydrogen fuelling stations with a minimum capacity of 2 tonnes/day and 700bar dispensers are to be located with a maximum spacing of 150km along the TEN-T networks. Article 7 specifies a number of requirements in relation to information on pricing and payment for hydrogen fuel. Annex II provides technical specification for hydrogen supply for road transport.

Article 13 places a requirement on Member States to develop National policy frameworks for the development of the market for alternative fuels in the transport sector, and the deployment of the relevant infrastructure.

Ireland's National Policy Framework – Alternative Fuels Infrastructure for Transport in Ireland 2017 - 2030 was published in 2017. While this document recognises the potential of hydrogen as a transportation fuel, hydrogen is viewed as a longer-term prospect, and likely to be 'prohibitively expensive' until after 2030. The Policy Framework states that EU Directive 2014/94/EU gives discretion to Member States in relation to its targets for hydrogen refuelling points. Therefore, Ireland has no immediate plans to develop hydrogen refuelling infrastructure, but the feasibility of such a network will be reviewed regularly given the pace of development in the area. (It is noted however that Hydrogen Mobility Ireland (HMI) see potential for up to 80 hydrogen fuelling stations being installed in Ireland by 2030).

Ireland's National Policy Framework includes one measure to be considered by the end of 2020 which could potentially be relevant to a hydrogen demonstrator at Rhode. This was to consider incentives for uptake of hydrogen, including accelerated capital allowances, to support investment in refuelling infrastructure.

2.2 Legislation

2.2.1 Electricity

The primary legislation relating to the electricity industry in Ireland is the Electricity Regulation Act, 1999. The Commission for Electricity Regulation (CER) was established with this Act, later becoming the Commission for the Regulation of Utilities (CRU) (see below). As Regulator, the CRU licenses operators of the electricity system.

2.2.2 Gas

The Gas Act (1976) established Bord Gáis Éireann as the semi-state body responsible for the development of the gas network in Ireland. With its various amendments since that time, it is still the primary legislation relating to gas undertakings in Ireland. Today, the entity responsible for the development and operation of the gas network is Gas Networks Ireland (GNI).

The Gas Amendment Act (2000) established the Commission for the Regulation of Utilities (CRU) as the Regulator for the gas industry.

2.3 Regulation

The Commission for the Regulation of Utilities (CRU) is responsible for the regulation of the energy and water industries in Ireland. At a high level, the CRU's role embodies the following core elements:

1. Safety

2. Sustainability, reliability and efficiency
3. Securing a low carbon future
4. Achieving the above at a reasonable price for customers

The Decarbonisation Division of the CRU is currently working on regulatory frameworks to support Ireland's transition away from carbon based energy. Among the areas that the Decarbonisation Division is active in is hydrogen.

2.3.1 Electricity

EirGrid is the licensed operator of the electricity transmission system (38kV and above), generally referred to as the Transmission System Operator (TSO). The technical aspects of how the transmission system operates and how to connect to this are covered in the Grid Code.

ESB Networks is the licensed operator of the electricity distribution network (38kV and below), generally referred to as the Distribution System operator (DSO). The technical aspects of how the distribution system operates and how to connect to this are covered in the Distribution Code.

As outlined above, CAP23 Action EN/23/7 is to develop a policy / regulatory roadmap for renewable hydrogen use. This is due to be published in early 2023. Where there may be existing market impediments to recovering curtailed renewable electricity via hydrogen production, it is expected that these will be addressed in new policy / regulation.

2.3.2 Gas

The CRU licenses GNI to operate the gas network in accordance with a Code of Operations. The Code of Operations governs the relationships between GNI as system operator, gas shippers and end users i.e. how the market for gas operates. The Code covers a wide range of issues including the quality / specification of gas that is transported within the network. Currently, only natural gas and blends of biogas are permitted. The Code of Operations will therefore need to be amended to cater for introducing hydrogen or blends of hydrogen into the Irish gas network.

Consent must be sought by GNI from the CRU for developments to the gas network such as proposed changes to the Code of Operations or changes to the physical network infrastructure. A key consideration for GNI is demonstrating to the CRU that any such changes are needed and above all, that they are safe.

2.3.2.1 Gas Safety Framework

The safe regulation and operation of the gas network is governed by the Gas Safety Framework. The Framework covers licensing of undertakings, compliance monitoring and enforcement where necessary. It also includes investigation of incidents so that these can be learned from and prevented in future.

Gas undertakings are licensed by the CRU and under the Framework must submit a Safety Case to the CRU for review and acceptance. The Safety Case documents how risks associated with their activities are managed in accordance with the ALARP principle i.e. that risks are managed to be As Low As Reasonably Practicable.

A Safety Case which has been developed by GNI will be reviewed by the dedicated Energy Safety Division of the CRU. The Safety Case must be updated and re-approved by the CRU when changes take place. Examples of recent such changes that have required up-dates to the Safety Case for the gas network are the introduction of biogas injection and the roll out of Compressed Natural Gas (CNG) installations for fuelling vehicles.

The injection of hydrogen into the natural gas network will require detailed work by GNI to demonstrate to the CRU that this can be done safely. This will need to be documented in an up-dated Safety Case. In parallel, other considerations require detailed work including understanding the potential impacts on gas customers due to the specific properties of hydrogen and hydrogen blends. For example, the performance of gas appliances and the metering of energy to customers. GNI is already active in these areas in preparation for a future where hydrogen plays a role in decarbonising the gas network.

2.3.3 Transport

Similar to injection of hydrogen into the gas network, a safety case (or similar) for the use of hydrogen as a transportation fuel will also need to be developed. However, this activity would be separate to the gas network.

The Department of Transport (DoT), in cooperation with the Department for Economy in Northern Ireland, under the Department of the Taoiseach's Shared Island Fund, is undertaking research on the safety regulation and interoperability of renewable hydrogen refuelling on the island of Ireland. This research is expected to be completed in 2023. The appropriate regulation authority for this activity therefore needs to be determined.

2.4 Other Relevant Policy Documents

2.4.1 ESB and Hydrogen

The ESB has published its strategy for achieving net zero carbon emissions by 2040. The strategy is '*Driven to Make a Difference: Net Zero by 2040*'. It includes targets for reducing the carbon intensity of electricity generation in Ireland from over 400gCO_2/kWh to 140gCO_2/kWh by 2030 and 100% decarbonisation of generation by 2040.

In addition to increasing the amount of wind power and battery storage, ESB also sees a role for large scale hydrogen production and subsurface storage of hydrogen. A number of flagship projects are in early stages of development including a major hydrogen production and storage facility in the areas of Moneypoint (the Green Atlantic @ Moneypoint project) and the Shannon Estuary. Subsurface hydrogen storage is also being examined in Aghada, Cork and Poolbeg, Dublin. Energy for the production of renewable hydrogen would come from large-scale floating offshore wind developments.

The ESB's policy for achieving net zero carbon emissions is clearly focussed on large-scale development of renewable hydrogen. Phase 1 of the Green Atlantic @ Moneypoint project was completed in 2022 with the installation of a €50m piece of equipment to facilitate allowing higher levels of wind power on the electricity grid. ESB states that during the next decade, there will be further investment to deliver floating offshore wind and renewable hydrogen production.

2.4.2 GNI and Hydrogen

Gas Networks Ireland published Vision 2050 as its plan for decarbonisation Ireland's gas network. The Plan identified hydrogen and biogas as key focus areas for achieving this.

In 2022, GNI published 'Hydrogen and Ireland's national gas network' which clearly outlines GNI's activities in response to the Climate Action Plans. This document covers all of the key issues and challenges to Ireland in realising hydrogen's potential in the gas network.

GNI also published its technical and safety feasibility study for injection of green hydrogen blends into Ireland's gas network. This document provides a comprehensive overview of GNI's progress in this area including regulatory & safety issues and a wide range of technical considerations. These include considerations for the transmission network, distribution network, end users and billing. A key next step for GNI that is outlined in the feasibility study is the development of a green hydrogen injection installation.

2.5 Statutory Planning

As for any similar proposed development, a demonstrator-scale hydrogen electrolyser in Rhode will require planning permission. If progressed, there would be lessons to be learned from the planning processes that took place for existing hydrogen production facilities in Ireland e.g. at the Irving Oil Whitegate facility, the BOC facility in Dublin and the 2MW hydrogen electrolyser is planned by Bord na Mona at their facility in Mount Lucas, Co. Offaly.

Among the key considerations at planning stage for a hydrogen production facility would be the quantity of hydrogen that may be stored and the associated safety and environmental risks. Hydrogen is listed as a dangerous substance in Chemicals Act (Control of Major Accident Hazards Involving Dangerous Substances) Regulations 2015 (S.I. 209 of 2015 or 'COMAH' Regulations). The qualifying quantity of hydrogen storage for the application of 'Lower Tier' requirements is 5 tonnes. This is many times higher than the envisaged required storage capacity for a demonstrator-scale electrolyser at Rhode.

3 HYDROGEN PRODUCTION

Hydrogen can be produced from water (H_2O) using a process called electrolysis. Electricity is consumed by the process. Hydrogen (H_2) and Oxygen (O_2) are produced as a result. Some of the key aspects of the production of hydrogen using electrolysis are outlined below.

3.1 Electrolyser Technology

Two of the most common electrolyser technologies which will likely dominate future hydrogen production are Alkaline (ALK) electrolysis and Polymer Electrolyte Membrane (PEM) electrolysis.

ALK electrolysis is the most commonly used technology for the production of hydrogen from water, having been developed over 100 years ago. The system contains an anode and cathode separated by a diaphragm and electrolyte of either a Potassium Hydroxide (KOH) or a Sodium Hydroxide (NaOH) solution. When electricity is passed through the circuit, water is reduced at the cathode producing hydrogen and OH^- ions. The OH^- ions travel through the diaphragm and react with each other at the anode to form oxygen and water (5).

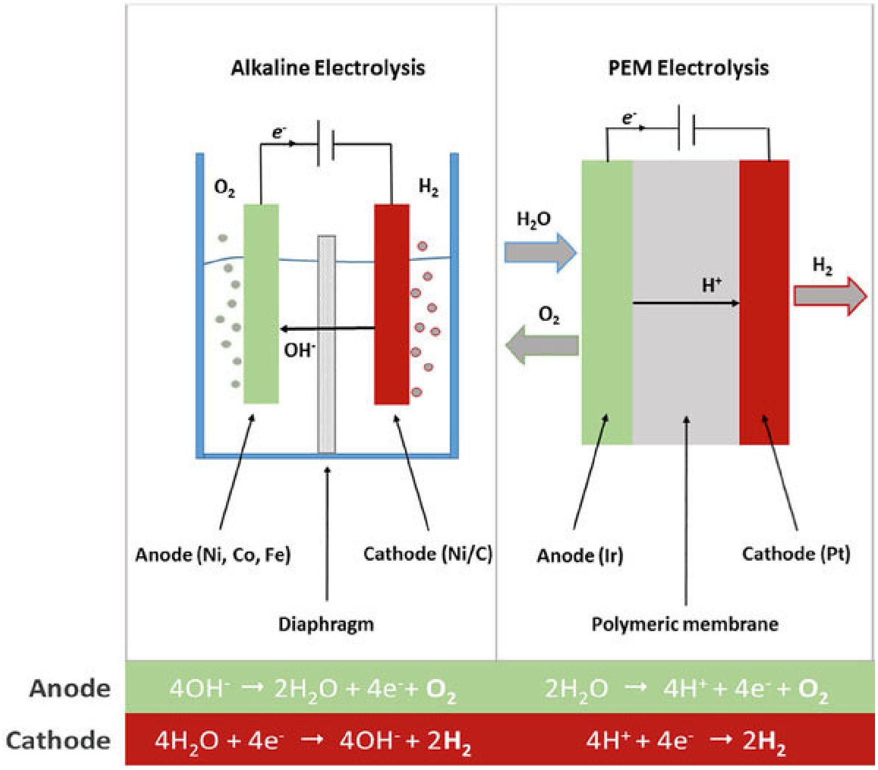


Figure 3-1: Operation of Alkaline and PEM Electrolysers (5)

PEM electrolysis is a more recent technology which has developed quickly and is projected to decrease in price in coming years, making it competitive if not cheaper than ALK systems (6). PEM electrolysers use a solid polymeric membrane instead of an electrolyte. Water decomposes at the anode, releasing protons (H^+ atoms) and oxygen. The protons move through the membrane to the cathode where they are combined with electrons to produce hydrogen (H_2) (5). Table 3-1 summarises the main technical characteristics of both electrolysis methods.

Table 3-1: Comparison of PEM and ALK Electrolysis Technical Parameters

Technical Parameter	PEM	ALK	Source
Efficiency[1] predicted 2024-2030	64-67%	68-69%	(7)
Water Consumption	0.015 m^3/kg_{H2}	0.015 m^3/kg_{H2}	(8)
Electricity Consumption (approximate)	50 - 52kWh/kg_{H2}	48 - 50 kWh/kg_{H2}	Note 2
Working Pressure (bar)	30-80	1-30	(9)
Working Temperature (°C)	50-80	60-80	(9)
Required Water Purity (µS/cm)	About 1 µS/cm	Below 5 µS/cm	(10)
Purity of Hydrogen Produced	99.99%	99.8%	(11)
Start-up times	Faster	Slower	(11)
Lifetime	Longer	Shorter	(11)

Notes:

1. *Electrolyser efficiency is defined as the ratio of the energy content of hydrogen produced (33.3 kWh/kg H_2) to the electricity consumption rate of the electrolyser. Electrolyser efficiency is dependent on the conductivity of water used.*
2. *Calculated figures based on efficiency values for PEM and ALK electrolysers above.*

3.1.1 Estimated Electrolyser CAPEX & OPEX

Output efficiency, capital expenditure (CAPEX) and operational expenditure (OPEX) are the main techno-economic parameters of interest when assessing the feasibility of an electrolyser installation. Predicted figures for each parameter for the years 2024 and 2030 are presented in Table 3-2.

Table 3-2: Techno-economic Parameters of PEM and ALK Electrolysers in 2024 and 2030 (7) (12)

	PEM Electrolysis		ALK Electrolysis	
	2024	2030	2024	2030
Efficiency[1]	64%	67%	68%	69%
CAPEX[2] (€)	1659.96 x $(^*kW)^{0.925}$	1185.69 x $(^*kW)^{0.925}$	1138.26 x $(^*kW)^{0.925}$	948.55 x $(^*kW)^{0.925}$
OPEX[2] (€)	463.8 x $(^*kW^{-0.305}$ x *kW)	349.8 x $(^*kW^{-0.305}$ x *kW)	328.13 x $(^*kW^{-0.305}$ x *kW)	266.6 x $(kW^{-0.305}$ x *kW)

Notes:

1. *Electrolyser efficiency is defined as the ratio of the energy content of hydrogen produced (33.3 kWh/kg_{H2}) to the electricity consumption rate of the electrolyser*
2. **kW refers to electrolyser plant size, in kW. OPEX means annual operating costs, other consumables, maintenance costs etc. excluding electrolyser power consumption.*
3. *Figures used later in report have been adjusted to align with one of the model scenarios (see later)*
4. *CAPEX values are exclusive of VAT*

The above figures are based on existing models which predict how these costs vary with electrolyser capacity (12). They have also taken into account data obtained for a specific 17.5MW PEM electrolyser installation manufactured by Siemens. Table 3-3 indicates the estimated CAPEX and OPEX for electrolyser plant sizes of 1MW, 10MW and 50MW based on the figures in Table 3-2.

Table 3-3: Estimated CAPEX & Annual OPEX for PEM and ALK Electrolysers for 2024 and 2030

Estimated CAPEX / OPEX (€)	PEM Electrolysis		ALK Electrolysis	
	2024	2030	2024	2030
CAPEX (€)				
1MW	€988,775	€706,271	€678,018	€565,015
10MW	€8,319,508	€5,942,527	€5,704,814	€4,754,012
50MW	€36,867,601	€26,334,096	€25,280,679	€21,067,232
OPEX (€/a)				
1MW	€56,407	€42,542	€39,907	€32,424
10MW	€279,467	€210,775	€197,718	€160,642
50MW	€855,293	€645,066	€605,104	€491,637

Notes:

1. *CAPEX & OPEX values are exclusive of VAT*

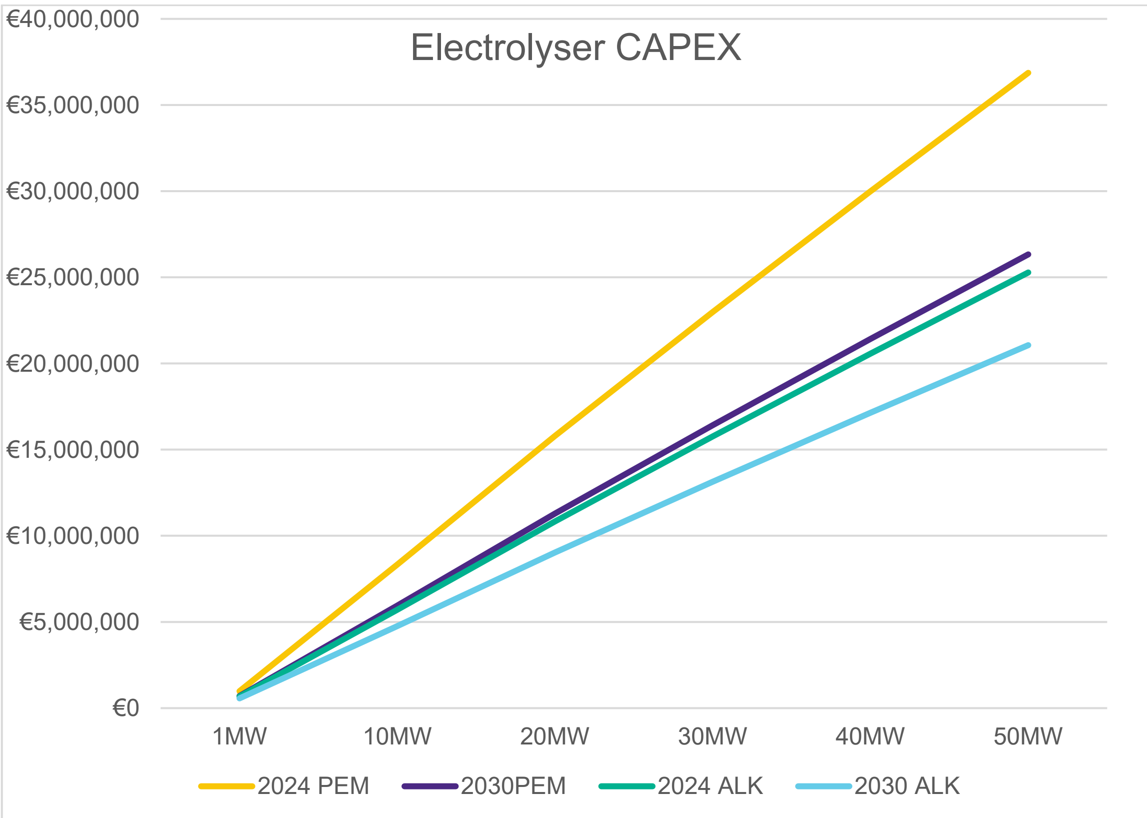


Figure 3-2: Estimated CAPEX for various electrolysers

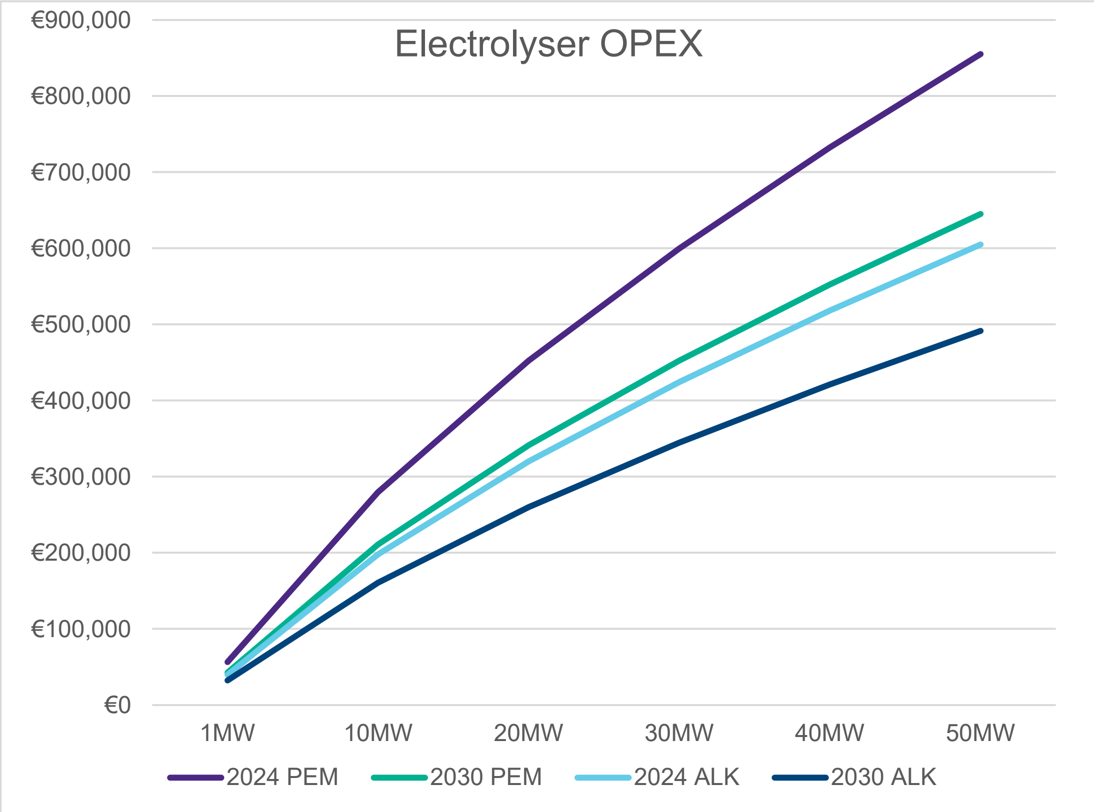


Figure 3-3: Estimated Annual OPEX for various electrolysers

3.2 Water Consumption

Electrolysis consumes water at a rate of approximately 0.015 m^3/kg H_2 produced. The rate of water consumption for electrolyser plant sizes of 1MW, 10MW and 50MW (working at full load) are indicated in Table 3-4 below. Daily consumption figures are also provided. Cumulative water consumption over longer periods of time will depend on the rate at which the electrolyser is used. Annual figures below assume 'full time' utilisation on the basis that this represents the maximum theoretical annual water demand.

Table 3-4: Water Demand for Hydrogen production

Electrolyser Size	Hydrogen Output[1]	Water Consumption[2]		
(MW)	(kg/hour)	m^3/hour	m^3/day	m^3/Annum[1]
1	20	0.3	7.2	2,250
10	4,828.90	3.0	72	22,500
50	24,144.50	15	360	112,500

Notes:

1. *Annual output based on 'full time' operation. This assumes a plant availability of 85% to allow for maintenance, which gives a total of approximately 7,500 hours of operation per annum.*
2. *Estimated water consumption rates for 2030. (Figures for 2030 are slightly higher than for 2024).*
3. *From Siemens electrolyser information*

Rhode Green Energy Park is supplied by a 100mm water main. It is estimated that this can deliver up to approximately 40m^3/hr to the site. Subject to confirmation with Irish Water, it appears that the water supply to the site is more than adequate to support a demonstrator scale electrolyser. However, consideration will have to be given to the input water quality. Chlorine and other impurities in the water will affect the performance of the electrolysers in terms of corrosion and efficiency (13) (14). Water quality testing data in Rhode indicate chlorine is present in the water occasionally above the acceptable level. An additional study may be required to investigate sourcing or on-site filtration for a higher purity water.

3.3 Electricity Consumption

An electrolyser requires electrical power to operate. The approximate relationship between hydrogen output and electrical power demand is summarised on Table 3-5 below.

Table 3-5: Hydrogen Output vs. Electrical Power Demand

Electrolyser Size[1] (MW)	Assumed Efficiency[2] (%)	Daily Hydrogen Output (kg H_2)	Theoretical Annual Output[3] (tonnes H_2)	Electricity Consumption (MWh)
1	67	497	154	7446
10	67	4,968	1,541	74,460
50	67	24,840	7,707	372,300

Notes:

1. *Based on maximum electrical demand.*
2. *67% used here for illustrative purposes. Actual efficiency will depend on electrolyser type and technological development. Estimated figures for ALK and PEM electrolysers are indicated in Table 3-2 above.*
3. *Assuming full-time operation at 85% availability. (Figures rounded).*

The source of electricity used for electrolysis is a key consideration for this report. The type of electricity used by the electrolyser will determine the carbon-intensity of the hydrogen produced. The hydrogen can be produced from power sourced from the existing grid. In this case, the carbon intensity of the hydrogen is a function of the balance of fossil-fuel and renewable power existing on the grid. Hydrogen can also be produced from a renewable source e.g. wind or solar.

Wind energy is the renewable energy source from which there will be most potential for curtailment (due to local abundance and the finite capacity of Derryiron substation). The opportunity to capture such curtailed or constrained wind power is a potential niche for an electrolyser. Wind power is therefore a primary focus of this study. However, it is duly noted that all sources of renewable energy, when available, could contribute to powering an electrolyser to produce renewable hydrogen. Source diversity could even be an advantage, with different sources counter-balancing daily and seasonal variations of one another.

3.4 Hydrogen

3.4.1 Physical Properties

Hydrogen is a flammable gas and extreme care must be taken when handling it. Hydrogen is colourless and odourless and therefore is not easily detected. Hydrogen has a much wider range of explosivity in air (4%-74% v/v) when compared to methane (CH_4) (5% - 15% v/v). This also means that hydrogen requires less air for combustion to occur.

If a hydrogen fire does occur, it contains less energy than equivalent natural gas fires. However, pure hydrogen burns with a pale flame and therefore can be more difficult to see. Hydrogen has a much lower density than both air or methane. If it escapes into the air, it will rise rapidly and disperse. If a leak occurs into an enclosed space such as a room or building, the hydrogen will rise to the ceiling and accumulate if there is no ventilation. The opposite occurs with natural gas which is heavier than air.

Hydrogen is classified as a dangerous substance under Directive 2012/18/EU. This Directive lays down rules for the prevention of major accidents which involve dangerous substances, and the limitation of their consequences for human health and the environment (15).

3.4.2 Carbon Intensity

In February 2023, the European Commission adopted a Delegated Act under the Renewable Energy Directive (2018/2021) which up-dates the classification of hydrogen by providing a singular definition of 'Renewable Hydrogen'. This is set to phase out the use of more colloquial terms such as green, blue and grey hydrogen within the European Union (see also Section 1.2 above). If 'green hydrogen' is referenced, alignment is assumed with the EU definition of 'Renewable Hydrogen'.

Strict regulation is now in place in order to be able to refer to hydrogen produced as being renewable. The classification of renewable hydrogen is highly dependent on the carbon intensity of the electricity used to produce the hydrogen. In order to produce renewable hydrogen, the electricity used must be characterised as fully renewable. The criteria for fully renewable electricity are outlined in detail in the European Directive on rules for the production of renewable liquid and gaseous transport fuels of non-biological origin. The Directive requires that the electricity used to produce renewable hydrogen should have a carbon intensity below 18g CO_2 equivalent/MJ. In this respect, the definition of 'Renewable Hydrogen' is equivalent to the definition of 'Green Hydrogen'. However, there is a further requirement that the installation providing electricity to produce hydrogen should be directly connected and should always supply renewable electricity (16).

If producing hydrogen from the electricity grid, the share of renewable electricity available should exceed 90% to allow meeting a minimum of 70% greenhouse gas savings. This typically requires that the number of full-load electrolyser hours be limited to ensure that the 90% renewable share is met. Further detail on this definition and restrictions exist to limit the use of fossil fuels to produce renewable hydrogen and therefore reducing the carbon intensity of the fuel (16).

3.4.3 Purity

Table 3-1 above shows the expected purity of the hydrogen produced by PEM and ALK processes. This is 99.99% and 99.8% respectively. The hydrogen purity specifications however have high standards for the accepted purity for use in fuel cells. SAE, ISO and EN purity standards for fuel cells dictate that the purity is required to be >99.97% (17). The ALK process falls below this threshold and therefore may need to be supplemented with a post-production purifying process.

3.5 Oxygen By-Product

The electrolysis of water also produces oxygen. O_2 gas currently has various applications in industry. Table 3-6 lists these applications, their corresponding constraints, and the potential for selling electrolysed O_2 to the industry based on local presence of the industry and consumption.

Table 3-6: Existing Oxygen applications in Ireland

Industry	Use in Industry	Constraints	Potential
Wastewater treatment	Increase dissolved oxygen	Price	Fair. Many existing facilities where it could potentially be used.
Water treatment	Increase dissolved oxygen	Price	Fair Many existing facilities where it could potentially be used.
Pharmaceuticals	Cell cultivation/fermentation	High quality standards	Weak High quality / purity requirement would mean additional processing.
Oxyfuel Combustion Processes	Air substitute in combustion	Price	Strong Many potential outlets. Not as limited by quality / purity factors
Pulp and Paper	Delignification	No Irish manufacturers	None
Medical	Breathing apparatus	High quality standards	Weak High quality / purity requirement would mean additional processing.
Wholesale suppliers	Supply industry	Price	Strong

The focus of this feasibility study is a demonstrator scale electrolyser at Rhode and the renewable energy potential in hydrogen. Therefore, while there are opportunities for recovering and using oxygen by-product from electrolysis, a detailed examination of this potential is outside the scope of the study. Based on the data above, identifying potential wholesale suppliers would be a recommended further step if it is proposed to examine end uses of oxygen at a later stage.

3.6 Hydrogen Storage and Transfer

3.6.1 Storage

Hydrogen storage is needed as a buffer between production and demand, both of which may be variable to different degrees. Storage requirements will therefore depend on the relative rates at which hydrogen is generated / consumed and the durations of these periods.

Hydrogen can be stored as a gas, liquid or solid. Solid state storage is currently in the R&D phase and is too nascent a technology to be considered for Rhode. Both liquid and compressed gas storage have benefits and drawbacks and are generally used for different applications.

Liquid hydrogen must be maintained below its boiling point of 253°C at 1atm (18). Long term storage of liquid hydrogen is difficult due to evaporation losses. The energy consumption during liquification is approximately 30-40% of the energy stored. Liquid hydrogen storage therefore has a much higher cost than compressed gas storage. Apart from these drawbacks liquid hydrogen has a considerably higher energy density compared to gaseous hydrogen and can be compressed and stored at pressures up to 700bar. This can be beneficial in terms of cost-effectiveness when storage of more than 10-tonnes of hydrogen is required. However, for the demonstrator-scale facility in Rhode it is not considered a practical option in terms of cost and energy required.

The most relevant form of hydrogen storage for a demonstrator project at Rhode is as a gas. Two different technologies exist for storing hydrogen as a pressurised gas:

1. Large, welded steel tanks, with a service pressure of 50 bar
2. Bundles of steel cylinders, making it possible to store hydrogen at pressures of up to 200 bar or even 350bar

Both of the above are currently widely used for small scale mobile and stationary applications.

Data, extracted from a study on early business cases for hydrogen in energy storage and more broadly power to hydrogen applications, estimates similar CAPEX for both tanks and bundles at approximately €470/kg hydrogen stored (19). Tanks appear to be easier to make but need more materials (steel) due to their bigger volume, while bundles are smaller but are more complex due to having to assemble groups of steel cylinders together into ‘banks’ of cylinders.

The lifetime of these storage vessels is estimated to be of 30-40 years, and maintenance must be carried out every 10 to 15 years.

3.6.2 Transfer

Gaseous hydrogen is usually transported by either pipeline or truck and ‘tube trailer’, these ‘tube trailers’ are usually comprised of several smaller cylindrical storage vessels. Demountable units are also transported by truck and trailer. These are referred to as Multi-Element Gas Containers (MEGCs). For the purposes of this feasibility study, no distinction has been made between tube trailers and MEGCs. Liquid hydrogen is moved by tanker which is typically one large cylindrical storage vessel.

When trucks are used to carry compressed gasses / liquids on a fixed route, they are sometimes referred to as ‘virtual pipelines’. Virtual pipelines are often used to supply LNG to remote locations. Depending on scale, the virtual pipeline system can mean having a number of mobile storage trailers (‘tube trailers’ / MEGCs). At any time, some of these will be in the process of being filled at source, transferred via road or in the process of being used at the destination. Directive 2010/35/EU relates to transporting hydrogen as it applies to the design, manufacture and assessment of transportable cylinders, tubes, cryogenic vessels and tanks for transporting gases (20). This is important as it represents a goal which should be met to ensure the hydrogen can be transported safely by virtual pipeline.

3.6.2.1 Pipeline

The most common form of gas transport is via pipeline. Pipelines are used to transport high volumes of gas over long distances. Most of these will be for natural gas, but hydrogen can also be transported by pipeline. Currently Air Liquide Canada Inc. is operating hydrogen dedicated pipelines which are transporting hydrogen between France, Belgium, and Netherlands (21).

Pipeline CAPEX is very dependent on material, diameter, ground conditions, reinstatement costs and whether there is a need for any specialised construction methods. However, in broad terms, gas transmission pipelines costs can be expected to be > €5m/km. Added to this will be the cost of modifying existing installations in order to facilitate connection, which could also amount to several million euros. The capital cost of gas distribution pipelines is similarly dependent on the specific scenario, but will be much lower.

The OPEX for a pipeline transporting gas to an injection point on the gas network will be made up of compression costs and general operational maintenance and supervision. An estimate for pipeline OPEX has been made in this study (See Section 6).

3.6.2.2 Tube Trailer

Tube trailers shown in Figure 3-4 are used widely for transporting many types of gases including natural gas and biogas. For hydrogen use, they typically contain approximately 400 kg of hydrogen gas, stored at a pressure of 350bar. They are used for small deliveries to customers who are usually close to the hydrogen production plant (up to 200km). Recent advancements in tube trailers means pressures can be increased to 500 bar increasing the payload to 1,000kg (18). Tube trailers can now transport hydrogen for distances up to 500km (18).

The approximate cost of a tube trailer for compressed hydrogen at 350bar is €280,000. A conventional HGV tractor unit is required to tow the tube trailer and this has a cost of approximately €120,000. These figures were sourced from a research paper by Yang and Odgen (22).

Figure 3-4: Tube Trailer for transporting Compressed Hydrogen Gas at 350bar

3.6.2.3 Tanker Trucks

Tanker trucks shown in Figure 3-5 are used to transport liquid hydrogen at a temperature of -253°C and a pressure of 1bar. They typically have a capacity of up to 3,500kg of hydrogen. Tanker trucks for liquid hydrogen only make economic sense for higher volumes and longer distances. As for liquid hydrogen storage, there are overall efficiency losses involved when transporting liquid hydrogen. This option is not considered to be a feasible transportation option for a demonstrator hydrogen electrolyser at Rhode due to cost.

Figure 3-5: Articulated Road Tanker for Transporting Liquid Hydrogen at -253ºC

3.6.3 Compression

A compressor is an essential part of any hydrogen utilisation system, pipeline or virtual pipeline transportation system. It is used to compress the hydrogen produced to the required usage / transport / storage pressure.

Compressors can be electrically powered or powered by natural gas / hydrogen or other fuels. The selection of compressor type and fuel source will depend on the scale of the system and expected demand. Table 3-7 below provides approximate CAPEX and OPEX figures for relevant compressor units that could potentially be used for a hydrogen demonstrator at Rhode.

Table 3-7: Estimated Costs for Hydrogen Compressors

Scenario	CAPEX[1] (€)	OPEX[1] (€/annum)
Injection to Gas Distribution Network at 4bar		
34kW compressor (1MW electrolyser)	61,165	64,400
135kW compressor (10MW electrolyser)	212,989	554,400
135kW compressor (50MW electrolyser)	212,989	1,676,800
Compressed Hydrogen Transport (350bar)[4] (1MW)	70,000	90,000
Liquified Hydrogen Transport (50MW) (1bar, -252.87°C)	40,000,000	9,200,000

Notes:

1. *CAPEX values are exclusive of VAT*
1. *Cost figures sourced from* (22)
2. *OPEX for 1MW, 10MW & 50MW electrolysers are based on dedicated wind, supply led, hydrogen supplies of 161, 1,386 and 4,192 tonnes respectively*
3. *OPEX for compressors assume 2kWh/kg H_2 for injection at 4 bar and 3kWh/kg H_2 for compression for injection at 70bar*
4. *OPEX for compressor for tube trailer based on 1MW electrolyser output and electrical demand of 2kWh/kg H_2. Cost of electricity assumed is €0.2/kWh*
5. *Electrolyser efficiency is defined as the ratio of the energy content of hydrogen produced (33.3 kWh/kg$_{H2}$) to the electricity consumption rate of the electrolyser*

4 RELEVANT END USE OPTIONS FOR HYDROGEN

As outlined in Section 1.3 of this report, Rhode Green Energy Park is a unique location to test and demonstrate an electrolyser system producing renewable / green hydrogen. Potential outlets for renewable hydrogen produced at Rhode are explored below. These include injection of hydrogen into the natural gas network, co-firing in power stations and transportation. Examples of locations where similar projects have been implemented are also provided. These serve to demonstrate the potential for Rhode.

4.1 Natural Gas Displacement

4.1.1 Hydrogen Blending and Injection

On a volumetric basis, natural gas has an energy density of approximately 35.2MJ/m^3. Hydrogen has a lower volumetric energy density of approximately 9.96MJ/m^3 (28% that of natural gas). Therefore, when hydrogen is blended with natural gas, the energy content of a given volume of blend will be lower than for natural gas. To continue supplying an equivalent energy demand, an increase in volumetric flowrate is required. Table 4-1 shows the percentage of energy supplied by hydrogen at various concentrations when mixed with natural gas and the reduction of carbon dioxide emissions due to injection of hydrogen.

Table 4-1: Energy content of hydrogen and methane at equal volume, and total energy in gas grid with hydrogen

% Hydrogen (v/v)	Calorific Value of Blend (MJ/m^3)	Reduction in Calorific Value of Blend	% Energy from hydrogen	% CO_2 emissions reduction
0%	35.2	0%	0%	0%
2%	34.7	1%	1%	0.6%
5%	33.9	4%	2%	1.5%
10%	32.7	7%	3%	3.2%
15%	31.4	11%	5%	5.3%
20%	30.2	14%	7%	7.0%

The percentages 2, 5, 10, 15 and 20 of hydrogen concentration are the most common to have been used in trials around the globe. There is a clear decrease in energy content correlated with an increase in hydrogen injection.

The quantity of hydrogen by volume that can be injected is limited by the end user of the gas and the specifications of the equipment delivering the gas. The lowest tolerance end user will set the limit for the whole grid. Figure 4-1 below gives an overview of the tolerance to hydrogen blending of common end users.

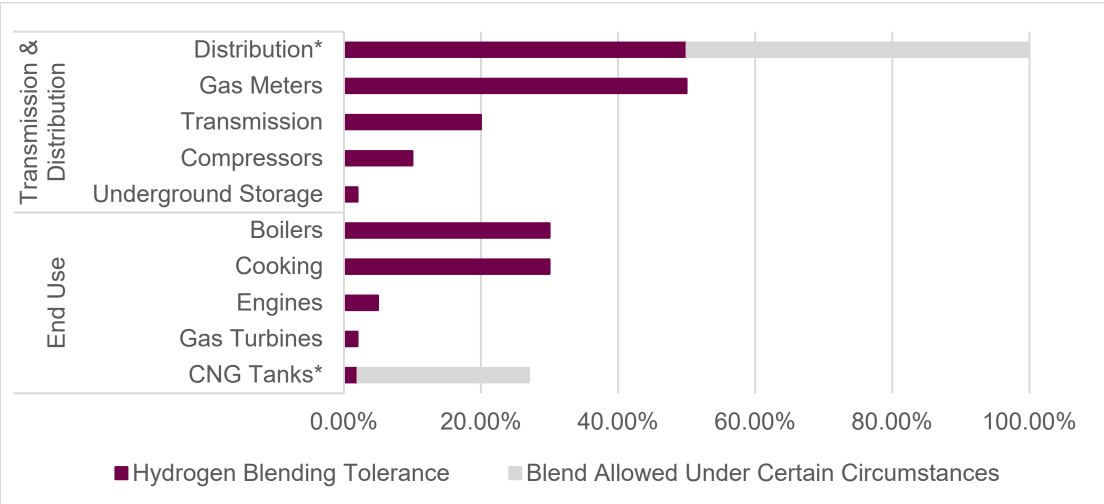


Figure 4-1: Tolerance of existing elements of the natural gas networks to hydrogen blend shares by volume (23)

Notes:

** The higher tolerance of CNG tanks is for Type IV tanks designed for hydrogen storage*

**The higher tolerance for distribution would require specific safety assessments*

Once hydrogen has been delivered to a node on the gas network (by whatever means), it can be injected into the high pressure transmission network (typically operating at 70barg in Ireland) or the medium pressure distribution network (typically operating at 4barg in Ireland).

Hydrogen injection equipment is similar to equipment used for the injection of biomethane into a natural gas network shown in Figure 4-2. It consists of flow meters, control valves, static mixers and gas samplers to determine the gas quality and composition before and after blending. There are several companies who supply this equipment including, Honeywell, Thyson Technology and Emerson. They can even come in pre-fabricated 'container' units for ease of installation.

An estimated cost for a hydrogen injection unit similar to that shown in Figure 4-3 (from conversations with a Honeywell representative) is in the range of €350K to €500k.

Figure 4-2: Thyson's Propane Vapour Injection equipment coupled with Opto Trim (24)

Current regulations governing the injection of biomethane into the gas network stipulate that the following parameters must be controlled.

- Calorific Value
- Water and Hydrocarbon dew points
- Trace compounds
- Odorisations

These parameters would also need to be monitored and controlled for hydrogen injection into the gas network.

It is also noted that with the introduction of hydrogen to natural gas, there is likely to be a need for changes in how some gas customers are charged. If there is a larger quantity of hydrogen in the pipelines, then the user may need to use more gas than if it were 100% natural gas.

Figure 4-3: Grid Entry Unit used for HyDeploy Phase 1 at Keele University

Source: chrome-extension://efaidnbmnnnibpcajpcglclefindmkaj/https://hydeploy.co.uk/app/uploads/2022/06/HyDeploy-Close-Down-Report_Final.pdf

The ability of hydrogen to contribute to the decarbonisation of the natural gas grid should also be compared to the potential of this green fuel in other sectors. The relatively high cost of producing hydrogen with respect to other renewable fuels may mean that it is more suitable for utilisation in end uses that have no alternative paths to decarbonisation i.e. where higher costs may be more justifiable.

4.1.2 Irish Gas Network

Ireland's gas network is over 14,000km long and connects towns and villages in 21 counties across the country.

The gas transmission network consists of over 2,400km of high pressure (70bar / 85bar) steel transmission mains and over 250 Above Ground Installations (AGIs), Compressed Natural Gas (CNG) offtakes and Biomethane injection facilities. The nearest AGI to Rhode Green Energy Park is Gaybrook AGI which is approximately 13km away to the north (see Figure 4-4 below).

The gas distribution network makes up the balance of the pipeline network and is predominantly Polyethylene (PE), with an operating pressure of 4bar. There are many installations within the network and at customer premises to reduce and regulate pressure including customer meters. Gaybrook AGI supplies gas at distribution pressure (4 bar) to the town of Mullingar (8km to the north). Mullingar is approximately 21km to the north of Rhode Green Energy Park (see Figure 4-4 below).

Gneevekeel AGI supplies gas at distribution pressure (4bar) to the towns of Tullamore and Clara. This AGI is approximately 25km from Rhode. It is approximately 18.5km to the west of Gaybrook AGI and is approximately 16km north of Tullamore. Tullamore is approximately 21km from Rhode Green Energy Park.

4.1.3 Injection into Local Gas Distribution Network

If hydrogen produced at Rhode Green Energy Park were to be injected into the Irish gas grid, it is assumed that possible locations for this to occur would be Gaybrook AGI (serving Mullingar) and Gneevekeel AGI (serving Tullamore and Clara) see Figure 4-4 below. This would enable hydrogen to be blended with natural gas and fed into the 4bar distribution networks serving Mullingar or Tullamore/Clara. It would also be accessing discreet parts of the wider distribution network i.e. unconnected to other sections of the gas network. This would be advantageous in terms of overall system control and ensuring that lessons learned could be used effectively if hydrogen is introduced to other nodes on the network. To access the distribution network, the hydrogen would need to be compressed to a pressure in excess of 4bar that will ensure that it can be discharged at an adequate flow rate into the network either directly or via local storage.

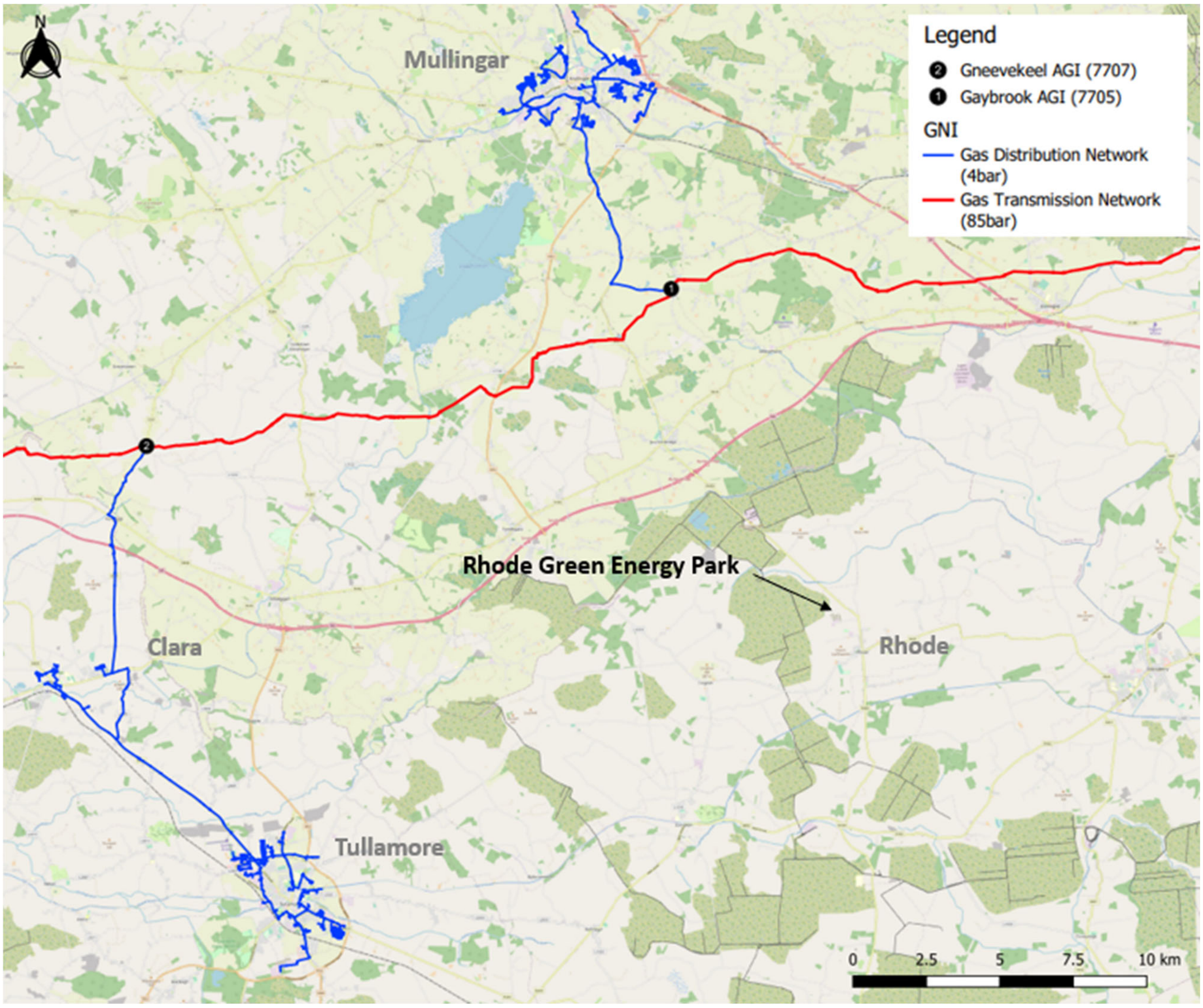


Figure 4-4: Locations of Gneevekeel and Gaybrook AGI's

The relative distances from Rhode Green Energy Park to Gaybrook AGI is approximately 13km and from Rhode Green Energy Park to Gneevekeel AGI is approximately 25km. This considered, there would be signifcantly lower CAPEX associated with a pipeline connection to Gaybrook AGI than to Gneevekeel AGI. In a similar way, a 'virtual pipeline' to Gneevekeel AGI would entail higher OPEX than for a 'virtual pipeline' to Gaybrook AGI. Even if hydrogen were delivered directly to a hydrogen injection facility in Tullamore, there would be higher CAPEX & OPEX for this option compared to the Gaybrook AGI option. However, the preferred approach would be to inject hydrogen at the AGI in order to ensure a consistent blend of hydrogen throughout the distribution network downstream.

It is worth noting that the gas demand for Tullamore/Clara is approximately 1.7 times greater than that for Mullingar. This means that if hydrogen injection to the gas distribution network were to be considered, and Gneevekeel AGI used as the location for this, Tullamore / Clara could support a larger electrolyser than Mullingar. Subject to further detailed cost benefit analysis, this option could still be relevant to Rhode Green Energy Park.

4.1.4 Injection into Gas Transmission Network

A second option would be to inject hydrogen generated at Rhode directly into the gas transmission network. Any hydrogen injected to the transmission network could find its way to any part of the distribution network. It is assumed that if this were to be done, Gaybrook AGI would be the best location as it is the closest location to Rhode.

The gas transmission network has a design pressure of 85bar and currently normally operates at pressures approaching 70bar. Higher storage/transport pressures would therefore be required to inject the hydrogen at the transmission pressure. The high cost of gas transmission pipelines would be prohibitively expensive for an electrolyser demonstrator at Rhode. However, a transmission pipeline could be avoided by adding a compression unit and storage at Gaybrook AGI. This option could also potentially still be feasible if the hydrogen is transported in a 'virtual pipeline' using tube trailers. These store hydrogen at up to 350bar and could be used to both transport the gas and to discharge it into the network at required rates.

4.1.5 Hydrogen Transportation to Injection Point

Two methods of transportation were investigated:

1. **Pipeline**: Gaybrook AGI is the closest GNI installation to Rhode and was therefore selected as the most likely location for injection of hydrogen to the gas network assuming that the hydrogen is transported there by pipeline.
2. **Virtual Pipeline**: A virtual pipeline would be based around the transportation of compressed hydrogen (350bar) tube trailers. Hydrogen transported by virtual pipeline could be delivered to various locations.

4.1.5.1 Pipeline

As outlined earlier report, a gas transmission pipeline connection to the existing gas transmission network would be prohibitively expensive for a demonstrator scale hydrogen electrolyser at Rhode. The materials, design and construction methods involved mean that the capital cost of a steel high pressure pipeline is an order of magnitude greater than the cost of a distribution pipeline of similar length. It is conservatively estimated that the CAPEX for such a pipeline from Rhode Green Energy Park could be over €25 million.

Due to the nature of gas transmission (high pressure and high flow), any option that could potentially use a high-pressure pipeline to access the transmission network would need to be based on high volumes of hydrogen production from a large-scale electrolyser. For these reasons, a gas transmission pipeline connection has been ruled out of consideration in this feasibility study which is concentrated on a demonstrator scale unit.

The other means of accessing the transmission network would be to compress the gas at source into tube trailers (350bar) for delivery to Gaybrook AGI or Gneevekeel AGI via road. This is the virtual pipeline option (see further below).

A 4-bar distribution pipeline connection from Rhode Green Energy Park to Gaybrook AGI was considered for accessing the gas distribution network of Mullingar. An indicative pipeline route from Rhode Green Energy Park to Gaybrook AGI was identified which mainly follows local roads. The main details of this pipeline are outlined on Table 4-2 below.

Table 4-2: Details of Hydrogen Pipeline Connection to Gas Distribution Network via Gaybrook AGI

Description		Distribution Pipeline	
Material		Polyethylene (PE)	
Design Pressure (bar)		4	
Length to Gaybrook AGI (km)		18.1	
Nominal (outer) Diameter (mm)	150	200	315
Volume (m^3)	251	447	1108
Storage Capacity at 4bar (kg H_2)[1]	83.4	148	368
Compressor (1MW electrolyser) (4bar, 34kW) CAPEX (€), OPEX (€/annum)		61,165	60,000[2]
Compressor (4bar, 10MW electrolyser) (4bar, 135kW) CAPEX (€), OPEX (€/annum)		212,989	600,000[3]
Estimated CAPEX (€)		2.5 – 3 million	
Estimated OPEX (General Maintenance etc.) (€/annum) (85% availability, 50% duty)		25,000	

Notes

1. *For comparison, the equivalent storage capacity of a 150mm diameter transmission pipeline at 16bar, 70bar and 85bar would be approximately 334kg, 1,415kg and 1,706kg respectively*
2. *Based on 150T of H_2 produced a 2kWh/kg and 0.2 €/kWh*
3. *Based on 1500T of H_2 produced a 2kWh/kg and 0.2 €/kWh*
4. *CAPEX values do not include VAT*

4.1.5.2 Virtual Pipeline

The typical tube trailer that would be used to establish a virtual pipeline for hydrogen will operate at 350bar and when full, will hold approximately 400kg of hydrogen. The virtual pipeline system that is envisaged for this study comprises a number of tube trailers. At least one tube trailer will be required at each of the following sections of the system:

- At the electrolyser site. Filling will take place here up to a pressure of 350bar.
- At the injection location (Gaybrook AGI). The compressed gas within the tube trailer will be discharged / 'decanted' into the gas distribution network here until the trailer is empty.
- Floating / Between locations. Depending on the rate of hydrogen production / injection into the gas network, there should be at least one tube trailer ready to replace a full / empty tube trailer and ensure continuity in the system at filling and discharging points. For practical reasons however, it would make sense that at each location, the next tube trailer would always be in place and ready for switching over before the tube trailer in service was full / empty. Therefore, an additional trailer(s) could be required to allow for the time required to travel between destinations and for switching over tube trailers.

The capacity of the tube trailer is therefore a key figure when considering how such a system will operate and its overall costs. As the rate of hydrogen production / injection increases, there will be a need for greater numbers of tube trailers. However, as tube trailers will be cycled through the system, the length of time it takes to fill / empty a tube trailer and its time in transit also become important in determining how many are required.

Tube trailers must be towed from site to site by a standard HGV tractor unit. Depending on the size of the operation and distances to travel, there may also be a need to have more than one tractor unit to ensure that the operation runs smoothly with minimal disruption to the flow of hydrogen.

For this study, it has been assumed that a virtual pipeline could potentially be relevant for electrolysers in the 1MW to 10MW scale. The estimated costs for these are summarised on Table 4-3 below.

Table 4-3: Details of Virtual Pipeline Connection to Gas Distribution Network

Description	Unit Cost (€)	Number		Cost (€)	
Electrolyser Size		**1MW**	**10MW**	**1MW**	**10MW**
Tube trailers	280,000	3	6	1,000,000	1,680,000
Tractor Unit	120,000	1	1	120,000	240,000
Compressor (350bar)	70,000	1	1	70,000	70,000
Compressor Energy Consumption (2kWh/kg H_2 @ €0.2/kWh)				90,000[2]	900,000[3]
Miscellaneous operational costs (Personnel, fuel, insurances etc.)				100,000	150,000
Estimated CAPEX (€)				1,190,000	1,990,000
Estimated OPEX (€/annum)				190,000	1,050,000

Notes

1. *The above details would be approximately the same for a virtual pipeline serving Derrygreenagh Power Station and for a virtual pipeline serving injection to the transmission network*
2. *Based on 150 tonnes of H_2 produced a 2kWh/kg and 0.2* €/kWh
3. *Based on 150 tonnes of H_2 produced a 2kWh/kg and 0.2* €/kWh
4. *CAPEX values are exclusive of VAT*

Unlike the pipeline option, there is flexibility with a virtual pipeline in terms of the destination for hydrogen produced. Either Gaybrook AGI (approximately 18km away by road) or Gneevekeel AGI (approximately 33km away by road) could be served. Gneevekeel AGI is further away and would entail some additional transportation costs. However, the Gneevekeel option should not be ruled out as a possibility when a virtual pipeline is used to transport hydrogen produced. In the overall context of the demonstrator project the additional transportation costs would be marginal.

Comparing Table 4-2 and Table 4-3, it is evident that the cost of transporting gas by virtual pipeline (tube trailers) has a lower CAPEX than for a distribution pipeline. This is a significant advantage to a demonstrator -scale project. However, the annual OPEX for the virtual pipeline is much higher than for the pipeline option. It will also be clear that as the volume of hydrogen produced increases with electrolyser scale, it would not be long before the operational costs of the virtual pipeline exceeded the capital costs of a pipeline option.

The flexibility of the virtual pipeline means that any surplus hydrogen produced can be delivered to other destinations to avail of alternative end use options such as transport. The virtual pipeline option is therefore more suited to a smaller scale electrolyser such as the Rhode demonstrator. It could be used while a demonstrator-scale electrolyser was being developed. If the demonstrator was to be increased in scale, the pipeline option could then be developed.

4.1.6 Example Projects: Injection to Transmission Network

Currently the only trial of injecting hydrogen into transmission lines in a gas network was carried out by Snam in Italy. However, there have been several feasibility studies carried out on the topic which have justified hydrogen injection into transmission lines at a concentration of up to 10% by volume.

The full extent to which hydrogen can be injected into the gas transmission network depends on many factors including pressure and material specification. Transmission pipelines for transporting natural gas are mostly made from carbon steel. For some grades of steel, the presence of hydrogen in the gas stream can introduce a risk of 'hydrogen embrittlement'. A consequence of this is that the overall lifespan of the asset will be reduced.

Currently, it is generally considered that hydrogen blends of up to 20% will be possible for most gas transmission networks. However, it should be noted that some steel grades are safe to use with higher proportions of hydrogen.

The Irish natural gas transmission network is all steel, but the material specifications of individual pipelines throughout the network are not the same. Therefore, the introduction of hydrogen into the gas network at any point is something that will be considered very carefully by Gas Networks Ireland.

4.1.6.1 Contursi Terme, Italy

In 2020 Snam began injecting hydrogen into the Contursi Terme natural gas transmission network at a volume of 10% as part of an experiment. The network was directly supplying two local industries, a pasta factory and a mineral water bottling company. The project was successful and production from local industry continued unaffected with the added advantage of less carbon emissions.

4.1.6.2 HyGreen, Southern France

As of 2019, France had 6 projects ongoing, 3 still in the study phase and 2 under construction. One such operation, HyGreen in Figure 4-5, is planning injection into the transmission network. Run by DLVA agglomeration community, Geomethane and PACA the project is estimated to cost €300 million using a 13kt H_2/year electrolyser with the electricity coming from a 900MW solar PV power project.

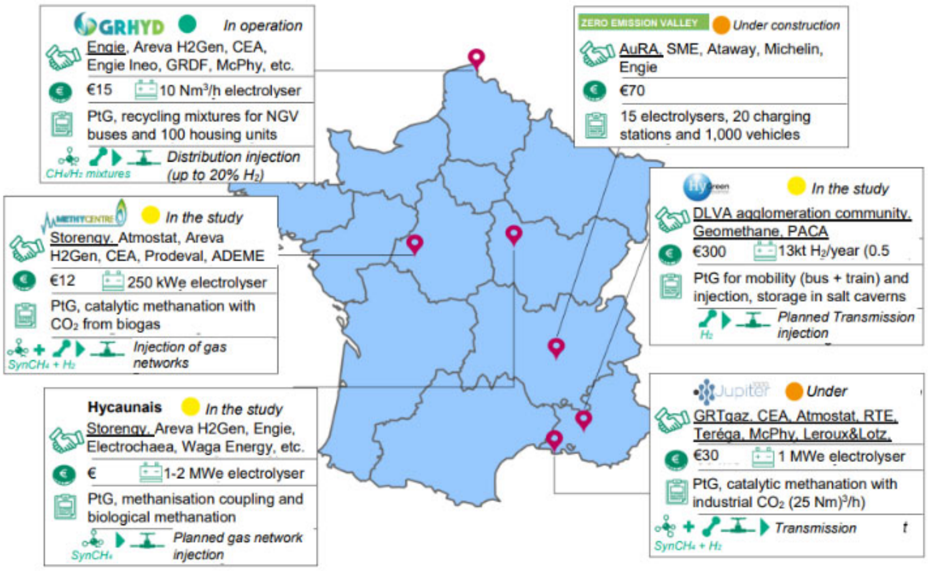


Figure 4-5: Hydrogen trials, France (25)

4.1.7 Example Projects: Injection into Distribution Network

There have been several successful trials for injection of hydrogen into distribution lines globally. Modern gas distribution networks are made from Polyethylene (PE) which is generally considered to be compatible with blends of hydrogen up to 100%.

Some case studies of relevance to Rhode Green energy Park are outlined on Table 4-4 below and further described in the following sections.

Table 4-4: Example projects for hydrogen injection into distribution network

Case Study	Location	Electrolyser Size (MW)	Injected (%)	CAPEX	Application
HyP SA	South Australia	1.25	5	\$14.5m (€9.28m)	>700 homes 40kg onsite storage
HyDeploy 1	Keele University UK	0.5	20	£7m (€8.2m)	100 homes 3 faculty buidings
HyDeploy 2	Winlaton, Newcastle upon Tyne, UK	N/A	20	£14.9m (€17.5m)	> 650 homes 1 school, 1 church
GRHYD	Northern France	0.05	20	€15m	100 homes 1 public establishment

Notes:

1. *Electrolyser efficiency is defined as the ratio of the energy content of hydrogen produced (33.3 kWh/kg$_{H2}$) to the electricity consumption rate of the electrolyser*

4.1.7.1 Hydrogen Park South Australia

Hydrogen Park South Australia or HyP SA is a 14.5-million-Austrialian Dollar project run by Australian gas networks alongside GPA engineering, Siemens, Valmec, AGIG and the South Australian government (26).

Figure 4-6: Hydrogen Park South Australia (26)

Source: https://www.agig.com.au/hydrogen-park-south-australia

HyP SA has a 1.25MW Polymer Electrolyte Membrane (PEM) electrolyser on-site shown in Figure 4-6. This is run on renewable electricity from wind and solar sources. The electrolyser can produce up to 20kg Figure 4-6of hydrogen per hour and 175tonnes of hydrogen per annum which is equal to the total gas use of hydrogen alone of 1500 homes.

The hydrogen is used for various applications. These are shown in Figure 4-7. The main application is blending 5% renewable hydrogen with natural gas in the distribution network to supply over 700 homes. HyP SA has 40kg of hydrogen storage onsite. The excess hydrogen is sent for use in industry through BOC using tube trailers.

This project demonstrates that hydrogen can be safely injected into the gas network with no issues arising from end uses in domestic appliances. It also demonstrates the capability of an electrolyser to provide hydrogen to a primary outlet such as the distribution network, while also maintaining a secondary outlet of industry customers. This ensures that the electrolyser is operational for more hours per annum i.e. it has a higher capacity factor, thereby improving the overall economic feasibility of the installation.

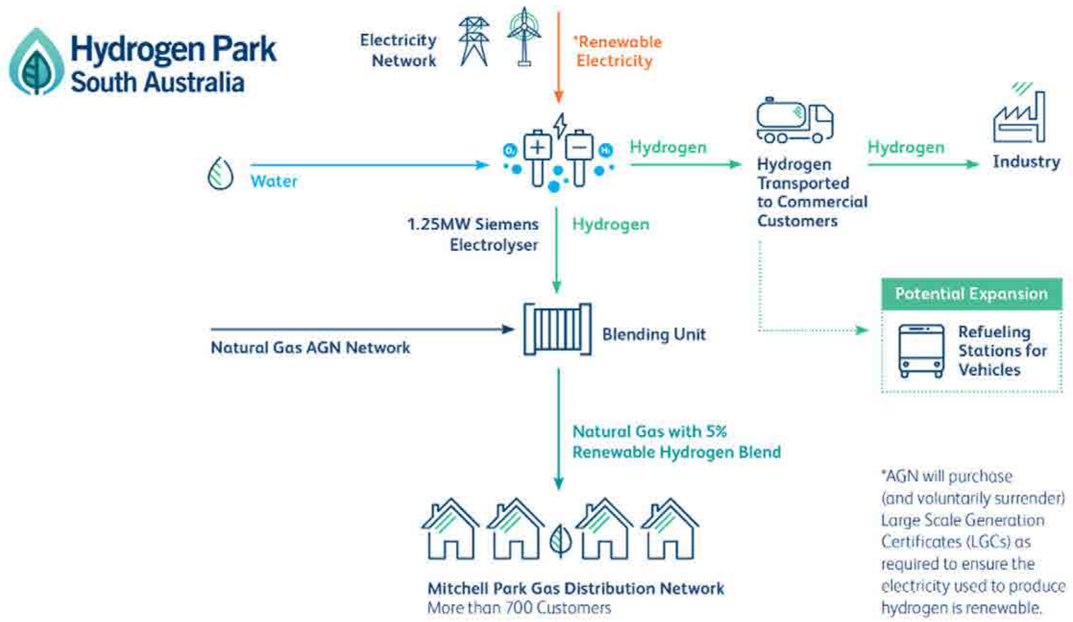


Figure 4-7: Schematic of Hydrogen Park South Australia Process (26)

4.1.7.2 HyDeploy Phase 1 - Keele University, UK

In 2019/2020 the UK's first grid-injected hydrogen trial, HyDeploy, began. The trial involved injecting 20% by volume of hydrogen into the natural gas distribution network supplying 100 homes and 30 faculty buildings at Keele University in Staffordshire using a 0.5MW electrolyser. The site is shown in Figure 4-8 and Figure 4-9.

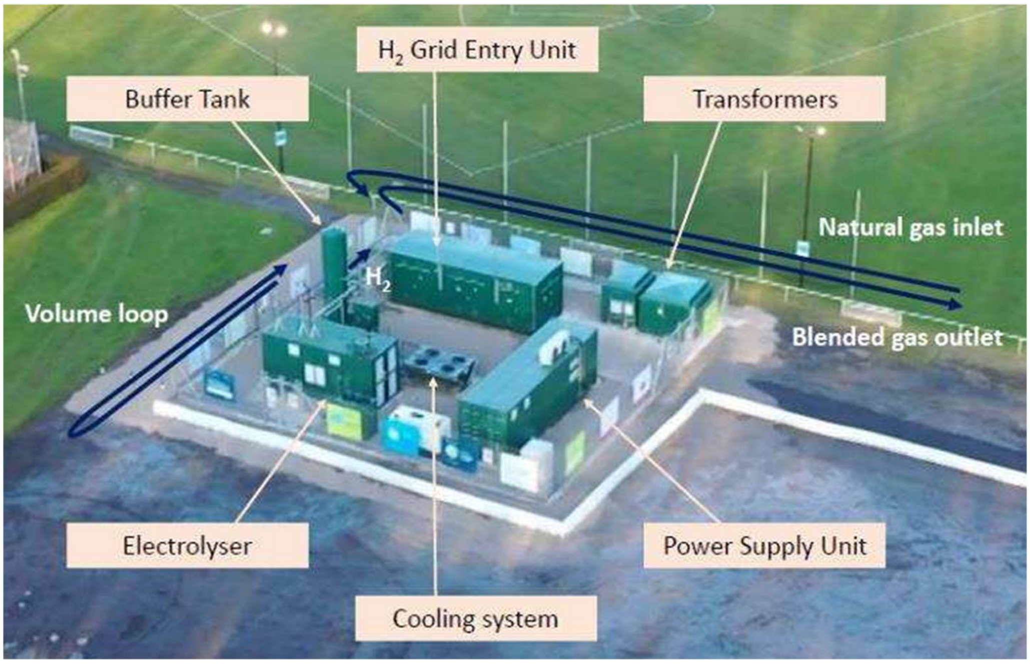


Figure 4-8: HyDeploy Phase 1 trial at Keele University, UK (27)

Source: chrome-extension://efaidnbmnnnibpcajpcglclefindmkaj/https://hydeploy.co.uk/app/uploads/2022/06/HyDeploy-Close-Down-Report_Final.pdf

The project cost £7 million (approximately €8.2 million) and was led by Cadent in partnership with Northern Gas Networks, the Health and Safety Executive (HSE) Science Division, ITM-Power, Keele University and Progressive Energy with backing from Ofgem's Network Innovation Competition.

Figure 4-9: HyDeploy Phase 1 0.5MW Electrolyser Installation at Keele University

Source: chrome-extension://efaidnbmnnnibpcajpcglclefindmkaj/https://hydeploy.co.uk/app/uploads/2022/06/HyDeploy-Close-Down-Report_Final.pdf

4.1.7.3 HyDeploy Phase 2 – Winlaton, Newcastle upon Tyne, UK

HyDeploy 2 followed and built on the experience gained on HyDeploy 1. This trial involves injection of up to 20% hydrogen by volume into the Cadent natural gas distribution network supplying over 650 homes, 1 school and 1 church. It is the first deployment of hydrogen into the UK's public gas network.

Figure 4-10: HyDeploy Phase 2 at Winlaton (Hydrogen blending and injection only)

Source: chrome-extension://efaidnbmnnnibpcajpcglclefindmkaj/https://hydeploy.co.uk/app/uploads/2022/06/HYDEPLOY2-THIRD-OFGEM-PPR.pdf

Hydrogen for this hydrogen injection trial was sourced from industry, but the design of the installation incorporates the necessary space and connections for a future electrolyser. This site is shown in Figure 4-10 above.

The project cost £14.9 million (approximately €17.5 million) and was led by Cadent in partnership with Northern Gas Networks, the Health and Safety Executive (HSE) Science Division, ITM-Power, Keele University and Progressive Energy with backing from Ofgem's Network Innovation Competition.

4.1.7.4 GRHYD Northern France

Launched in 2014, the GRHYD hydrogen energy storage demonstrator project in Northern France is being conducted by ENGIE and supported by the French government. The 15-million-euro project injected 20% by volume hydrogen into the distribution grid supplying 100 homes and one public establishment with a hydrogen/natural gas blend. The hydrogen comes from a 10Nm^3/h electrolyser which is approximately equivalent to 0.1MW. This project demonstrated the capability of a relatively small electrolyser to provide high blends of hydrogen into a distribution grid.

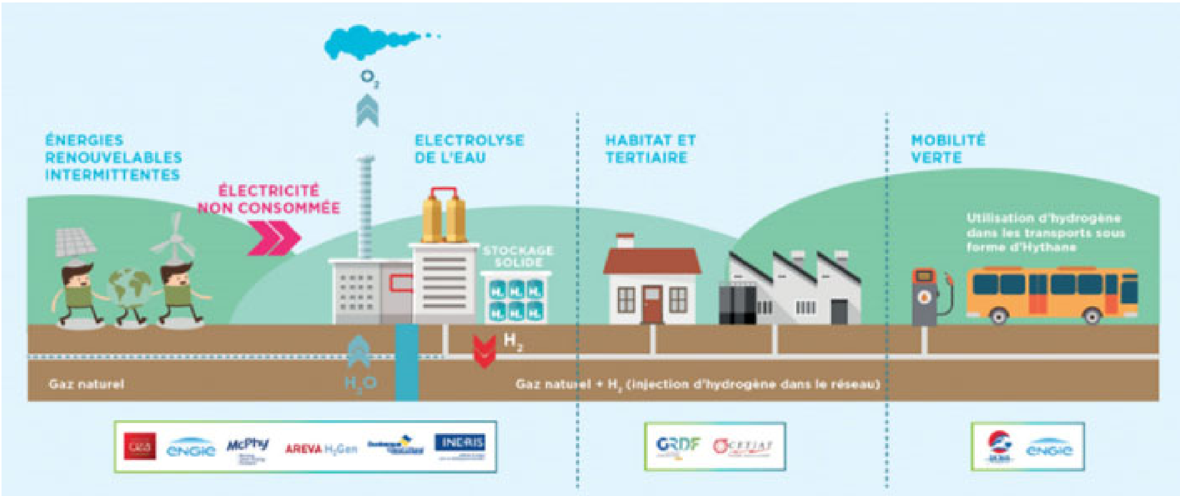


Figure 4-11: GRHYD project (28)

4.2 Electricity Grid Balancing

Electricity grid balancing is the process of preventing any minor or major blackouts or damage to the grid due to a sudden shortage in electricity or an oversupply. With an increase in renewable energy supplying electricity to the grid, shortages and excesses can become more common and more extreme due to the variability of renewable energy. Currently fossil fuel power plants are ramped up to meet the peak demands in times of electricity shortage. This causes a surge in fossil fuel consumption and consequently an increase in CO_2 and NO_x emissions. There are a number of power stations on the electricity grid that are only used in times of peak demand when other sources of power are not sufficient or available. These are often referred to as 'peaking plants' for this reason. They are typically fuelled with natural gas or liquid fuel (diesel / 'distillate').

It has been estimated that '*approximately 20% of the expected reduction in carbon dioxide, and approximately 100% of the expected reduction of oxides of nitrogen, from using wind and solar power could be lost' 'due to the necessary ramping up of power plants to account for renewable energy variability*' (29). Other 'cleaner' methods of grid balancing exist and are gradually becoming more popular. Hydrogen or battery storage are two possible, 'cleaner', methods of grid balancing.

Excess renewable energy could be diverted into a hydrogen electrolyser, with the hydrogen produced stored in tanks or pipelines. This excess renewable electricity would be consumed locally, without entering the electricity grid i.e. would be used 'behind the meter'. When needed, the hydrogen could be fed into a fuel cell or combusted and the stored hydrogen (energy) can be converted back to electricity. This electricity would be sold onto the grid in the same way as for when the wind turbines are generating. New small-scale hydrogen fuelled generation capacity would be required on or adjacent to the local wind farm in order for these benefits to be realised at the level of the local wind farm. Stored hydrogen could also be used at peaking power plants for grid balancing. However, in this scenario, the grid balancing advantages would be relevant at a national grid level. In both cases, there will be CO_2 advantages by using hydrogen for grid balancing.

A 104MW distillate fuelled peaking power plant is located adjacent to Rhode Green Energy Park and operated by SSE Thermal. This is one possible outlet for renewable hydrogen produced by an electrolyser at Rhode. Hydrogen storage and blending equipment would be needed at the facility. The technical compatibility of the prime movers with hydrogen would also need to be assessed. However, subject to the long-term plans of the operator for this installation, the peaking plant at Rhode could be very compatible with a demonstrator scale electrolyser at Rhode. Its main advantages include its proximity to Rhode Green Energy Park and its relative scale to that of a demonstrator facility. There is likely to be scope for such a facility having the capacity to consume a large amount of the hydrogen produced by a demonstrator-scale electrolyser. A challenge would be matching peaking demand with hydrogen production.

4.3 Hydrogen Blending at Gas Fired Power Stations

Natural gas fired power stations are potential end users for hydrogen. Unlike peaking power plants described above, their demand for energy is relatively constant. Hydrogen can be blended with natural gas at these locations to achieve CO_2 emissions reductions. As for peaking plants, the ability of a power station to use a blend of natural gas and hydrogen needs to be investigated on a plant by plant basis. However, there is good reason to be confident that newer and future gas fired power generators are or will be 'hydrogen blend ready'.

Two companies, Mitsubishi and GE have power plants that are trialling a hydrogen retrofit option (30). Two of their power plants, in Australia and the Netherlands, are outlined in the case studies below.

4.3.1 General Electric (GE), Australia & USA

GE are introducing their 9F.05 open cycle hydrogen-and-gas capable turbine to Australia in the 316MW Tallawara B power station. They hope to have it operating in their summer of 2023-2024. The turbine has up to 65% hydrogen capability (31).

GE have also got similar projects in the USA where they have started the construction on a 485MW combined cycle powerplant. They plan to start the power generation by burning 15-20% of hydrogen by volume with the end goal of transitioning to 100% hydrogen (32).

4.3.2 Mitsubishi, Netherlands

Mitsibishi offer a Combined Cycle Gas Turbine (CCGT) with hydrogen gas adaptability achieving up to an initial 30% hydrogen mix by retrofit and eventually transitioning to 100% (33). In the Netherlands, the Vattenfall power plant has installed three Mitsubishi M701F natural-gas-fired turbine units, each of which can generate up to 440 megawatts of electricity — enough to power more than 60,000 homes (34). These co-fuelled power generation systems provide a clear and simple use of hydrogen to decarbonise the energy grid.

Figure 4-12: Mitsubishi Hitachi Power Systems at Vattenfall's Magnum power plant in the Netherlands (33)

4.3.3 Derrygreenagh Power Station, Co. Offaly

A new gas fired power station is under development by Bord na Móna / Powergen at Derrygreenagh, Co. Offaly. The location of the plant is approximately 4.5km from Rhode Green Energy Park. It will comprise a 170MW Open Cycle Gas Turbine (OCGT) peaking plant and a 430MW Combined Cycle Gas Turbine (CCGT).

This plant appears to be a possible outlet for renewable hydrogen produced by an electrolyser at Rhode Green Energy Park. Hydrogen blending equipment would be needed at the facility. A pipeline or virtual pipeline would also need to be in place to bring hydrogen to the plant. The required amount of hydrogen storage will be lower than for a peaking plant of the same scale. This is because, Derrygreenagh will be generating more often.

The technical compatibility of the turbines with natural gas / hydrogen blends would also need to be assessed. This plant could be very compatible with a demonstrator scale electrolyser at Rhode. Its main advantages include its proximity to Rhode Green Energy Park and its relative scale to that of a demonstrator facility. Subject to establishing the technical feasibility of using a hydrogen blend in this facility, it is likely that it could comfortably consume all of the hydrogen produced by a demonstrator-scale electrolyser.

An interesting aspect of the Derrygreenagh Power Station is that it will be supplied with natural gas from the gas transmission network, located approximately 13km to the north of Rhode. The flow of gas in this new pipeline will be in one direction only, to Derrygreenagh. However, if blending natural gas and hydrogen is not feasible for Derrygreenagh, there may be potential for laying a new hydrogen pipeline in parallel with the new pipeline to Derrygreenagh. This could result in significant cost savings for the CAPEX of an electrolyser and pipeline system which was focussed on injection of hydrogen into the gas network.

4.4 Transportation Fuel Displacement

In 2021, transport accounted for 34% of total carbon emissions in Ireland by energy consumption (35). Transport is by far the largest source of CO_2 emissions with private cars, heavy goods vehicles and international aviation being the main contributors. The breakdown is shown in Figure 4-13 below.

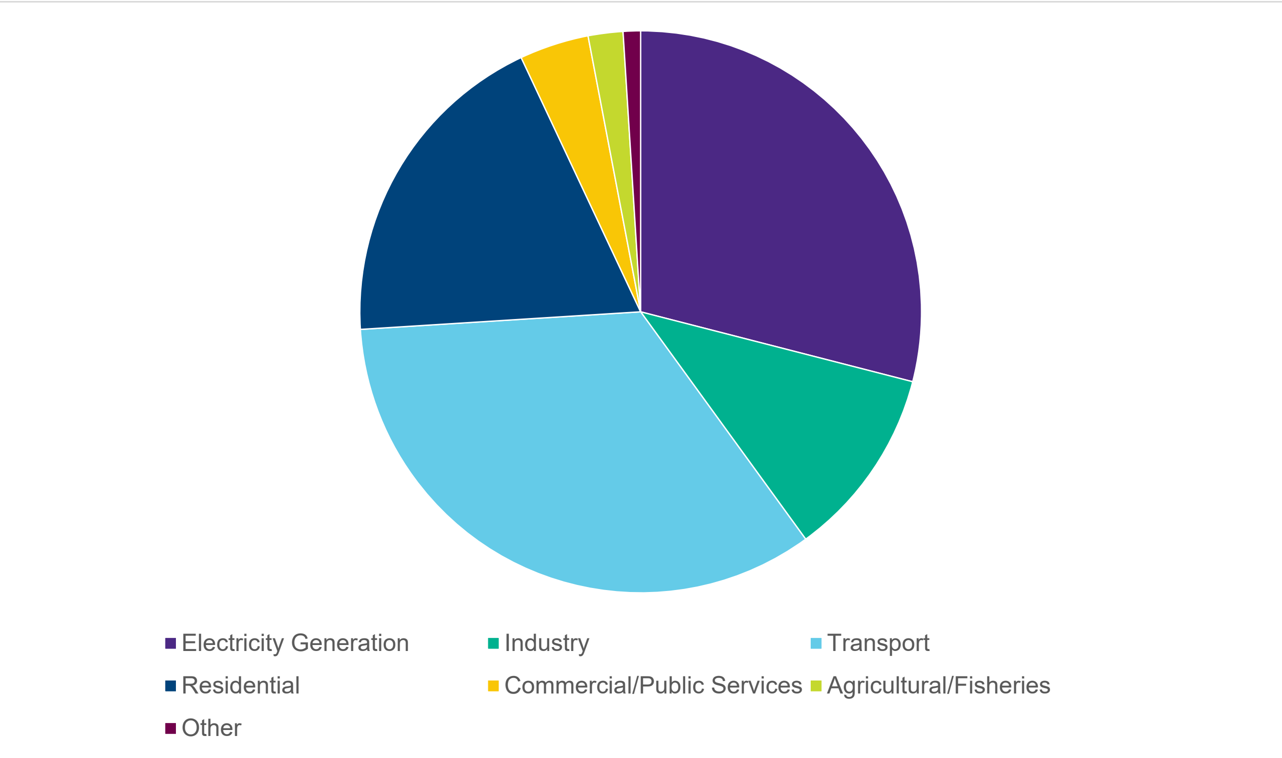


Figure 4-13: Breakdown of Ireland's CO_2 emissions by Sector (2021) (35)

Hydrogen is becoming a key focus area of some vehicle manufacturers and many large transport companies. This is because it can displace fossil fuels, thereby reducing the carbon footprint of transportation. Hydrogen can be used as a transportation fuel, either as a fuel on its own (with fuel cells) or blended with conventional fuels.

Ireland's National Policy Framework – Alternative Fuels Infrastructure for Transport in Ireland 2017 - 2030 was published in 2017. While this document recognises the potential of hydrogen as a transportation fuel, hydrogen is viewed as a longer-term prospect, and likely to be 'prohibitively expensive' until after 2030. Ireland has no immediate plans to develop public hydrogen refuelling infrastructure, but the feasibility of such a network will be reviewed regularly given the pace of development in the area. If hydrogen fuelling stations are developed in Ireland, it is likely that they would be located along the Trans European Transportation Network (TEN-T) in accordance with European Directive 2014/94/EU and its replacement. The M4 and M6 motorway routes in the vicinity of Rhode are not currently part of the TEN-T network. However, they both carry high volumes of traffic and have significant potential to become part of the network in the future.

Currently there are no commercial fuelling stations in the Republic of Ireland that would cater for vehicles using hydrogen as a fuel. A demonstrator electrolyser could be combined with a local fuelling station on the same site. Alternatively, tube trailers could be used to deliver hydrogen to a future commercial fuelling station that is located on the TEN-T network, or closer to where relevant transportation fleets operate or even at fleet depots. The feasibility of these options is explored below based on details described in Section 3.4 of this report.

4.4.1 Vehicle Technologies

Like the electric vehicle, fuel cell technology is not new. However, there have been major advancements in this technology in recent years. Fuel cells have been used in a variety of mobile machinery, in particular cars and Heavy Goods Vehicles (HGVs). The only emission from a fuel cell using hydrogen is water. This also makes hydrogen and fuel cells particularly attractive for some mobile plant applications e.g. indoor materials handling (forklifts) due to the absence of harmful emissions. At present, it appears that there is no commercial option for converting a conventionally fuelled vehicle to fuel cells. This could potentially be an option in the future, particularly for some HGVs, municipal vehicles and buses.

Table 4-5 below shows the technology readiness level for each transport type to use hydrogen and how ready it will be by 2024 and 2030.

Table 4-5: Assessment of vehicle readiness level for hydrogen in Ireland

Vehicle Type	Previously Demonstrated	Current TRL[1]	Infrastructure in Place	2024 Ready[2]	2030 Ready
Ship	US	4	No	No	No
Aircraft	ZeroAvia (UK)	5	No	No	Maybe
Train	Germany/China	7	No	No	Yes
HGV	UK	8	No	Maybe	Yes
Bus	IRL-Trial	8	No	Maybe	Yes
Car	UK	9	No	Maybe	Yes
Forklift	US/UK/Belgium	9	No	Yes	Yes

Notes:

1. *Technology Readiness Levels:*
   a. *4 – Validated in laboratory*
   b. *5 - validated in relevant environment (industrially relevant environment in the case of key enabling technologies)*
   c. *7 - system prototype demonstration in operational environment*
   d. *8 - system complete and qualified*
   e. *9 - actual system proven in operational environment (competitive manufacturing in the case of key enabling technologies)*
2. *Ready in the context of this table implies commercial scale deployment*
3. *Data sourced from 'A Hydrogen Mobility Strategy for Ireland' Hydrogen Mobility Ireland, 2019*

From various sources the cost of buying a hydrogen powered fuel cell HGV is in the range of €140,000 to €600,000 but is likely to be at the higher end of this bracket until they can be produced at scale (36) (37). According to Plug Power, an outfitted fuel cell forklift can cost up to $58,000 (approximately €55,000) which is about twice as much as one with a standard lead-acid battery (38).

Modern conventional internal combustion engine vehicles can also be converted to run on blends of diesel and hydrogen or petrol and hydrogen. This involves adding a separate high pressure hydrogen storage unit (fuel tank) and equipment to effectively manage the addition of hydrogen to the vehicle's fuel system. If used in this way, hydrogen is a supplemental fuel that can extend a vehicle's range and reduce its overall CO_2 emissions. One manufacturer that has been developing such systems for both Light and Heavy Goods Vehicles (LGVs and HGVs) is ULEMCo in the UK.

Discussions with a ULEMCo representative suggests a diesel engine conversion cost ranging from £35k-£50k (approximately €35k - €59k). With van conversions starting at the lower end of the range and truck conversions at the higher end of the range. The average diesel fuel displacement is 25% - 35%, resulting in carbon emissions reductions of 25% - 35%. ULEMCo continues to develop its dual fuel technology and higher diesel displacement rate of 70% is claimed to be achievable for a higher cost conversion.

Each of the above approaches to using hydrogen in transportation has its advantages. Fuel cell vehicles offer zero emissions at point of use, but are relatively expensive when compared to conventional vehicles, even when these are converted for hydrogen blends. A fuel cell vehicle will also be dependent on the availability of hydrogen to operate and will therefore be limited in its range to locations where there are hydrogen fulling stations.

A significant advantage of the conversion of conventional vehicles to hydrogen blends approach is the reduced cost. The total reduction in CO_2 emissions will be lower than for fuel cell vehicles, but a converted vehicle will still be able to operate on conventional fuels. This has advantages in terms of flexibility and vehicle range as conventional fuels are widely available.

Typically, HGVs will operate for many hundreds of thousands of kilometres. They often also operate for periods that are on average significantly longer than the average operational life of private cars. There is also often significant investment in specialised vehicle bodies and ancillary equipment. The relative cost of fuel cell vehicles and conversion of existing vehicles needs to be evaluated by individual operators having regard to their specific requirements.

4.4.2 Hydrogen Fuel Consumption

Diesel has an energy density of approx. 45.5 MJ/kg. Hydrogen has an energy density of 120 MJ/kg. As a fuel, hydrogen is over 2.5 times more energy dense than diesel - when compared on the basis of relative mass. However, hydrogen has a low molecular mass and at atmospheric pressure exists as a low density gas (approximately 0.083g/litre). Therefore, 1kg of hydrogen at atmospheric pressure (i.e. gaseous hydrogen) has a volume of approximately 12m^3. In comparison, diesel fuel has a density of approximately 0.85kg/litre – this is over 10,000 times denser than hydrogen gas. 1kg of diesel fuel, which is a liquid at atmospheric pressure, has a volume of approximately 1.17 litres (0.00117m^3). On a volumetric basis, the energy densities of hydrogen and diesel (at atmospheric pressure) are approximately 10MJ/m^3 and 39,000MJ/m^3 respectively, a ratio of approximately 1:3,900. For this reason, hydrogen must be compressed to high pressures (up to 350bar) to make it feasible to use as a transportation fuel.

Diesel is a liquid fuel and is normally bought / sold by volume (€ / litre). Hydrogen gas in comparison would be bought / sold by mass (€/kg) or potentially by energy content (€/MJ). The above comparisons are technically informative, but neither gives a practical sense of potential impact of using hydrogen or hydrogen blends in transport. A far more intuitive metric is the amount of diesel fuel (litres) that could be displaced by hydrogen (kg) if used as a replacement for diesel (either in blends or as a hydrogen only fuel). This relationship will of course depend on the type of vehicle used for the comparison. Relevant vehicle types therefore need to be selected.

There is a large variety of vehicle sizes and configurations in the Heavy Goods Vehicle (HGV) market. However, many waste collection vehicles, road gritting vehicles, larger delivery vehicles and buses / coaches have weights of approximately 10 – 12 tonnes. Therefore, for the purposes of this assessment, it is considered that a 12 tonne HGV is an appropriate size of vehicle. Another useful vehicle for consideration is a typical Light Goods Vehicle (LGV) which will have gross vehicle weights of no more than 3.5 tonnes. This type of vehicle is widely used in fleets. Both of the above classes of commercial vehicles can be supplied as fuel cell powered or as hydrogen / diesel – hydrogen blend powered vehicles. They are a good basis for relevant metrics to assess the potential impact of hydrogen / hydrogen blends on transportation.

A 12-tonne truck travelling 20,000km per annum with a rate of fuel consumption of 21.4 litres/100km (39) will consume approximately 4,280 litres of diesel fuel. The approximate equivalent mass of hydrogen required to deliver the same amount of energy is approximately 1,379kg. On the basis of this comparison, one can assume that for a 12 tonne HGV, every 1kg of hydrogen will displace approximately 3.1 litres of diesel. In a similar way, a typical LGV travelling 20,000km per annum with a rate of fuel consumption of 14.9l/100km (40) will consume approximately 2,980 litres of diesel fuel. The approximate equivalent mass of hydrogen required to deliver the same amount of energy is approximately 961kg. The above figures do not factor in the relative efficiencies of fuel cells and combustion engines, but the metrics above are considered sufficiently accurate for the needs of this feasibility study.

The specific output of a hydrogen electrolyser can be related to potential transportation outlets, such as local fleets composed of 12 tonne HGVs and < 3.5tonne LGVs. Figure 4-14 and Figure 4-15 below show how the potential annual hydrogen consumption of each vehicle type could vary depending on the proportion of hydrogen used. This gives an indication of how consumption would vary from using hydrogen as a fuel extender in diesel – hydrogen blends up to 100% hydrogen which includes the fuel cell option.

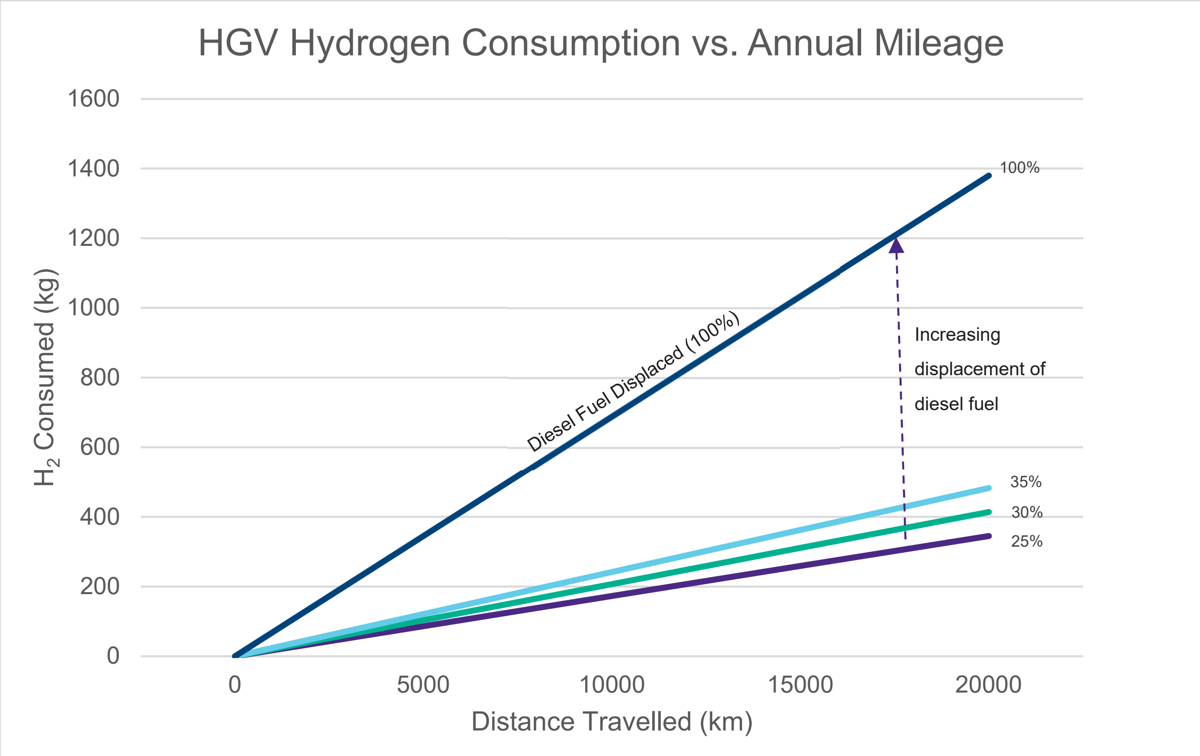


Figure 4-14: Potential Annual Hydrogen Consumption for a 12 tonne HGV

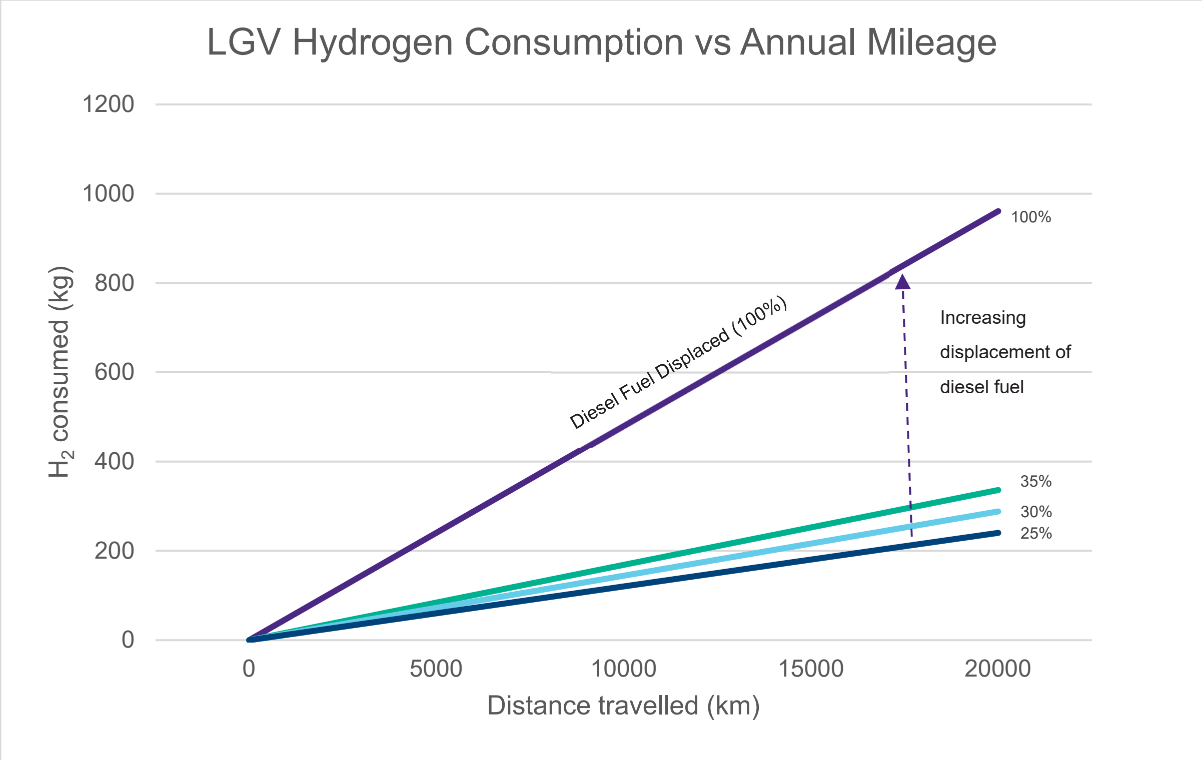


Figure 4-15: Potential Annual Hydrogen Consumption for a LGV (< 3.5 tonnes)

On the basis of the metrics described above, the price relativity of hydrogen (per kg) with respect to the price of diesel (per litre) is indicated below. With an average price of diesel fuel in Ireland in the period October, 2022 – January, 2023 of €1.87 per litre (equivalent in energy terms to 17.4 c/kWh), the price at which for hydrogen fuel becomes competitive with diesel fuel is approximately €5.80/kg (17.4c/kWh). It is important to note that the above relationship in terms of cost only considers the delivered cost of the fuel on an energy equivalent basis. Other costs are not included.

The estimated costs of fuel cell vehicles or dual fuel conversions is shown on Table 4-6 below. This table provides an indication of the relative CAPEX to fuel cost savings which apply to fuel cell and dual fuel options.

Table 4-6: Estimated Costs of Hydrogen Prepared Vehicles

	Fuel Cell		Dual Fuel	
(Figures per vehicle)	**HGV**	**LCV**	**HGV**	**LCV**
Estimated CAPEX (€)	500,000[1]	200,000[1]	59,000[2]	35,000[2]
Estimated Diesel Diversion (per annum)[3]	10,700	2,980	7,490	5,215
Estimated CO_2 emissions reduction (tonnes per annum)[4]	30	21	21	15
Value of Diverted Diesel (@ €1.87/litre)	20,000	14,000	14,000	9,750
Ratio of CAPEX to Value of Diesel Diverted	25	14.4	4.2	3.6

Notes:

1. *Estimated based on available literature in public domain*
2. *Figures sourced directly from ULEMCo in 2023*
3. *Based on assumed vehicle annual distance travelled of 50,000km*
4. *Assuming 2,835g CO_2 / litre diesel consumed and renewable hydrogen with emission rate of 0g CO_2 / litre*
5. *CAPEX values do not include VAT*

4.4.3 Hydrogen Fuelling Infrastructure

There are currently no hydrogen refuelling stations and no commercially available hydrogen powered vehicles in the Republic of Ireland. (The hydrogen fuel cell bus that was recently trialled in Dublin was refuelled by BOC gases in their Bluebell facility on the Naas Road). However, the EU alternative fuels infrastructure directive will require hydrogen filling stations every 100km on the TEN-T network (41). Clearly, the supply chain for hydrogen fuel and a market for hydrogen powered vehicles need to be developed together over time – each requires the other to grow.

Figure 4-16: Hydrogen Fuel Cell Bus refuelling in Kittybrewster, Aberdeen

Source: [Fuel Cell Electric Buses | Knowledge base (fuelcellbuses.eu)]

The cost of building a commercial hydrogen refuelling station with a 400kg capacity is approximately €2 million (36). Hydrogen Mobility Ireland (HMI) has proposed a strategy for hydrogen in transport in Ireland which would involve installing 80 hydrogen filling stations in Ireland by 2030 (36).

The first of these fuelling stations is planned for launch in 2023 when hydrogen powered vehicles are also due to go on sale for the first time. HMI claims that if all these installations are built, it would ensure that 50 per cent of the population would live in a town with a hydrogen refuelling station as well as providing coverage of major roads. Hydrogen would be sourced from electrolysers powered by renewable energy and also industrial production.

A hydrogen refuelling station project, is also currently under development in Galway. This is the Galway Hydrogen Hub (GH2) project which aims to build a hydrogen refuelling station in Galway by 2026.

As most petrol and diesel refuelling stations can cater for trucks, buses and cars, the addition or change to H_2 within these facilities should result in minimal impact as most of the ancillary infrastructure is already in place. A similar approach has been successfully used for Compressed Natural Gas (CNG) vehicles under the Causeway and Green Connect projects by Gas Networks Ireland.

4.4.4 Carbon Emissions

Diesel fuel has a carbon intensity of 263.9 gCO_2 / kWh (42).This equates to approximately 2.83kg CO_2/litre of diesel consumed.

It has been stated above that 1kg of hydrogen has the same energy content as 3.1litres of diesel. Therefore, in transportation applications, every kg of renewable hydrogen used will result in CO_2 emissions reductions of 0.91kg.

For a typical dual fuel operation, CO_2 emissions reductions of 25%-35% have been estimated by ULEMCo. Assuming that renewable hydrogen (0 gCO_2/kg) is used only, this corresponds to the same reduction in diesel fuel consumption and a displacement of 25% - 35% of diesel fuel with hydrogen.

Hydrogen fuel cell vehicles running on renewable hydrogen do not emit any CO_2. Therefore, where they replace diesel fuelled vehicles, there will be a 100% reduction in CO_2 emissions.

4.4.5 Example Projects: Hydrogen Fuelling

A selection of projects in Ireland and UK are outlined briefly below. There are other similar projects across the UK, Europe and further afield. However, the example projects below demonstrate that the technology of using hydrogen in transportation exists and is continually developing.

4.4.5.1 Aberdeen

There is a lot of activity in the area of hydrogen fuelled transportation in Aberdeen, led by Aberdeen City Council under an initiative named ‘H2 Aberdeen’ and which is outlined in the Aberdeen City Region Hydrogen Strategy & Action Plan 2015 – 2025 (43).

A fleet of hydrogen powered vehicles (including buses, cars, vans, road sweepers and waste collection vehicles) has been assembled and two publicly accessible hydrogen refuelling stations have been developed.

Figure 4-17: Aberdeen Hydrogen Vehicles Fleet (42)

Source: Hydrogen Case Study: Aberdeen

The hydrogen refuelling locations in Aberdeen both dispense renewable hydrogen produced on-site using alkaline electrolysers supplied by HySTAT. The sites also incorporate hydrogen storage. Details of each facility are outlined below.

- **Kittybrewster**: Built, operated and maintained by BOC. Opened in 2015 to support the Aberdeen Hydrogen Bus Project (10 hydrogen fuel cell buses). The site is located adjacent to the Aberdeen City Council Operations and Protective Services premises but is publicly accessible. Dispensing capacity: 360kg H_2/Day. Hydrogen storage capacity: 420kg. This facility was expanded in 2018 to facilitate fuelling cars and vans at 700bar. Funded by HyTransit, Scottish Government and Aberdeen City Council. (See Figure 4-17 above).

Figure 4-18: Kittybrewster Hydrogen Fuelling Centre, Aberdeen

(Image: Google Maps)

- **Aberdeen City Hydrogen Energy Storage (ACHES)**: Built by Hydrogenics and opened in 2017. Operated by Norco. Production capacity: 360kg H_2/Day. Hydrogen storage capacity: 150kg. Can dispense hydrogen at 350bar and 700bar and can facilitate fuelling buses, HGVs, LGVs and cars. Funded by Aberdeen City Council. The ACHES facility is located approximately 6km to the south of the Kittybrewster site and is located in a mixed residential / commercial area. It is also accessible to the public.

Figure 4-19: Aberdeen City Hydrogen Energy Storage (ACHES)

(Image: Google Maps)

Aberdeen is actively exploring various options for utilising hydrogen in transport including fuel cells and diesel / hydrogen ‘dual fuel’ operation. The city is where the world’s first fleet of fuel cell double decker buses manufactured by Wright Bus was first deployed. This development began with a £19 million demonstration project which saw 10 hydrogen powered vehicles introduced into the existing Stagecoach and First bus fleets in Aberdeen, and has been operational since March 2015. Aberdeen has also been an active participant in the HyTIME project which was a trial of dual fuel vehicles (see further below).

Aberdeen City Council are currently participating in the HECTOR project (Hydrogen Waste Collection Vehicles in North West Europe). The aim of the HECTOR Project is to demonstrate that fuel cell refuse trucks provide an effective solution to reducing emissions from road transport. The project will see the deployment and testing of fuel cell refuse trucks in normal operating conditions. The trucks will use existing hydrogen refuelling infrastructure and when possible, the pilot sites will use renewable hydrogen to fuel the trucks, thus maximising the emission reductions.

4.4.5.2 Glasgow

In 2021, Glasgow City Council ordered a fleet of 20 hydrogen-fuelled Waste Collection Vehicles (WCVs) from Ballard Motive Solutions, UK. The cost of the fleet of vehicles was £7 million.

Figure 4-20: Hydrogen Fuel Cell powered Waste Collection Vehicle in Glasgow

Additionally, Glasgow City Council has commissioned 20 gritter vehicles for diesel / hydrogen 'dual fuel' operation. Around half of the fleet of 20 vehicles will be converted to hydrogen dual fuel, while the rest will be hydrogen enabled from new. Dual fuel conversions will be made by ULEMCo.

Figure 4-21: Retro-fitted HGVs (Road Gritters) in Scotland carried out by ULEMCo

The council has committed to the use of renewable hydrogen and the development of a supporting infrastructure utilising renewable sources.

Renewable hydrogen will be produced in Glasgow at a new PEM electrolyser and storage facility to be developed by ITM Power and BOC in conjunction with Scottish Power's hydrogen division. The facility will be located adjacent to Scottish Power's Whitelee windfarm. It will be capable of producing up to 10 tonnes of renewable hydrogen per day. The maximum electrical demand is stated as 23MW. An electrolyser of this scale will be capable of fuelling well over 200 buses on local routes. UK government funding of £9.4 million for the facility was announced in 2021. This was under the Business, Energy & Industrial Strategy (BEIS) Energy Innovation Portfolio.

4.4.5.3 Levenmouth Community Energy Project, Fife, Scotland

Fife Council is working towards the development of hydrogen as a transportation fuel. This includes the development of renewable hydrogen refuelling stations at their Bankhead Central Depot, Glenrothes and adjacent to the Hydrogen Office in Methil. The site at Methil also has renewable hydrogen generation and storage and will support the refuelling facilities at Glenrothes.

Renewable hydrogen is produced by a 250kW PEM electrolyser powered by an on-site wind turbine and solar PV panels. The wind turbine and solar panels also supply an electricity microgrid in the business park, and they are supported by a 100kW PEM fuel cell to cater for times when electricity demand exceeds renewable generation. Hydrogen dispensing to hydrogen fuelled vehicle will be at 350bar at both sites.

Fife Fleet Operations introduced dual fuelled diesel and hydrogen vehicles including 2No. Waste Collection Vehicles (WCVs) in Levenmouth in 2016 (see Figure 4-22 below). These were delivered by ULEMCo and at the time they were the first of their kind. 5No. Light Goods Vehicles (mid-size vans) were also put into service in Levenmouth. In addition to this, project partner Bright Renewable hydrogen lease a fleet of 10No. small vans powered by Symbio fuel cells. The Levenmouth Project ran for 5 years until 2020. It has since been replaced by the H100 Fife project to bring a renewable hydrogen district heating network to homes on the Fife coast.

Figure 4-22: Waste Collection Vehicle (WCV) in Fife converted to diesel / hydrogen 'dual fuel' operation

The Fife hydrogen project had three main partners which are Fife Council, Bright Renewable hydrogen and Toshiba. It was awarded £4.4 million in funding through the Scottish Government's Local Energy Challenge Fund.

(The Methil site is located next to the Fife Renewables Innovation Centre in the Methil Docks Business Park. This location was a major coal exportation port and therefore the project demonstrates the transition away from fossil fuels to clean renewable fuels. In this respect, the project has some similarities with the Rhode Green Energy concept).

4.4.5.4 Dublin

The first hydrogen bus trial was conducted in the ROI in 2020. The 60kW Toyota fuel cell powered Caetano bus was the first-ever hydrogen FCEV in operation in Ireland (44). Bus Éireann operated the vehicle on sections of a transport route between Dublin Airport and Ashbourne. Dublin Bus also operated it on the Dublin Airport campus and Dublin City University campus. Over a period of 8 weeks, the bus covered a total of approximately 3,000km with a hydrogen consumption rate of 5.6kg/100km (3). This is equivalent on an energy basis to around 17litres of diesel per 100km. A double decker fuel cell powered bus was also trialled by Dublin Bus for a short period.

In 2021, three double decker hydrogen fuel cell buses were put into service by the National Transport Authority (NTA) / Bus Éireann on a route from Fairyhouse, Co. Meath to UCD via Merrion Row in Dublin City Centre. They were manufactured in Northern Ireland by Wright Bus and are powered by a Ballard fuel cell. They have a range of approximately 400km and each bus cost approximately €800,000. Refuelling takes place at BOC's premises in Bluebell, Dublin where the company operates an electrolyser that generates hydrogen for industry.

Figure 4-23: Hydrogen Fuel Cell bus Trialled in Dublin (45)

Figure 4-24: Hydrogen Fuel Cell Double Deckers now in service between Dublin and Ratoath

Bus Éireann estimates that during the initial 6 months operation of these three buses, approximately 40 tonnes of CO_2 was saved. In full scale operation, it is estimated that each bus could account for a reduction in CO_2 emissions (compared to diesel fuel) of 60 - 75 tonnes per annum.

The project partners on this project included the Department of Transport, NTA/TFI, CIE, Bus Éireann, Dublin Bus, BOC Gases, Dublin Airport, Dublin City University, Hydrogen Mobility Ireland and Toyota / Caetano.

4.4.5.5 Belfast

Northern Ireland's main public transport provider, Translink, launched their first hydrogen powered fuel cell buses in Belfast and Derry in 2020/2021. A fleet of 20 buses were built by Wrightbus and are powered by a Ballard fuel cell. Each hydrogen bus (see Figure 4-25) cost approximately £500,000, twice the cost of a diesel equivalent. However, with an increase in sales, this cost could be significantly reduced (46). The project is said to have cost £10.6 million (47).

Figure 4-25: Hydrogen Fuel Cell Double Decker Bus in Belfast

Source: https://council.ie/first-hydrogen-powered-buses-enter-service-in-belfast/

4.4.5.6 Conversion to Diesel / Hydrogen 'Dual Fuel' Operation

There are a number of relevant case studies where HGVs in passenger service and municipal service have been converted to diesel / hydrogen 'dual fuel' operation. A significant trial in this respect was the HyTIME (Hydrogen Truck Implementation for Maximum Emissions reductions) project.

HyTIME (Hydrogen Truck Implementation for Maximum Emissions reductions) was a two-year trial (2017 – 2019) involving the conversion of 11 urban trucks and vans for dual-fuel operation. The trial was led by ULEMCo. Vehicle operators involved on the trial included London Fire Brigade, Aberdeen City Council Westminster City Council and Veolia among others. (The project was part of the Low Emission Freight and Logistics Trial (LEFT) to investigate the practical deployment of hydrogen-powered vehicles in the UK. The LEFT work was partly funded by the Office for Low Emission Vehicles (OLEV) in partnership with Innovate UK).

Figure 4-26: Waste Collection Vehicle in Aberdeen converted to diesel / hydrogen 'dual fuel' operation (HyTIME Project / H2 Aberdeen)

During the trial approximately 20%-45% of the diesel fuel consumption across these vehicles was replaced by renewable hydrogen. The conversions were carried by ULEMCo. A total of 60,000km was covered with 1,619kg hydrogen consumed. At least 96 per cent of the hydrogen used in the trial came from on-site electrolysis using renewable electricity.

The demonstrated benefits would have been even more dramatic had the hydrogen infrastructure been more developed. When the vehicles were not using hydrogen in their day-to-day operations, the principal reason was the lack of available refuelling facilities.

Project data show that the CO_2 saving could have been up to approximately 45 tonnes per annum across the 11 vehicles if there was greater availability of hydrogen.

Figure 4-27: Road Sweep in Aberdeen converted to diesel / hydrogen 'dual fuel' operation (HyTIME Project / H2 Aberdeen)

Separately, in 2017, Oxfordshire based Grundon Waste Management was the first private sector vehicle to be converted to hydrogen dual-fuel. It was the first such conversion of a DAF vehicle and was carried out by ULEMCo on a Waste Collection Vehicle.

Figure 4-28: Waste Collection Vehicle (WCV) in Oxfordshire converted to diesel / hydrogen 'dual fuel' operation

4.4.6 Summary of Transportation Options

The use of hydrogen in transportation technologies is rapidly progressing and improving. Its development has been most prevalent in heavy commercial vehicles (HCVs) such as trucks and buses. Being larger and more adaptable platforms for a range of different requirements, they are also more suitable for adapting to hydrogen fuels (fuel cell or dual fuel). HCVs typically cover many more miles per annum than cars which improves their investment case.

Fuel cell vehicles offer the advantage of zero CO_2 emissions at point of use, but are dependent on a reliable source of hydrogen. The cost of fuel cell powered vehicles is relatively high compared to conventional diesel powered vehicles. This means that there will be a high CAPEX investment involved.

Dual fuel technologies offer fuel flexibility which will be an advantage to operators when renewable hydrogen may not yet be readily available. While the carbon emissions reductions for dual fuel options are approximately 30% those for fuel cells, the CAPEX involved is much lower than for a fuel cell option also. Dual fuel vehicles therefore represent a practical option for transitioning from diesel power to hydrogen power in transportation.

There is very limited hydrogen refuelling infrastructure in Ireland at present and it is not expected that this will change until after 2030. If public hydrogen fuelling stations are developed in Ireland, it is likely that they would be located along the Trans European Transportation Network (TEN-T) in accordance with European Directive 2014/94/EU and its replacement. The M4 and M6 motorway routes in the vicinity of Rhode are not currently part of the TEN-T network. However, they both carry high volumes of traffic and have significant potential to become part of the network in the future.

The example projects described above demonstrate that transportation outlets could also be relevant to the Rhode hydrogen demonstrator project. A fleet of dual fuel converted vehicles could also become a useful and reliable outlet for surplus hydrogen produced by a demonstrator electrolyser at Rhode that cannot be injected into the gas network. If there is no commercial or other hydrogen refuelling infrastructure located nearby, this would be required adjacent to the electrolyser or at a local transportation depot. This option would represent further integration of energy systems within the Region. A local fleet of suitably branded hydrogen powered vehicles would also raise awareness within local communities of some of the possibilities that hydrogen offers in reaching our climate change objectives.

4.5 Other Potential Local Hydrogen End Use

Renewable hydrogen produced at Rhode could potentially be used as a primary or supplemental source of energy by a new tenant or developer within or adjacent to the green energy park. One possibility could be a data centre, for which the zero carbon nature of renewable hydrogen could be very attractive. There could be many other possibilities where the organisations or businesses involved, place a value on decarbonising their activities and recognise how renewable hydrogen can play a role in this.

A small-scale demonstrator electrolyser producing renewable hydrogen could make a relatively small but also very significant contribution to reducing a large energy consumer's energy carbon footprint. Once a small-scale modular demonstrator had proved the concept, it could be expanded in a modular way to realise larger-scale benefits.

An advantage of local end uses for renewable hydrogen would include minimising the requirements for transporting hydrogen either in pipelines or by road. This option could be one way of establishing a small, local hydrogen gas network.

A renewable hydrogen demonstrator could potentially provide a source of low carbon / zero carbon heat to the village of Rhode. Rhode Green Energy Park is located approximately 2km from Rhode which has a population of over 800 people. This could be achieved by developing a hydrogen distribution network serving Rhode. This approach has been used close to Manchester with the Hynet project. Another approach would be to develop a district heating system in Rhode, heated by a hydrogen fuelled boiler. There would be reduced safety challenges for this option because risks would be managed at a single location by experienced personnel. This option would replace the hydrogen distribution network with a district heating network with flow and return temperatures of approximately 80ºC and 40ºC respectively.

For all of the above options, there would be challenges around balancing the supply of hydrogen or heat with demand. Energy storage would be needed which could take the form of hydrogen storage, battery storage or hot water storage. When considering a hydrogen network or district heating network for space heating, there would also be many challenges around rate of connection of new end users and load diversity. However, there are regulatory challenges associated with developing a hydrogen gas network in Ireland, much of which are focussed on safety.

5 ENERGY PROFILES AT RHODE

An assessment on the potential for using curtailed / constrained renewable energy for the generation of hydrogen in the demonstrator-scale electrolyser is a key aspect in the objectives of the study. The possible outlet of the hydrogen to the gas network and the fluctuations in demand must also be considered. Profiles for available renewable power and for the rate of flow in the gas network needed to be developed to determine if and how such a system could work. The following sections describe the energy profiles used in modelling a Levelised Cost of Hydrogen (LCOH) for the study.

5.1 Wind

Hourly data for windfarm outputs near Rhode was used to assess the availability of wind. Outputs have been categorised as either Wind Farm Output or Dispatch Down. Wind Farm Output is the measured electrical power that was produced by the windfarm and accepted onto the grid. Dispatch Down refers to renewable electricity that is available but cannot be accepted onto the system. Dispatch down can be further categorised as curtailment when causes are system-wide, or constrained when the causes for this are in the localised network.

One year of data is shown in Figure 5-1. Dispatch Down typically occurs when there is a high amount of wind generation, and it is not all required by the grid. The wind farm capacity factor is the ratio of actual electricity output to the system's maximum possible output. The data shows that a wind farm in the area around Rhode will have an annual capacity factor of approximately 33%.

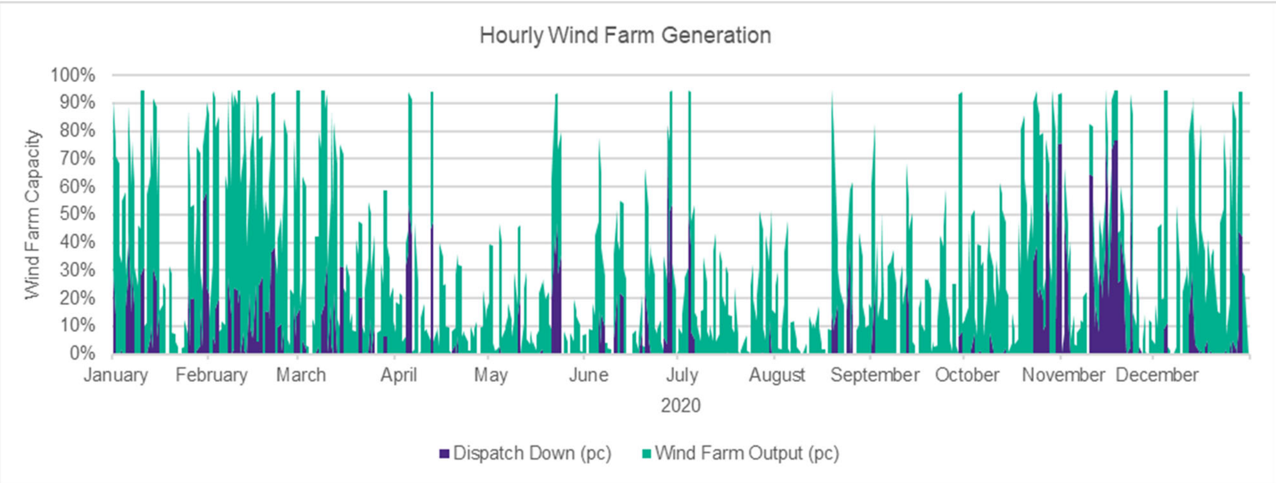


Figure 5-1: Hourly Wind Generation and Dispatch Down representative of wind farms in Rhode for the Year 2020

Using dispatch down generation to run an electrolyser allows the wind farm to increase operating hours and reduce the amount of energy not utilised i.e. wasted. Dispatch down electricity is assumed to be provided free of cost, offering a cheap and green source of electricity to the demonstrator electrolyser. In the absence of actual available data, this was considered to be a reasonable assumption as a 'base case' for the feasibility study. It is made having regard to the value of the knowledge to be gained from learning how to operate demonstrator electrolyser powered by this otherwise lost renewable power. Figure 5-2 shows the annual dispatch down availability and highlights the long periods without dispatch down availability, particularly in summer months.

If dispatch down is the sole energy source for hydrogen production, substantial storage will be essential to sustain a constant hydrogen supply during these times. The magnitude of dispatch down available varies significantly, reaching peaks of 85% of the wind farm capacity, and a mean production of 5% of the wind farm capacity. This presents issues with sizing an electrolyser solely dependent on this source of renewable electricity. A small electrolyser will have relatively high run hours but there will be significant dispatch down unused. A large electrolyser, sized to meet peaks, will be able to consume more energy, but the system will likely be expensive with a low electrolyser capacity factor. The wind data used has 37.2 GWh of dispatch down available annually, which is approximately 5% of the wind farm's capacity.

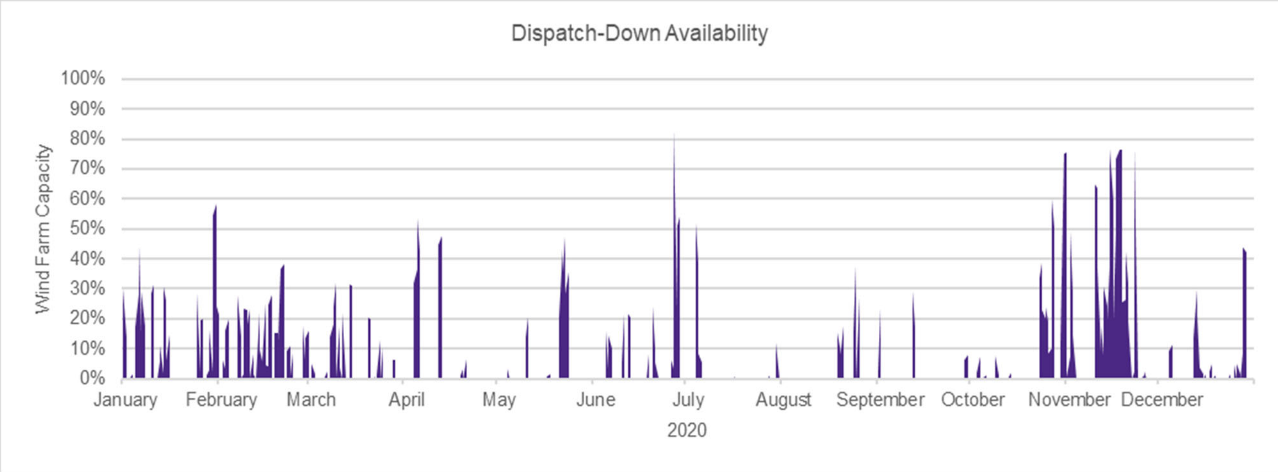


Figure 5-2: Dispatch Down Availability for 2020 based on data from wind farms in Rhode area

A Dedicated Wind Farm in this context is one that supplies all electricity generated to one source. Two dedicated wind compositions were modelled for this feasibility study: one prioritising hydrogen production, and one prioritising exports to the electricity grid.

Figure 5-3 shows how the electricity generation could be assigned to either the production of hydrogen (positive axis) or exported to the grid (negative axis) for a system prioritising hydrogen production using an assumed 84-MW wind farm and a 50MW electrolyser as an example. If any dispatch down generation is available, the electrolyser will use it. If the power generated by the wind farm is less than the electrolyser capacity (50MW), then the electrolyser will use all of this power, preventing it from exporting that power to the grid.

In dedicated wind scenarios, no grid electricity is used to run the electrolyser. However, this graph shows that if there is less than 50MW of electricity available from wind, grid electricity could be used to keep the electrolyser operating at peak output. If the wind farm generates more electricity than the electrolyser can use, the excess will be exported to the grid. In this configuration, because of the size of the electrolyser chosen, there are long periods of time when no electricity would be exported to the grid, particularly in the summer months. With smaller electrolyser sizes there is more electricity available to export to the grid.

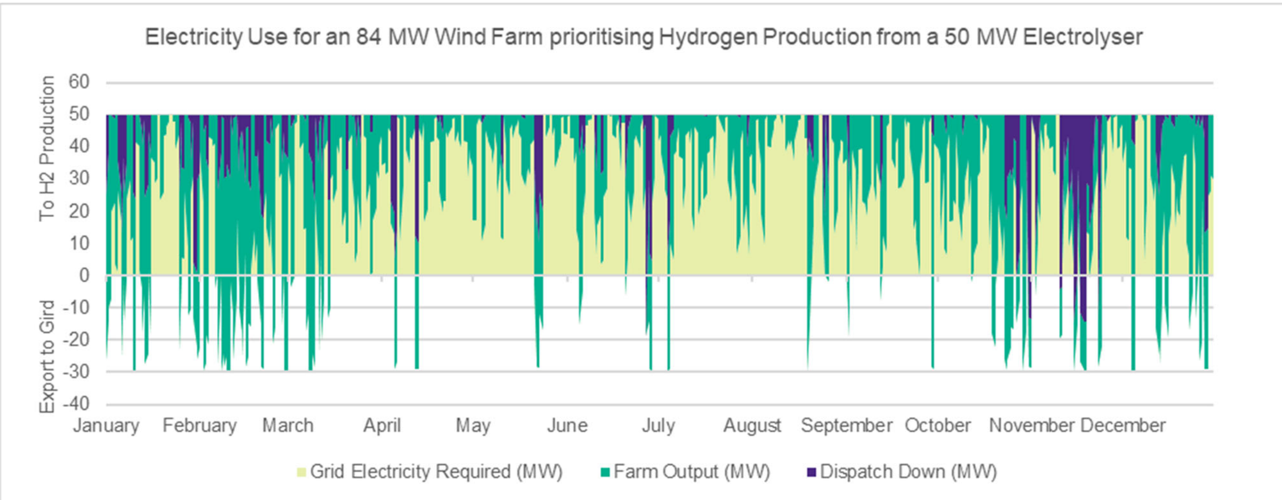


Figure 5-3: Electricity Exports for an assumed 84MW Wind Farm prioritising Hydrogen Production from a 50MW electrolyser

Figure 5-4 shows how a system prioritising grid electricity up to a limit of 21 MW could operate. Any generation of 21 MW or lower is exported to the grid. When electricity generation exceeds 21 MW, it can be diverted to the production of hydrogen. Dispatch down generation is always available for hydrogen production. Three versions of this model have been generated, with limits of 21 MW, 42 MW, and 59 MW, which represent 25%, 50%, and 70% of the wind farm's capacity, respectively. Setting a threshold over which any electricity can be diverted to an electrolyser allows more certainty to the amount of power that can be given to the production of hydrogen, based on average winds in the area. Windfarm operators may benefit from a hybrid model of both electricity generation for the grid and also producing hydrogen once capacity allows.

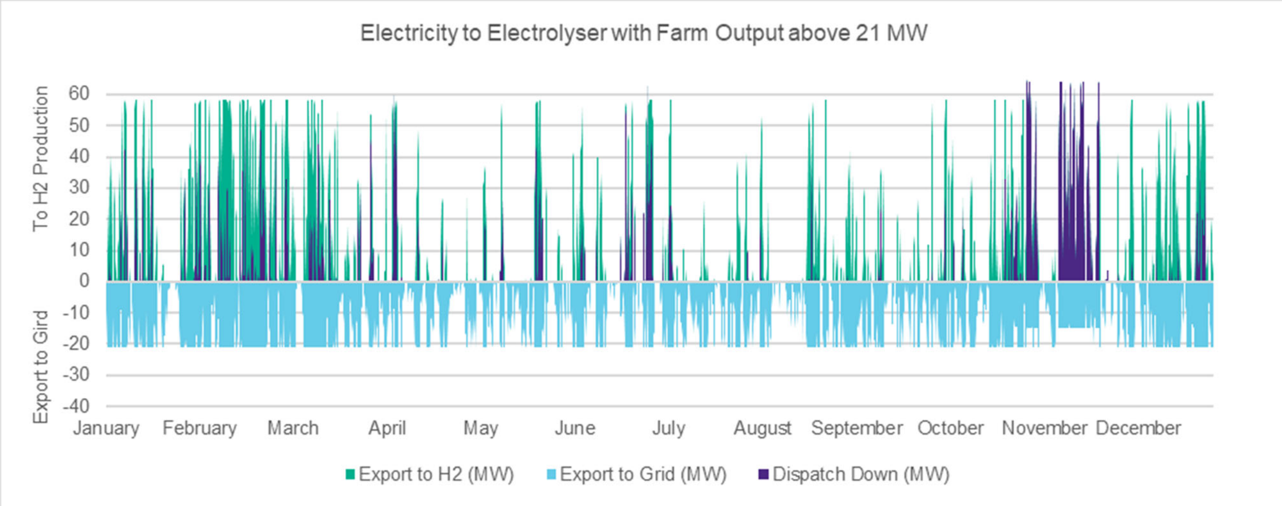


Figure 5-4: Electricity Exports for an assumed 84MW Wind Farm prioritising Electricity Exports up to 21MW

It is clear from above that the availability of power to run an electrolyser is highly variable. Less wind is available in the summer months and a capacity factor of 33% for a windfarm in Rhode means that large scale windfarms are required to maximise generation once the wind is available and they are dispatchable. This means that a large electrolyser will have a low capacity factor. In a similar way, a smaller electrolyser, unlike the 50MW unit, would have a higher capacity factor. This is because it will be able to produce hydrogen more consistently, with its lower power requirements being met on a more regular basis.

5.2 Solar

The development of Srah and Clonin solar farms near the Rhode Green Energy Park suggest that there is potential for solar to be a useful resource for projects in the area. The predictable cyclical nature of solar generation, with high amounts of generation in the middle of the day and hours of no production each night, requires storage so the energy generated can be fully utilised. Hydrogen generation from solar is one method to store the energy produced.

Simulated solar generation was attained for the area using the online resource Renewables Ninja (48) and is plotted in Figure 5-5. This data shows that a 1MW solar farm would have a capacity factor (ratio of actual output to maximum output of the solar farm) of 11.6%.

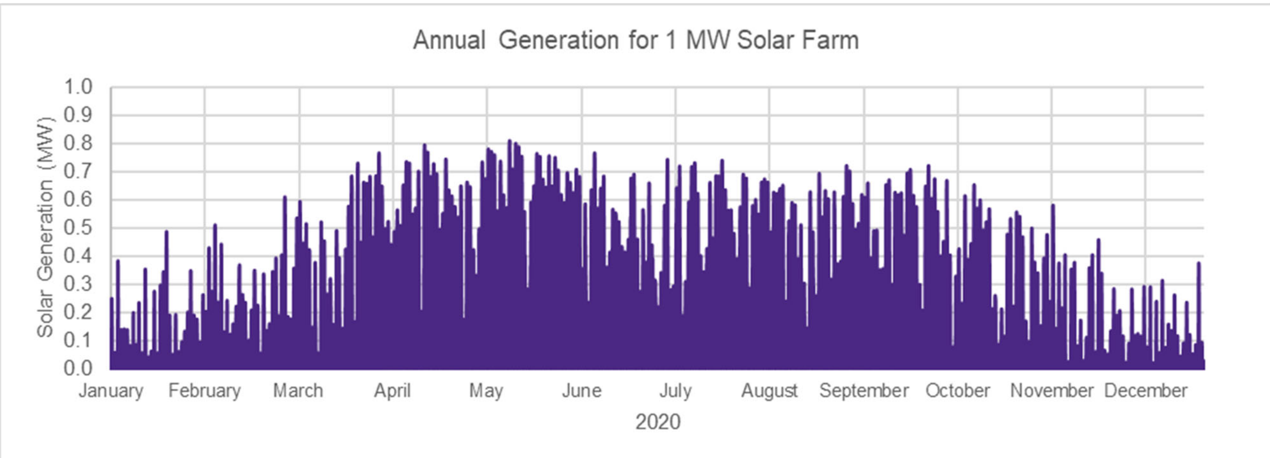


Figure 5-5: Annual Generation for a 1MW Solar Farm 2020 (47)

Figure 5-6 highlights the difference between summer and winter generation, with June and December representing the respective seasons. In December, the solar generation is approximately one eighth of that in

June, suggesting that high summer generation and high levels of storage will be needed to provide a consistent hydrogen output averaged over the annual production of hydrogen for the year. A consistent output of hydrogen is important in being able to ensure supply to the chosen application of the fuel. This is likely to increase costs as larger electrolysers and storage will be required.

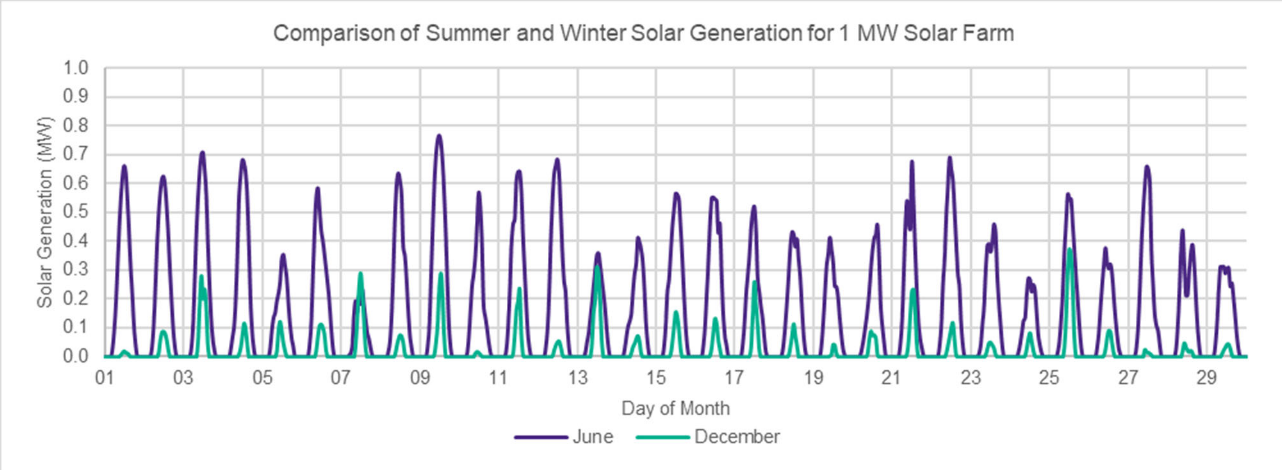


Figure 5-6: Comparison of Summer and Winter Solar Generation for a 1MW Solar Farm (2020) (47)

Wind power has been selected as the primary renewable energy source for techno-economic modelling in this study mainly due to its higher capacity factor (33% for wind versus 11% for solar). This means that the quantity of storage required for wind is lower than that required for solar. Therefore, the overall costs will be lower. However, solar power could potentially become a supplementary source of renewable power for an electrolyser in Rhode. It should therefore remain in consideration for any future possible demonstrator project.

5.3 Biomass

Biomass includes all organic materials such as plants, trees, and animal waste used to produce fuel. Depending on how it is processed, biomass can be used to produce renewable fuel in a solid, liquid or gaseous form.

Biomass derived renewable fuel can be used in turn to generate renewable electricity. This is more likely to be done using solid fuel biomass because there is less energy involved in producing it. Liquid biofuels take more energy to produce but are more easily transported. They are therefore more likely to be used in higher value end uses such as transportation or heating where the higher costs of production are justified by their mobility and high energy density. Anaerobic digestion of animal wastes and other biomass generates biogas. Biogas has characteristics that are similar to natural gas. It can be used to generate power directly or it can be injected into the gas grid. All of the above involve processing and transportation which requires energy. This is often technically and economically feasible, with the outputs contributing to decarbonising the gas network or the electricity network.

Using renewable electricity derived from biomass to produce hydrogen will not be as efficient overall as using wind or solar power to generate renewable hydrogen. Hydrogen produced in this way would in turn either be injected into the gas grid, used in transportation or used to generate electricity. Each of these end uses could be achieved directly with the biomass derived renewable fuel, thereby avoiding an additional processing step and the waste associated with that.

At Rhode, SDCL / New Leaf has submitted a planning application for the use of wet wood chips or energy crops to produce biofuels in a process that combines gasification, carbon capture and Solid Oxide Fuel assisted Electrolysis Cells (SOFECs) that produce hydrogen for reforming with carbon into a renewable natural gas (RNG) product. The proposal envisages injection of the RNG into the gas network. It also includes gas storage and Combined Heat and Power (CHP) installation to enable surplus RNG to be used for electricity production. This innovative combination of a variety of technologies could potentially become the basis for a local energy crop industry and is very compatible with the overall concept of Rhode Green Energy Park. However, as described above for other sources of biomass derived renewable fuels, using the outputs to generate electricity would not be as ‘green’ as wind power or solar power.

Other potential sustainable sources of solid biomass fuel of relevance to Rhode are forestry thinnings, Short Rotation Forestry (SRF) and clean waste timber e.g. certain types of pallets and saw mill waste. Edenderry

Power Station (located approximately 10km from Rhode) is the main consumer of such materials in Offaly (and the wider Midlands Region). Power generated by Edenderry Power Station is exported to the national electricity grid. The renewable power generated at Edenderry is therefore not locally available to the Rhode demonstrator project. It is a component of the overall energy mix in Ireland and makes its own significant contribution to reducing the carbon intensity of grid power.

On the basis of the above, biomass as a source of renewable power was not considered for the feasibility study for a hydrogen electrolyser in Rhode.

5.4 Grid Power

Depending on the Greenhouse Gas (GHG) intensity of grid power, and the amount of grid power used, hydrogen produced may be considered low-carbon and be afforded similar benefits to renewable hydrogen.

The GHG intensity of grid electricity is assumed to be 0.221 t_{CO2}/MWh in 2024 and 0.142 t_{CO2}/MWh in 2030. This has been calculated using the current grid electricity carbon intensity (49) and goals to increase renewable generation to 70% of Ireland's electricity by 2030 (50). However with the current average carbon intensity of the grid, grid electricity could only provide less than 1.5% of the electricity for the electrolyser before the hydrogen would not be considered renewable. This means that until the Irish grid is significantly decarbonised, it cannot be used to create hydrogen that can be classified as 'Renewable Hydrogen' according to EU rules published in 2023.

A consequence of the above limitation on using grid power is that a small demonstrator electrolyser at Rhode will be better able to use available dispatch wind down power while at the same time maximising its total operational hours i.e. its capacity factor. Using grid power to maintain capacity factor would mean the renewable hydrogen classification could be lost. Therefore, increasing capacity factor while maintaining the renewable hydrogen status will depend on the availability of renewable power from other sources. All of this is complicated by the fact that the primary source, and other sources, of renewable electricity may only be accessible via the grid. Changes to the Grid Code are required in order for the electrolyser to access sources of renewable electricity that are not co-located.

5.5 Gas Transmission Network

Gaybrook AGI, located approximately approximately 13km to the north of Rhode is the nearest node on the gas transmission network where hydrogen could be injected. The network here forms part of a national 'ring main'. Most of the gas flow passes through the AGI, serving customers downstream. Hydrogen injected to the transmission network will therefore find its way through the network and to any downstream customer.

Gaybrook AGI is on the 85bar transmission network, but it also supplies gas at 4bar to the distribution network serving the town of Mullingar (see below). Therefore, with modifications to accommodate the required injection equipment, this location could be used for injecting hydrogen into the transmission network or the distribution network.

The annual gas transmission flow at Gaybrook AGI in 2022 was approximately 801,146,000m^3 / 7,833,426 MWh.

Gas flow data was obtained from GNI for Gaybrook AGI and used by the project team to generate maximum, minimum, and average flows for winter and summer in 2024 and 2030 (see also Appendix A). This was then used, with the annual gas profile published by SEAI to assign a gas transmission flow at Gaybrook AGI for each month (see Figure 5-7 below). (A similar approach could be used to model the gas transmission flow at Gneevekeel AGI).

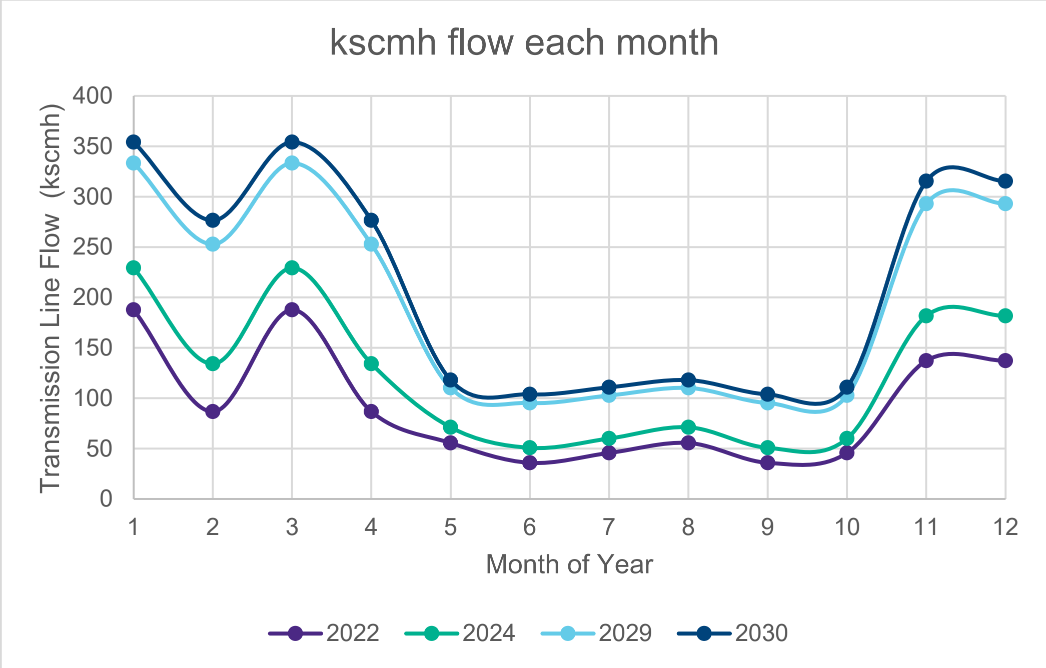


Figure 5-7: Estimated Gas Transmission Flow at Gaybrook AGI

The gas flow data summarised in Figure 5-7 was used with the wind electricity generation profiles above as a basis for modelling hydrogen injection to the gas transmission network. Demand and supply led scenarios at different rates of injection (2%, 5%, and 20%) were modelled.

The different profiles of wind energy production and gas demand within the gas network mean that sizing an electrolyser system and its associated hydrogen storage for meeting given rates of hydrogen injection is a difficult challenge. Detailed modelling of a range of scenarios has been carried out and is covered in the next chapter.

Table 5-1 below gives an indication of the rate of hydrogen injection that would be required to reach these percentages of the minimum and maximum gas transmission flows. It will be evident that the large flow of gas through Gaybrook AGI could potentially accommodate a proportionately large flow of hydrogen. The approximate size of electrolysers that would be required to meet flows of 2%, 5%, 10% and 20% are also indicated on Table 5-1. This is a simplification and only intended to give a sense of the relative scales of gas transmission flow and electrolysers required to meet specific blends of hydrogen.

Table 5-1: Rates of Hydrogen Injection for Minimum and Maximum Gas Transmission Flows at Gaybrook AGI

Percentage of Hydrogen in Natural Gas[1]	Minimum Flow Natural Gas[2] (m^3/day)	Required Flow Hydrogen (m^3/day)	Approximate Size of Electrolyser Required (MW)	Maximum Flow Natural Gas (m^3/day)	Required Flow Hydrogen (m^3/day)	Approximate Size of Electrolyser Required (MW)
2%	960,000	19,200	**2.2**	8,400,000	168,000	**29**
5%		48,000	**5.5**		420,000	**72**
10%		96,000	**16.5**		840,000	**144**
20%		192,000	**33**		1,680,000	**290**

Notes:

1. *Percentage of flow by volume (volumetric)*
2. *Min / Max gas transmission flows sourced from GNI. Maximum hourly flow based on Figure 5-7 above. 1 day = 24 hours*

For all scenarios modelled, it was assumed that the hydrogen produced at Rhode would be transported to Gaybrook AGI using tube trailers.

5.6 Gas Distribution Network

5.6.1 Mullingar

The current total annual gas demand in Mullingar is approximately 5,063,824m^3 per annum / 49,513 MWh. This gas is supplied to over 2,000 gas customers in the town via the 4bar distribution network. It amounts to approximately 0.63% of the gas transmission flow through Gaybrook AGI.

In the absence of a readily available profile for gas demand that is specific to Mullingar, for this study it was decided to model the gas demand profile for Mullingar as a percentage of the gas transmission flow profile (see Figure 5-8). Using this approach, the maximum / minimum flow rates to Mullingar are approximately 2,200m^3/hr and 250m^3/hr respectively.

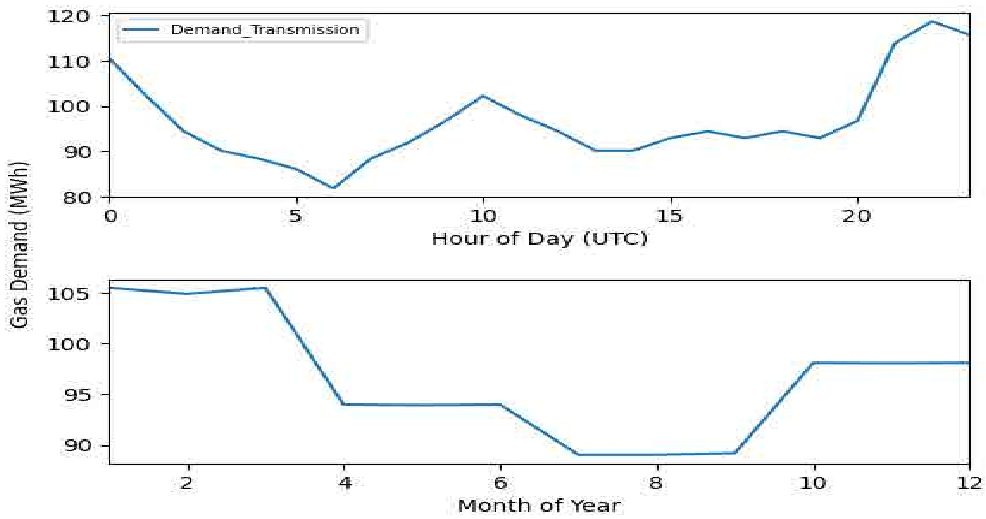


Figure 5-8: Hourly average (top) and monthly average (bottom) profiles for gas flow in the transmission network at Gaybrook

Similar to Table 5-1 above, the relative scale of gas distribution flow to Mullingar and electrolysers required to meet specific blends of hydrogen is summarised on Table 5-2 below. These figures should be considered to be theoretical and are intended for illustrative purposes only. In a 'real-world' scenario, with flow rates varying depending on the time of day, the electrolyser would be operated in conjunction with hydrogen storage. When demand for hydrogen is less than the capacity of the electrolyser, surplus hydrogen can be generated and stored. Stored hydrogen can then supplement the output of the electrolyser to enable peak demands to be met. This means that a given size of electrolyser can be capable of meeting a demand that is greater than its specific output. Storage will be capable of balancing short-term fluctuations in demand that can happen over the course of a day. However, the cost of storing hydrogen is significant in the context of a hydrogen production facility. Storage should not be seen as a means of managing seasonal variations due to the much larger demand in winter compared to summer.

Table 5-2: Rates of Hydrogen Injection for Minimum and Maximum Gas Flows to Mullingar

Percentage of Hydrogen in Natural Gas[1]	Minimum Flow Natural Gas[2] (m³/day)	Required Flow Hydrogen (m³/day)	Approximate Size of Electrolyser Required (MW)	Maximum Flow Natural Gas (m³/day)	Required Flow Hydrogen (m³/day)	Approximate Size of Electrolyser Required (MW)
2%	6,068	121	**0.02**	53,094	1,062	**0.2**
5%		303	**0.05**		2,655	**0.5**
10%		607	**0.10**		5,309	**1**
20%		1,214	**0.21**		10,619	**1.8**

Notes:

1. *Percentage of flow by volume (volumetric)*
2. *Total annual gas flow to Mullingar sourced from GNI. Min / Max gas distribution flows to Mullingar based on applying factor of 0.0063 to transmission min / max flows for Gaybrook AGI (based on Figure 5-7 above). 1 day = 24 hours. 0.0063 factor based on relative size of annual transmission flow through Gaybrook AGI and annual gas flow to Mullingar*

The challenge of balancing the hydrogen output of an electrolyser with demand for injection of this hydrogen in the natural gas network is discussed in the next chapter. It will be clear from above that when well sized, the electrolyser will be active as much as possible (i.e. it will have a high capacity factor). Being able to meet peak winter demands means that the electrolyser will either be inactive for significant periods during the summer (lower capacity factor) or, the available capacity can be used to meet other demands for hydrogen e.g. in transportation.

As described earlier, as the proportion of hydrogen is increased in the natural gas network, the calorific value of the natural gas / hydrogen blend decreases. This is one limitation on the amount of hydrogen that can be blended. Also, the profiles for renewable electricity generation, electricity demand and gas demand all vary in different ways. As a result, detailed modelling of these profiles is required to find an appropriate balance of electrolyser scale, hours of operation, hydrogen storage and source of electricity. The next chapter describes how these issues were considered in the study.

5.6.2 Tullamore/Clara

The current total annual gas demand in Tullamore / Clara is approximately 8,677,000m³ per annum / 84,842MWh. This gas is supplied to just under 2,000 customers via the 4bar distribution network, with the notable inclusion of the Midlands Regional Hospital in Tullamore. This gas consumer uses approximately 11% of the total gas demand in the area. The total gas demand for Tullamore / Clara amounts to approximately 1.09% of the gas transmission flow through Gneevekeel AGI.

Using a similar approach to that used above for Mullingar, the maximum / minimum flow rates to Tullamore / Clara are approximately 3,800m³/hr and 435m³/hr respectively.

The relative scale of gas distribution flow to Tullamore / Clara via Gneevekeel AGI and electrolysers required to meet specific blends of hydrogen is summarised on Table 5-3 below.

Table 5-3: Rates of Hydrogen Injection for Minimum and Maximum Gas Flows to Tullamore / Clara

Percentage of Hydrogen in Natural Gas[1]	Minimum Flow Natural Gas[2] (m³/day)	Required Flow Hydrogen (m³/day)	Approximate Size of Electrolyser Required (MW)	Maximum Flow Natural Gas (m³/day)	Required Flow Hydrogen (m³/day)	Approximate Size of Electrolyser Required (MW)
2%	10,460	209	**0.04**	91,557	1,831	**0.32**
5%		523	**0.06**		4,578	**0.79**
10%		1,046	**0.18**		9,156	**1.58**
20%		2,093	**0.36**		18,311	**3.15**

Notes:

1. *Percentage of flow by volume (volumetric)*
2. *Total annual gas flow to Tullamore / Clara sourced from GNI. Min / Max gas distribution flows to Tullamore / Clara based on applying factor of 0.0109 to transmission min / max flows for Gneevekeel AGI (based on Figure 5-7 above). 1 day = 24 hours. 0.0109 factor based on relative size of annual transmission flow through Gneevekeel AGI and annual gas flow to Tullamore / Clara*

As outlined above for the Mullingar scenario, the figures Table 5-3 are theoretical and do not consider hydrogen storage.

5.7 Transportation Outlets

A profile for a possible demand from transportation outlets was not developed. For dual fuel operation (diesel hydrogen blends), there would greater flexibility because vehicles could run on diesel when hydrogen is not available. A transportation outlet could potentially therefore operate in parallel with gas injection at variable rates.

6 TECHNO-ECONOMIC MODELS OF GAS INJECTION

Two techno-economic models were developed during the study to estimate a Levelised Cost of Hydrogen (LCOH) injected into the gas network. These were:

1. Injection to the gas **transmission** network via Gaybrook AGI
2. Injection to the gas **distribution** network serving Mullingar via Gaybrook AGI or Tullamore/Clara via Gneevekeel AGI

The methodologies used for these models is outlined below. Results are included in Appendix C.

6.1 Injection to Gas Transmission Network

For this model, it is assumed that the source of electricity for the electrolyser will be wind only or a mixture of wind power and grid power.

It has been assumed that the size of the local wind farm that will supply renewable power to the electrolyser is 84MW. This key assumption is based on a review of recent onshore wind farm developments in Ireland. It is a relevant size to Rhode considering current planned / permitted wind farm developments in the Rhode area. It has a direct influence on the model outputs. If a different size of wind farm were to be considered, the values for LCOH would need to be recalculated.

The techno-economics of producing hydrogen are affected by the year in which the project is commissioned. For this reason, systems are assessed for projects starting in both 2024 and 2030. Models for capital and operational expenditure were developed based on 2024 and 2030 targets (7) and existing models which predict how these expenses vary with electrolyser capacity (12).

All of the modelled scenarios assume container/tube trailer storage and transfer for hydrogen produced to Gaybrook AGI.

The model has also been used to calculate the carbon intensity of hydrogen produced when electricity is sourced from the national grid.

6.1.1 Scenarios Modelled

There are two approaches for running the electrolyser:

1. **Demand Led**: The electrolyser is designed to meet a specific target percentage of hydrogen injection to the natural gas transmission grid only. The size of electrolyser varies depending on the target hydrogen percentage (see further below).
    a. Demand-led scenarios use hydrogen demands of **2%, 5%**, or **20%** (v/v) of hydrogen in the natural gas
    b. Demand led scenarios have been modelled for years **2024** and **2030**
2. **Supply Led**: This configuration assumes a specific size of electrolyser. It also assumes that all of the hydrogen produced is used either in the gas transmission network or by another end user e.g., in transportation.
    a. Electrolyser sizes of **1MW, 10MW** and **50MW** have been modelled for Supply Led scenarios
    b. Supply led scenarios have been modelled for years **2024** and **2030**

Four distinct scenarios by which electricity is provided to power the electrolyser are considered in the model:

1. **Dispatch Down**: This refers to renewable energy that is produced by the wind farm but cannot be accepted onto the system. It can be categorised as curtailment when causes are system-wide, or constrained when causes are in the localised network.
2. **Dedicated Wind Farm - Hydrogen Prioritised**: Wind farm electricity generation prioritises hydrogen production, with any remaining generation going to the electricity grid.
3. **Dedicated Wind Farm - Grid Prioritised**: A portion of electricity is prioritised for the electricity grid up to a set threshold (see below). The balance of electricity that is generated above this threshold is then supplied for hydrogen production. Three threshold levels are used: **21 MW, 42 MW** and **59MW**.

4. **Wind and Grid**: Where imported grid electricity is used to supplement wind energy. This method of electricity supply ensures the electrolyser has a 100% capacity factor i.e., it operates constantly regardless of wind energy availability. (Wind and Grid also means that the electrolyser will use a combination of dispatch down, wind and grid power).

The above parameters lead to a total of 60No. scenarios (24No. Demand Led and 36No. Supply Led) which have been modelled.

Scenarios have been labelled either 'D' (Demand Led) or 'S' (Supply Led) with a number corresponding to the scenario. The full list of scenarios modelled is included in Appendix B.

6.1.2 Hydrogen Hub Model

The Hydrogen Hub Model (51) forms the basis for all techno-economic calculations conducted for this study. The model was provided with annual wind farm generation data, grid market price data, and hydrogen demand based on natural gas transmission flows at Gaybrook AGI. This data, along with the specific input parameters of each scenario, was then used to calculate the LCOH, CO_2 emissions, and hydrogen production from each scenario. Figure 6-1 summarises the calculation procedure.

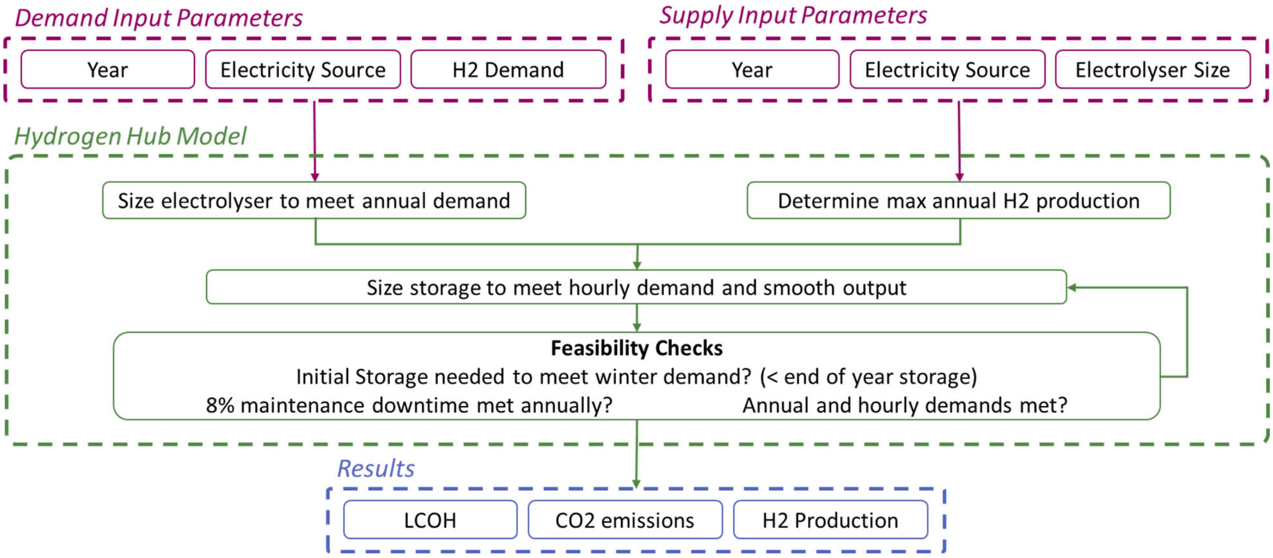


Figure 6-1: Procedure for use of Hydrogen Hub Model to perform techno-economic calculations

The model calculates the associated Levelised Cost of Hydrogen (LCOH) (see below). It also calculates the breakdown of electricity sources where scenarios contain multiple sources. For example. in scenarios where wind and grid electricity are utilised, the model shows quantities of H_2 produced by dispatch down, dedicated wind and grid.

6.1.3 Levelised Cost of Hydrogen

The Levelised Cost of Hydrogen (LCOH) is a measure of the lifetime costs of producing, storing, and delivering hydrogen, divided by the lifetime production of hydrogen.

$$LCOH(€/kg_{H2}) = \frac{Present\ Value\ of\ Lifetime\ Costs}{Present\ Value\ of\ Lifetime\ Generation} = \frac{\sum_{t=1}^{n}(CAPEX_t + OPEX_t + Fuel_t)(1+r)^{-t}}{(kg_{H2})\ (1+r)^{-t}}$$

Equation 1: Levelised Cost of Hydrogen.

The levelised cost of hydrogen from production ($LCOH_P$) includes the capital and operational expenditure of any power converters, electrolysers, and compressors, in addition to water and electricity costs. The levelised cost of hydrogen from storage ($LCOH_S$) accounts for the capital and operational costs of the chosen storage. The levelised cost of transporting the hydrogen ($LCOH_T$) is calculated based on the capital and operational expenditure of delivery infrastructure, additional compressors if required, and electricity needed to run the compressors. The total LCOH is the sum of these three individual costs.

$$LCOH_{Total}(€/kg_{H2}) = LCOH_{Production} + LCOH_{Storage} + LCOH_{Transportation}$$

Equation 2: Levelised Cost of Hydrogen as the sum of production, storage, and transportation costs.

It has been assumed that dispatch down (curtailed / constrained) electricity is sourced at zero cost. The cost of the remaining electricity required for running the electrolyser is also excluded from the modelled LCOH figures. The relative values of LCOH from modelling are therefore of most interest here. A separate definition - 'Estimated Cost of Hydrogen' (ECOH) - is used later in this report. This includes the cost of electricity for powering the electrolyser. It is used to compare specific scenarios of particular interest to Rhode and for the proposed demonstrator project (see further below and Section 10).

6.1.4 Capacity Factor

Capacity factor is a measure of how much time plant / equipment is actually used compared to what is considered to be full-time use (allowing for maintenance etc.). It is expressed as a percentage and can be measured simply as the cumulative number of hours of operation divided by the maximum feasible number of hours available. A higher capacity factor means that the plant / equipment is used more.

An electrolyser's capacity factor has a very significant bearing on the overall cost per kg of hydrogen produced. This is evident in the modelled results of this feasibility study. Electrolysers have a higher capacity factor with dedicated power supply but use less and less of their capacity as their size increases relative to the size of the source of electricity that supplies them.

It is possible to determine capacity factor for each size of electrolyser and each power supply, as shown by Table 6-1.

Table 6-1: Capacity Factor for electrolyser sizes of 1M, 10MW and 50MW

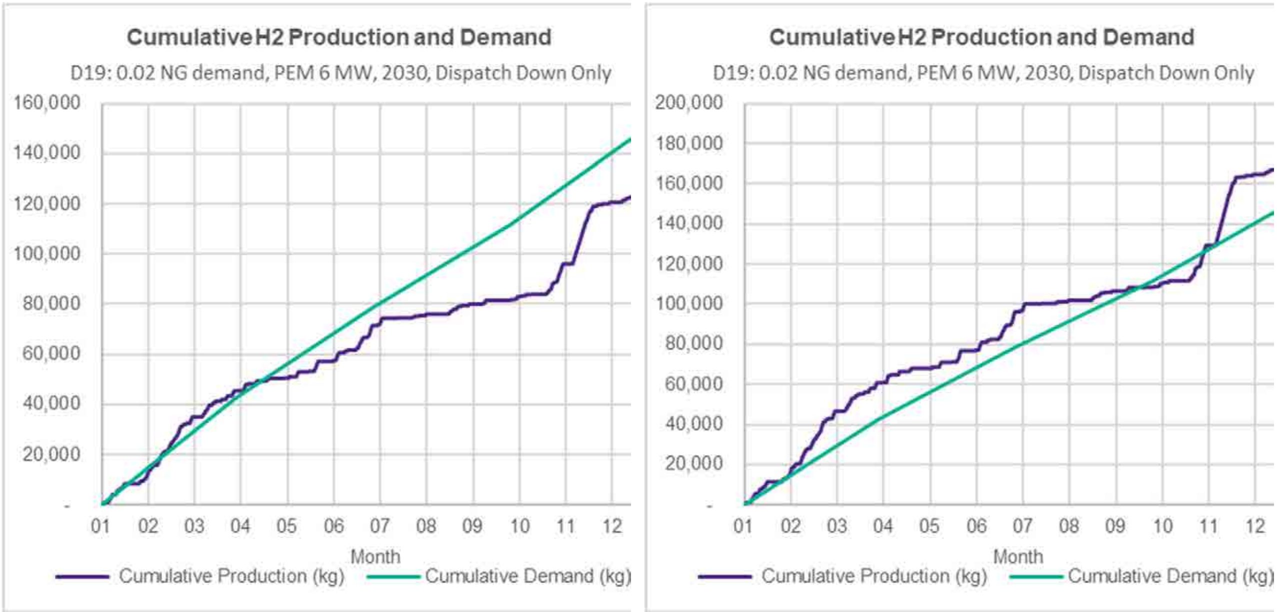
Electrolyser size	1 MW		10 MW		50 MW	
Power supply	Curtailed	Dedicated	Curtailed	Dedicated	Curtailed	Dedicated
Capacity Factor	**15.98%**	**69.95%**	**12.19%**	**59.93%**	**6.14%**	**36.26%**

6.1.4.1 Battery Coupling

Including battery storage for renewable electricity generation to support an electrolyser may be beneficial in terms of raising its capacity factor. Battery storage can be used for grid balancing over short durations (hours). It could allow for more renewable power to be used with a smaller electrolyser and less hydrogen storage. Depending on the costs involved, it could potentially result in a lower LCOH. However, exploring this option is outside the scope of this feasibility study and it is not included in the techno-economic model.

6.1.5 Electrolyser Sizing

In demand led scenarios, the first step in assessing the system is appropriately sizing an electrolyser to meet the annual demand. Figure 6-2 shows the cumulative hydrogen production and demand for Scenario D19 over the course of a year. In plot (a), the cumulative production fails to meet the annual demand at the end of the year, indicating that the electrolyser chosen is too small. In plot (b), production surpasses demand at the end of the year, showing that there will be excess generation annually. The next step is to appropriately size storage so that instances where the production fails to match the demand, in this example in around October, there is adequate hydrogen available from storage to sustain delivery and meet demand.



(a) Electrolyser too small, cumulative demand exceeds production

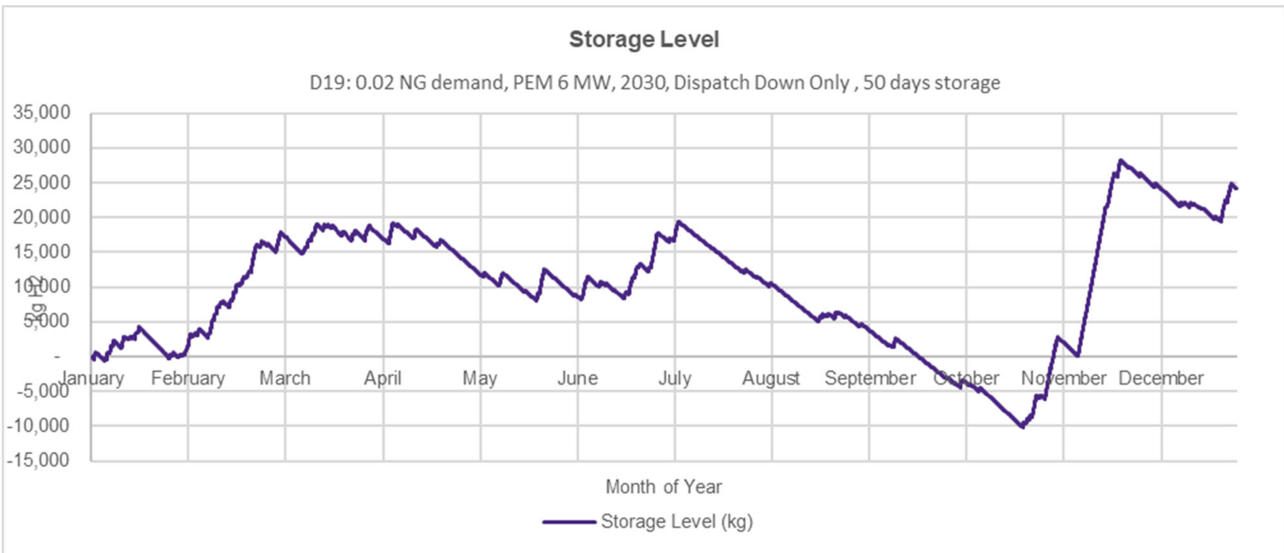
(b) Electrolyser sized appropriately

Figure 6-2: Electrolyser Sizing for Demand Scenarios

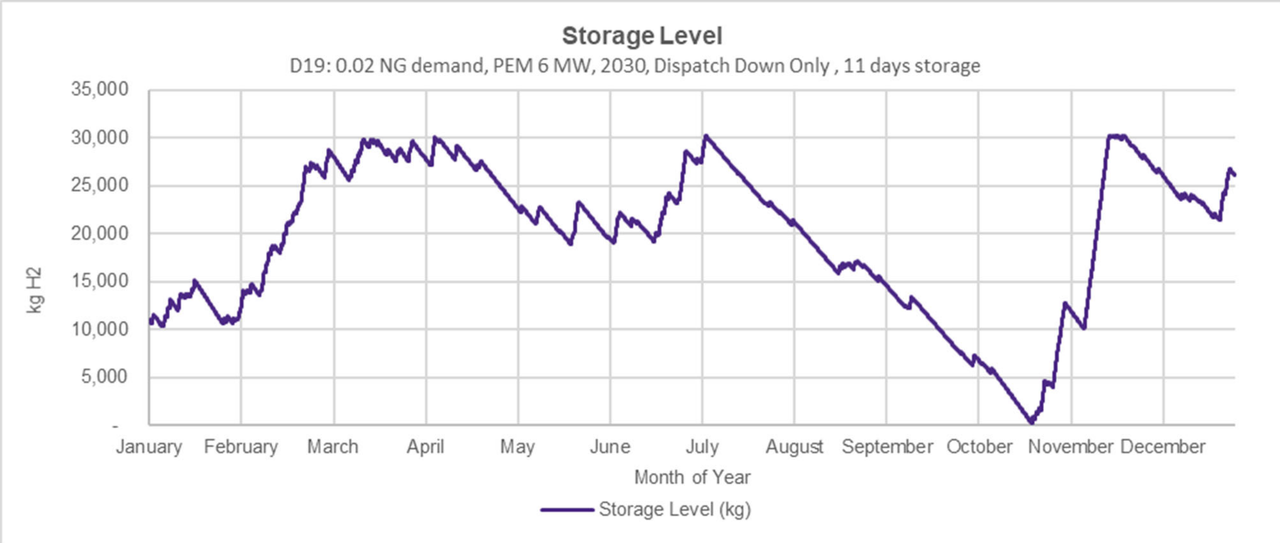
For supply-led scenarios, the electrolyser size is specified, and the annual generation is smoothed to a constant output year-round. The system is then sized using the same method as the demand scenarios with storage to support the hourly exports required.

6.1.6 Storage Sizing

Compressed tank storage is used for all scenarios modelled, with a cost of €470 /kg H_2 (19) at a pressure of 350 bar. Figure 6-3 (a) shows Scenario D19 with 50 days of storage allowance. Starting with a very large storage allows for the storage capacity necessary to be identified, in this scenario it is around 30 tonnes, which is approximately 11 days of storage. It is also important to note the period in October when the storage is negative indicating that some initial storage should be set in January to allow for that demand to be met. The initial storage, set at 11 tonnes in this example, should be equal to or lower than the end-of-year storage level to ensure it is possible. In plot (b) the impact of setting this initial storage is shown, as the demand is met year-round. Storage capacity is rarely met showing that it is possible to export or store all hydrogen produced.



(a) Identifying storage requirements



(b) Appropriately sized storage taking all hydrogen produced and supporting times of low generation

Figure 6-3: Storage Sizing for Demand and Supply-led scenarios

6.1.7 Carbon Intensity of Electricity

Only one group of the scenarios modelled involves the use of electricity that is sourced from the national electricity grid. This group is labelled 'Grid and Wind'. All other scenarios use only renewable power and therefore, hydrogen produced can be seen as being renewable hydrogen, with a carbon footprint that is below 18g $CO_{2\ equiv}$/ MJ. This is equivalent to 4.36kg CO_2 / kg H_2 produced.

The model has been used to calculate the carbon footprint / intensity of hydrogen produced for all 'Grid and Wind' scenarios. The Green House Gas (GHG) intensity of grid electricity was assumed to reflect the EU average as 178.25 gCO_2e/kWh in 2024 and 86.15 gCO_2e/kWh in 2030. This was used as opposed to the Republic of Ireland data. The Irish GHG intensity of the grid is expected to 'catch up' with EU averages in the coming years.

6.1.8 Estimated LCOH for Gas Transmission Injection

The results of modelling for injection to the gas transmission network are summarised on Table 6-2 (Demand Led scenarios) and Table 6-3 (Supply Led scenarios).

The scenarios that are considered to be of most relevance to the Rhode demonstrator project are high-lighted. Scenarios where LCOH values are above €5/kg and demand scenarios that could not meet demand targets are shown in grey.

Table 6-2: Ranking of Demand Led Scenarios for Feasibility Study

Year	Demand Led Scenario (H_2 %)	Dispatch Down Only	Grid and Wind	Dedicated Wind Priority Hydrogen	Dedicated Wind Priority Electricity
2024	**2%**	D7 6MW, €21.25/kg 167t H_2/annum	D10 1MW, €8.66/kg 152t H_2/annum 0.76kg CO_2/kg H_2	D1 1MW, €7.24/kg 155t H_2/annum	D4 1MW, €18.92/kg 161t H_2/annum
	5%	D8 Unable to meet demand target	D11 2.5MW, €5.62/kg 378t H_2/annum 1.06kg CO_2/kg H_2	D2 2.5MW, €7.14/kg 398t H_2/annum	D5 2.5MW, €19.17/kg 409t H_2/annum
	20%	D9 Unable to meet demand target	D12 10MW, 4.92/kg 1,522t H_2/annum 2.12kg CO_2/kg H_2	D3 10MW, €6.10/kg 1,549t H_2/annum	D6 10MW, €14.93/kg 1,515t H_2/annum
2030	**2%**	D19 6MW, €17.40/kg 166t H2/annum	D22 1MW, €4.55/kg 152t H_2/annum 0.38kg CO_2/kg H_2	D13 1MW, €4.67/kg 151t H_2/annum	D16 5MW, €13.98/kg 172t H_2/annum
	5%	D20 22MW, €21.35/kg 390t H2/annum	D23 **3MW, €3.95/kg** **378t H_2 / annum** 0.59kg CO_2/kg H_2	D14 2.5MW, €4.07/kg 377t H_2/annum	D17 14MW, €15.35/kg 445t H_2/annum
	20%	D21 Unable to meet demand target	D24 **11MW, €3.46/kg** **1,518t H_2/annum** 1.13kg CO_2/kg H_2	D15 12MW, €4.11/kg 1,532t H_2/annum	D18 26MW, €12.95/kg 1,579t H_2/annum

Notes:

- *Yellow: Scenario of most interest for 'small electrolyser (1MW – 5MW) – cross reference with Supply Led scenario*
- *Blue: Scenario of most interest for 'medium electrolyser' (approximately 10MW) – cross reference with Supply Led scenario*
- *Figures for kg CO_2 emissions per kg H_2 produced relate to Wind and Grid mode only as this is the only mode where there is a component of non-renewable electricity used*

Table 6-3: Ranking of Supply Led Scenarios for Feasibility Study

Year	Supply Led Scenario (MW)	Dispatch Down Only	Grid and Wind	Dedicated Wind Priority Hydrogen	Dedicated Wind Priority Electricity	Wind Farm Threshold (MW)
2024	**1MW**	S19 €23.35/kg 36t H_2 / annum	S22 €4.78/kg 154t H_2 / annum 0.78kg CO_2/kg H_2	S16 €5.52/kg 155t H_2 / annum	S13a	**59MW**
					S13b	**42MW**
					S13c	**21MW**
	10MW	S20 €19.98/kg 271t H_2 / annum	S23 **€3.63/kg** **1,536t H_2 / annum** 2.16kg CO_2/kg H_2	S17 €6.04/kg 1,327t H_2 / annum	S14a	**59MW**
					S14b	**42MW**
					S14c	**21MW**
	50MW	S21 €30.50/kg 683t H_2 / annum	S24 €4.06/kg 7,686t H_2 / annum 5.62kg CO_2/kg H_2	S18 €10.00/kg 4,017t H_2 / annum	S15a	**59MW**
					S15b	**42MW**
					S15c	**21MW**
2030	**1MW**	S7 €22.60/kg 37t H_2 / annum	S10 **€3.94/kg** **160t H_2 / annum** 0.40kg CO_2/kg H_2	S4 €5.12/kg 161t H_2 / annum	S1a	**59MW**
					S1b	**42MW**
					S1c	**21MW**
	10MW	S8 €18.96/kg 282t H_2 / annum	S11 **€3.06/kg** **1,597t H_2 / annum** 1.19kg CO_2/kg H_2	S5 €5.50/kg 1,386t H_2 / annum	S2a	**59MW**
					S2b	**42MW**
					S2c	**21MW**
	50MW	S9 €27.45/kg 710t H_2 / annum	S12 €6.39/kg 7,457t H_2 / annum 3.15kg CO_2/kg H_2	S6 €9.03/kg 4,192t H_2 / annum	S3a	**59MW**
					S3b	**42MW**
					S3c	**21MW**

Notes:

- *Yellow: Scenario of most interest for 'small electrolyser (1MW – 5MW) – cross reference with Demand Led scenario*
- *Blue: Scenario of most interest for 'medium electrolyser' (approximately 10MW) – cross reference with Demand Led scenario*
- *Figures for kg CO_2 emissions per kg H_2 produced relate to Wind and Grid mode only as this is the only mode where there is a component of non-renewable electricity used*
- *Scenarios S13a to S3c and their corresponding wind farm threshold all have high LCOH figures which make them unfeasible*

6.2 Injection to Gas Distribution Network

The results of the modelling of hydrogen injection into the gas transmission network were used to develop estimated LCOH values for the distribution injection case. Scenario S10 (1MW, LCOH = €3.94/Kg H_2) was taken as the key reference point. This scenario is based around a 1MW electrolyser which is considered to be at the upper end of how large the Rhode demonstrator project should be.

High-level figures shown in Section 5.6 of this report suggest that a 1MW electrolyser, with an appropriate storage capacity, would be capable of meeting the requirements for hydrogen injection to the gas distribution networks of Mullingar and Tullamore / Clara. Figure 6-4 (Mullingar) and Figure 6-5 (Tullamore / Clara) were generated to explore this further. These figures show annual profiles for hydrogen injection (at rates of 2%, 5%, 10%, 15% and 20%) that are based on an estimated annual demand profiles for each distribution network. The estimated cumulative annual hydrogen output from a 0.5MW and a 1MW electrolyser is also shown on each figure. This appears as a straight line indicating an ideal, nearly constant output which corresponds to a high capacity factor of 91.2%. The cumulative demand for hydrogen and cumulative output from an electrolyser are represented by the area under curves on Figure 6-4 and Figure 6-5.

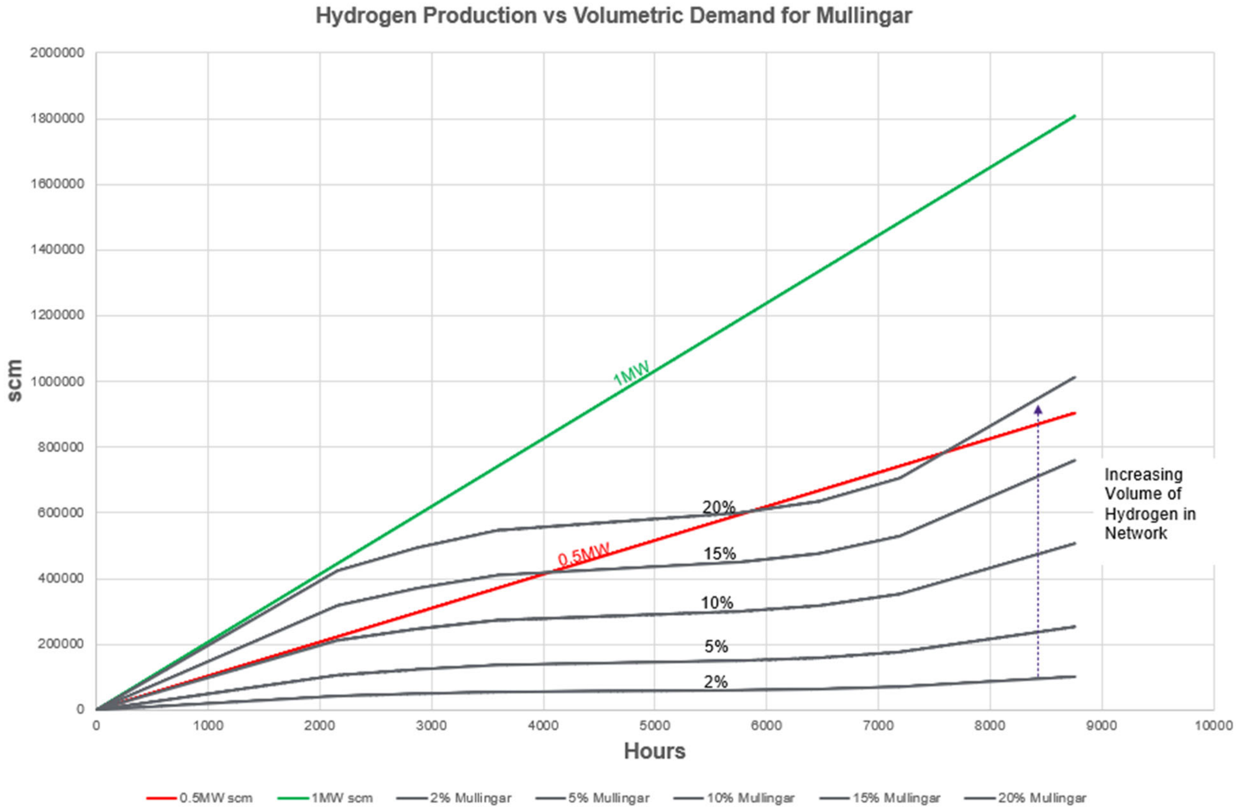


Figure 6-4: Volumetric Demand of Mullingar network compared to output of 0.5MW and 1MW

Figure 6-4 above demonstrates that a 1MW electrolyser, is capable of producing more hydrogen than would be required in the Mullingar gas distribution network in all scenarios up to the maximum injection rate of 20% hydrogen. This figure also shows that a 0.5MW electrolyser can similarly meet the requirement for 10% hydrogen injection for all scenarios. Higher injection rates can be achieved when storage capacity is added. However, this is not modelled here.

A 1MW electrolyser may therefore be an unsuitable size for Mullingar unless other end uses for the surplus hydrogen are identified. The 0.5MW electolyser is likely to be a more appopriate size. With the appropriate hydrogen storage capacity, it could be configured to match a target average annual demand in Mullingar. This electrolyser could provide 10% hydrogen in the network and should still exceed the consumption of Mullingar.

In a similar way, Figure 6-5 below demonstrates that a 1MW electrolyser could be a good fit for supplying hydrogen for injection into the gas distribution network supplying Tullamore / Clara. This would depend on there being adequate hydrogen storage capacity available. A 0.5MW electrolyser could potentially supply sufficient hydrogen for hydrogen injection up to 5% in natural gas for Tullamore / Clara. Increasing amounts of storage is required above this rate of hydrogen injection.

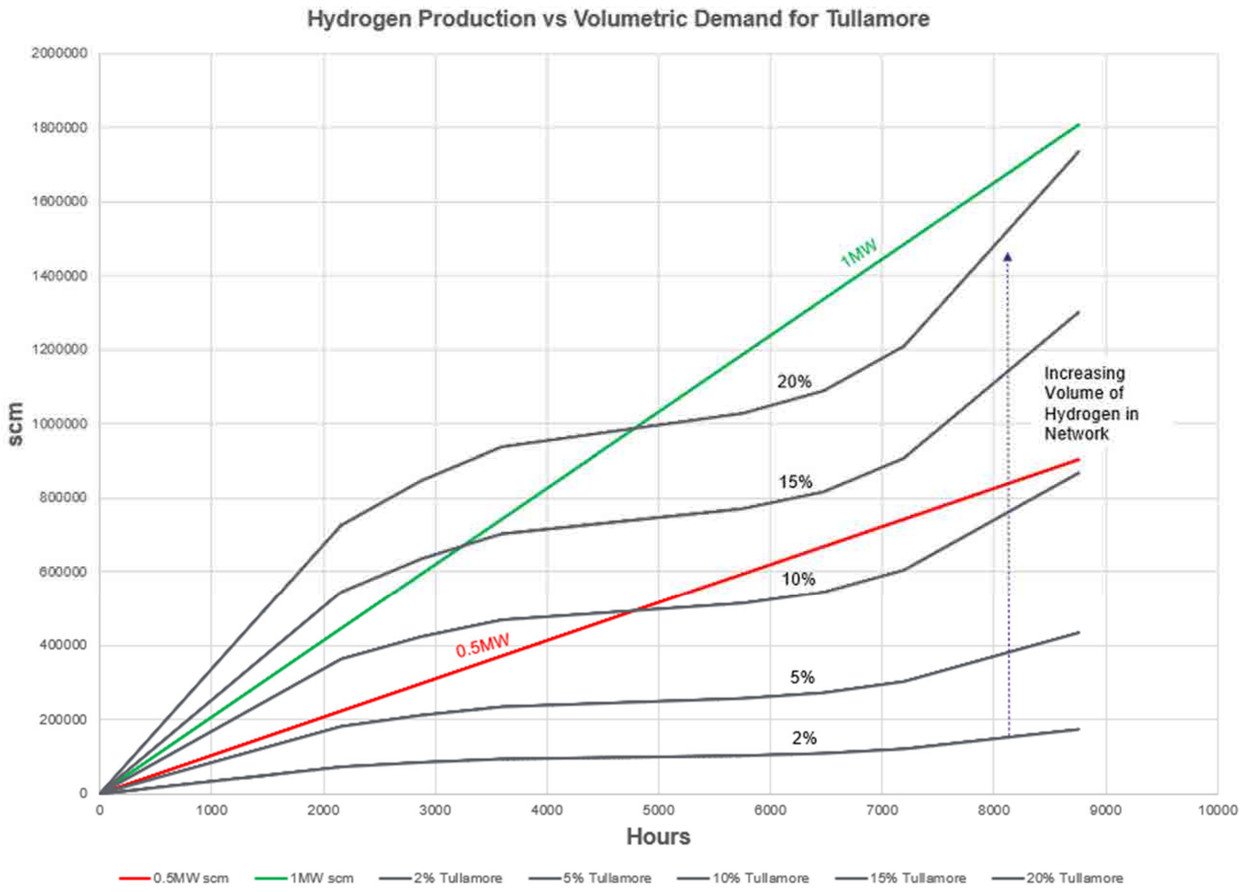


Figure 6-5: Volumetric demand of Tullamore/Clara network compared to output of 0.5MW and 1MW electrolyser

In order to minimise excessive storage requirements, the output capacity of the electrolyser should match or exceed the volumetric demand for hydrogen from the gas distribution network. Any surplus hydrogen will be available for other end uses or stored. If there are no other end uses or the storage capacity is full, the electrolyser would be shut down until needed. However, this will impact on capacity factor and result in higher overall costs.

6.2.1 Estimated LCOH for Gas Distribution Injection

The Levelised Cost of Hydrogen (LCOH) for Scenario S10 (1MW electrolyser) was made up of 3 components as follows:

1. **Production Cost** (€3.23/kg H_2):. Assuming the same high capacity factor of 91.2% is also achieved for the electrolyser, it is reasonable to assume that the cost of producing hydrogen will remain the same at €3.23/kg.
2. **Transport Cost** (€0.55/ kg H_2): For the injection of hydrogen into the gas transmission network it was assumed that virtual pipeline was used to trasport hydrogen from the electrolyser to Gaybrook AGI. As described above, a virtual pipeline would also be used for trasportation of hydrogen for injection into gas distribution network at Gaybrook AGI (18km) or Gneevekeel AGI (33km). For the purposes of this study it is considered reasonable to assume that the cost of transportation of hydrogen from he electrolyser at Rhode to an injection point in Gaybrook AGI or Gneevekeel AGI is the same as was modelled for the transmission injection scenario.
3. **Storage Cost** (€0.16/kg H_2.): Scenario S10 included a storage capacity of 460kg of hydrogen. The required storage for injection into the Tullamore/Clara distribution network at 10% blend is 592kg (refer to Table 6-7 below). It is assumed that the 3 tube trailers have sufficient capacity to facilitate this storage. The storage cost is therefore assumed to be the same for injection into the distribution network and injection into the transmission network.

On the basis of the above it is considered reasonable to assume that the LCOH for a 1MW electrolyser supplying hydrogen to the distribution network will be the same as the LCOH for the transmission network, provided that the electrolyser has a high capacity factor and there is an outlet for surplus hydrogen.

It is therefore concluded that the levelised cost of hydrogen for a 1MW electrolyser configured for injection of hydrogen into the gas distribution network of Tullamore / Clara will be approximately €3.94/kg H_2. This size of electrolyser (1MW) will be capable of delivering sufficient quantities of hydrogen for injection into the gas distribution network of Tullamore / Clara at a rate of up to 10%. However, it is also concluded that a 1MW electolyser will be capable of producing surplus quantities of hydrogen during periods of lower demand for natural gas in Tullamore / Clara. Therefore, achieving this LCOH figure of €3.94/kg H_2 on an ongoing basis is dependent on finding other end uses for surplus hydrogen in order to keep capacity factor high.

Using the above as a reference point, a figure for LCOH for a 0.5MW electrolyser serving Mullingar has been estimated by factoring the cost elements above for the 1MW scenario. This is summarised below.

1. **Production Cost** (€4.85/kg H_2): A factor of 1.5 has been applied to the production cost for the 1MW electrolyser unit.
2. **Transport Cost** (€0.55/kg H_2) The same transportation cost was used as the transport cost of the 1MW electrolyser on the basis that the same equipment will be used. The rationale for transport costs is given above.
3. **Storage Cost** (€0.16/kg H_2): It is assumed that the virtual pipeline system will still need 3 tube trailers to function effectively. These will have more than sufficient capacity to facilitate storage for the 0.5MW electrolyser (345kg H_2 for 10% blend in Mullingar – Refer to Table 6-6 below).

On the basis of the above the estimated LCOH for a 0.5MW electrolyser is €5.55/kg H_2. This is considered a reasonable estimate given the rationale for factoring the production costs and including the same equipment. Achieving this LCOH figure is dependent on finding other end uses for surplus hydrogen in order to keep capacity factor high. A 0.5MW electrolyser is capable of delivering hydrogen blends of 5% in the Tullamore/Clara network and similar to the 1MW it will produce surplus hydrogen at times of low demand.

The estimated costs for a 0.5MW and a 1MW electrolyser with injection of hydrogen into the natural gas distribution network are summarised on Table 6-4 and Figure 6-5 below.

Table 6-4: Estimated CAPEX and Annual OPEX for 0.5MW Electrolyser and Gas Injection

Injection & Virtual Pipeline[2]		Injection & PE Pipeline	
CAPEX[1]		CAPEX[1]	
0.5MW Electrolyser (estimated)	€ 750,000	0.5MW Electrolyser (estimated)	€ 750,000
Gas storage[3]	€ 0	Gas Storage[4]	€ 108,100
3 Tube Trailers + 1 Tractor Unit	€ 960,000	Pipeline	€ 2,500,000
Gas Injection Unit at AGI	€ 0	Gas Injection Unit at AGI	€ 0
Compressor (350bar)	€70,000	Compressor (4 bar)	€61,165
Total CAPEX	**€ 1,780,000**	**Total CAPEX**	**€ 3,419,265**
OPEX		OPEX	
0.5MW Electrolyser	€ 75,000	0.5MW Electrolyser	€ 75,000
Electrolyser Power	€ 569,563	Electrolyser Power	€ 569,563
Compressor (350bar)	€ 67,500[5]	Compressor (4bar)	€ 45,000[6]
General Maintenance (4% of CAPEX)	€ 71,200	General Maintenance (4% of CAPEX)	€ 136,770
Miscellaneous (Personnel, fuel, Insurances etc.)	€ 75,000	Miscellaneous (Maintenance etc.)	€ 25,000
Total OPEX (annual)	**€ 858,263**	**Total OPEX (annual)**	**€ 851,333**

Notes:

1. *Estimated CAPEX for plant and equipment only, figures do not include for land, civil works etc*

2. *Virtual pipeline option is compatible with injection of hydrogen to gas transmission network and gas distribution network. Additional compression would be required at AGI if 4bar pipeline was used to transport hydrogen to injection point*
3. *Equivalent to approximately 1 day of hydrogen output (230kg H_2). It is assumed that the required hydrogen storage capacity is available within the virtual pipeline system made up of three tube trailers each with a capacity of 400kg of hydrogen (1 filling, 1 in transit and 1 unloading)*
4. *Equivalent to approximately 1 day of hydrogen output (230kg H_2), storage cost €470/kgH_2*
5. *Based on 75tonnes of H_2 produced a 3kWh/kg and 0.2 €/kWh*
6. *Based on 75tonnes of H_2 produced a 2kWh/kg and 0.2 €/kWh*
7. *CAPEX values are exclusive of VAT*
8. *Estimated CAPEX is €350,000 - €500,000. It is assumed that the investment in this infrastructure would be borne by GNI as owner and operator of the gas network*

Table 6-5: Estimated CAPEX & Annual OPEX for 1MW Electrolyser and Gas Injection

Injection & Virtual Pipeline[2]		Injection & PE Pipeline	
CAPEX[1]		CAPEX[1]	
1MW Electrolyser	€ 1,000,000	1MW Electrolyser	€ 988,203
Gas storage[3]	€ 0	Gas Storage[4]	€ 216,200
3 Tube Trailers + 1 Tractor Unit	€ 960,000	Pipeline	€ 2,500,000
Gas Injection Unit at AGI	€ 0	Gas Injection Unit at AGI	€ 0
Compressor (350bar)	€70,000	Compressor (4 bar)	€61,165
Total CAPEX	**€ 2,030,000**	**Total CAPEX**	**€ 3,765,568**
OPEX		OPEX	
1MW Electrolyser	€ 75,000	1MW Electrolyser	€ 75,000
Electrolyser Power	€ 1,139,126	Electrolyser Power	€ 1,139,126
Compressor (350bar)	€90,000[5]	Compressor (4bar)	€ 60,000[6]
General Maintenance (4% of CAPEX)	€ 81,200	General Maintenance (4% of CAPEX excluding pipeline)	€ 151,094
Miscellaneous (estimated) (Personnel, fuel, Insurances etc.)	€ 100,000	Miscellaneous (estimated) (Maintenance etc.)	€ 25,000
Total OPEX (annual)	**€ 1,485,326**	**Total OPEX (annual)**	**€ 1,350,220**

Notes:

1. *Estimated CAPEX for plant and equipment only, figures do not include for land, civil works etc*
2. *Virtual pipeline option is compatible with injection of hydrogen to gas transmission network and gas distribution network. Additional compression would be required at AGI if 4bar pipeline was used to transport hydrogen to injection point*
3. *Equivalent to approximately 1 day of hydrogen output (460kg H_2). It is assumed that the required hydrogen storage capacity is available within the virtual pipeline system made up of three tube trailers each with a capacity of 400kg of hydrogen (1 filling, 1 in transit and 1 unloading)*
4. *Equivalent to approximately 1 day of hydrogen output (460kg H_2), storage cost €470/kgH_2*
5. *Based on 150tonnes of H_2 produced a 3kWh/kg and 0.2 €/kWh*
6. *Based on 150tonnes of H_2 produced a 2kWh/kg and 0.2 €/kWh*
7. *CAPEX values are exclusive of VAT*
8. *Estimated CAPEX is €350,000 - €500,000. It is assumed that the investment in this infrastructure would be borne by GNI as owner and operator of the gas network*

Table 6-6 and Table 6-7 below show the estimated quantities and cost of hydrogen storage needed for 0.5MW and 1MW electrolysers supplying hydrogen for injection into the gas distribution networks of Mullingar and Tullamore / Clara respectively. This is based on the average annual demand of the respective networks for a given target percentage of hydrogen (2%, 5%, 10%, 15% and 20%). Backup storage of hydrogen is required to cater for hourly fluctuations in demand. A storage capacity of 3 days' output of hydrogen consumption was considered to be sufficient for this purpose. This would be used when the demand is at a peak during the day and would be replenished during off-peak hours.

The quantity of storage is important during the winter months when demand is high to ensure that the peaks can be provided for. However, this quantity of storage is too small to cater for seasonal variations. It is likely that it would remain full during the summer period. A cost of €470/kg of hydrogen (19) is used to estimate the cost of storage for the given mass.

Table 6-6: Storage and cost estimates for a 0.5MW and 1MW electrolyser serving the Mullingar network

Mullingar		2%	5%	10%	15%	20%
0.5MW Electrolyser	Storage (kg)	69	173	345	NA	NA
	Cost (€)	€32,467	€81,169	€162,337	NA	NA
1MW Electrolyser	Storage (kg)	69	173	345	NA	NA
	Cost (€)	€32,467	€81,169	€162,337	NA	NA

Table 6-7: Storage and cost estimates for a 0.5MW and 1MW electrolyser serving the Tullamore/Clara network

Tullamore		2%	5%	10%	15%	20%
0.5MW Electrolyser	Storage (kg)	118	296	NA	NA	NA
	Cost (€)	€55,634	€139,085	NA	NA	NA
1MW Electrolyser	Storage (kg)	118	296	592	NA	NA
	Cost (€)	€55,634	€139,085	€278,169	NA	NA

6.3 Conclusions from Modelling

The main conclusions from the techno-economic modelling of electrolysis with injection of hydrogen into the gas network are summarised below.

- The optimum size of a demonstrator-scale electrolyser for Rhode is between 0.5MW and 1.0MW.
    - A 0.5MW electrolyser would have an annual output of approximately 75 tonnes of hydrogen. This installation would be able to provide up to a 10% blend in the distribution network in Mullingar with approximately 33 tonnes of surplus hydrogen being available for other end uses e.g. transportation.
    - A 1MW electrolyser would have an annual output of approximately 150 tonnes of hydrogen. This would be able to provide up to a 10% blend in the distribution network in Tullamore/Clara, with approximately 78 tonnes of surplus hydrogen also being available for other end uses.
- It is considered that a 10MW electrolyser is too large to become the Rhode demonstrator project due to the high CAPEX involved. However, a smaller-scale demonstrator electrolyser could potentially be expanded in size over time. The modelling has shown that Scenario S10 (1MW) has a similar LCOH value (€3.94/kg H_2) as scenarios D24 (11MW, €3.46/kg H_2) and S11 (10MW, €3.06/kg H_2). Each of these scenarios are based on injection of hydrogen into the gas transmission network. This comparison shows that even with a 1MW electrolyser, there is the opportunity of achieving a low LCOH that is comparable to much larger installations. Therefore, a 1MW unit appears to be a reasonable basis for a demonstrator project.
- The theoretical output from a 50MW hydrogen electrolyser would far exceed the 20% hydrogen blending limit for the gas distribution networks in Mullingar and Tullamore / Clara. The available quantity of dispatch down renewable electricity at Rhode would also be small relative to the output of a 50MW electrolyser. Therefore, it is not considered feasible for Rhode Green Energy Park at present.
- Scenario S10 is for injection of hydrogen into the gas transmission network. It has the following features:
    - 1MW electrolyser. This can produce up to approximately 150 tonnes of hydrogen in 1 year, or approximately 460kg per day.

- o 460kg of hydrogen storage capacity. This is equivalent to the hydrogen output from the electrolyser for approximately 1 day.
- o It operates in 'Supply Led' mode using a combination of curtailed wind power, dedicated wind with priority for hydrogen production and grid electricity.
- o By using the above combination of sources of electricity, this scenario has a high-capacity factor of 91.2%.
- o With a high-capacity factor and relatively low storage capacity, this scenario has a relatively low LCOH of €3.94/kg H_2 compared to many of the other scenarios modelled.
- o A Supply Led / Variable rate of injection. This keeps costs at a minimum by avoiding sourcing additional hydrogen / grid power.

- Scenario S10 was used as a basis for developing estimated LCOH values for injection of hydrogen into the gas distribution network for electrolyser sizes of 0.5MW and 1.0MW. The corresponding estimated LCOH values are €5.55/kg H_2 and approximately €3.94/kg H_2 respectively.
- Capacity factor is a critical component of the modelled Levelised Cost of Hydrogen (LCOH). The lowest values of LCOH coincide with the highest capacity factors.
- When grid exports are prioritised by the wind farm, electrolysers will run infrequently. Therefore, excess hydrogen needs to be produced for storing when the electrolyser is running. This stored excess hydrogen needs to be available when the electrolyser is not running. The additional costs of greater storage capacity result in higher values of LCOH.
- Sizing an electrolyser to the peaks of available renewables is likely to result in low electrolyser capacity factors and operational hours, leading to increased production and storage costs. There are large seasonal variations in demand for natural gas. The minimum demand in summer time is approximately 10% of the maximum demand in winter time. This means that the corresponding demand for hydrogen for injection into the gas network at fixed rates will also vary in the same manner. This variation in demand for hydrogen can be managed using storage or by shutting off the electrolyser when it is not needed. However, storage is expensive and the volume of storage needed to cater for seasonal factors is large. Shutting off the electrolyser will reduce capacity factor resulting in a higher overall value for LCOH. These additional costs can be mitigated if alternative outlets for the hydrogen produced can be identified e.g. transportation.
- The ideal scenarios use as much dispatch down and wind energy as possible, with the support of some grid supply to ensure a high electrolyser capacity factor and keep costs down. These are the 'Grid and Wind' scenarios.
- The modelled results suggest that only using dispatch down (curtailed) electricity is not currently a feasible option.
- A variable rate of hydrogen injection would give additional flexibility to an electrolyser. It is therefore preferred over a fixed rate. Flexibility in this area is an advantage to the electrolyser because it helps to minimise the requirement for sourcing additional hydrogen. For a demonstrator project, any additional financial burden of this nature would impact on overall feasibility. However, flexibility in hydrogen injection rate is unlikely to be acceptable to Gas Networks Ireland.
- The model has assumed that wind or wind and grid will supply electricity for the electrolyser. If other renewable sources of energy are added to the mix e.g., solar, the capacity factor of the electrolyser could be improved, and some scenarios would be more competitive.
- This study assumes that dispatch down electricity produced by wind can be accessed 'behind the meter' i.e. avoiding the Electricity Grid. For an electrolyser that is not located on the wind farm site, this would require a private connection between the wind farm operator and the electrolyser operator. Current regulation in Ireland prevents this. However, the Climate Action Plan has identified the need for harnessing more renewable energy, including for the generation of hydrogen. Updates to these regulations are due to be published in 2023 and may remove the current limitations in certain scenarios.
- The scenarios modelled all use container/tube trailer storage and transfer. Due to this, the transport and storage costs are high.

7 TRANSPORT FLEET OPTION FOR RHODE

An option for a demonstrator-scale electrolyser at Rhode would be to target transportation outlets, either as a primary outlet for hydrogen produced or as an alternative outlet to hydrogen injection into the natural gas network. Depending on scale of electrolyser and costs involved, there could even be benefits in running both options in parallel.

There are a number of relatively large vehicle fleet operators in the Midlands Region who are likely to have interest in exploring low carbon solutions for their operations. Those who have expressed an interest in the possibilities for using hydrogen include Offaly County Council, BNM and Enva. Given that a demonstrator electrolyser focussed on injection of hydrogen into the gas distribution network will have spare capacity during the summer time, it was considered important to examine the transportation end use option as a means of maintaining the electrolyser's capacity factor as high as possible. A project combining both of these end use options (hydrogen injection and transportation) could also further demonstrate energy integration at Rhode.

7.1 Electrolyser Output

The estimated hydrogen output of electrolysers and its potential for displacing conventional diesel fuel in transportation is summarised on Table 7-1 below.

Table 7-1: Electrolyser Output and Potential for Displacing Diesel Fuel in Transportation

Electrolyser Size	1MW	10MW	50MW
Electrolyser Output (Tonne/annum)	150	1,500	7,500
Diesel Energy Equivalent (Litres / annum)	465,000	4,650,000	23,200,000
Electrolyser Output (kg/day)	480	4,800	24,000
Diesel Energy Equivalent (Litres / day)	1,500	15,000	75,000
Estimated No. HGVs[1,3] (Fuel Cell)	43	434	2,169
Estimated No. LCVs[2,3] (Fuel Cell)	62	623	3,116
Estimated No. HGVs[1,3,4] (Dual Fuel)	144	1,446	7,233
Estimated No. LCVs[2,3,4] (Dual Fuel)	207	2,077	10,388

Notes:

1. *Heavy Goods Vehicle (HGV) is assumed to be a 12-tonne truck*
2. *Light Commercial Vehicle (LCV) is assumed to be a typical van / jeep <3.5 tonnes GVW. Engine sizes for such vehicles are typically in the range 2.4 – 3.0 litres*
3. *Assumed annual distance travelled by HGV / LCV is 50,000km. Fuel consumption rates of 21.4l/100km and 14.9l/100km respectively*
4. *Dual fuel operation will displace approximately 30% of diesel consumed by HGV or LCV. Consequently, the number of converted vehicles required to consume hydrogen output from electrolysers is higher*

Based on the above, for every 1MW of electrolyser capacity, there would be potential to fuel approximately 40 Fuel Cell HGVs, or approximately 60 Fuel Cell LCVs, or various combinations of these depending on fleet make up. As dual fuel operation displaces approximately 30% of diesel, the number of dual fuel vehicles required to consume the hydrogen produced would be correspondingly higher at approximately 140 and 200 respectively.

The figures used further below are based on the 1MW electrolyser. This facilitates comparison with the gas injection Scenario S10 which has previously been identified as being relevant to the Rhode demonstrator concept (see Section 6). Figures used here for the transportation outlet can be readily scaled up or down for different larger electrolyser sizes.

7.2 CAPEX

7.2.1 Vehicle Costs

It has been shown above how many fuel cell vehicles and dual fuel vehicles could potentially be fuelled by a 1MW electrolyser. Assuming a 1MW electrolyser as a basis, the estimated costs of fuel cell vehicles or dual fuel conversions is shown on Table 7-2 below.

Table 7-2: Estimated Costs of Hydrogen Prepared Vehicle Fleets

	Fuel Cell		Dual Fuel	
(Figures in each column represent a different hypothetical vehicle fleet)	**HGV (Fleet 1)**	**LCV (Fleet 2)**	**HGV (Fleet 3)**	**LCV (Fleet 4)**
Number of Vehicles Assumed	40	60	140	200
Estimated CAPEX[1,2] (€)	20,000,000	12,000,000	8,260,000	7,000,000
Estimated Diesel Diversion (per annum)	428,000	447,000	449,400	447,000
Value of Diverted Diesel (@ €1.87/litre)3	800,360	835,890	840,378	835,890
Ratio of CAPEX to Value of Diesel Diverted	25	14.4	9.8	8.4
Estimated CO_2 emissions reduction (tonnes per annum)[4]	1,213	1,267	1,274	1,267

Notes:

1. *Estimated based on available literature in public domain*
2. *Figures for dual fuel conversions sourced directly from ULEMCo in 2023*
3. *Based on assumed vehicle annual distance travelled of 50,000km. HGV: 12 tonne truck. LCV: <3.5tonnes van / jeep*
4. *Assuming 2,835g CO_2 / litre diesel consumed and renewable hydrogen with emission rate of 0g CO_2 / litre*
5. *CAPEX values do not include VAT*

7.2.2 Refuelling Station

Hydrogen Mobility Ireland (HMI) has indicated that a hydrogen refuelling station only becomes feasible at a scale of 400kg hydrogen per day (52). This size is approximately equal to the output of a 1MW electrolyser. It is also approximately the same as 1 tube trailer load of hydrogen per day.

The cost of a refuelling station used in this study is based on figures produced by HMI. It is estimated that the CAPEX for the fuelling station element (not including electrolyser) is €2 million. It is assumed that this cost is for a stand-alone refuelling station which could be located adjacent to the electrolyser or located at a distance.

7.2.3 Hydrogen Transportation

In the scenario where the refuelling station is located remotely from the electrolyser, it is assumed that hydrogen would be compressed into tube trailers for delivery by road to the refuelling station. The estimated costs for a virtual pipeline used for the gas injection option would be approximately the same for the fuelling station option. Therefore, the same figures are used in the CAPEX and OPEX summary below.

7.3 OPEX

Vehicle fuelling typically takes place at a hydrogen pressure of 350bar. (A higher pressure of 700bar may also be used for faster filling times and higher tank capacities). For this study, the equipment required for pressurising hydrogen for a virtual pipeline is very similar to that used for fuelling. Therefore, the estimated OPEX associated with a fuelling station is based on figures provided earlier.

7.4 Summary of CAPEX and OPEX

The estimated costs for a hydrogen electrolyser and associated refuelling infrastructure for alternative vehicle fleets is summarised on Table 7-3 below.

Table 7-3: Summary of CAPEX and Annual OPEX for 1MW Electrolyser and Local or Remote Fuelling

Description	Local Fuelling	Remote Fuelling
CAPEX		
1MW Electrolyser	€ 1,000,000	€ 1,000,000
Gas Storage (460kg H_2)	€ 216,200	€ 216,200
Vehicle Refuelling Station[1]	€ 500,000	€ 2,000,000
Compressor (350bar)	€ 70,000	€ 70,000
Virtual Pipeline[2]	€ 0	€ 960,000
Total CAPEX	**€ 1,786,200**	**€ 4,246,200**
OPEX (annual)		
1MW Electrolyser	€ 75,000	€ 75,000
Electrolyser Power[3]	€ 1,139,126	€ 1,139,126
Compressor Power (350bar)[4]	€ 90,000	€ 90,000
General Maintenance (4% of CAPEX)	€ 71,448	€ 169,848
Miscellaneous (Personnel, fuel, insurances etc.)[5]	€50,000	€ 100,000
Total OPEX (annual)	**€ 1,425,574**	**€ 1,573,974**

Notes:

1. *Estimated. Local fuelling installation is assumed to be industrial in nature and located adjacent to the electrolyser site. Figure for remote fuelling station is from Hydrogen Mobility Ireland. This is assumed to be a commercial and publicly accessible installation*
2. *It is assumed that a virtual pipeline is not required for local fuelling station*
3. *Based on 150 tonnes of H_2 produced at 48kWh/kg and 0.2 €/kWh*
4. *Based on 150 tonnes H_2 compressed at 3kWh/kg and 0.2 €/kWh*
5. *Estimate*
6. *CAPEX values are exclusive of VAT*

The cost of hydrogen powered vehicles (new fuel cell vehicles or dual fuel conversions of existing vehicles) is not included above. Based on figures presented earlier in this report, this ranges from €7m to €20m depending on vehicle size and fuelling option. For the purposes of this study, vehicle costs are not included in CAPEX and OPEX for comparison with other end use options for hydrogen produced.

Cost savings arising from reduced diesel fuel consumption and reductions in CO_2 emissions will accrue to the operator. Vehicle operators will make investment decisions on the basis of these and other factors. A key parameter will be the cost of hydrogen 'at the pump' and carbon savings.

The retail price of diesel at the time of writing this report was €1.87/litre, which is equivalent to 17.4c/kWh. The corresponding value for hydrogen with the same energy content is €5.80/kg. If hydrogen can be produced at a lower cost, it could result in net reductions in fleet fuel costs for the transport fleet. Natural gas has a lower cost than diesel of approximately 9.5c/kWh. Therefore, there appears to be more value in hydrogen when it is used as a transportation fuel. However, this has not been modelled in detail for this study and potential cost savings are not included in the OPEX figures above.

In addition to the above, if a hydrogen fuelling network is developed in Ireland in the future, renewable hydrogen produced by an electrolyser at Rhode could be delivered to a remote fuelling station by tube trailer or by pipeline depending on location. Although there are no publicly accessible commercial hydrogen fuelling stations in operation in Ireland at present, it is predicted by HMI that 80 hydrogen filling stations will be built here by 2030. In this scenario, the CAPEX for the refuelling station could therefore be removed from the overall cost of a demonstrator project.

7.5 Conclusions

A high-level assessment of the potential for using hydrogen produced by a demonstrator electrolyser at Rhode in transportation end uses was carried out. The figures produced are based on a 1MW electrolyser. Transportation end uses are seen as an alternative outlet for surplus hydrogen produced by the electrolyser during seasonal periods of low gas demand. This will ensure a higher capacity factor for the electrolyser and reduce the amount of hydrogen storage required. If sufficient demand exists for hydrogen from transportation, this end use option could further demonstrate energy integration at Rhode. The key conclusions regarding the transportation end use option are outlined below.

- Hydrogen can be used to fuel HGVs and LCVs that are either fitted with fuel cells or converted to run on diesel / hydrogen blends in dual fuel operation. Dual fuel operation has an advantage of flexibility, but overall reductions in CO_2 savings will be lower than for fuel cells.
- Every 1kg of hydrogen has the same energy content as 3.1litres of diesel. In cost terms, this means that to be competitive (at today's prices), renewable hydrogen used in commercial transportation will need to be produced at a price of approximately €5.80/kg (17.4c/kWh). In comparison, the price of natural gas today is approximately 9.5c/kWh. This means that transportation outlets for hydrogen have a higher monetary value than gas injection.
- For every 1MW of electrolyser capacity, there would be potential to fuel approximately 40 Fuel Cell HGVs, approximately 60 Fuel Cell LCVs, or various combinations of these depending on fleet make up.
- Dual fuel hydrogen / diesel vehicles displace approximately 30% of the diesel fuel that would be consumed by an unconverted vehicle. The number of dual fuel vehicles that could consume the hydrogen output of a 1MW electrolyser would be approximately 140 converted HGVs, approximately 200 converted LCVs, or various combinations of these depending on fleet make up.
- The estimated CAPEX for a hydrogen fuelling station that could cater for refuelling hydrogen fuel cell vehicles or converted hydrogen / diesel dual fuel vehicles is approximately €2m. Lower cost options that would be more suitable for commercial use only, appear to be available on the market. These could potentially be more suitable for a demonstrator project targeting renewable hydrogen as a transportation fuel. However, to justify the expenditure on a fuelling station, there would need to be access to a relatively large captive fleet / fleets. Offaly County Council operates a mixed fleet of commercial vehicles. There is potential for Offaly County Council to work with operators of other fleets in exploring the feasibility of developing hydrogen fuelling in the county or Region.
- Renewable hydrogen produced by a demonstrator electrolyser could be supplied to a remote hydrogen fuelling station using tube trailers or a pipeline. Such a facility could potentially be developed in the medium to longer term future at a point on the Trans European Transport Network (TEN-T). A virtual pipeline transportation option would have lower CAPEX than a physical pipeline and would offer flexibility in relation to location. However, it would have higher OPEX than a physical pipeline.

8 DISTRICT HEATING OPTION FOR RHODE

In Section 4.5, the possibility of a hydrogen fuelled district heating network serving for Rhode was indicated. The potential advantages of such an outlet for hydrogen produced by a demonstrator scale electrolyser located at Rhode Green Energy Park include:

- This option would be a single point of use for locally generated renewable hydrogen.
- As district heating can be combined with other forms of primary energy, there would be real potential to combine a hydrogen fuelled central boiler with other renewable sources of heat such as geothermal energy, biogas and biomass, but also sources of waste heat that may be accessible. This would result in a more flexible system capable of adjusting to varying amounts of available curtailed / constrained renewable electricity.
- It would avoid the technical and regulatory challenges associated with developing a small-scale hydrogen gas network. A hydrogen gas network would entail safely bringing hydrogen into customer premises, with the associated challenges of educating end users in relation to hydrogen safety.
- It is noted that the UK government funded Hy4Heat project which ran from 2017 to 2021 fully explored the development of 100% hydrogen appliances for domestic and commercial use. This project involved a large amount of collaboration between gas operators NGN and Cadent and various manufacturers to develop 100% hydrogen ready appliances. Demonstration homes fuelled by 100% hydrogen were also built in Gateshead, Newcastle upon Tyne, to show-case proto-type appliances. This successful project will be developed further into a 100% hydrogen village in the coming years, followed by further expansion.
- Given the existing primary heat sources in Rhode, a heating outlet for renewable hydrogen (if fully utilised) will deliver more greenhouse gas offsets than displacing natural gas by injecting hydrogen into the gas network and similar offsets as for displacing conventional transportation fuels.
- If this option were to be developed, it would represent a tangible direct benefit to the local community in terms of access to renewable heat.

For the above reasons, the possibilities of developing this option have been examined at a high-level. Detailed modelling of costs and potential need for hydrogen storage etc. has not been carried out.

8.1 Heating Demand in Rhode

Rhode is located approximately 2km from Rhode Green Energy Park and has a population of approximately 800 people. A preliminary review using Google Maps indicates that there are approximately 280 homes and 11 commercial premises located in clusters around Rhode village.

Rhode is not connected to the Irish natural gas network. It appears from desktop survey that the main sources of heating in the village and surrounding habitation are solid fuel and home heating oil, with LNG and electrical heating also likely.

An average heat load for buildings in Rhode is assumed to be 75 W/m^2. This is based on the assumption that the consumption of residential and commercial properties in Rhode will balance out due to the variances between small bungalows, larger detached houses and small businesses. This gives a rough estimate for the total heat demand in Rhode to be 2.8MW including a capacity for losses in the system.

The minimum heating demand of Rhode is assumed to be 20% of the maximum load. This gives an estimate of 0.55MW as a minimum load. The minimum load is of importance as it indicates a constant minimum capacity that is required of the hydrogen boiler on a year round basis. This is an equivalent baseline for the amount of hydrogen that will need to be consumed.

Matching the base heat load to a dependable heat source is an important consideration for a district heating system. Peak heating demands can be met from other sources or stored heat. The reliability of the overall district heating system will be of critical importance to customers. Therefore, peak load and back-up boilers are essential parts of the system. This also means that in practice, it is likely that alternative outlets for renewable hydrogen produced by the electrolyser would be needed to ensure that capacity factor is maximised.

8.2 Indicative District Heating Network

A district heating network operates similarly to a typical house central heating system, but on a much larger scale. Heated water is circulated through a system of insulated flow and return pipelines which extend throughout the community which the system serves. The system comprises twin pipelines (flow and return) which are laid in parallel and underground with approximately 900mm cover.

Hot water leaves the central boiler with a temperature of approximately 85ºC – 90ºC, and returns to the central boiler with a temperature of approximately 35ºC – 40ºC. Customer premises are connected to the district heating system with individual heat exchanger / meter installations. Within customer premises, the system would typically be designed to operate with flow and return temperatures of 80ºC and 40ºC respectively. The above temperatures would be typical for district heating networks in Denmark, but different temperature ranges could also be used.

A possible layout for a district heating network serving Rhode from a central boiler located at Rhode Green Energy Park is indicated in Figure 8-1 below.

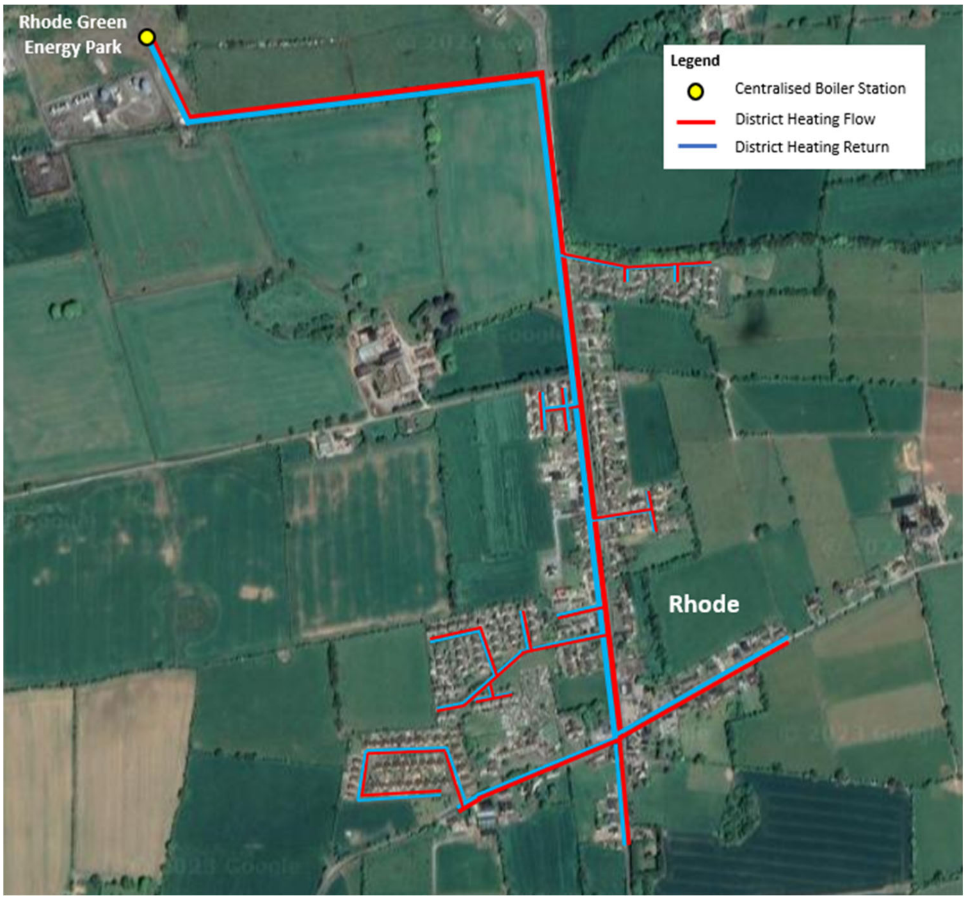


Figure 8-1: Possible Layout for Hydrogen Fuelled District Heating Network for Rhode

Detailed design would be required to confirm the technical details of any district heating network. However, a simple district heating network layout has been developed for the purposes of generating a high-level CAPEX estimate. The network comprises the following key elements:

1. Central boiler station including peak load & back-up boiler and heat storage unit to assist with meeting variable demand. It has been assumed that the boiler capacity required for a district heating network in Rhode would need to be approximately 2.8MW, with a base load assumption of 0.5MW – 1MW. It should be noted that future commercial heat users will occupy premises at Rhode Green Energy Park which will increase the overall heat demand in the network.
2. Water treatment and pumping equipment, including control systems etc. The district heating system is a closed system, but the water within it needs to be treated to inhibit corrosion. The rate of pumping will depend on the heat demand and also the rate at which heat is lost to the ground from the network

itself. Longer networks can be expected to have higher rates of heat loss and therefore, more pumping is required to circulate the water within the system.

3. District heating pipeline network. For this study it has been assumed that the district heating pipeline network would be made up of pipe sizes ranging from 125mm down to 25mm.

Linear heat density is a parameter indicated by Codema as one measure of the viability of a district heating network. The linear heat density of the above indicative district heating network has been calculated to be approximately 980kWh/m. Further detailed work would be required to explore the overall viability of the network. However, for this study, a high-level estimate of the expected CAPEX and OPEX has been produced.

8.3 CAPEX & OPEX

A high-level CAPEX and OPEX estimate has been developed based on information relating to district heating that is publicly available from SEAI and Codema (53).

Table 8-1: Estimate CAPEX for Hydrogen Electrolyser and District Heating Option for Rhode

Item	Description	Estimated Cost (€ ex VAT)
1	1MW Electrolyser	1,000,000
2	Boiler plant	50,000
3	Thermal store	45,000
4	Electrical and Data	135,000
5	Controls	65,000
6	Engineering	135,000
7	Civil Plant	85,000
8	DN125 2 Pipe System	1,355,250
9	DN80 2 Pipe System	441,325
10	DN50 2 Pipe System	1,373,815
11	**Total Estimated CAPEX**	**4,685,390**
12	1MW Electrolyser	75,000
13	Electrolyser Power	1,139,126
14	Estimated OPEX for DH network (4% of DH CAPEX)	147,416
15	**Estimated OPEX** (4% of CAPEX) (€ per annum)	**1,361,541**
16	Estimated cost of consumer unit (Residential)	5,000
17	Estimated cost of consumer unit (Commercial)	10,000
18	**Total estimated cost of consumer installations**[2]	**1,515,000**

1. *CAPEX values are exclusive of VAT*
2. *Based on 281 residential units and 11 commercial units. For information. Not included in CAPEX figures*

Due to the requirement to install a network of district heating pipes, CAPEX for the district heating option is relatively high compared to other potential outlets for hydrogen produced by an electrolyser at Rhode. There is no equivalent for district heating to the virtual pipeline option for injection of hydrogen into the natural gas network. However, the following could reduce the impact of the cost of the pipeline network on a developing district heating system:

1. The district heating network could be developed in stages. Although the indicated district heating network outline for Rhode is relatively small, it could still be developed in stages.

2. If new commercial units to be built at Rhode Green Energy Park are designed to be district heating compatible, they could increase the overall heat demand very significantly and with minimal length of district heating piping. They could therefore represent an important base load for the overall system.
3. A district heating pipeline network will have a long service life of approximately 40 – 50 years. Unlike mechanical plant and equipment, it could therefore be financed over a longer period, with consequently reduced financial impact on the business case for the system.

The CAPEX associated with consumer units should be assumed to be borne by individual consumers. This could be considered in the same way as vehicle conversion or replacement costs were considered for the transportation fuel outlet options described earlier in this report. For the purposes of comparison of the alternative options, the cost of consumer units has therefore not been included.

A major challenge to the development of any district heating network is to secure a sufficient number of consumers to justify the business case for the system. All of premises in Rhode have their existing heating systems which it can be expected will have varying amounts of remaining lifespan. This means that any move away from existing heating to a newly developed district heating system would happen over a period of time. The increasing cost of fossil based fuels and associated increasing cost of carbon, should act as positive incentives to change. Similar to the gradual but accelerating move to electric vehicles in Ireland, decisions on investing in low carbon heat at a domestic level will depend on individuals' circumstances. Financial support could be very important to building up a sufficient scale of district heating consumer base at Rhode within a short timeframe.

9 CO_2 EMISSIONS REDUCTION POTENTIAL

A 1MW electrolyser can produce approximately 150 tonnes of hydrogen per annum or approximately 460kg per day. Table 9-1 below shows the potential CO_2 offsets that could be achieved by a 1MW electrolyser when hydrogen produced is injected into the gas grid or used to replace conventional transportation fuel (diesel).

Table 9-1: 1MW Electrolyser CO_2 Emissions Savings

CO_2 Offset	Gas Injection Virtual Pipeline[3]	Gas Injection 4Bar Pipeline	Vehicle Fuelling [4]	District Heating
tonnes CO_2 / year	854	908	1,160	1,265
tonnes CO_2 / day	2.3	2.5	3.2	3.5
kg CO_2 saved / kg H_2 used	5.7	6.1	7.7	8.4

Notes:

1. *When renewable hydrogen is used in the natural gas network, it will result in CO_2 emissions savings of approximately 6.8kg CO_2 for every 1kg of H_2 injected. This corresponds to approximately 1.9kg CO_2 for every m^3 of gas that is displaced / not used*
2. *When renewable hydrogen is used as a replacement for diesel fuel, the corresponding CO_2 emissions savings are approximately 8.8kg CO_2 for every 1kg of H_2 consumed. This corresponds to approximately 2.8kg CO_2 for every 1litre of diesel not used*
3. *The virtual pipeline option accounts for the hydrogen requirement of a dual fuel truck to transport the hydrogen to the injection point*
4. *Vehicle fuelling accounts for emissions saved when 60 fuel cell LCV's are used*

The above annual CO_2 offsets for a 1MW electrolyser and gas injection via virtual pipeline are approximately equivalent to the annual CO_2 emissions of approximately 28 HGVs or approximately 40 LCVs. The corresponding figures for a 1MW electrolyser where the hydrogen dual fuel system is used for transportation are approximately 38 HGVs or approximately 55 LCVs.

Gas injection into Derrygreenagh Power Station would result in a similar offset in emissions compared to injection directly into the gas grid. A blend of natural gas and hydrogen would be used and could likely comfortably consume all of the output of the 1MW electrolyser.

The CO_2 emissions savings for a range of blends of hydrogen in natural gas (on a volumetric basis) were outlined earlier in this report. This ranges from 0.6% reduction in CO_2 using a 2% hydrogen blend to 7% reduction in CO_2 using a 20% blend. It should be noted that even though hydrogen has a much higher energy content than natural gas per kilogram (kg), it has a much lower energy content than natural gas per cubic metre (m^3). This means that volumetric blends of hydrogen in natural gas result in a reduced calorific value of the blended gas. Therefore, for the same energy content, there needs to be an increased flow of blended gas.

For this reason, the rate of CO_2 offset by renewable hydrogen replacing natural gas is given in Table 9-1 above on a kg CO_2 / kg H_2 basis. This is also directly comparable to the figure for diesel. It can be seen that transportation outlets for hydrogen offer approximately 30% more CO_2 reduction than gas injection as they directly replace diesel which is more 'carbon dense' than natural gas.

Just as for the above comparison between natural gas and diesel above, Figure 9-1 shows the potential annual CO_2 savings if renewable hydrogen is used to replace fuels commonly used for home heating. Common fuels for home heating include natural gas, electricity, coal, peat briquettes, fuel oil (equivalent to diesel fuel) and Liquified Petroleum Gas (LPG). It is clear that there is greater potential CO_2 savings when renewable hydrogen displaces more carbon dense fuels such as electricity, coal, peat and fuel oil. In many rural areas, where there is no existing natural gas network, these more carbon dense fuels are used widely. There is therefore an opportunity to maximise CO_2 emissions reductions from renewable hydrogen by exploring how it could be used in the heating market. However, to access this market, there needs to be a distribution network. One option is a hydrogen gas network, with user appliances converted to hydrogen. Another option is a centralised hydrogen boiler, heating a district heating network, with users converted to this using local heat exchangers. With both of these options, there would also be the challenge of identifying a suitable cluster of premises with good load diversity and connecting a sufficient number of these to the system.

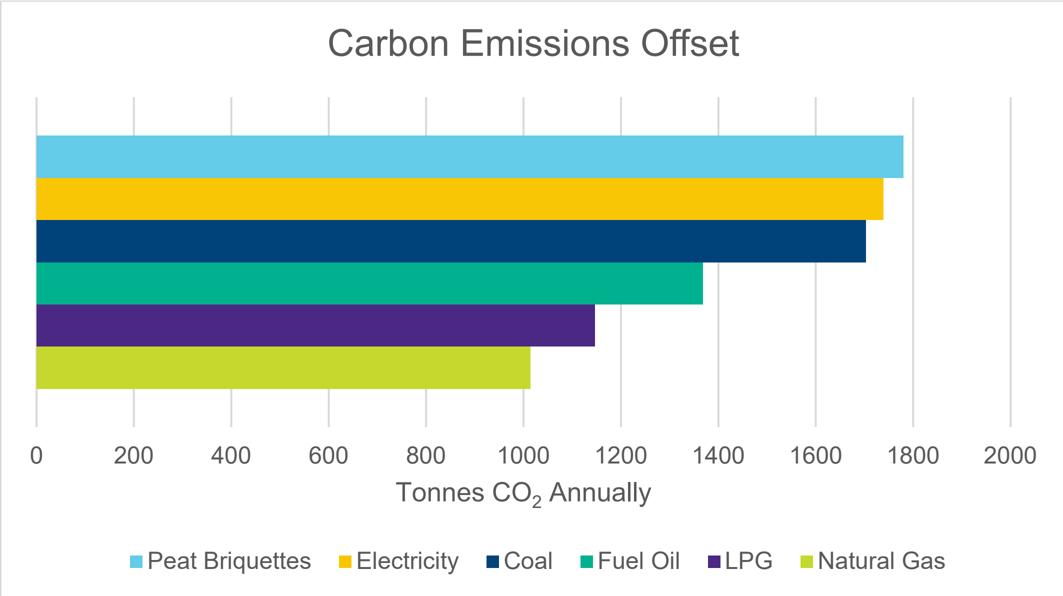


Figure 9-1: CO_2 Offset by Replacing Home Heating Fuels with Hydrogen

Table 9-2: 1MW Electrolyser CO_2 Emissions Offset Compared to Conventional Production

Product	Common Emission Per kg Produced ($kg\ CO_2$)	Emissions Offset ($tonnes\ CO_2$)
Hydrogen	12.00	1800.00
Oxygen	0.08	11.73

Table 9-2 above shows emissions offset by creating hydrogen and oxygen using renewable energy which produces no emissions. 99.6% of the hydrogen produced globally is derived from reforming of fossil fuels and not green processes such as electrolysis (54). This means that most hydrogen being used in Ireland today comes at a carbon cost. Approximately 71% of hydrogen produced is known as 'grey hydrogen' and produces around 12 kg CO_2 per 1kg of hydrogen produced (55). Given a local market for the sale of hydrogen and replacement of grey hydrogen with renewable hydrogen, approximately 1,800 tonnes of CO_2 could be offset by a 1MW electrolyser. This would be contingent on a consistent and likely industry driven need for pure hydrogen nearby. Ireland currently consumes 2,000 tonnes of hydrogen every year (56) , the majority of which is grey hydrogen.

High purity oxygen for industrial use is commonly produced using cryogenic distillation. Although the feedstock is just decontaminated air, the process is quite energy efficient and requires 0.201 kWh per kilogram of oxygen produced (57). On the current Irish grid which burns fossil fuels, 0.389 kg of CO_2 is created per kWh (58). This means that for the total amount of oxygen a 1MW electrolyser could produce (75 tonnes), 11.73 tonnes of CO_2 would be offset per annum. Relative to the 1,800 tonnes of CO_2 offset by the hydrogen production, this figure is small.

10 PROPOSED DEMONSTRATOR PROJECT FOR RHODE

10.1 Key Considerations

This report builds on the Opportunity Assessment Report for Rhode Green Energy Park that was carried out in 2020. The potential opportunity for a green (renewable) hydrogen electrolyser was identified in that report, but specific details were not investigated. This report has explored the feasibility of a demonstrator-scale electrolyser at Rhode that is focussed on harnessing curtailed / constrained wind power and injection of the renewable hydrogen generated into the gas network. A high-level multi-criteria analysis of the main options considered for this feasibility study is presented on Table 10-1 below.

The multi-criteria analysis shows that each of the alternative options explored in this feasibility study have their own advantages and disadvantages. None of the options stand out as being strongly preferred, but on balance, Option 1 and Option 2 appear to be more preferred than the other options. The project configuration that has been developed for a proposed hydrogen demonstrator project for Rhode Green Energy Park has combined features from Option 1 and Option 2. It also includes an element of Option 6 (see further below). The following considerations were important in defining the proposed demonstrator project:

- As a demonstrator project, the size of the electrolyser should be relatively small. One of the objectives of the demonstrator will be to prove the concept of using curtailed / constrained wind power or 'dispatch down' to generate renewable hydrogen. Another objective will be to integrate this with injection of hydrogen into the gas network. When all of this has been done successfully, many lessons will have been learned. These lessons can be used to develop the concept further and at larger scale.
- The electrolyser should also be sized so as to maximise the quantity of available curtailed / constrained wind power or 'dispatch down' power used. This will help to ensure that the hydrogen produced meets the EU rules for Renewable Hydrogen, while also keeping costs at a minimum.
- The approach to injection of hydrogen into the gas transmission network is similar to that for injection of hydrogen into the gas distribution network. However, at this early stage of hydrogen development in Ireland, there are advantages to be gained when injecting hydrogen into a discrete gas network such as the networks serving Mullingar or Tullamore / Clara. Injecting hydrogen into a discrete gas distribution network means that relevant preparations can be made to ensure that the distribution network is fully compatible with hydrogen blends. The downstream effects of hydrogen blends can also be studied and monitored, with results being of relevance to the future roll out of hydrogen injection in other sections of the wider gas network. It is understood that this approach is preferrable to Gas Networks Ireland (GNI). It is therefore considered that this is the appropriate outlet if renewable hydrogen produced at Rhode is injected into the gas network.
- The demand for natural gas within the distribution network is seasonal, with peak demand being many times larger than minimum demand. An electrolyser sized to meet peak demand of hydrogen for injection into the gas network is likely to be under-utilised during times of low demand. For a smaller electrolyser sized for average hydrogen demand, storage requirements will also be high if alternative outlets for surplus hydrogen are not available. If the electrolyser is under-utilised i.e. has a low capacity factor, this will have a large negative impact on the overall project's economic feasibility. Therefore, it will be a big advantage to the demonstrator if alternative outlets for surplus hydrogen are available. Having alternative outlets will mean that electrolyser operational hours can be maximised. This will help to keep the cost of renewable hydrogen produced as low as possible.
- The sizes of electrolyser that could deliver sufficient renewable hydrogen for meeting up to 10% of peak demand from the gas distribution networks in Mullingar and Tullamore / Clara are 0.5MW and 1.0MW respectively.
- The virtual pipeline system for transporting renewable hydrogen from electrolyser to end use options has a relatively low CAPEX compared to a fixed pipeline. It also offers flexibility in terms of end use destination. This advantage means that either Mullingar or Tullamore / Clara could potentially be the location for injection of hydrogen into the gas network. It also means that potential future hydrogen fuelling stations could be served by a virtual pipeline.
- For transportation end uses, converted 'dual fuel' (hydrogen / diesel) vehicles offer lower CAPEX and greater fuel flexibility. These could be a very suitable means of maximising the use of surplus hydrogen. This would also allow time for a public hydrogen fuelling system to develop and a future transition to fuel cell vehicles operating on 100% hydrogen.

Table 10-1: Multi-Criteria Analysis of Main Options considered for the Rhode Hydrogen Demonstrator

Colour Coding	
Colour Coding	Preferred / Highest Scoring (green)
	Acceptable / Medium Scoring (blue)
	Less Preferred / Lowest Scoring (red)

Criterion	Option 1 Electrolyser & Hydrogen Injection to Gas Distribution Network with Virtual Pipeline.	Option 2 Electrolyser & Hydrogen Injection to Gas Distribution Network with Physical H_2 Pipeline (18km).	Option 3 Electrolyser & Hydrogen Transport to Derrygreenagh Power Station by Physical H_2 Pipeline (5km).	Option 4 Electrolyser & Local Vehicle Fuelling Station. No virtual pipeline. No physical pipeline.	Option 5 Electrolyser & Remote Vehicle Fuelling Station with Virtual Pipeline.	Option 6 Electrolyser & District Heating (DH) Network in Rhode.	Comments
Compatibility with RGEP objectives	High	High	Medium	Medium	Medium	High	Gas network injection and DH network powered by H_2 are preferred in terms of local energy systems integration.
Delivery Challenges	Medium No H_2 injection permitted at present in Ireland.	Medium No H_2 injection or H_2 pipelines permitted at present in Ireland.	Medium No H_2 pipelines permitted at present in Ireland.	Low Existing small-scale examples in Ireland.	Low Existing small-scale examples in Ireland.	Low DH network eliminates regulatory aspects of a H_2 pipeline network	GNI is actively exploring the injection of H_2 into the gas network. A pilot project is planned. Regulatory approval will be required from CRU. Small-scale H_2 fuelling for pilot projects has taken place in Dublin (BOC) and in Belfast (Translink)
System Flexibility	High	Low	Low	Medium	High	Low	A physical pipeline is point to point only. Virtual pipeline is flexible for multiple end users. Local fuelling station is likely to be further from vehicle fleets. DH network will only serve local customers.
Estimated CAPEX (€ ex VAT)	2.0m	3.8m	2.1m	1.8m	4.2m	4.7	<€1.99m: Green €2m-€3.99m: Blue >€4m: Red
Estimated OPEX (€ per annum ex VAT)	1.49m	1.35m	1.35m	1.43m	1.57m	1.36m	OPEX is dominated by the cost of electricity for running the electrolyser.

Estimated Cost of Hydrogen for Break even	€10.90/kg H_2 32.70 c/kWh	€10.85/kg H_2 32.57 c/kWh	€10.05/kg H_2 30.16 c/kWh	€10.71/kg H_2 32.14 c/kWh	€12.58/kg H_2 37.73 c/kWh	€11.38/kg H_2 34.13 c/kWh	Estimated Cost of Hydrogen (including cost of electricity for running electrolyser) to return NPV of zero at end of Year 20.
Estimated Annual Revenue (€ ex VAT)	1.63m	1.63m	1.51m	1.61m	1.89m	1.71m	Based on above ECOH values and output of 1MW electrolyser (150 tonnes H_2 per annum).
Impact on end users if H_2 production is interrupted.	Low Natural gas network is highly resilient.	Low Natural gas network is highly resilient.	Low Natural gas network is highly resilient.	Medium **Dual Fuel**: Diesel availability is good. **FCEV**: Availability of alternative H_2 supply is limited.	Medium **Dual Fuel**: Diesel availability is good. **FCEV**: Availability of alternative H_2 supply is limited.	High Conventional fuel back-up is needed.	DH network would be a new utility Service provider input with customer support experience would be required. Back-up heat source e.g. geothermal / other needs to be confirmed.
Potential for Expansion	High Many locations accessible with virtual pipeline.	Low Constrained by fixed location of pipeline.	Medium Constrained by fixed location of pipeline but potentially large demand from power station.	Medium Would need addition of virtual pipeline to expand.	High Many locations accessible with virtual pipeline.	Medium Opportunity to expand network to Rhode village.	It is assumed that upper limit of demand for hydrogen for injection in distribution network is at 20% H_2.
Estimated Carbon Savings (Tonnes CO_2 / annum)	854	908	908	1,160	1,050	1,265	Natural gas is the lowest carbon fossil fuel. Therefore, reductions in CO_2 emissions achieved through displacement of diesel / heating oil are greater than for natural gas. Physical pipeline options eliminate the CO_2 emissions arising from transportation by virtual pipeline.

- Hydrogen storage can be achieved using mobile tube trailers / Multi-Element Gas Containers (MEGCs). The typical tube trailer has a capacity of approximately 400kg hydrogen which is a useful batch size corresponding to roughly 1 day of hydrogen output from a 1MW electrolyser. Additional tube trailers could also be used if necessary.
- This project was initiated by the North Offaly Development Fund (NODF) and Offaly County Council. Rhode Green Energy Park is located within County Offaly where there is a long tradition of energy generation from peat and ongoing developments in renewable energy. If feasible, a demonstrator project located in County Offaly and having tangible benefits within the county would be preferable to the project partners.
- The 'green effect' or carbon savings arising from injection of hydrogen into the gas network will be much more significant locally in a smaller confined distribution network compared to injection into the gas transmission network. In a similar way, if surplus hydrogen is used in local transportation fleets, the carbon benefits will also be realised locally.

10.2 Proposed Demonstrator Project

The proposed demonstrator project is described schematically on Figure 10-1 below. On the basis of the foregoing considerations, it has the following features:

- **A 1MW PEM electrolyser**. An electrolyser of this size can produce up to 150 tonnes of renewable hydrogen per annum (approximately 460kg per day).
- The electrolyser would be powered firstly by **curtailed / constrained wind power**, supplemented by other renewable power including wind and solar power. The electrolyser must be powered by renewable electricity in order to ensure that it meets the requirements for classifying the hydrogen produced as 'Renewable Hydrogen'.
- **Injection of renewable hydrogen into the gas distribution network of Tullamore / Clara via Gneevekeel AGI** (approximately 33km away by road). As explained earlier, injection of hydrogen into a discrete section of GNI's gas distribution network will facilitate a carefully controlled introduction of hydrogen blends to gas customers. This approach is more likely to be aligned with GNI's objectives.
- The Tullamore/ Clara gas distribution network was chosen for its wide variety of end users including a hospital and a distillery. Being located within County Offaly is also an advantage in terms of maximising the overall project's contribution to the energy transition of County Offaly.
- Use of renewable hydrogen in **local transport fleets**, such as that operated by Offaly County Council. BNM and Enva have separately indicated their interest in exploring this possibility also. Converted dual fuel (hydrogen / diesel) vehicles offer lower CAPEX and greater flexibility. These features are considered to be compatible with the demonstrator concept.
- The estimated **hydrogen storage requirement is 592kg**, or 3 days' worth of the average consumption of Tullamore/Clara at a rate of injection of hydrogen of 10%.
- A **virtual pipeline** system is required to deliver hydrogen generated to end users. A total of **3 tube trailers and 1 tractor unit** is sufficient. At any given time, 1 trailer would be filling at Rhode, 1 trailer would be unloading at Gneevekeel AGI and 1 trailer would be storing hydrogen at Rhode, waiting to be delivered to the end use location. This number of tube trailers will meet the above storage requirement of 592kg.
- Assuming 460kg of hydrogen is produced per day on average, 48% of this would be required for injection into the gas distribution network serving Tullamore / Clara.
- The remaining 52% (on average) would be available for other end uses such as in local transport fleets. The estimated number of vehicles (dual fuel or fuel cell) that can be fuelled by this quantity of hydrogen is summarised on Table 10-2 below.

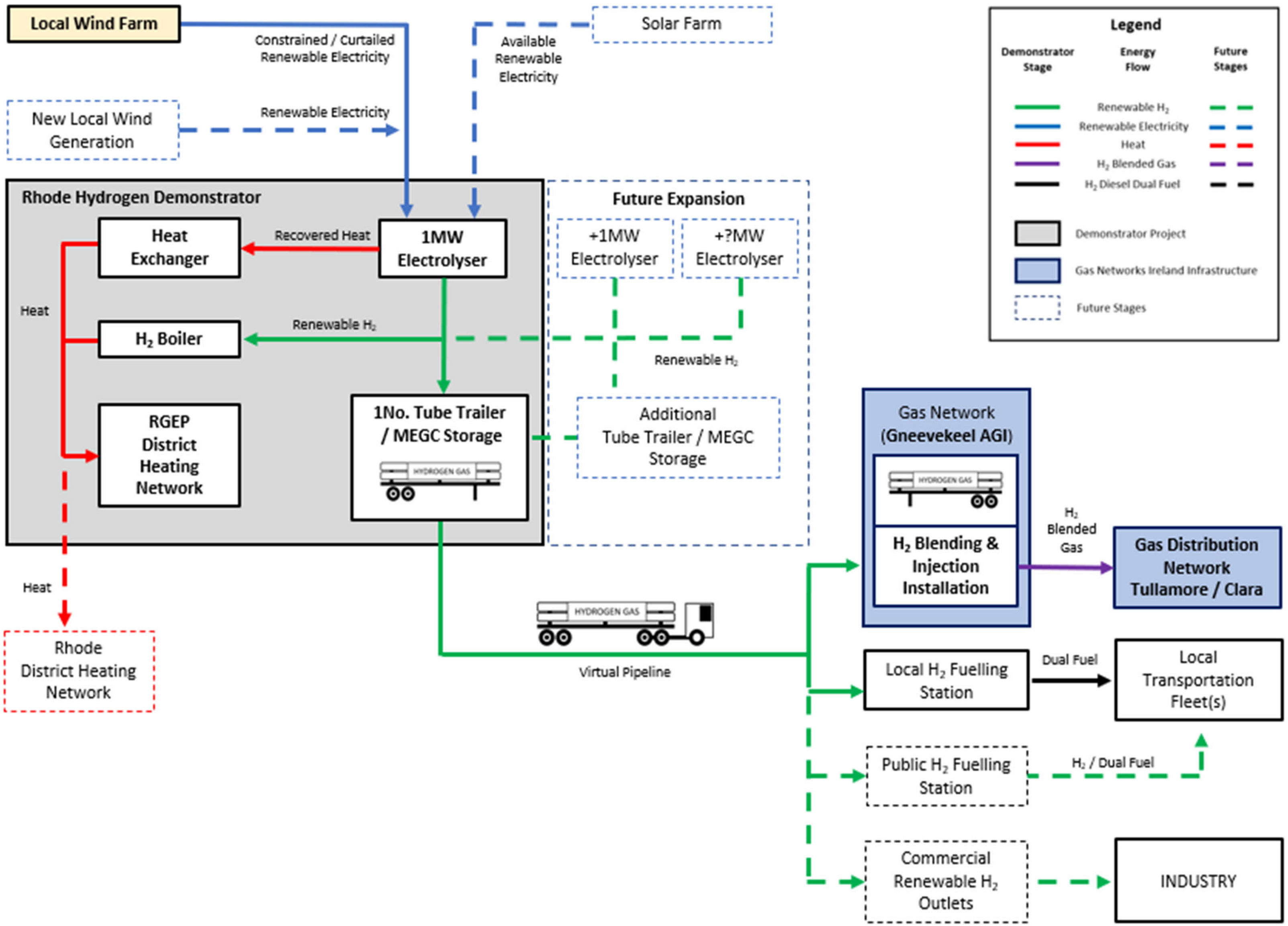


Figure 10-1: Schematic of Proposed Rhode Hydrogen Demonstrator Project

Table 10-2: Potential vehicle fleet sizes that can be supported by Rhode demonstrator after injection of hydrogen into Tullamore / Clara gas distribution network

Tullamore / Clara Scenario	Surplus Hydrogen (kg/annum)	Dual Fuel LCVs (No.)	Dual Fuel HGVs (No.)	Fuel Cells LCVs (No.)	Fuel Cells HGVs (No.)
1MW 10% Blend	77,992	115	80	34	24
1MW 5% Blend	113,996	168	117	50	35
0.5MW 5% Blend	38,996	57	40	17	12
0.5MW 2% Blend	60,598	89	62	19	19

Notes:

1. *Assumes a HGV consumption of 4.5kg H_2/100km and an LCV consumption of 6.5kg H_2/100km*
2. *It is assumed dual fuel systems use 30% hydrogen as fuel*
3. *Annual distance travelled is modelled as 50,000km*

- It is proposed that a 'back-up' outlet for renewable hydrogen produced is within the developing market for renewable hydrogen via gas retailers such as BOC. The market for renewable hydrogen is developing quickly. As further momentum is gained in the transition away from carbon based fuels, we can expect there to be demand for this product.
- The demonstrator project should be designed and configured to facilitate the recovery of waste heat from the electrolyser and potentially the use of renewable hydrogen in a **local district heating network within Rhode Green Energy Park**. A local district heating network at this scale would be an ideal way of demonstrating further energy integration at Rhode with minimum costs.
- If fully realised, the proposed demonstrator project will have the advantage of demonstrating **energy systems integration across the electricity, gas, transport and heating sectors**.
- As mentioned, the 1MW electrolyser will produce enough renewable hydrogen for a 10% hydrogen / natural gas blend in Tullamore/Clara. At the same time, it can provide approximately 30% of the fuel demand of local transport fleet(s) when these are converted to dual fuel operation. These outlets for renewable hydrogen produced will each offset the use of different fossil fuel types (Natural Gas and Diesel). The injection of approximately 72 tonnes per year of hydrogen into the gas distribution network will offset approximately 487 tonnes of CO_2 per year. The use of the rest of the hydrogen produced (approximately 78 tonnes per year) for fuelling 'dual fuel' (hydrogen / diesel) converted vehicles will offset approximately 686 tonnes of CO_2 per year. Combined, this is an **estimated annual CO_2 emissions saving of 1,173 tonnes**.

10.3 Investment Case

A high-level investment case for the proposed Rhode demonstrator project has been carried out. This uses key cost information for the alternative options assessed and details from the techno-economic modelling, in particular Scenario S10 which was used as a reference point. The investment case is based on two components:

1. Estimated CAPEX and annual OPEX (including cost of electricity for the electrolyser)
2. Net Present Value (NPV) calculation, which yields an Estimated Cost of Hydrogen (ECOH)

These are outlined in the following sections.

10.3.1 Estimated CAPEX and Annual OPEX

The CAPEX for each component part of the proposed demonstrator is sourced from the CAPEX estimates for the alternative options considered in this feasibility study. Where relevant, OPEX figures from these options have also been used. The results are summarised on Table 10-3 below. Where adjustments have been made that are specific to the proposed demonstrator, these are noted below the table.

Table 10-3: Estimated CAPEX and Annual OPEX for Proposed Demonstrator Project

Description	CAPEX[1] (€ ex VAT)	OPEX (€ ex VAT)
1MW Electrolyser	1,000,000	75,000
Power Consumption for Electrolyser[2]		1,139,000
Gas storage[3]	280,000	
3 Tube Trailers + 1 Tractor Unit	960,000	
Compressor (350bar)[4]	€70,000	90,000
Gas Injection facility at Gneevekeel AGI[5]	0	0
On Site Fuelling Facility Storage[6]	€220,000	
On Site Fuelling Facility Pump/Compressor[7]	€250,000	
RGEP Local DH network[8]	€100,000	
General Maintenance (4% of CAPEX)		115,200
Miscellaneous (Personnel, fuel, Insurances etc.)		100,000
Totals (€ ex VAT)	**2,880,000**	**1,519,326**

Notes:

1. *Estimated CAPEX for plant and equipment only. Figures are rounded and do not include for land, civil works etc*
2. *Based on an electrical demand of 48.31kWh$_{elec}$/kg H_2 produced and a cost of electricity of €0.2/kWh*
3. *Equivalent to 3 days of storage for 10% average annual blend in Tullamore/Clara network (592 kg H_2). Storage cost based on €470/kg of H_2*
4. *Based on an electrical demand of 3kWh$_{elec}$/kg H_2 compressed and a cost of electricity of €0.2/kWh. Total annual production of renewable hydrogen by 1MW electrolyser is 150 tonnes or approximately 460kg/day*
5. *Estimated CAPEX for hydrogen blending and injection installation is €500,000 ex VAT. It is assumed that the investment in this infrastructure would be borne by GNI as owner and operator of the gas network. However, it is noted that such a scenario would depend entirely on the regulatory model developed around delivering such facilities. Development of such regulations does not appear to have been started at this time.*
6. *Equivalent to storage of 1 day average of hydrogen production (460kg of H_2)*
7. *Estimated. It has been assumed that for a local transport fleet, this installation can be industrial in nature i.e. does not need to meet requirements of a commercial publicly accessible hydrogen fuelling station*
8. *Estimated cost for hydrogen fuelled boiler, heat exchanger and district heating network in immediate vicinity of the electrolyser in Rhode Green Energy Park*

It will be noted from Table 10-3 that total annual OPEX for the demonstrator is approximately 55% of total CAPEX. Electricity costs account for approximately 75% of annual OPEX. It is evident that the cost of electricity will have a very significant bearing on the overall financial status of the project and the resulting value for ECOH (see below).

10.3.2 Net Present Value (NPV)

A net present value (NPV) calculation was carried out to find the full cost of the project when all CAPEX and annual OPEX costs are considered together and discounted over the life of the project. The NPV analysis was also used to determine the Estimated Cost of Hydrogen (ECOH) required to enable the project to break even financially. The NPV calculations are included in Appendix D. The main assumptions in carrying out this work are summarised below.

- CAPEX and OPEX figures for the proposed demonstrator project have been taken from Table 10-3 above.

- CAPEX figures are for mechanical plant only and do not include the cost of land, site preparation works, civil works utility connections etc.
- The cost of hydrogen blending equipment at Gneevekeel AGI and any associated civil works etc. is not included in the CAPEX and OPEX figures for the proposed demonstrator.
- It is assumed that water of a suitable quality is readily available to the project. No costs for purchase of water or water treatment have been included in CAPEX and OPEX figures.
- The project lifespan is assumed to be 20 years.
- A discount rate of 4% is assumed. This is the value recommended by Department of Public Expenditure for use in cost-benefit and cost-effectiveness analysis of public sector projects (59).
- The value for ECOH has been adjusted to achieve a NPV value of zero at the end of Year 20.
- Scenario S10 from the techno-economic modelling has been used as a reference point. This scenario assumed an electrolyser capacity factor of 91.2%. 21% of the renewable electricity powering the electrolyser is 'dispatch down' with an assumed cost of €0/kWh. The remaining 79% of renewable electricity is assumed to be sourced from local wind or solar farms directly or via the electricity grid at a wholesale cost of 20 c/kWh averaged over daily and night rates (60).
- The NPV calculation does not include costs of finance.
- The calculation does not include a profit margin.
- All figures used are exclusive of VAT.
- No monetary value has been attributed to the quantity of CO_2 that would be offset when renewable hydrogen is used to displace natural gas or diesel (1,173 tonnes per annum).

The main results of the NPV analysis are as follows:

- The resulting NPV of the project (CAPEX and OPEX costs combined over 20 years and discounted at 4% per annum) is approximately **€23.5m** (see Appendix D1).
- When values are assumed for hydrogen, based on whether it is used for gas network injection or transportation i.e. offset costs based on the assumed price for natural gas or diesel, the resulting NPV for the project (otherwise as calculated above) is reduced to approximately **€11.6m** (see Appendix D2).
- Based on the NPV analysis, the calculated ECOH for the project is **€11.54/kg H_2** (equivalent to 34.63c/kWh). This is the estimated minimum cost that renewable hydrogen produced at the proposed demonstrator electrolyser at Rhode could be sold for, in the absence of any financial support, in order to return an NPV of zero at the end of Year 20. As might be expected, this is much higher than the comparative prices of natural gas (9.5c/kWh) and diesel (€1.87/litre or 17.4c/kWh) that have been assumed for this project. (It is duly noted that the price of natural gas and diesel are always subject to change).
- The energy input required to power the electrolyser makes up a large part of the ECOH figure above – even when it is assumed that 21% of this is power is 'dispatch down' with zero cost. When the cost of other renewable power is removed from the NPV calculation, the resulting ECOH (equivalent to the LCOH used in the techno-economic modelling) drops to approximately €7/kg H_2 (approximately 21c/kWh).

Further detailed work will be required to develop a firmer estimate for ECOH having regard to the specific details of the proposed demonstrator. This is also necessary given the current volatility on the energy market and supply chain for specialised plant and equipment such as that required for the proposed demonstrator project.

10.4 Future Possibilities

In order for the proposed demonstrator project to have the best chance of being implemented, it will be necessary to focus on the core project elements outlined above. However, while the project is still at feasibility study stage, it is still worth considering the future possibilities that a successful demonstrator project in Rhode could open up. Figure 10.1 above identifies some of these possibilities which are outlined briefly below:

- Designing the demonstrator in a modular way will facilitate expansion at a later stage. The proposed 1MW electrolyser could be replicated to deliver more renewable hydrogen for multiple end uses.
- It is envisaged that the initial transportation end use option would be based on dual fuel vehicles for reasons of fuel flexibility and cost. It can be expected that a commercial hydrogen fuel network will be developed in Ireland over time, but this may not take place at scale until after 2030. Hydrogen fuelling locations will need to be developed in parallel with hydrogen production facilities. As this infrastructure develops, there will be greater confidence in accessing hydrogen fuel for transportation. This will in turn facilitate a shift to fuel cell vehicles. This transition can be planned for as converted dual fuel vehicles reach the end of their service lives. It can also coincide with expansion of the electrolyser at Rhode as demand for renewable hydrogen grows.
- As commercial hydrogen fuelling stations are developed, these will become potential outlets for renewable hydrogen produced at Rhode. Hydrogen fuelling stations on the planned TEN-T network are possible outlets, with others potentially being developed on the motorway network closer to Rhode. Demonstrating the generation and use of renewable hydrogen in transport using the Rhode demonstrator will be good preparation to avail of this opportunity. As outlined above, transportation end use appears to be an important outlet for renewable hydrogen a successful demonstrator project.
- The option of developing new local wind generation specifically for powering the electrolyser can be explored as the demonstrator becomes operational. This could make sense for scenarios where additional wind power is needed to maintain high capacity factor. There may even be opportunities in the coming years to acquire used wind turbines from older windfarms as these reach the end of their permitted lifespans. Older turbines are likely to be smaller than the preferred size of units today and in the future, but could be ideal for powering a demonstrator electrolyser, provided that they were serviceable.
- It is noted that the annual profile of heating demand from district heating network will be similar to that for the demand for natural gas within the residential and commercial sectors. A district heating outlet for renewable hydrogen from Rhode would therefore compete for renewable hydrogen from the Rhode electrolyser with the injection of renewable hydrogen into the natural gas distribution network at Tullamore / Clara. As noted above, a local renewable hydrogen fuelled district heating network within Rhode Green Energy Park could be very feasible. This is especially true considering that this location does not currently have access to the gas network and a new heating system will need to be developed there. There is also the possibility of using an available geothermal heat resource at Rhode for base heating load.
- Given that there is no natural gas network in Rhode, currently most homes and businesses there are heated using oil, Liquified Natural Gas (LNG), electricity or solid fuels. In the context of the Just Transition, there may be opportunities to take lessons learned from a small district heating network in Rhode Green Energy Park and to apply these to the development of a larger district heating network for Rhode that is fuelled by renewable hydrogen, geothermal energy and potentially other sources of renewable energy such as biomass. There may also be the possibility of accessing recovered heat from future possible industry located in or close to Rhode Green Energy Park. A project of this nature would have real benefits to the local community in sustainability terms and could also be replicated in other locations.

11 FUNDING OPPORTUNITIES

Funding in relation to hydrogen is available in the areas of Energy, Transport, Innovation and Research and Development at both EU and National Level. Regarding the next steps at Rhode, the following funds have been identified as potential opportunities:

EU Funding Streams:

- EU Just Transition Mechanism (JTM) (61)
- EU Innovation Fund
- European Regional Development Fund, Cohesion Fund and REACT-EU

National Funding Streams:

- Gas Networks Ireland Gas Innovation Fund
- The Climate Action Fund (CAF)
- The SEAI National Energy Research Development and Demonstration (RD&D) Funding Programme
- Connecting Europe Facility (CEF) – Energy/Transport

11.1 EU Funding Streams

11.1.1 EU Just Transition Mechanism

The Just Transition Mechanism1 (JTM) is a key tool to ensure that the transition towards a climate neutral economy happens in a fair way by providing targeted support over the period 2021-2027 in the most affected regions in the EU through 3 pillars:

1. A Just Transition Fund (Pillar 1)
2. An InvestEU 'Just transition' scheme (Pillar 2)
3. A new public sector loan facility (Pillar 3)

In December 2022, it was announced that €169 million will be invested in Ireland's wider midlands area with the EU's adoption of Ireland's Territorial Just Transition Plan (TJTP) (62) with support from the Just Transition Fund.

The approval of Ireland's TJTP opens the door to dedicated financing under the two other pillars of the JTM; InvestEU and public sector loan facility. Proposed investments in larger projects, for example, in relation to transport, renewable energy, energy efficiency, or retrofitting, may be better suited to seeking support from these pillars, particularly if sponsored by larger private sector entities or by public bodies.

11.1.1.1 Pillar 1: EU Just Transition Fund

The EU Just Transition Fund (EUJTF) is Pillar 1 of the European Union Just Transition Mechanism (63). The purpose of the EUJTF is to assist the most affected territories in transitioning to a climate neutral economy. Ireland is set to receive up to €84.5 million from the EU Just transition Fund over the period to 2027. With the Government of Ireland's match funding using Exchequer resources, up to €169 million will be available.

The fund will invest in specific projects that will generate employment in less carbon-intensive industries and help to absorb redundancies from the reduction in size or closure of the existing factories or plants in the regions. There is particular focus on the midlands as it has been particularly affected by climate mitigation policies.

11.1.1.2 Pillar 2: InvestEU Just Transition Scheme

Investments under the EUJTF may be complemented by a combination of grants and loans to private sector entities, for example, the InvestEU programme (64). The InvestEU Programme supports sustainable investment, innovation and job creation in Europe. The InvestEU Fund aims to mobilise more than €372 billion of public and private investment through an EU budget guarantee of €26.2 billion that backs the investment of implementing partners such as the European Investment Bank and other financial institutions.

11.1.1.3 Pillar 3: Public Sector Loan Facility

The public Sector Loan Facility (PSLF) is the third pillar of the Just Transition Mechanism (65). It is managed by the European Investment Bank and targets beneficiaries that are public sector entities including private law bodies with a public service mission. It supports projects addressing the challenges deriving from the transition to the European Union's climate target objectives in the territories most negatively affected by the climate transition as identified in the previously approved Territorial Just Transition Plans. PSLF is a blending instrument combining grants up to €1.525 billion from the EU budget with loans up to €10 billion from the European Investment Bank, and aims to mobilise around €18.5 billion of public investments. Successful projects receive a grant from the European Commission and a loan from the European Investment Bank.

Rhode Green Energy Park was successful in attracting grant aid under the Government of Ireland Just Transition Fund in 2021. The total funding awarded was €738,000. This was for carrying out infrastructure works to ensure that Rhode Green Energy Park is ready for new tenants and activities with the full complement of required services. The grant was also provided to complete a Feasibility Study entitled '*Exploring Data Centre Integration with Renewable Energy and Green Hydrogen in the Midlands*'.

11.1.2 EU Innovation Fund

The Innovation Fund is one of the world's largest funding programmes for the demonstration of innovative low-carbon technologies (66). The money raised via the Emissions Trading System (ETS) is reinvested into the Innovation Fund: one of the world's largest funding programmes for innovative low-carbon technologies.

The Innovation Fund will provide around €38 billion of support from 2020 to 2030, for the commercial demonstration of innovative low-carbon technologies. It aims to bring to the market, industrial solutions to decarbonise Europe and support its Europe's transition to climate neutrality.

The goal of the Fund is to help businesses invest in clean energy and industry to boost economic growth, create local future-proof jobs and reinforce European technological leadership on a global scale.

This is done through calls for large and small-scale projects focusing on:

- General Decarbonisation (budget: €1 billion)
- Innovative electrification in industry and hydrogen (budget: €1 billion)
- Clean technology manufacturing (budge: €0.7 billion)
- Mid-sized pilots (budget: €0.4 billion)

A number of various sized Hydrogen Projects have received funding or have been invited for grant preparation under the EU Innovation Fund (67). Examples of relevance for Rhode include a small-scale (5MW) renewable hydrogen production facility in Poland which includes a photovoltaic plant, energy management system and waste heat recovery system. This project is focussed on hydrogen for use in public transport (84 buses). (Another small-scale (1MW) electrolyser project based in Poland has been invited for grant preparation. However, details for this project are not yet clear. It could potentially be related to the 5MW project mentioned above). A small-scale (2MW) renewable hydrogen electrolyser project focussed on hydrogen for transport in Cyprus has been invited for grant preparation under the EU Innovation Fund.

11.1.3 EU Cohesion Policy Funds

The EU Cohesion Policy Funds (68) comprise the following:

- The European Regional Development Fund (ERDF)
- Cohesion Fund (CF)
- European Social Fund
- Just Transition Fund

Taken together, these funds represent almost one third of the total Multiannual Financial Framework budget for 2021 – 2027 (€1.211 trillion – € 1.074 trillion in 2018 prices), with ERDF being the biggest chunk. The ERDF and the Cohesion Fund will invest €234 billion in the EU's regions (respectively, €191 billion through ERDF and €43 billion through CF).

Although hydrogen is not specifically mentioned in the objectives or the key priorities of the funds, ERDF and CF have specific targets of 30% and 37% respectively to support innovation and entrepreneurship in the transition to a climate neutral economy. Since REACT-EU is providing additional funds to ERDF, it has the same objectives. This means that EU countries and regions will spend a minimum amount of their ERDF and CF allocations in these thematic areas.

Therefore, opportunities for funding hydrogen projects will depend on priorities identified in the national and regional programmes. This means that for hydrogen related projects, it needs to explored on a case-by-case basis whether they could fit into the priorities of the relevant programmes and the Smart Specialisation Strategies of the EU countries or region where the potential beneficiary is located.

There are many hydrogen related projects that were financed by the previous programming period 2014 -2020, for example, the Renewable hydrogen Project for Bremerhaven which received almost €20 million of EU funding in 2020 to develop a hydrogen production plant from an 8 megawatt wind turbine. Hydrogen storage methods will also be explored and developed.

CF and ERDF are implemented through national and regional programmes implemented by the relevant nation and regional authorities in line with the shared management approach.

11.2 National Funding

11.2.1 National Hydrogen Strategy - Early Hydrogen Innovation Fund

The National Hydrogen Strategy recognises the value of renewable hydrogen demonstrator projects to the advancement of these technologies in Ireland. Action 2 of the Strategy is to '*establish an early hydrogen innovation fund to provide co-funding supports for demonstration projects across the hydrogen value chain*'. This action has a timeline of 2023 – 2027. Details of the fund are due to be published in the near future.

The basis for the innovation fund aspect of the Strategy is clearly outlined in the following statement:

'Government commits to supporting pilot projects that can demonstrate hydrogen technology in an Irish context across the value chain, that demonstrate and develop our regulatory regime and can provide early evidence of the market opportunity for renewable hydrogen. It is expected that collaborative projects will deliver most learning'.

The proposed Rhode hydrogen demonstrator project appears to be very well aligned with the overall concept and objectives of the Early Hydrogen Innovation fund as outlined above. The project is also sufficiently well defined at this stage to facilitate a focussed application for funding. Once details of the Early Innovation Innovation Fund are available, it will be possible to review these and develop a possible application for funding for a Rhode demonstrator that will help to advance the technology of renewable hydrogen in Ireland.

11.2.2 GNI Gas Innovation Fund

The Gas Innovation Fund promotes and encourages and environment of innovation in the gas industry (69). The aim of the Fund is to provide support for research and demonstration projects. In addition, a small allocation of funding goes to Gas Networks Ireland for programme management. The gas innovation fund has been divided into the following two broad categories: Research (€1 million) and Strategic Projects (€3.17 m).

Examples of previous funded projected by Gas Networks Ireland include

- A Front End Engineering Design (FEED) for the first large scale transmission Central Grid Injection (CGI) (70) . This project is linked to the innovation fund's goals of assisting in the transition to a low carbon economy, increasing throughput through the gas system and delivering significant carbon savings. This is done by facilitating the building of a CGI which will deliver biomethane to the gas network.
- A Hydrogen Innovation Centre at Brownsbarn, West Dublin, where pipelines, meters and appliances are being tested for use with a variety of gases and hydrogen blends.

11.2.3 Climate Action Fund (CAF)

The Climate Action Fund (CAF) was established by Government in 2020 to provide assistance and financial support to projects which will help Ireland achieve its climate and energy targets (71). The CAF will provide at least €500 million in government funding up to 2027 towards this aim. The Fund will allow for the development of innovative initiatives which, without this support, may not otherwise be possible to accomplish. The Department of the Environment, Climate and Communications (DECC) is responsible for the Fund's implementation.

The CAF will have a number of calls for applications. The scope and scale of projects that will be supported by the various calls may need to vary to ensure the full objectives of the CAF are realised. This may include calls focusing on specific sectors (such as electricity, transport, heat or agriculture) or specific areas (such as capacity building, innovation or community participation). An example of the types of projects, initiatives and research that may be funded are:

- Projects that seek to increase the production, or use, of renewable energy in the State
- Initiatives and/or Research involving potentially innovative solutions to:
    - reduce greenhouse gas emissions in the State
    - increase the production or use of renewable energy in the State
    - increase energy efficiency in the State
    - increase climate resilience in the State
    - increase the removal of greenhouse gas in the State

11.2.4 SEAI National Energy RD&D Funding Programme

The SEAI National Energy Research, Development and Demonstration Funding Programme invests in innovative energy RD&D projects which contribute to Ireland's transition to a clean and secure energy future.

'Renewable hydrogen production from Irish onshore and offshore wind resources' is listed under small or medium scale projects in the call for submission of applications document.

11.2.5 Connecting Europe Facility (CEF)

The Connecting Europe Facility (CEF) fund supports the development of high performing, sustainable and efficiently interconnected trans-European networks in the fields of transport, energy and digital services.

The fund is suited to demonstration projects, studies, and co-financing of development of energy infrastructure.

Hydrogen related projects that can be funded include demonstration projects, studies, and co-financing of development for energy infrastructure.

11.2.5.1 CEF for Transport

The Connecting Europe Facility for Transport (CEF-T) is the funding mechanism that supports the implementation of the Trans European Network for Transport (TEN-T). It supports alternative fuels infrastructure (including electricity fast-charging and hydrogen refuelling infrastructure on the TEN-T road network, TEN-T rail network and TEN-T ports). CEF-T Alternative Fuels Infrastructure Facility (AFIF) calls for funding 1 – 4 include the M50, M1 (M50 to north of Balbriggan), M7 (to Portlaoise), M8 (Dublin-Cork route), M6 (Galway – Athlone) and M17 (Athenry – Tuam). Currently, the M4 / M6 routes are not included, but due to their high traffic volumes, they could be in the future. The process for nominating routes on the TEN-T network should be reviewed by Offaly County Council with the view to making the case for the inclusion of the M4 and M6 motorways.

11.2.5.2 CEF Energy

This element of the fund supports projects meeting the criteria outlined below.

- Only 100 MW electrolysers and above are eligible if they have a network related function
- Hydrogen production must comply with life cycle greenhouse gas emissions savings requirement of 70% relative to a fossil fuel comparator
- Cross-border hydrogen infrastructure that match some project archetypes of transmission and distribution, notably transmission pipelines for hydrogen, giving access to multiple network users on a transparent and non-discriminatory basis, which mainly contains high-pressure hydrogen pipelines, but excluding pipelines for the local distribution of hydrogen
- Equipment or installation aiming at enabling and facilitating the integration of renewable and low-carbon gases (including biomethane or hydrogen) into the network

11.2.6 Clean Hydrogen Partnership

This is a public private partnership whose objective is to support the development and scaling up of hydrogen production and applications. It contributes to the EU Green Deal which aims to make Europe climate neutral by 2050. It also works closely with the hydrogen strategy. The partnership contributes up to 100% of overall project budget to projects mainly relating to an area of researching and improving hydrogen related technologies. €195 million was made available in 2023, 132 proposals were submitted with the majority related to renewable hydrogen production, storage and distribution and hydrogen end uses such as transport and clean heat and power. A target of supporting 60 hydrogen demonstrator projects has been set 2027 with the number supported increasing each year. The feasibility study would be suitably aligned at a more advanced stage to submit a proposal identifying the key criteria specified by the partnership to receive funding.

12 RECOMMENDATIONS

12.1 Short-term (1-2 years)

- The Hydrogen Strategy for Ireland was published by DECC in July 2023. This document provides greater clarity around various aspects of a hydrogen industry in Ireland. The Strategy contains a number of actions that are well aligned with the proposed Rhode hydrogen demonstrator. This needs to be explored further in the context of the hydrogen innovation fund which is to be delivered by the National Hydrogen Strategy to support the development of the demonstrator. The proposed demonstrator appears to be well aligned with the objectives of the National Hydrogen Strategy.
- Further work is needed to determine the level of interest among the potential outlets for renewable hydrogen identified in this feasibility study. This includes consideration of other industrial energy users. It is recommended that initial engagement take place with the following:
    - ***Gas Networks Ireland***: GNI is already actively working on the challenges for introducing renewable hydrogen into its network. Injection of renewable hydrogen at Gneevekeel AGI would need changes to the Code of Operations which must be agreed with GNI and accepted by the CRU. Physical changes would also be required at the AGI. The option of injecting renewable hydrogen into the gas distribution network serving Tullamore / Clara offers an opportunity to create a discrete section of the gas network where hydrogen blending is trialled. This proposal would need to be discussed further with GNI.
    - ***Bord na Móna***: The possibility of supplying renewable hydrogen to Derrygreenagh Power Station should be explored with BNM. The new power station will be located approximately 5km from Rhode Green Energy Park and could potentially consume all of the hydrogen the demonstrator could produce.

      BNM also recently submitted a planning application which includes a 2MW renewable hydrogen electrolyser at Mount Lucas Wind Farm. It will be beneficial to all parties involved to understand BNM's future plans and how these projects can be mutually supportive. BNM may also be considering injection of hydrogen into the GNI gas network. There could be mutual benefits to the Rhode demonstrator, BNM and GNI through potentially shared infrastructure costs and a back-up source of hydrogen.
    - ***SSE Thermal***: The possibility of supplying renewable hydrogen to the SSE thermal peaking plant which is located adjacent to Rhode Green Energy Park needs to be explored further with SSE. The main challenge for this option is likely to be the need for more hydrogen storage capacity.
    - ***Industry***: If there are proposals for locating new industry in the vicinity of Rhode Green Energy Park, potential synergies with the renewable hydrogen demonstrator project should be explored. One possible such outlet that was identified as a possibility in the 2020 Options Assessment Report was a data centre. Another possibility would be to use renewable hydrogen for heating purposes, potentially in a local district heating network within the campus. This could potentially be expanded into Rhode, subject to further detailed study. Other local, established industrial energy users should also be identified for their suitability for hydrogen use which has the possibility to offset more carbon intensive fuels in the local area.
    - ***Local Transport Fleets***: The potential for using hydrogen fuel in local transport fleets should be explored. It has been shown that a 1MW demonstrator electrolyser can supply approximately 480kg of hydrogen per day, which is equivalent in energy terms to approximately 1,500 litres of diesel per day. However, as described in this feasibility study, alternative outlets for hydrogen such as transportation will help to ensure that the electrolyser achieves a higher capacity. Transportation outlets for renewable hydrogen generated can therefore work alongside injection of hydrogen into the gas distribution network.

      Engagement with local fleet operators is recommended to gauge the level of interest in developing hydrogen as a fuel for either fuel cell or dual fuel operation. During this study, some potential interest was expressed by Offaly Co. Co., Bord na Móna and Enva who each operate a fleet of vehicles. There could be advantages in a joint approach across public and private fleets to achieve a shared hydrogen fuelling system for these fleets within the Region. The location of the fuelling station could be at the electrolyser in Rhode. It could also be located at a fleet depot, with hydrogen delivered there by tube trailer.

- o ***Existing demonstrator projects in UK and Europe***: The operators of relevant example projects with similar characteristics to the proposed Rhode demonstrator electrolyser should be engaged with in order to learn from their experience. There should be good opportunities to do so particularly with European funded projects. For the best chance of succeeding, this activity should be led by NODF / Offaly Co. Co. There will also be longer term benefits in establishing such links so as to share knowledge and develop the renewable hydrogen community.

- Continued engagement with the promoters of the proposed **Newleaf Energy Limited** facility to produce Renewable Natural Gas (RNG) could enable potential economies of scale to be developed at Rhode that can benefit both projects.
- An indicative site layout should be developed for the proposed 1MW renewable hydrogen electrolyser and its associated components within Rhode Green Energy Park.
- A site location for the demonstrator project should be chosen based on confirmed space requirements and possibilities for expansion. This should be done having regard to NODF's vision for Rhode Green Energy Park as a place where opportunities for symbiotic relationships between park occupants are maximised.
- A Pre-FEED (Front End Engineering Design) Study should be undertaken of the proposed 1MW renewable hydrogen electrolyser to enable better project definition and a more accurate cost estimate to be developed.
  - o Suppliers should be contacted to obtain up-to-date market prices for equipment and associated ancillary equipment. Key equipment items include:
    - Small-scale (0.5MW – 5MW) PEM electrolysers should be contacted to obtain up-to-date market prices for this equipment and associated ancillary equipment including system controls
    - Hydrogen storage
    - Tube trailers and tube trailer loading / unloading
    - Hydrogen fuelling equipment
    - Fuel cell vehicles and dual fuel conversions of existing vehicles
  - o The quality of potential source water for an electrolyser at Rhode should be assessed to confirm its suitability or if additional treatment equipment will be required to make it suitable.
- Options for installing a direct electrical connection to a local wind farm i.e. not connecting via the Electricity Grid should be explored. If a direct connection to a local wind farm is permitted under updated regulations, it would mean that 'use of system' charges would be avoided. This arrangement would result in a lower cost of electricity to the demonstrator electrolyser and could be a significant boost to renewable hydrogen generation. It appears that this arrangement is planned to be used by the electrolyser project under development by BNM. In this case, the electrolyser is located on a wind farm site owned and operated by BNM. It is understood that the regulations need to be amended to facilitate the supply of electricity directly to off-site users.

12.2 Medium-term (2-5 years)

- North Offaly Development Fund and Offaly County Council will ultimately benefit by selecting a project partner (or partners) who can manage commercial and operational aspects.
- The most appropriate procurement and contracting strategy for the project should be determined.
- Consideration should be given to using renewable hydrogen for heating of premises within Rhode Green Energy Park as it develops and expands. A local district heating system fuelled by renewable hydrogen could be expanded over time, potentially even into Rhode village. This could also be supplemented by the nearby geothermal heat resource or process heat from future possible energy park tenants.
- The opportunity to supply greater levels of hydrogen to the strategic transport network should be developed as the use of transport in hydrogen advances in Ireland.
- A modular development of electrolyser capacity is recommended, enabling both the gas grid integration and transport energy opportunities to be developed and expanded progressively.

- Mapping the overall energy landscape in the Midlands – including cement plants, large energy users, transport fleets, power generation – will be beneficial in developing the wider opportunity for decarbonisation using hydrogen (and associated products such as oxygen).

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Appendix A
Gas Transmission Profile Data

Gas Flow data provided by GNI is used to generate max, min, and average flows for winter and summer 2024 and 2030. This, with the annual gas profile from SEAI is used to assign each month an average flow.

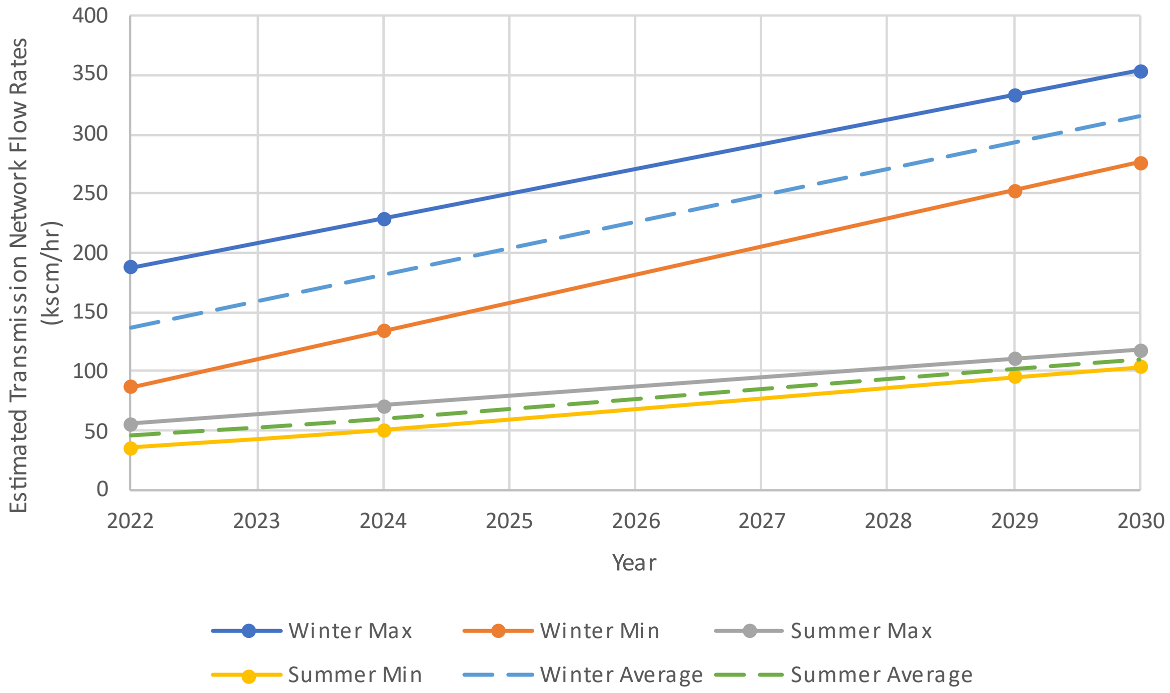
kscm/hr = kilo standard cubic metre / hour

Estimated Transmission Network Flow Rates (kscm/hr)	***2022***	***2024***	***2029***	***2030***
Winter Max	187.68	229.29	333.33	354.14
Winter Min	86.67	134.15	252.84	276.58
Winter Average	137.18	181.72	293.09	315.36
Summer Max	55.55	71.16	110.19	118.00
Summer Min	35.92	50.77	95.33	103.82
Summer Average	45.74	59.99	102.76	110.91

Estimated Annual Flow (kscm/yr)	801,145.80	1,058,698.40	1,733,801.10	1,867,037.57

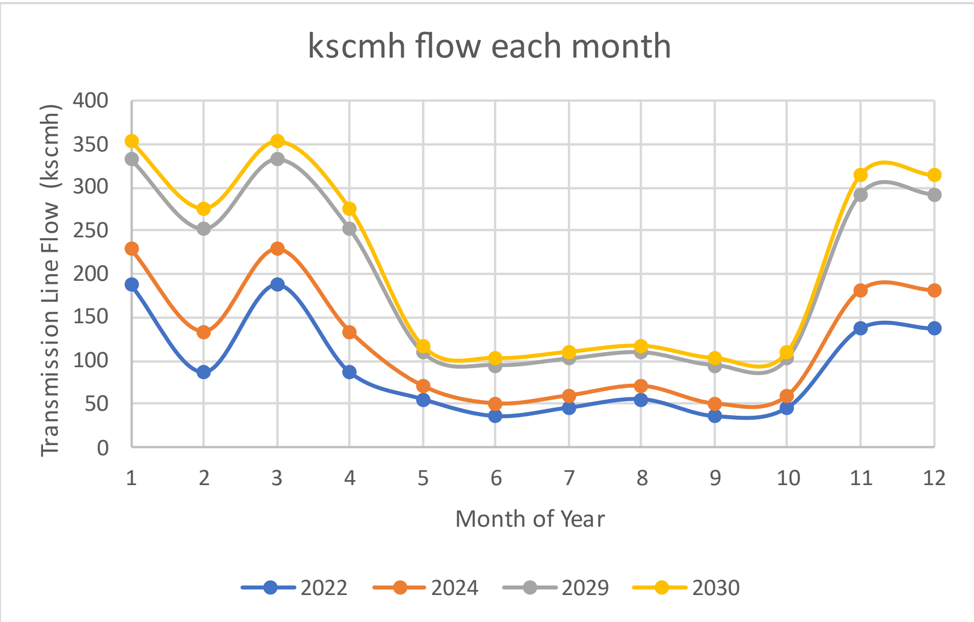
Source: GNI Estimated Transmission Flow at Gaybrook AGI - Winter and Summer Max/Min 2022 and 2029. The rest of this table has been predicted using a linear model as shown below

Gaybrook is a 70 bar - 4 bar AGI (Rhode Assessment by RPS)



Values in MW

Month	**Class**	**2022**	**2024**	**2029**	**2030**
1	Winter Max	187.68	229.29	333.33	354.14
2	Winter Min	86.67	134.15	252.84	276.58
3	Winter Max	187.68	229.29	333.33	354.14
4	Winter Min	86.67	134.15	252.84	276.58
5	Summer Max	55.55	71.16	110.19	118.00
6	Summer Min	35.92	50.77	95.33	103.82
7	Summer Average	45.74	59.99	102.76	110.91
8	Summer Max	55.55	71.16	110.19	118.00
9	Summer Min	35.92	50.77	95.33	103.82
10	Summer Average	45.74	59.99	102.76	110.91
11	Winter Average	137.18	181.72	293.09	315.36
12	Winter Average	137.18	181.72	293.09	315.36



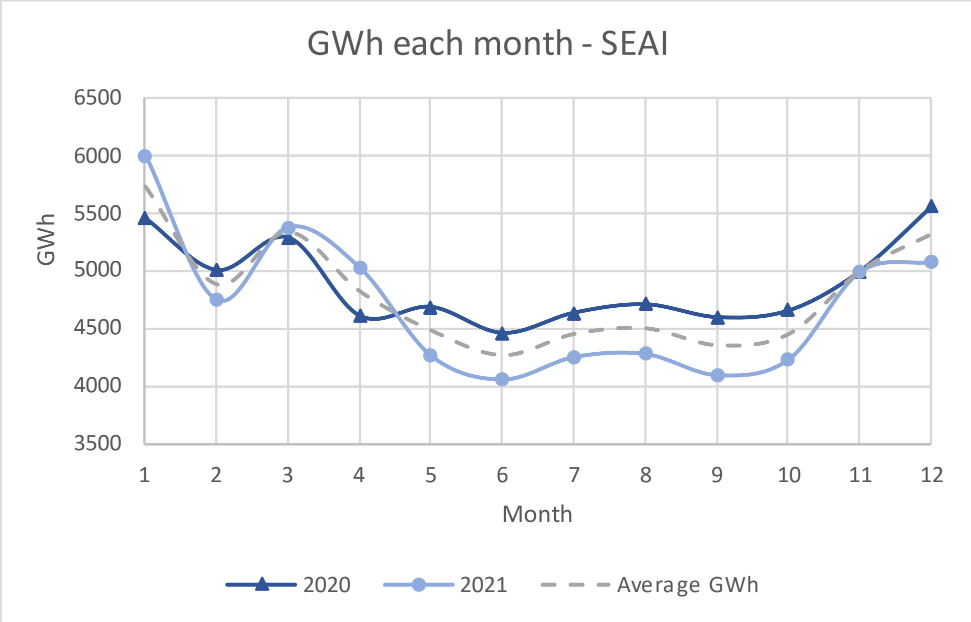
Natural Gas Supply curve from SEAI used to determine how NG supply varies annually, and assign seasonal min/avg/max to each

(SEAI 2022) https://www.seai.ie/data-and-insights/seai-statistics/monthly-energy-data/gas/

	2020			2021				
Month	***GWh***	***% max***	***%min***	***GWh***	***% max***	***%min***		***Average GWh***
January	5466	98%	122%	6008	100%	148%		5737
February	5015	90%	112%	4753	79%	117%		4884
March	5298	95%	119%	5383	90%	132%		5340.5
April	4616	83%	103%	5031	84%	124%		4823.5
May	4694	84%	105%	4269	71%	105%		4481.5
June	4467	80%	100%	4066	68%	100%		4266.5
July	4644	83%	104%	4260	71%	105%		4452
August	4716	85%	106%	4285	71%	105%		4500.5
September	4604	83%	103%	4103	68%	101%		4353.5
October	4663	84%	104%	4240	71%	104%		4451.5
November	5007	90%	112%	4996	83%	123%		5001.5
December	5569	100%	125%	5080	85%	125%		5324.5

Year Max	5569		6008
Month Max	December		January
Year Min	4467		4066
Month Min	June		June

Month	***2021 rank***	***AVG rank***	***Class***
January	1	1	Win max
March	2	2	Win max
December	3	3	Win avg
November	5	4	Win avg
February	6	5	Win min
April	4	6	Win min
August	7	7	Summax
May	8	8	Sum max
October	10	10	Sum avg
July	9	9	sum avg
September	11	11	sum min
June	12	12	sum min


GWh each month - SEAI
6500
6000
5500
5000
4500
4000
3500
GWh
1
2
3
4
5
6
7
8
9
10
11
12
Month
2020
2021
Average GWh

Appendix B
Gas Transmission Injection Modelling Scenarios

Scenario	Year	Electrolyser Operation	Demand
D1	2024	Dedicated Wind Priority Hydrogen	2% NG
D2	2024	Dedicated Wind Priority Hydrogen	5% NG
D3	2024	Dedicated Wind Priority Hydrogen	20% NG
D4	2024	Dedicated Wind Priority Electricity	2% NG
D5	2024	Dedicated Wind Priority Electricity	5% NG
D6	2024	Dedicated Wind Priority Electricity	20% NG
D7	2024	Dispatch Down Only	2% NG
D8	2024	Dispatch Down Only	5% NG
D9	2024	Dispatch Down Only	20% NG
D10	2024	Grid and Wind	2% NG
D11	2024	Grid and Wind	5% NG
D12	2024	Grid and Wind	20% NG
D13	2030	Dedicated Wind Priority Hydrogen	2% NG
D14	2030	Dedicated Wind Priority Hydrogen	5% NG
D15	2030	Dedicated Wind Priority Hydrogen	20% NG
D16	2030	Dedicated Wind Priority Electricity	2% NG
D17	2030	Dedicated Wind Priority Electricity	5% NG
D18	2030	Dedicated Wind Priority Electricity	20% NG
D19	2030	Dispatch Down Only	2% NG
D20	2030	Dispatch Down Only	5% NG
D21	2030	Dispatch Down Only	20% NG
D22	2030	Grid and Wind	2% NG
D23	2030	Grid and Wind	5% NG
D24	2030	Grid and Wind	20% NG

Scenario	Year	Electrolyser Operation	Electrolyser Size
S1a	2030	Dedicated Wind Priority Electricity up to 59 MW	1-MW
S1b	2030	Dedicated Wind Priority Electricity up to 42 MW	1-MW
S1c	2030	Dedicated Wind Priority Electricity up to 21 MW	1-MW
S2a	2030	Dedicated Wind Priority Electricity up to 59 MW	10-MW
S2b	2030	Dedicated Wind Priority Electricity up to 42 MW	10-MW
S2c	2030	Dedicated Wind Priority Electricity up to 21 MW	10-MW
S3a	2030	Dedicated Wind Priority Electricity up to 59 MW	50-MW
S3b	2030	Dedicated Wind Priority Electricity up to 42 MW	50-MW
S3c	2030	Dedicated Wind Priority Electricity up to 21 MW	50-MW
S4	2030	Dedicated Wind Priority Hydrogen	1-MW
S5	2030	Dedicated Wind Priority Hydrogen	10-MW
S6	2030	Dedicated Wind Priority Hydrogen	50-MW
S7	2030	Dispatch Down Only	1-MW
S8	2030	Dispatch Down Only	10-MW
S9	2030	Dispatch Down Only	50-MW
S10	2030	Grid and Wind	1-MW
S11	2030	Grid and Wind	10-MW
S12	2030	Grid and Wind	50-MW
S13a	2024	Dedicated Wind Priority Electricity up to 59 MW	1-MW
S13b	2024	Dedicated Wind Priority Electricity up to 42 MW	1-MW
S13c	2024	Dedicated Wind Priority Electricity up to 21 MW	1-MW
S14a	2024	Dedicated Wind Priority Electricity up to 59 MW	10-MW
S14b	2024	Dedicated Wind Priority Electricity up to 42 MW	10-MW
S14c	2024	Dedicated Wind Priority Electricity up to 21 MW	10-MW
S15a	2024	Dedicated Wind Priority Electricity up to 59 MW	50-MW
S15b	2024	Dedicated Wind Priority Electricity up to 42 MW	50-MW
S15c	2024	Dedicated Wind Priority Electricity up to 21 MW	50-MW
S16	2024	Dedicated Wind Priority Hydrogen	1-MW
S17	2024	Dedicated Wind Priority Hydrogen	10-MW
S18	2024	Dedicated Wind Priority Hydrogen	50-MW
S19	2024	Dispatch Down Only	1-MW
S20	2024	Dispatch Down Only	10-MW
S21	2024	Dispatch Down Only	50-MW
S22	2024	Grid and Wind	1-MW
S23	2024	Grid and Wind	10-MW
S24	2024	Grid and Wind	50-MW

Appendix C
Results of Techno-Economic Model

RESULTS OF TECHNO-ECONOMIC MODELLING

C1 - Demand Led – Dedicated Wind

The results for dedicated wind scenarios in 2030 only are featured below. Note that 2024 scenarios follow the same trends. The results show that a wind farm prioritising hydrogen production significantly reduces the total levelised cost of hydrogen, with results almost one third of that in cases where electricity exports are prioritised. The transport costs are minimally affected by the change in electrolyser operation and contribute little to the overall cost in all scenarios.

Costs increase when the wind farm prioritises exporting electricity to the grid over hydrogen production. This is reflected by lower capacity factors and larger electrolysers being used to utilise peaks of electricity when it is available. The required hydrogen storage capacity is also much higher when grid electricity exports are prioritised by the wind farm, in order to compensate for periods of time with little or no electricity available. This increases storage costs significantly.

Table 0-1: Technical Outputs for Demand Led Scenarios using Dedicated Wind Electricity in 2030

Scenario	Electrolyser Operation	Demand	Electrolyser Size	Electrolyser Capacity Factor	Annual H_2 Production ($tonnes_{H2}$)	Storage Capacity ($tonnes_{H2}$)	*Levelised Cost of Hydrogen (€/kg_{H2})*			
							Production	Transport	Storage	Total
D13	Dedicated Priority Hydrogen	2% NG	**1-MW**	86.2%	151	2.29	3.26	0.57	0.84	**4.67**
D14	Dedicated Priority Hydrogen	5% NG	**2.5 MW**	86.1%	377	5.72	2.93	0.30	0.84	**4.07**
D15	Dedicated Priority Hydrogen	20% NG	**12 MW**	72.9%	1,532	32.93	2.75	0.17	1.19	**4.11**
D16	Dedicated Priority Electricity up to 59 MW	2% NG	**5 MW**	19.7%	172	22.88	6.10	0.52	7.36	**13.98**
D17	Dedicated Priority Electricity up to 59 MW	5% NG	**14 MW**	18.1%	445	76.84	5.49	0.28	9.59	**15.35**
D18	Dedicated Priority Electricity up to 21 MW	20% NG	**26 MW**	34.7%	1,579	250.55	3.59	0.17	9.19	**12.95**

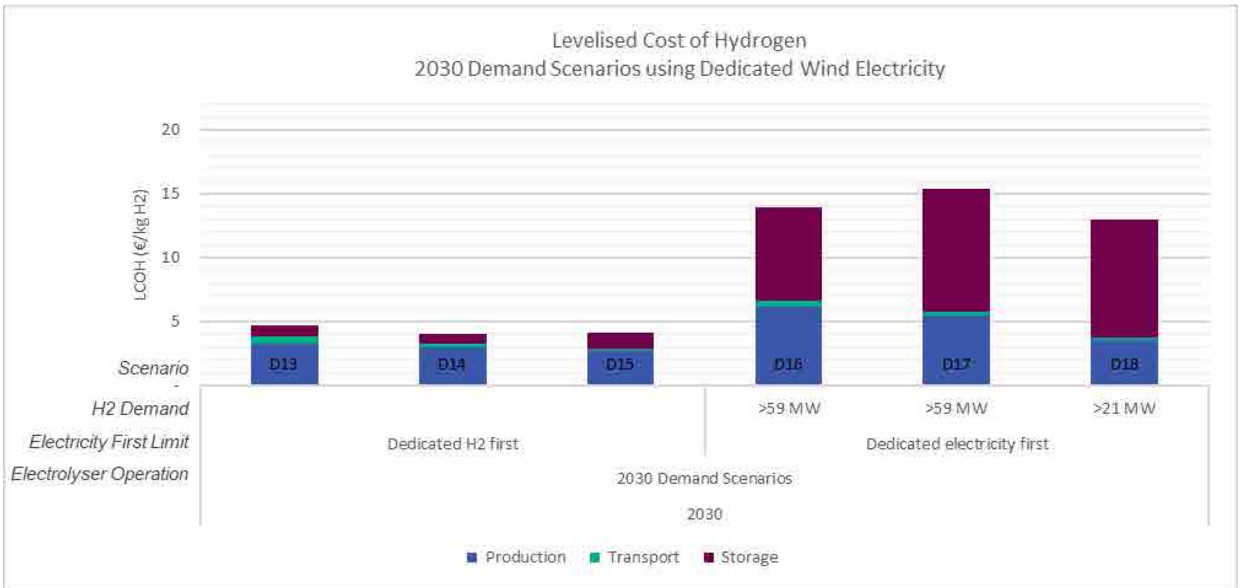


Figure 0-1: Levelised Cost of Hydrogen for Demand Led scenarios using Dedicated Wind Electricity in 2030

The model uses dispatch down Priority Electricity if it is available, however because of the size of the electrolysers chosen to meet the demand, this is often a small portion of the overall electricity used. As shown below, the larger electrolyser sizes allow for more dispatch down and dedicated wind to be used.

Table 0-2: Hydrogen Production for Demand Led scenarios using Dedicated Wind Electricity in 2030

Scenario	Electrolyser Operation	Demand	Electrolyser Size	*H_2 Produced by Electricity Source (tonnes$_{H2}$/yr)*		
				Dispatch Down	Dedicated Wind	Total
D13	Dedicated Priority Hydrogen	2% NG	**1-MW**	35	116	**151**
D14	Dedicated Priority Hydrogen	5% NG	**2.5-MW**	84	294	**377**
D15	Dedicated Priority Hydrogen	20% NG	**12-MW**	296	1,237	**1,532**
D16	Dedicated Priority Electricity up to 59 MW	2% NG	**5-MW**	127	45	**172**
D17	Dedicated Priority Electricity up to 59 MW	5% NG	**14-MW**	316	129	**445**
D18	Dedicated Priority Electricity up to 21 MW	20% NG	**26-MW**	515	1,064	**1,579**

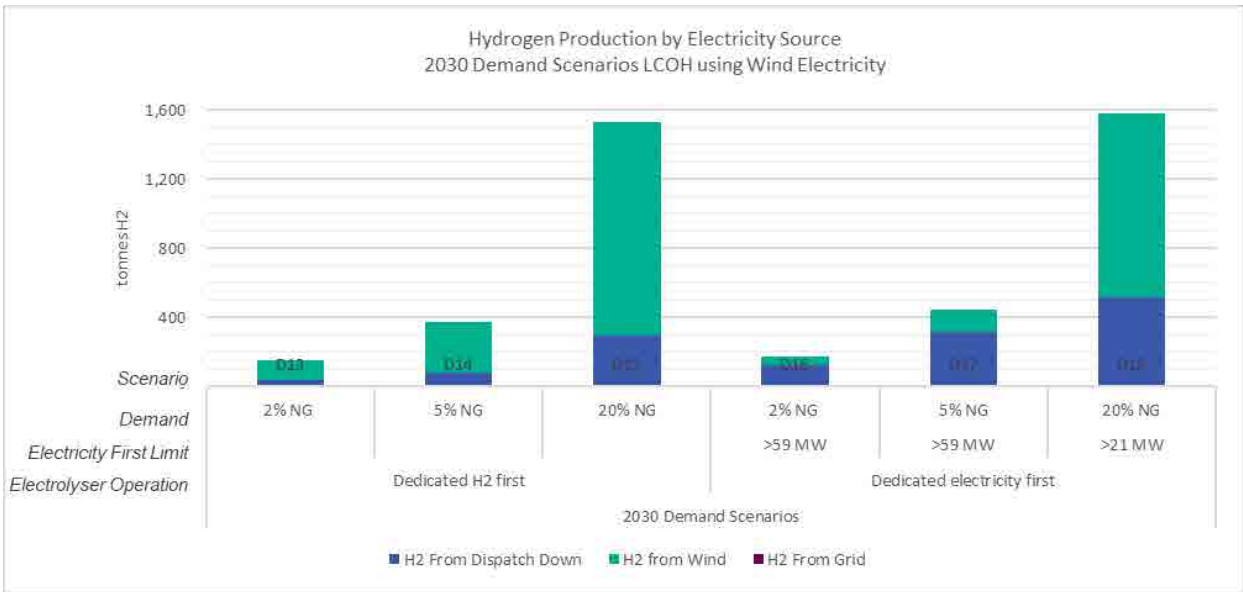


Figure 0-2: Hydrogen Production by Electricity Source for Demand Led scenarios using Dedicated Wind Electricity in 2030

C2 - Demand Led – Dispatch Down Only

As one might expect, solely using dispatch down electricity to meet gas demand is an expensive option. Transport costs remain low, in the same range as what was seen for dedicated wind scenarios. However, both production and storage costs are very high. Whereas Scenario D13 (2030, Dedicated Wind, 2% H_2) uses dedicated wind and needs only a 1-MW electrolyser to support the 2% NG load, scenarios D7 and D19 (see Table 0-3 below) require a 6-MW electrolyser to meet the same demand using dispatch down power.

Results for scenarios D8, D9, and D21 have not been included in the results section as it was not possible to generate enough hydrogen to meet their target demands using only dispatch down electricity.

Table 0-3: Technical Outputs for Demand-led Scenarios using Dispatch Down Electricity

Scenario	Year	Demand	Electrolyser Size	Electrolyser Capacity Factor	Annual H_2 Production ($tonnes_{H2}$)	Storage Capacity ($tonnes_{H2}$)	*Levelised Cost of Hydrogen (€/kg_{H2})*			
							Production	Transport	Storage	Total
D7	2024	2% NG	**6 MW**	16.5%	167	36.91	8.45	0.53	12.27	**21.25**
D19	2030	2% NG	**6 MW**	15.8%	166	30.20	6.76	0.53	10.10	**17.40**
D20	2030	5% NG	**22 MW**	10.1%	390	90.68	8.18	0.30	12.88	**21.35**

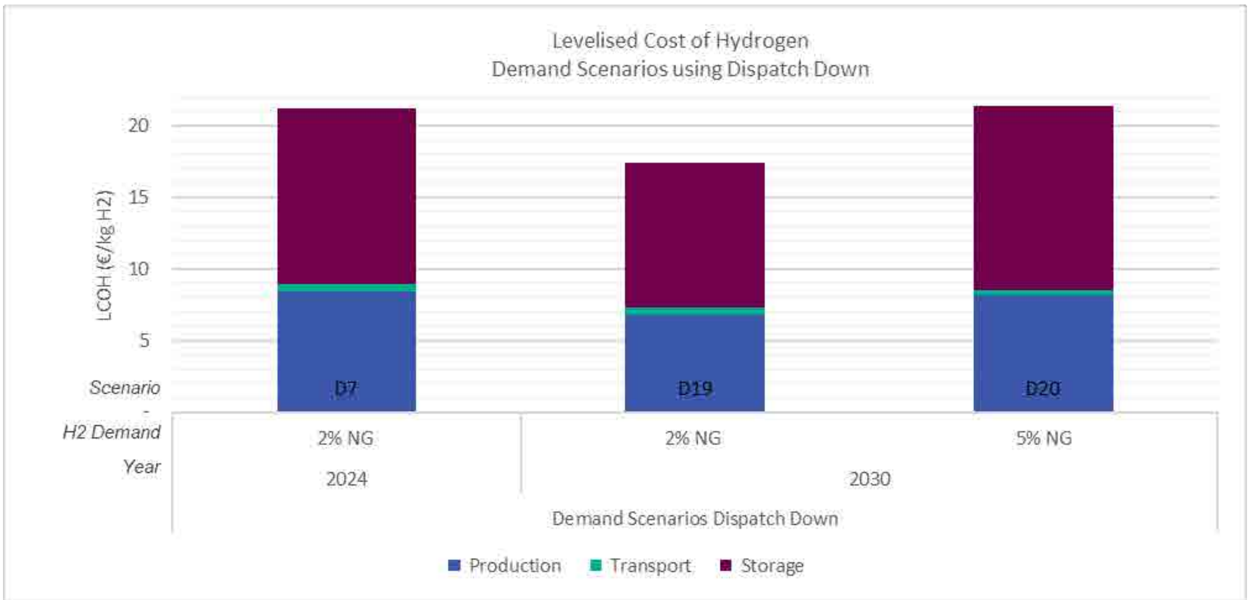


Figure 0-3: Levelised Cost of Hydrogen for Demand-led Scenarios using Dispatch Down Only Electricity

To meet a natural gas demand of 2% by volume, the system used only 23% of the dispatch down available, and to meet a natural gas demand of 5% by volume, only 52% of the available dispatch down was used. These scenarios are already very expensive, so expanding them to use more of the dispatch down will not be feasible. However, there may be scope to incorporate battery storage from the wind farm to allow for more consistent electricity available at smaller volumes.

Table 0-4: Hydrogen Production for Demand Led scenarios using Dispatch Down Only Electricity

Scenario	Year	Demand	H_2 Produced *($tonnes_{H2}$/yr)*	% Of Available Dispatch Down Used	Modelled LCOH (€/kg H_2)
D7	2024	2% NG	167	**23%**	21.25
D19	2030	2% NG	166	**22%**	17.40
D20	2030	5% NG	390	**52%**	21.35

C3 - Demand Led - Grid and Wind

Using grid electricity in addition to wind to meet a hydrogen demand reduces dependence on storage. This is reflected by lower storage capacities required, and lower storage costs (see Table 0-5 below). These scenarios also show the importance of producing enough hydrogen as the scenarios with higher demands have cheaper LCOH. At 3.46 €/kg, scenario D24 has the lowest levelised cost for any demand-led scenario modelled.

Table 0-5: Technical Outputs for Demand Led Scenarios using Grid and Wind Electricity

Scenario	Year	Demand	Electrolyser Size	Electrolyser Capacity Factor	Annual H2 Production (tonnes$_{H2}$)	Storage Capacity (tonnes$_{H2}$)	*Levelised Cost of Hydrogen (€/kg$_{H2}$)*			
							Production	Transport	Storage	Total
D10	2024	2% NG	**1-MW**	90.1%	152	10.97	4.07	0.57	4.02	**8.66**
D11	2024	5% NG	**2.5 MW**	89.7%	378	10.98	3.70	0.30	1.61	**5.62**
D12	2024	20% NG	**10-MW**	90.3%	1,522	39.53	3.31	0.17	1.44	**4.92**
D22	2030	2% NG	**1-MW**	86.6%	152	1.83	3.31	0.57	0.67	**4.55**
D23	2030	5% NG	**3 MW**	71.8%	378	2.76	3.24	0.30	0.40	**3.95**
D24	2030	20% NG	**11-MW**	78.8%	1,518	12.64	2.83	0.17	0.46	**3.46**

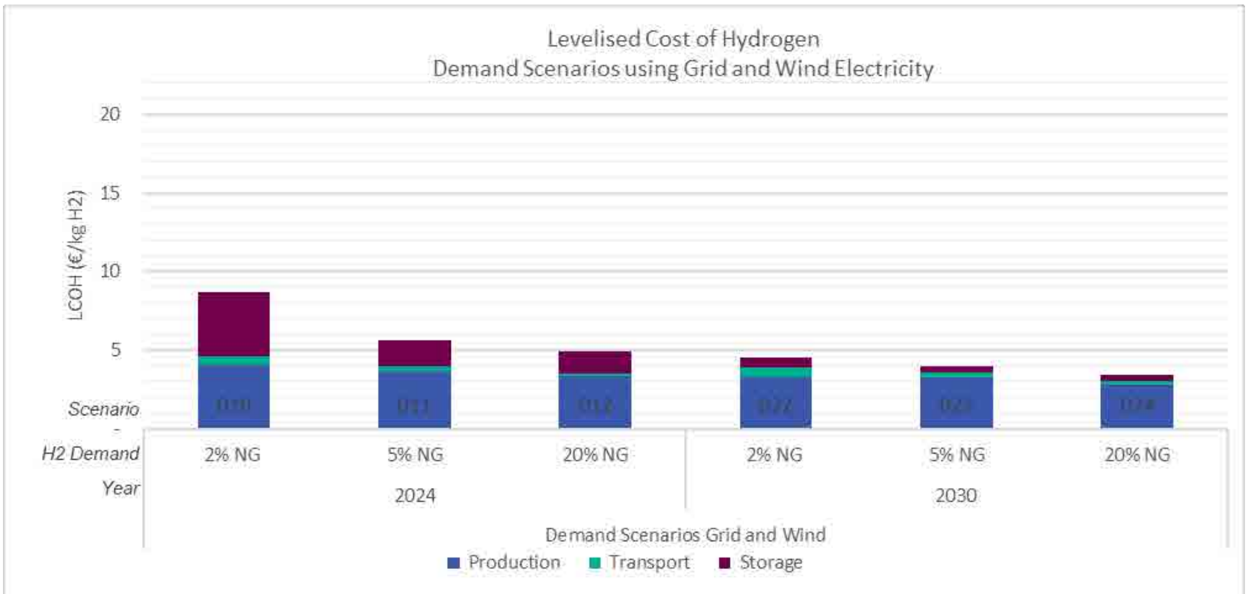


Figure 0-4: Levelised Cost of Hydrogen for Demand-led Scenarios using Grid and Wind Electricity

While scenarios using grid electricity were consistently cheaper than purely wind-powered alternatives, it is interesting to note that the grid electricity used is only a small portion of the overall electricity used to generate hydrogen. The carbon emissions rates for all demand scenarios are below the 'low-carbon' threshold of 4.36 kg$_{CO2eq}$/kg$_{H2}$., meaning that the hydrogen produced can be considered low-carbon. Scenario D12 has the highest percentage of grid electricity used to produce hydrogen, with 18.4% of its hydrogen coming from grid electricity. D22 has the lowest percentage of grid electricity used, with only 5.2% of its hydrogen coming from grid sources.

Table 0-6: Hydrogen Production and Emissions for Demand Led scenarios using Grid and Wind Electricity

Scenario	Year	Demand	H_2 Produced by Electricity Source ($tonnes_{H2}$/yr): Dispatch Down	Dedicated Wind	Grid Electricity	Total	Emissions (t_{CO2eq}/yr)	Emissions Rate (kg_{CO2}/kg_{H2})
D10	2024	2% NG	33	108	10	**152**	114.56	**0.76**
D11	2024	5% NG	78	265	35	**378**	401.48	**1.06**
D12	2024	20% NG	256	986	280	**1,522**	3,219.29	**2.12**
D22	2030	2% NG	34	110	8	**152**	57.24	**0.38**
D23	2030	5% NG	77	269	31	**378**	223.05	**0.59**
D24	2030	20% NG	261	1,016	241	**1,518**	1,708.64	**1.13**

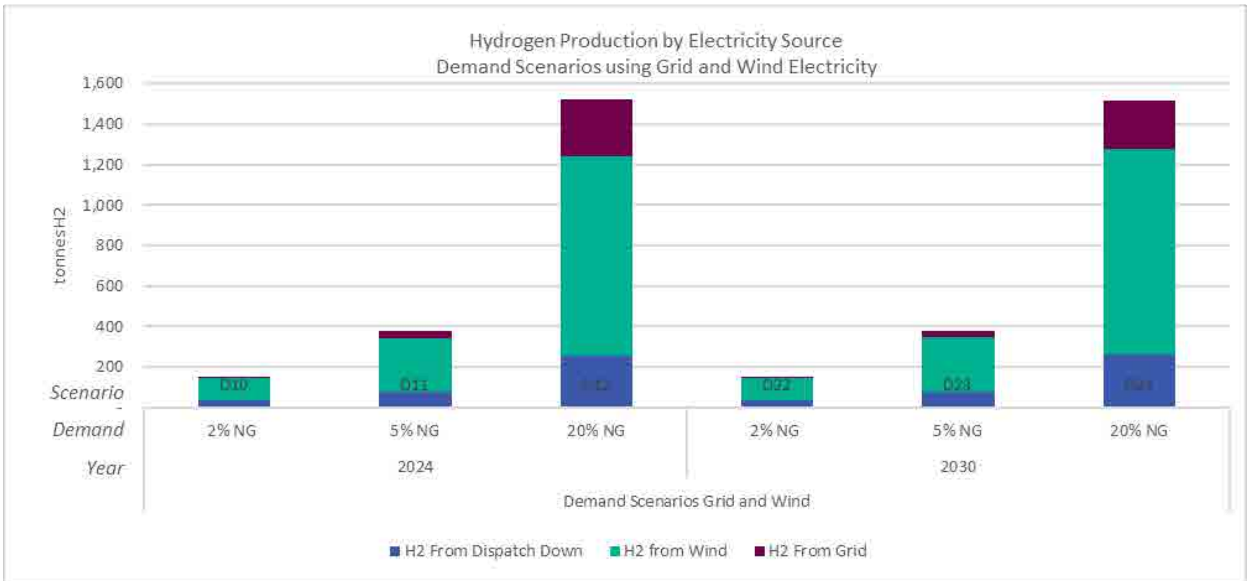


Figure 0-5: Hydrogen Production by Electricity Source for Demand-led Scenarios using Grid and Wind Electricity

C4 - Supply Led – Dedicated Wind

The supply-led scenarios which use a wind farm prioritising hydrogen production are substantially cheaper than those using electricity generated above a specific threshold, consistent with findings from demand-led scenarios. In scenario S4 a 1MW electrolyser is provided with all available wind energy and the LCOH reaches a minimum of 5.60 €/kg_{H2}. In this scenario, the electrolyser has a capacity factor of 91.9%.

When hydrogen becomes second priority for the wind farm, even with a threshold as low as 21 MW in S1c, the electrolyser's capacity factor drops to only 49.3%, with an LCOH of 13.15 €/kg_{H2}. The capacity factor continues to decrease as there is less electricity made available, and the costs increase. The storage costs increase most dramatically as the amount of electricity available decreases. With $LCOH_{Storage}$ results ranging from 1.42 €/kg_{H2} when hydrogen is prioritised in S4, to 13.61 €/kg_{H2} when electricity generation is only available above the 59 MW threshold for hydrogen production in S1a. This pattern is repeated in scenarios with 10MW and 50MW electrolysers.

Table 0-7: Technical Outputs for Supply led scenarios using Dedicated Wind Electricity in 2030

Scenario	Electrolyser Operation	Electrolyser Size	Electrolyser Capacity Factor	Annual H_2 Production ($tonnes_{H2}$)	Storage Capacity ($tonnes_{H2}$)	*Levelised Cost of Hydrogen (€/kg_{H2})* Production	Transport	Storage	Total
S1a	Dedicated Priority Electricity up to 59 MW	**1-MW**	26.6%	47	11.23	6.38	1.59	13.61	**21.57**
S1b	Dedicated Priority Electricity up to 42 MW	**1-MW**	32.6%	57	12.00	5.55	1.32	11.11	**17.98**
S1c	Dedicated Priority Electricity up to 21 MW	**1-MW**	49.3%	86	12.71	4.29	0.91	7.94	**13.15**
S2a	Dedicated Priority Electricity up to 59 MW	**10-MW**	21.9%	383	93.49	4.89	0.30	13.25	**18.44**
S2b	Dedicated Priority Electricity up to 42 MW	**10-MW**	28.1%	492	114.02	4.22	0.26	12.38	**16.86**
S2c	Dedicated Priority Electricity up to 21 MW	**10-MW**	43.3%	759	107.09	3.38	0.21	7.69	**11.28**
S3a	Dedicated Priority Electricity up to 59 MW	**50-MW**	10.2%	889	219.52	7.83	0.20	12.85	**20.88**
S3b	Dedicated Priority Electricity up to 42 MW	**50-MW**	15.1%	1,320	294.63	5.88	0.17	12.50	**18.55**
S3c	Dedicated Priority Electricity up to 21 MW	**50-MW**	26.8%	2,347	488.17	4.11	0.17	11.36	**15.64**
S4	Dedicated Priority Hydrogen	**1-MW**	91.9%	161	4.01	3.15	0.55	1.42	**5.12**
S5	Dedicated Priority Hydrogen	**10-MW**	79.1%	1,386	72.17	2.68	0.17	2.75	**5.60**
S6	Dedicated Priority Hydrogen	**50-MW**	47.9%	4,192	439.58	3.11	0.17	5.75	**9.03**

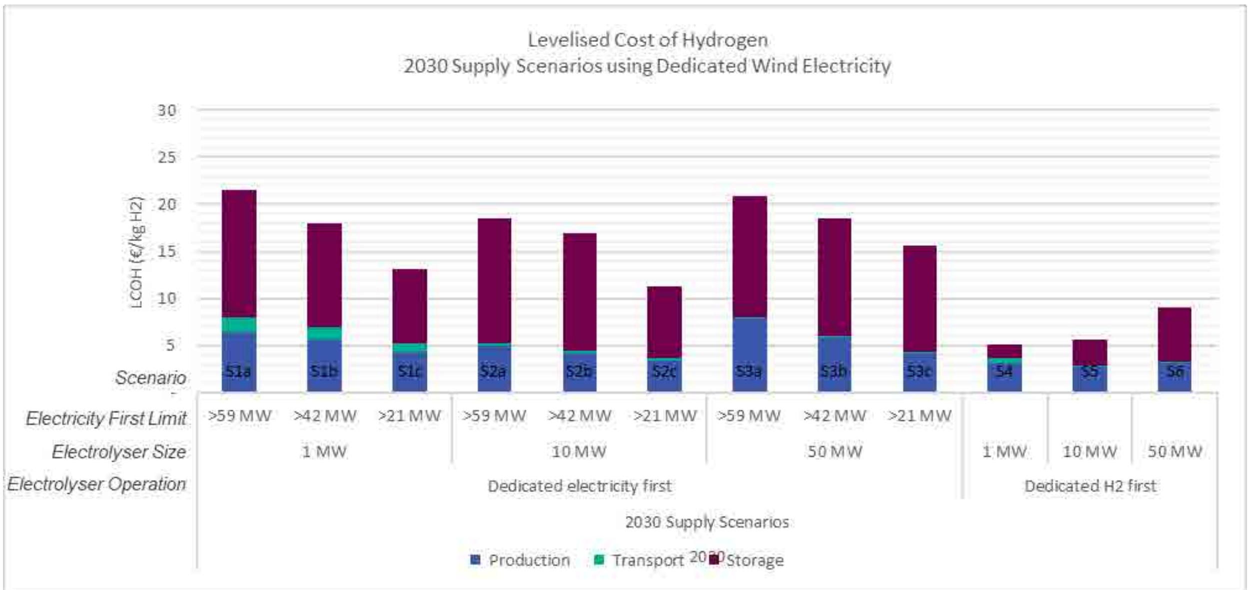


Figure 0-6: Levelised Cost of Hydrogen for Supply Led scenarios using Dedicated Wind Electricity in 2030

In the following scenarios, the amount of hydrogen produced from dispatch down remains constant for each size of the electrolyser chosen. The disparities in dedicated wind used are a direct result of the wind that is available depending on what is prioritised by the wind farm (see **Table 0-8** below).

Table 0-8: Hydrogen Production for Supply Led scenarios using Dedicated Wind Electricity in 2030

Scenario	Electrolyser Operation	Electrolyser Size	*H_2 Produced by Electricity Source ($tonnes_{H2}$/yr)* Dispatch Down	Dedicated Wind	Total
S1a	Dedicated Priority Electricity up to 59 MW	**1-MW**	37	10	**47**
S1b	Dedicated Priority Electricity up to 42 MW	**1-MW**	37	20	**57**
S1c	Dedicated Priority Electricity up to 21 MW	**1-MW**	37	49	**86**
S2a	Dedicated Priority Electricity up to 59 MW	**10-MW**	282	101	**383**
S2b	Dedicated Priority Electricity up to 42 MW	**10-MW**	282	210	**492**
S2c	Dedicated Priority Electricity up to 21 MW	**10-MW**	282	478	**759**
S3a	Dedicated Priority Electricity up to 59 MW	**50-MW**	710	179	**889**
S3b	Dedicated Priority Electricity up to 42 MW	**50-MW**	710	610	**1,320**
S3c	Dedicated Priority Electricity up to 21 MW	**50-MW**	710	1,637	**2,347**
S4	Dedicated Priority Hydrogen	**1-MW**	37	124	**161**
S5	Dedicated Priority Hydrogen	**10-MW**	282	1,104	**1,386**
S6	Dedicated Priority Hydrogen	**50-MW**	710	3,483	**4,192**

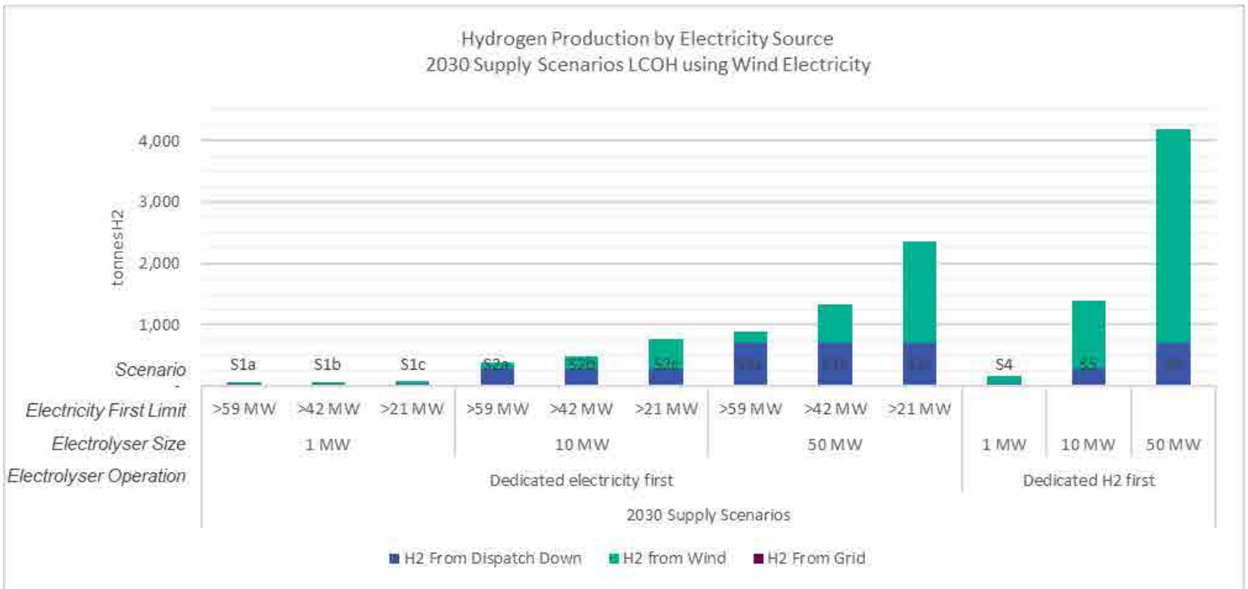


Figure 0-7: Hydrogen Production by electricity Source for Supply Led scenarios using Dedicated Wind Electricity in 2030

C5 - Supply Led – Dispatch Down Only

Supply-led scenarios using dispatch down electricity are the most expensive scenarios modelled, with levelised costs ranging from 18.96 – 30.50 €/kg$_{H2}$. This is a result of very low electrolyser capacity factors, and very large amounts of storage. Storage requirements reach up almost a third of the annual generation in scenarios S9 and S21 with 50-MW electrolysers. As a result of less hydrogen being produced in these systems, the transportation system is under-utilised and unit costs peak.

Table 0-9: Technical Outputs for Supply Led scenarios using Dispatch Down Only Electricity

Scenario	Year	Electrolyser Size	Electrolyser Capacity Factor	Annual H2 Production (tonnes$_{H2}$)	Storage Capacity (tonnes$_{H2}$)	*Levelised Cost of Hydrogen (€/kg$_{H2}$)*			
						Production	Transport	Storage	Total
S7	2030	1-MW	21.1%	37	8.94	7.57	1.97	13.05	22.60
S8	2030	10-MW	16.1%	282	64.26	5.99	0.36	12.61	18.96
S9	2030	50-MW	8.1%	710	228.27	9.35	0.22	17.88	27.45
S19	2024	1-MW	21.1%	36	7.57	9.62	2.04	11.68	23.35
S20	2024	10-MW	16.1%	271	60.63	7.89	0.37	11.71	19.98
S21	2024	50-MW	8.1%	683	221.99	12.40	0.22	17.88	30.50

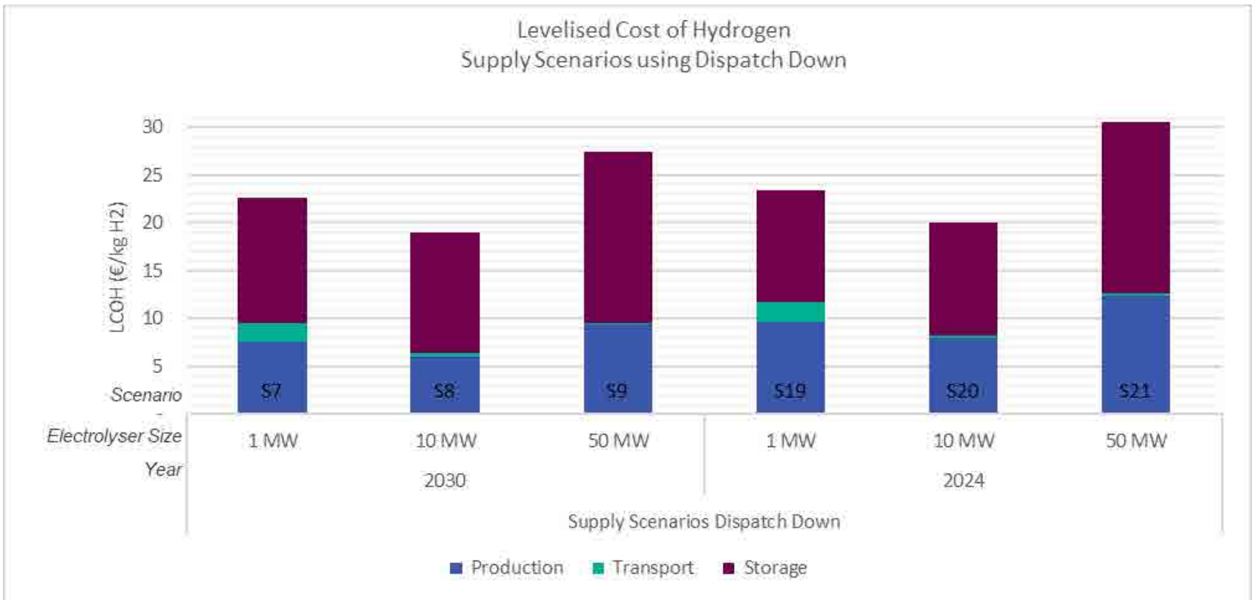


Figure 0-8: Levelised Cost of Hydrogen for Supply Led scenarios using Dispatch Down Only Electricity

Table 0-10 shows that a 50-MW electrolyser is required for 95% of the available dispatch down electricity to be used. These scenarios have high levelised costs of hydrogen and are not feasible even at the scale of 1MW.

Table 0-10: Hydrogen Production for Supply scenarios using Dispatch Down Only Electricity

Scenario	Year	Electrolyser Size	H_2 Produced *(tonnes$_{H2}$/yr)*	% Of Available Dispatch Down used	Modelled LCOH (€/kg H_2)
S7	2030	**1-MW**	37	**5%**	22.60
S8	2030	**10-MW**	282	**38%**	18.96
S9	2030	**50-MW**	710	**95%**	27.45
S19	2024	**1-MW**	36	**5%**	23.35
S20	2024	**10-MW**	271	**38%**	19.98
S21	2024	**50-MW**	683	**95%**	30.50

C6 - Supply Led - Grid and Wind

In some scenarios that use grid electricity, storage is less important, as the electrolyser always has the capacity to generate hydrogen to the required rate, simply from electricity that is available. This is not possible with larger electrolyser sizes and more substantial storage was required for 50-MW electrolyser scenarios. The results are competitive and in line with the demand-led scenarios using grid electricity. The closest comparable supply-led scenario was S4 and S5, which have LCOH values of 5.12 €/kg$_{H2}$ and 5.60 €/kg$_{H2}$. With most of the grid scenarios having LCOH values of less than 5 €/kg$_{H2}$, it is the cheapest option.

It is worth noting that scenario S12 is more expensive at 6.39 €/kg$_{H2}$, because it is running at an 85.1% capacity, instead of 91% (see Table 0-11 below). This slight reduction in running hours means that the system relies more heavily on storage, and has a slightly lower annual generation, which drives up costs. As a high electrolyser capacity factor is important for maintaining low LCOH values, it is vital that customers are found, and all hydrogen produced by the system is sellable.

Table 0-11: Technical Outputs for Supply Led scenarios using Grid and Wind Electricity

Scenario	Year	Electrolyser Size	Electrolyser Capacity Factor	Annual H_2 Production (tonnes$_{H2}$)	Storage Capacity (tonnes$_{H2}$)	*Levelised Cost of Hydrogen (€/kg$_{H2}$)*			
						Production	Transport	Storage	Total
S10	2030	**1-MW**	91.2%	**160**	0.46	3.23	0.55	0.16	**3.94**
S11	2030	**10-MW**	91.2%	**1,597**	4.58	2.73	0.16	0.16	**3.06**
S12	2030	**50-MW**	85.1%	**7,457**	456.14	2.82	0.17	3.40	**6.39**
S22	2024	**1-MW**	91.2%	**154**	0.44	4.05	0.57	0.16	**4.78**
S23	2024	**10-MW**	91.2%	**1,536**	4.40	3.31	0.17	0.16	**3.63**
S24	2024	**50-MW**	91.3%	**7,686**	109.70	3.10	0.17	0.79	**4.06**

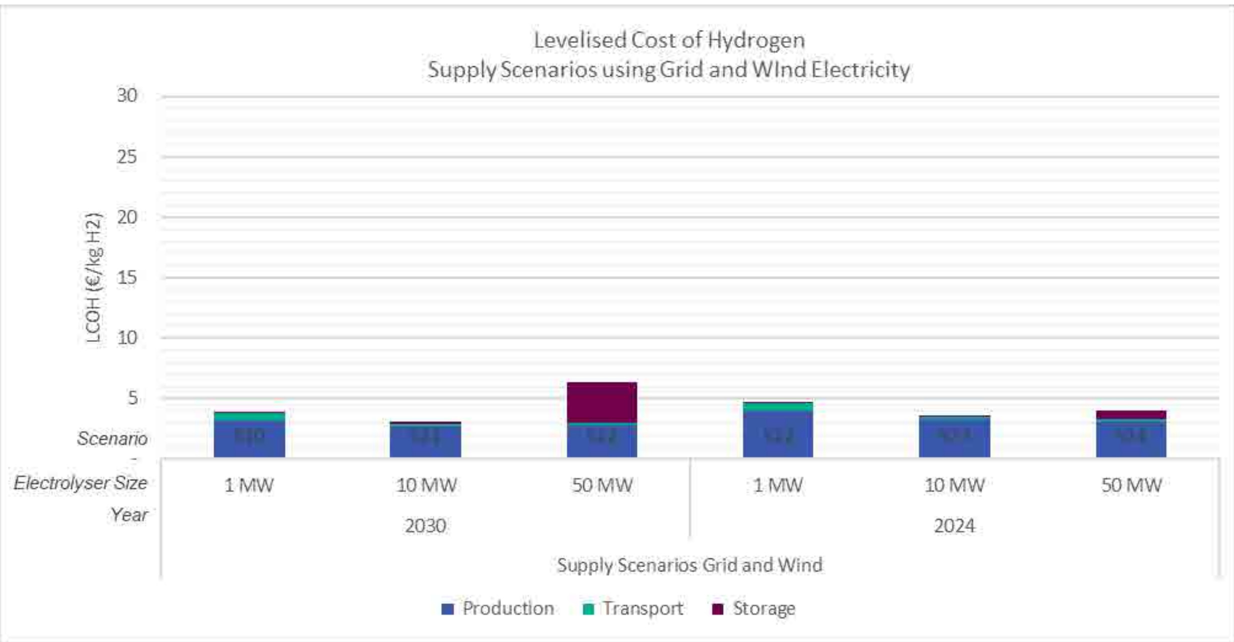


Figure 0-9: Levelised Cost of Hydrogen for Supply Led scenarios using Grid and Wind Electricity

The 50MW electrolysers below are significantly larger than any modelled in the demand-led scenarios. They require more electricity modelled in the supply scenarios and more often exceed what the wind farm can supply, leading to larger amounts of grid electricity being used. The 1MW and 10MW scenarios use small proportions of grid electricity, which is reflected in their low emissions.

Scenario S24 is the only scenario that has exceeded the limit of 4.36 kg_{CO2eq}/kg_{H2} and cannot be considered low carbon. However, it should be noted that this calculation is based on the grid carbon emissions for 2024, which will continue to reduce every year going forward. The 2030 version of this scenario, S12, is below this limit, showing that in the few years in between, if the grid is decarbonised as is planned, using grid electricity for hydrogen generation will be more acceptable.

Table 0-12: Hydrogen Production and Emissions for Supply Led scenarios using Grid and Wind Electricity

Scenario	Year	Electrolyser Size	*H_2 Produced by Electricity Source (tonnes$_{H2}$/yr)* Dispatch Down	Dedicated Wind	Grid Electricity	Total	Emissions (t_{CO2eq}/yr)	Emissions Rate (kg_{CO2eq}/kg_{H2})
S10	2030	**1-MW**	34	116	9	**160**	64	**0.40**
S11	2030	**10-MW**	268	1,061	268	**1,597**	1,899	**1.19**
S12	2030	**50-MW**	703	3,448	3,307	**7,457**	23,462	**3.15**
S22	2024	**1-MW**	33	111	10	**154**	119	**0.78**
S23	2024	**10-MW**	251	997	288	**1,536**	3,315	**2.16**
S24	2024	**50-MW**	666	3,265	3,756	**7,686**	43,235	**5.62**

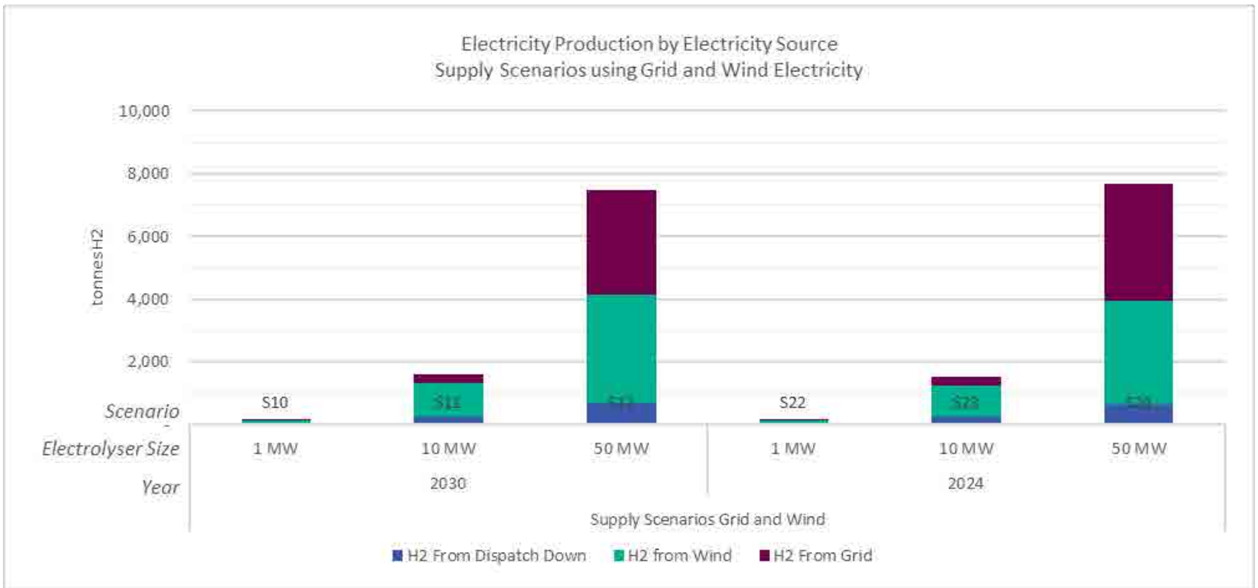


Figure 0-10: Hydrogen Production by electricity Source for Supply Led scenarios using Grid and Wind Electricity

Appendix D
Investment Case Figures

Rhode Hydrogen Feasibility Study

Appendix D1: Investment Case Figures - Net Present Value (NPV) Calculations for All Scenarios

Description	Electrolyser & H2 Transport by Road (Injection & Virtual Pipeline)	Electrolyser & H2 Transport by 4bar Pipeline (Injection & Physical Pipeline)	Electrolyser & H2 Transport by 4bar Pipeline to Derrygreenagh Power Station	Electrolyser & Local Fuelling Station	Electrolyser & Remote Fuelling Station with Virtual Pipeline	Electrolyser & District Heating Network in Rhode	Proposed Demonstrator	Alignment with Scenario S10
CAPEX (€)	2,030,000.00	3,777,365.00	2,140,624.67	1,786,200.00	4,246,200.00	4,685,390.00	2,880,000.00	2,880,000.00
OPEX (€ / annum)	1,485,326.00	1,350,220.60	1,350,220.60	1,425,574.00	1,573,974.00	1,361,541.60	1,519,326.22	380,200.00
Calculated ECOH (€/kg H_2)	**10.90**	**10.85**	**10.05**	**10.38**	**12.58**	**11.38**	**11.54**	**3.95**
Calculated ECOH (c/kWh H_2)	32.70	32.57	30.16	31.14	37.73	34.13	34.63	11.84
Annual Revenue from Sales of H_2 (€ / annum)	1,634,696.95	1,628,165.73	1,507,731.51	1,557,005.72	1,886,416.83	1,706,300.80	1,731,241.66	592,115.44
Annual Cash Flow (€ / annum)	149,370.95	277,945.13	157,510.91	131,431.72	312,442.83	344,759.20	211,915.44	211,915.44
Year								
1	143,625.92	267,254.93	151,452.80	126,376.66	300,425.80	331,499.23	203,764.85	203,764.85
2	138,101.84	256,975.90	145,627.69	121,516.02	288,870.96	318,749.26	195,927.74	195,927.74
3	132,790.23	247,092.21	140,026.63	116,842.32	277,760.54	306,489.67	188,392.06	188,392.06
4	127,682.92	237,588.66	134,640.99	112,348.39	267,077.44	294,701.61	181,146.21	181,146.21
5	122,772.04	228,450.64	129,462.49	108,027.30	256,805.23	283,366.93	174,179.05	174,179.05
6	118,050.03	219,664.07	124,483.16	103,872.40	246,928.11	272,468.20	167,479.85	167,479.85
7	113,509.65	211,215.45	119,695.35	99,877.31	237,430.87	261,988.66	161,038.32	161,038.32
8	109,143.89	203,091.78	115,091.68	96,035.87	228,298.91	251,912.17	154,844.54	154,844.54
9	104,946.05	195,280.56	110,665.08	92,342.18	219,518.19	242,223.24	148,888.98	148,888.98
10	100,909.66	187,769.77	106,408.73	88,790.56	211,075.18	232,906.96	143,162.48	143,162.48
11	97,028.52	180,547.86	102,316.08	85,375.54	202,956.90	223,949.00	137,656.23	137,656.23
12	93,296.66	173,603.71	98,380.85	82,091.87	195,150.87	215,335.58	132,361.76	132,361.76
13	89,708.32	166,926.64	94,596.97	78,934.49	187,645.07	207,053.44	127,270.92	127,270.92
14	86,258.00	160,506.39	90,958.63	75,898.54	180,427.95	199,089.85	122,375.89	122,375.89
15	82,940.39	154,333.06	87,460.22	72,979.37	173,488.41	191,432.54	117,669.12	117,669.12
16	79,750.37	148,397.18	84,096.36	70,172.47	166,815.78	184,069.75	113,143.39	113,143.39
17	76,683.05	142,689.59	80,861.89	67,473.53	160,399.79	176,990.15	108,791.72	108,791.72
18	73,733.70	137,201.53	77,751.81	64,878.39	154,230.57	170,182.83	104,607.42	104,607.42
19	70,897.79	131,924.55	74,761.36	62,383.07	148,298.62	163,637.34	100,584.06	100,584.06
20	68,170.95	126,850.53	71,885.92	59,983.72	142,594.83	157,343.60	96,715.44	96,715.44
Total Discounted Cash Flow (€)	2,030,000.00	3,777,365.00	2,140,624.67	1,786,200.00	4,246,200.00	4,685,390.00	2,880,000.00	2,880,000.00
Total Discounted Cash Flow - CAPEX (€)	- 0.00	- 0.00	- 0.00	0.00	- 0.00	- 0.00	- 0.00	- 0.00
Total Discounted CAPEX and OPEX (€)	- 22,216,065.07	- 22,127,303.59	- 20,490,563.26	- 21,160,215.89	- 25,637,020.32	- 23,189,184.68	- 23,528,139.15	- 8,047,042.08

Notes

Annual Hydrogen Output	150,000	kg
Discount Rate	4%	
H_2 Energy Content	33.33	kWh/kg

Rhode Hydrogen Feasibility Study

Appendix D2: Investment Case Figures - Net Present Value (NPV) Calculations for All Scenarios including Offset Prices for Natural Gas and Diesel

Description	Electrolyser & H2 Transport by Road (Injection & Virtual Pipeline)	Electrolyser & H2 Transport by 4bar Pipeline (Injection & Physical Pipeline)	Electrolyser & H2 Transport by 4bar Pipeline to Derrygreenagh Power Station	Electrolyser & Local Fuelling Station	Electrolyser & Remote Fuelling Station with Virtual Pipeline	Electrolyser & District Heating Network in Rhode	Proposed Demonstrator	Alignment with Scenario S10
CAPEX (€)	2,030,000.00	3,777,365.00	2,140,624.67	1,786,200.00	4,246,200.00	4,685,390.00	2,880,000.00	2,880,000.00
OPEX (€ / annum)	1,485,326.00	1,350,220.60	1,350,220.60	1,425,574.00	1,573,974.00	1,361,541.60	1,519,326.22	380,200.00
Diesel offset inflow							452400.00	
Natural Gas offset inflow							426240.00	
Cash in	888,000.00	888,000.00	888,000.00	870,000.00	870,000.00	454,109.17	878,640.00	
Annual Cash Flow (€ / annum)	- 597,326.00	- 462,220.60	- 462,220.60	- 555,574.00	- 703,974.00	- 907,432.43	- 640,686.22	- 380,200.00
Year								
1	- 574,351.92	- 444,442.88	- 444,442.88	- 534,205.77	- 676,898.08	- 872,531.18	- 616,044.44	- 365,576.92
2	- 552,261.46	- 427,348.93	- 427,348.93	- 513,659.39	- 650,863.54	- 838,972.29	- 592,350.43	- 351,516.27
3	- 531,020.64	- 410,912.43	- 410,912.43	- 493,903.26	- 625,830.32	- 806,704.12	- 569,567.72	- 337,996.42
4	- 510,596.77	- 395,108.11	- 395,108.11	- 474,906.98	- 601,759.93	- 775,677.04	- 547,661.27	- 324,996.55
5	- 490,958.43	- 379,911.64	- 379,911.64	- 456,641.33	- 578,615.31	- 745,843.31	- 526,597.37	- 312,496.69
6	- 472,075.41	- 365,299.65	- 365,299.65	- 439,078.20	- 556,360.88	- 717,157.03	- 506,343.63	- 300,477.58
7	- 453,918.67	- 351,249.67	- 351,249.67	- 422,190.58	- 534,962.38	- 689,574.06	- 486,868.87	- 288,920.75
8	- 436,460.26	- 337,740.06	- 337,740.06	- 405,952.48	- 514,386.91	- 663,051.99	- 468,143.15	- 277,808.42
9	- 419,673.32	- 324,750.06	- 324,750.06	- 390,338.92	- 494,602.79	- 637,549.99	- 450,137.64	- 267,123.48
10	- 403,532.04	- 312,259.68	- 312,259.68	- 375,325.89	- 475,579.61	- 613,028.83	- 432,824.65	- 256,849.50
11	- 388,011.58	- 300,249.69	- 300,249.69	- 360,890.28	- 457,288.09	- 589,450.80	- 416,177.55	- 246,970.67
12	- 373,088.06	- 288,701.62	- 288,701.62	- 347,009.88	- 439,700.08	- 566,779.62	- 400,170.72	- 237,471.80
13	- 358,738.52	- 277,597.71	- 277,597.71	- 333,663.35	- 422,788.54	- 544,980.40	- 384,779.54	- 228,338.27
14	- 344,940.88	- 266,920.88	- 266,920.88	- 320,830.14	- 406,527.44	- 524,019.62	- 369,980.33	- 219,556.03
15	- 331,673.92	- 256,654.69	- 256,654.69	- 308,490.52	- 390,891.77	- 503,865.01	- 355,750.32	- 211,111.56
16	- 318,917.23	- 246,783.36	- 246,783.36	- 296,625.50	- 375,857.47	- 484,485.59	- 342,067.61	- 202,991.89
17	- 306,651.19	- 237,291.69	- 237,291.69	- 285,216.83	- 361,401.42	- 465,851.53	- 328,911.16	- 195,184.51
18	- 294,856.91	- 228,165.09	- 228,165.09	- 274,246.95	- 347,501.36	- 447,934.16	- 316,260.73	- 187,677.41
19	- 283,516.26	- 219,389.51	- 219,389.51	- 263,698.99	- 334,135.93	- 430,705.93	- 304,096.86	- 180,459.05
20	- 272,611.79	- 210,951.45	- 210,951.45	- 253,556.72	- 321,284.54	- 414,140.31	- 292,400.83	- 173,518.32
Total Discounted Cash Flow (€)	- 8,117,855.27	- 6,281,728.80	- 6,281,728.80	- 7,550,431.97	- 9,567,236.40	- 12,332,302.81	- 8,707,134.81	- 5,167,042.08
Total Discounted Cash Flow - CAPEX (€)	- 10,147,855.27	- 10,059,093.80	- 8,422,353.47	- 9,336,631.97	- 13,813,436.40	- 17,017,692.81	- 11,587,134.81	- 8,047,042.08

Notes

Annual Hydrogen Output	150,000 kg	Natural Gas Offset Price (€/kg)	5.92	Offset Price= Cost of an amount of a given fuel with the same amount of energy as 1kg of H2
Discount Rate	4%	Diesel Offset Price (€/kg)	5.8	
H_2 Energy Content	33.33 kWh/kg	Heating Oil Offset Price (€/kg)	3.03	