National Heat Study

Low Carbon Gases for Heat

Potential, Costs and Deployment Options in Ireland

seai SUSTAINABLE ENERGY AUTHORITY OF IRELAND

Low Carbon Gases for Heat:

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Report 5 of the National Heat Study

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V1.2

The National Heat Study and associated reports were commissioned by a project team across the SEAI Research and Policy Insights Directorate and developed with the assistance of Element Energy and Ricardo Energy and Environment.

Sustainable Energy Authority of Ireland

SEAI is Ireland's national energy authority investing in, and delivering, appropriate, effective and sustainable solutions to help Ireland's transition to a clean energy future. We work with the public, businesses, communities and the Government to achieve this, through expertise, funding, educational programmes, policy advice, research and the development of new technologies.

SEAI is funded by the Government of Ireland through the Department of the Environment, Climate and Communication.

Key insights

- **Ireland's gas network currently delivers around 53 TWh per year.**

  The power sector uses half of all gas (27 TWh) to produce electricity. Industry uses 14 TWh (27% of total gas demand), including in combined heat and power plants. The residential sector uses 7 TWh (13%) for heating and cooking, and the commercial and public sectors use 5 TWh (9%). The recent trend has been for a growth in gas used in the power sector due to a move away from coal and peat, and for strong growth in gas used in industry, which has more than doubled since 2005.

- **The future resource potential for green hydrogen is far greater than Ireland's 2020 gas network demand.**

  Over 90 TWh of hydrogen production may be possible because of the abundance of wind energy resources, especially offshore wind. The long-run variable cost (LRVC) of green hydrogen is estimated to be 17-23 c_{2019}/kWh. Most of the resource potential estimated is produced from floating offshore wind, and falls at the high end of this range. This cost estimate includes inter-seasonal storage of hydrogen as ammonia and the costs of converting the gas networks to carry hydrogen.

- **Green hydrogen is unlikely to be available at scale in Ireland until the 2030s.**

  Several pathways for hydrogen generation are possible. In line with Government policy, only those pathways that produce hydrogen from renewable sources are considered. Green hydrogen produced using bioenergy and wind-generated renewable electricity is unlikely to be available at scale until the 2030s. However, within the 2020s, there may be a role for the initial development of green hydrogen with dedicated wind generation in parts of the country where the capacity of the electricity transmission grid is limited. For example, access to the electricity transmission grid is constrained in the northwest of Ireland.

- **Using domestic bioresources could supply a maximum potential of around 5 TWh of biomethane.**

  The largest potential resource comes from purpose-grown mixed-species grass silage mixed with cattle slurry. The estimated available resource is based on a detailed spatial analysis of the available land accounting for environmental constraints, the national projections for the animal herd and their fodder requirements, and increases in farm productivity. In a scenario where the cattle herd reduces by more than is projected, a greater land area is available for silage crops. In this hypothetical scenario, around 5 TWh of biomethane fuel may be available. Biomethane LRVC is projected to be 2-11 c_{2019}/kWh, with most of the resource available above 10 c_{2019}/kWh in 2050. The cost and carbon emissions depend on the feedstocks used and the production method. The carbon emissions associated with biomethane production from a grass silage/slurry mix and its combustion are around 38 kg $CO_{2\,eq}$/MWh. For comparison, carbon emissions from the combustion of fossil gas are 185 kg $CO_{2\,eq}$/MWh.

- **Co-ordinated action within the 2020s is needed to determine the future trajectory of the gas network and to begin planning for the changes required.**

  Most large-scale changes to the gas network, if pursued, would not start before 2030 due to the low technology readiness. In the nearer term, testing of hydrogen in existing appliances and trial conversions of gas infrastructure at smaller scales could de-risk the future use of hydrogen for heating. Actions possible within the 2020s include engaging with stakeholders at all levels to build consensus on the future use of the gas grid, further spatial analysis of future demand for a range of scenarios and consideration of whether low-energy-density hydrogen using the existing gas network capacity could meet this. Policy supports required for growth of anaerobic digestion (AD) crops and biomethane production could also be considered.

- **Reliance on low-carbon gases for significant decarbonisation of heat in Ireland has many associated risks.**

  Hydrogen is only likely to be widely available for consumers in the 2030s, and this late potential uptake means significant portions of existing gas users may have already switched to an alternative low-carbon fuel option. Significant upfront investment in low-carbon gas infrastructure would also be required, which would likely need to be paid for by grid operators and the state, before end consumers consider the adoption of hydrogen for heat. If these low-carbon gases do not turn out to be cost competitive with other low-carbon alternatives for consumers, there is a risk that this upfront investment may be wasted. Production of these low-carbon gases would also result in additional competition for electricity generation from wind and for domestic biomass use.

Acknowledgements

SEAI, Element Energy and Ricardo Energy and Environment would like to convey our thanks to stakeholders within the following bodies for their valuable inputs to the study:

- Commission for the Regulation of Utilities
- Department of the Environment, Climate and Communications
- Devenish Farms
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- Environmental Protection Agency
- Ervia
- ESB Group
- Gas Networks Ireland
- Geological Survey Ireland
- Indaver
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- University College Cork
- Teagasc
- Trinity College Dublin

To avoid doubt, this acknowledgement does not imply endorsement by the stakeholders listed, and this report is solely the work of Element Energy, Ricardo Energy and Environment and the Sustainable Energy Authority of Ireland.

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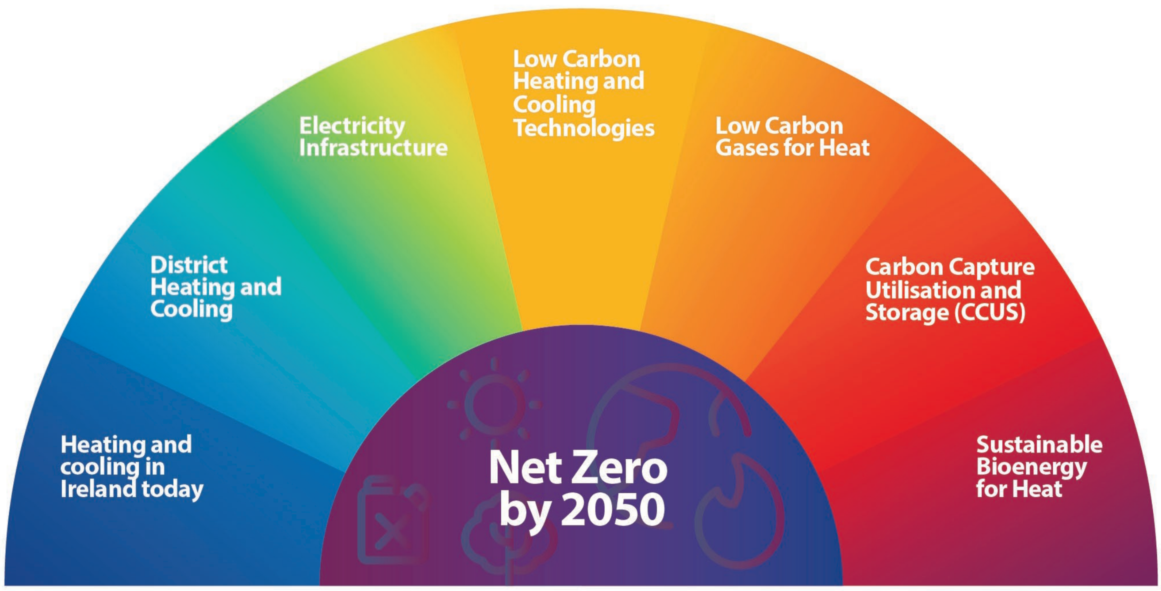
Executive summary

Ireland's 2021 Climate Action and Low Carbon Development (Amendment) Act commits Ireland to reducing greenhouse gas emissions by 51% by 2030 and to achieving economy-wide carbon neutrality by 2050. This requires immediate emissions reductions in every sector. Energy used for heating and cooling accounts for 24% of Ireland's greenhouse gas emissions, but the current pace of decarbonisation falls short of the cuts required. Almost every sector of Ireland's economy uses heat energy, and decarbonisation efforts will need to be implemented by industry, businesses and households. This requires a comprehensive, robust and actionable evidence base, which policymakers and other stakeholders can use to make decisions.

To provide this evidence base, the Sustainable Energy Authority of Ireland (SEAI) commissioned Element Energy and Ricardo Energy and Environment to work with SEAI on the National Heat Study. The study evaluates the costs and benefits of various pathways that reach net zero by 2050. The evaluation was based on a comprehensive understanding of heating and cooling demand in Ireland and the deployment costs, potential and suitability of technologies, infrastructure and fuels to reduce emissions.

SEAI has separated the insights and analysis from this study into eight reports (outlined in *Figure 1*)[1]. These reports provide a rigorous and comprehensive analysis of options for decarbonisation of heating and cooling in Ireland up to 2050. The findings support Ireland's second submission to the EU of a 'national comprehensive assessment of the potential for efficient heating and cooling', as required by Article 14 of the Energy Efficiency Directive[1]. There are eight major technical reports, each focusing on topics that form the overall analysis. The concluding report is *Net Zero by 2050* [2], which outlines the study's key insights across scenarios that achieve net-zero emissions from heating and cooling.

Figure 1: Framework of reports



This report, *Low Carbon Gases for Heat*, describes the data inputs and key assumptions used to develop projections for the availability, cost and carbon content of low-carbon gases in Ireland and possible future scenarios for the evolution of the gas network to 2050. This includes analysis of the two primary options for decarbonised gases in Ireland − green hydrogen and biomethane − as well as an assessment of the current gas demand and changes to that demand in the future. Conceptual schematics for how the gas network

[1] All reports and supporting materials published as part of the National Heat Study are available from www.seai.ie/NationalHeatStudy/

might change to accommodate low-carbon gases are in two of the National Heat Study scenarios, where low-carbon gases are assumed as most prevalent (Rapid Progress and Decarbonised Gas). The report also discusses the challenges, opportunities and possible next steps if such scenarios are pursued. This report presents the assumptions feeding into the modelling in the National Heat Study for each scenario considered, with the results of these modelled scenarios outlined within the *Net Zero by 2050* report.

In 2020, Ireland's gas network delivered 53 TWh for electricity generation and heating, as shown in *Figure 2*. The National Heat Study considers five scenarios for the future of heating and cooling in Ireland, as outlined in *Table 1*. In all decarbonisation scenarios, the usage, extent, and composition of gas in the gas network will change substantially to reach net zero by 2050. The Decarbonised Gas scenario makes use of the gas network as a key vector for decarbonisation of heat in buildings and industry, with potential demand of around 30 TWh of low-carbon (non-fossil based) gas for heat and process use. At the other extreme, demand for low-carbon gas may be less than 5 TWh per year in the High Electrification scenario, where heat pumps and electric heating systems are widely deployed, along with heat networks and solid biomass. In this case, the bulk of the gas distribution and transmission networks may be decommissioned. In between these are the Balanced scenario, in which the gas distribution network is maintained although its use is somewhat reduced, and the Rapid Progress scenario, in which the current gas transmission network is maintained and a hydrogen transmission network is built, while the distribution network is decommissioned.

Figure 2: Gas network demand by sector, 2000-2020

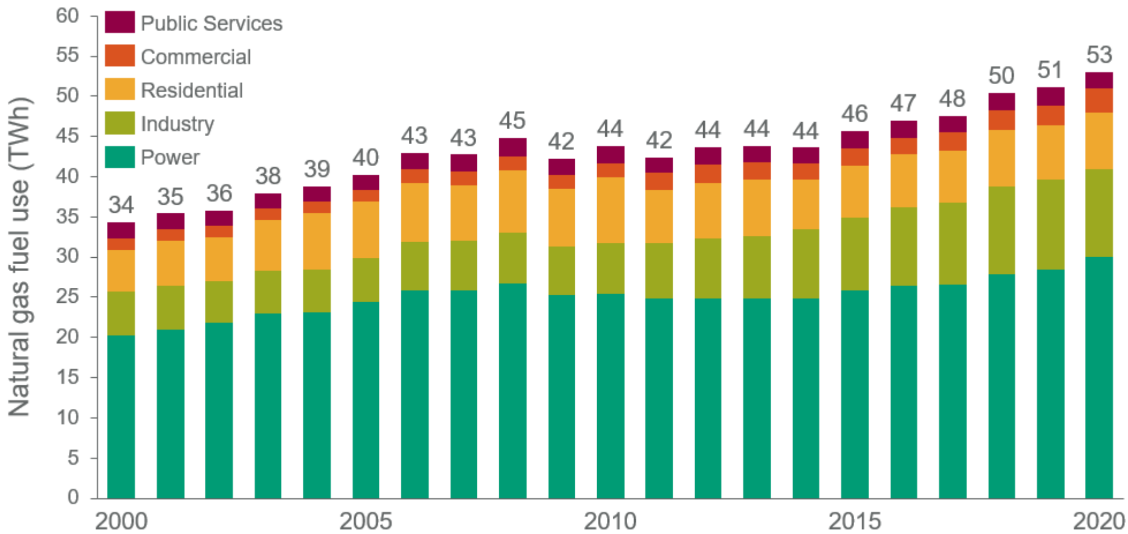


Table 1: Overall narrative and evolution of the gas network in each decarbonisation scenario

Relationship to Overall Modelling

Baseline	Business-as-usual scenario where all sectors continue to use carbon-intensive practices.
	Limited deployment of heat networks, new technologies or fuel switching.
	Includes policy measures from the 2019 Climate Action Plan that had existing implementing measures such as funding and planning or legislation in place by the end of 2020.
	It does not achieve net zero by 2050.
High Electrification	Weighted towards electrification, coupled with minimal amounts of bio-derived gases, CCUS and green hydrogen.
	High levels of heat networks deployment and significant efficiency uptake.
	Achieves net zero by 2050.
Decarbonised Gas	Weighted towards green hydrogen use, CCUS infrastructure or bio-derived gases, or both, coupled with domestic and commercial fuel switching to green hydrogen or bio-derived gases, or both.
	Low levels of heat networks deployment and efficiency uptake.
	Achieves net zero by 2050.
Balanced	Progresses steadily and comprises a mix of cost-effective deployment of low-carbon technologies (electricity, bio-derived gases, green hydrogen).
	Medium level of industrial CCUS, heat networks and efficiency deployed.
	Achieves net zero by 2050.
Rapid Progress	Accelerated progress, driven by policy targets; all low-temperature applications are quickly electrified, while bio-derived gases are prioritised for industry sites.
	High levels of heat networks deployment and energy efficiency uptake.
	Achieves net zero by 2050.

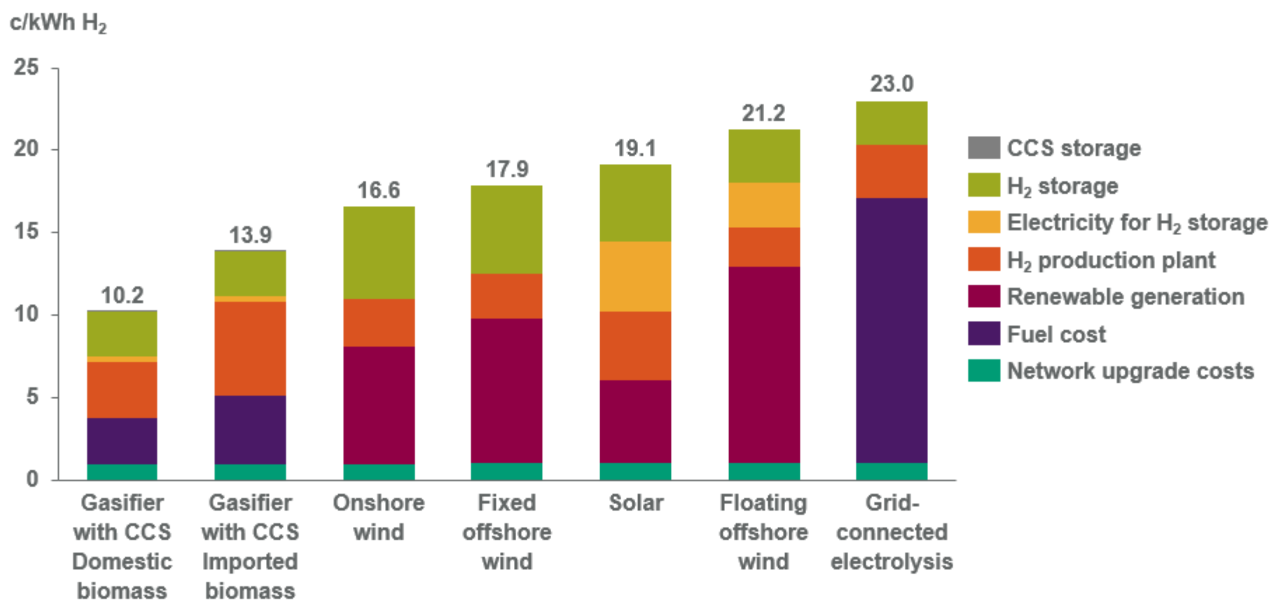
High-level details of the Baseline and Scenarios examined

Potential for hydrogen and biomethane

The technical potential of green hydrogen has been estimated at over 90 TWh, significantly more than the 27 TWh existing fossil gas use in the heat sector and 53 TWh used in total annually in Ireland today. Hydrogen, therefore, has the technical potential to fully replace the fossil gas heating demand in Ireland today, with the potential to expand the gas distribution network to increase the number of connected consumers. Hydrogen could provide an important decarbonisation option for high-temperature processes in the industry sector, for which electrification may be more challenging. The timing, availability and cost of hydrogen present barriers to its uptake, which are key considerations in the context of alternative pathways to net zero. These are discussed below.

Green hydrogen for heat is likely to lead to an increase in annual heating costs seen by the consumer, compared to fossil fuel use or to electrification. The estimated 2050 long-run variable cost (LRVC) of hydrogen is significantly higher for all production routes than for fossil gas, and is comparable with that of electricity in terms of c/kWh of fuel delivered. Production of hydrogen from electricity for subsequent use in heating represents a less efficient use of electricity than direct electric heating. However, the production of hydrogen from electricity allows for greater consumption of low-cost electricity generated from variable renewables, and so presents an opportunity to reduce demands on the electricity network if the hydrogen energy system is designed effectively. The cost of hydrogen production depends upon the production method, the cost of fuel or dedicated renewable electricity generation, the requirements for hydrogen storage, and the costs to develop a hydrogen transmission network and convert the existing gas distribution network to support hydrogen (see *Figure 3*). Floating offshore wind contributes over half of the future hydrogen resource potential and may offer an export opportunity if there is a market for hydrogen at costs over 20 c/kWh.

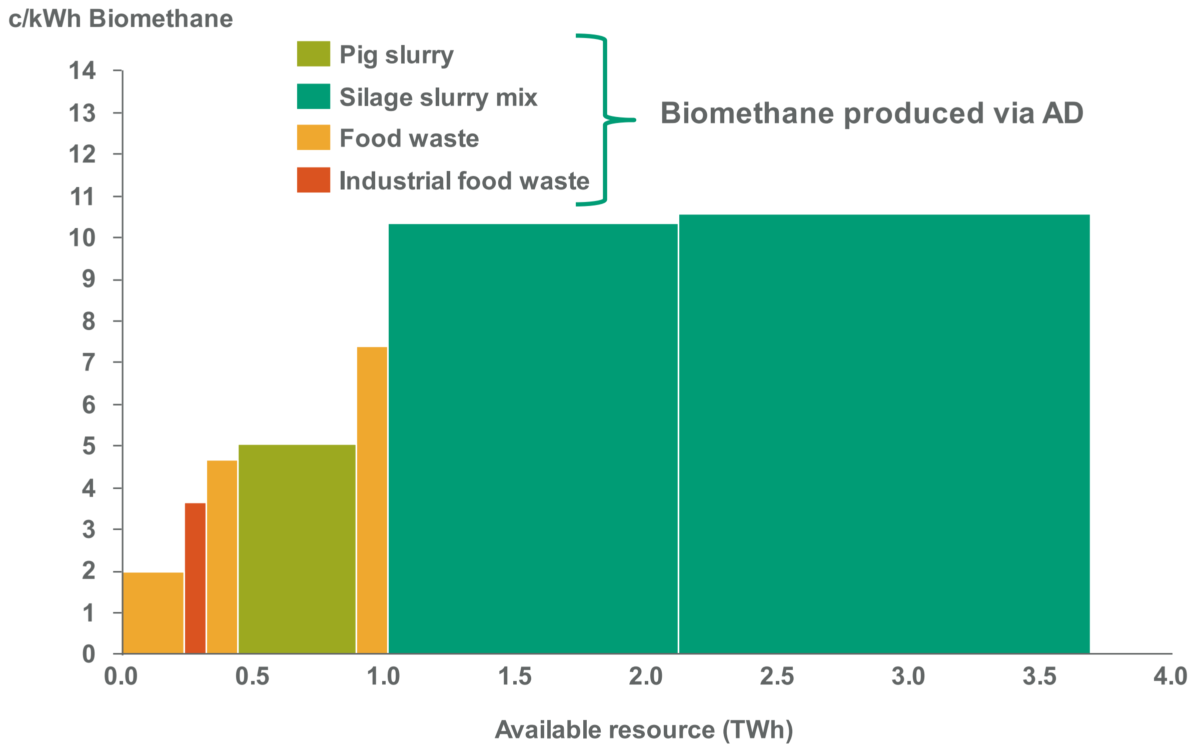
Figure 3: LRVC breakdown for each hydrogen production route in 2050



Ireland has little known opportunity for geological storage of hydrogen, and may require significant volumes of hydrogen to be stored using other methods. Due to the seasonal nature of heat demand, if geological storage is not available, Ireland would need pressurised steel containers or chemical bonding of hydrogen to form ammonia or LOHCs to store up to 40% of the annual demand of hydrogen. For annual demand of 20 TWh, this represents 2 million cubic meters of ammonia (about the size of 50 typical above-ground oil storage tanks). This level of energy storage is not unprecedented in Ireland, but it is a significant infrastructure requirement. As shown in *Figure 3*, hydrogen storage contributes about 20% of the cost of hydrogen.

The domestic biogenic resource potential for biomethane production is about 3.7 TWh. With changes in land use and reductions in the size of the national herd, up to 5 TWh may be available. Biomethane LRVC is projected to be 2-11 c_{2019}/kWh, with most of the resource available above 10 c_{2019}/kWh in 2050. The competing demands for land use in Ireland for resource production is explored in the Sustainable Bioenergy for Heat report [3] in this National Heat Study, but even if resources for production of biomethane (via anaerobic digestion (AD)) are prioritised with policy support, biomethane supply would equal only 11% of the 53 TWh of fossil methane gas consumed in 2020. Therefore, it is likely that both cheaper and more expensive biomethane production routes would need to be deployed, resulting in an increasing average cost of biomethane for heat to over 10 c/kWh (see *Figure 4*).

Figure 4: LRVC of biomethane production in 2050 in the Decarbonised Gas scenario

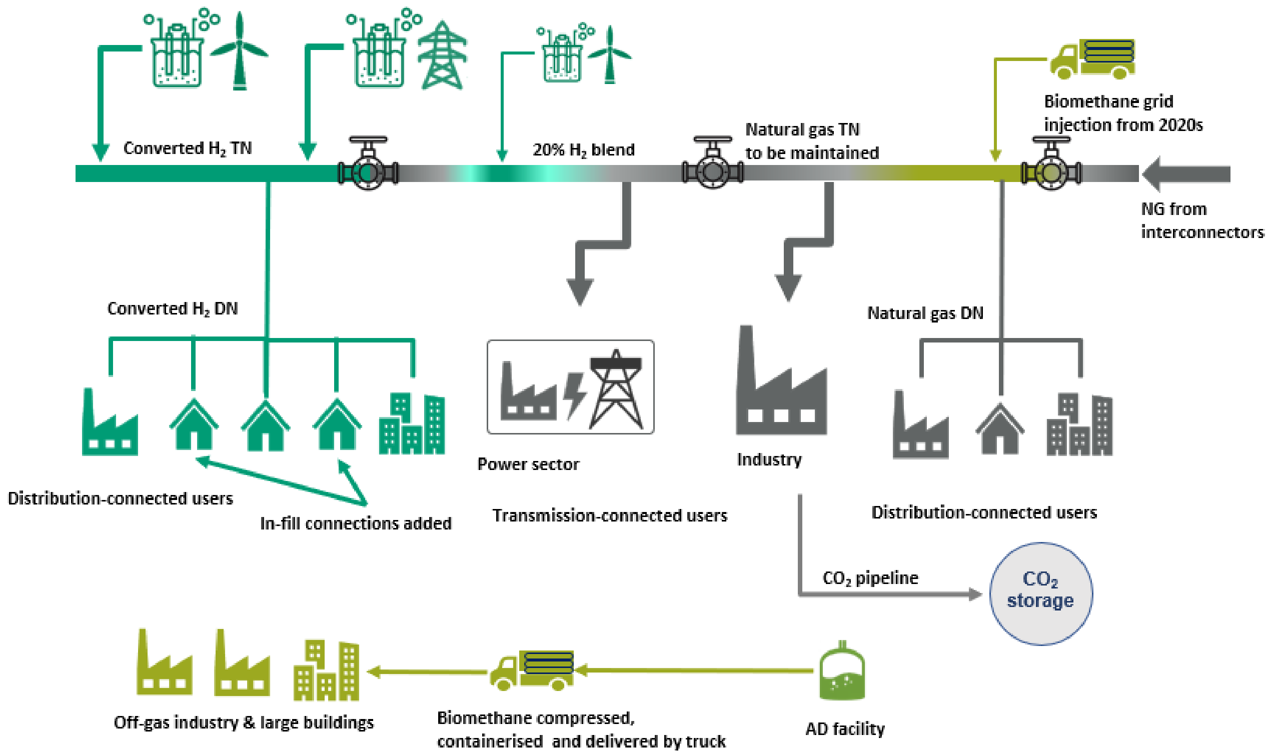


Gas network evolution

Significant and sustained co-ordination and policy support would be needed across the entire supply chain to enable the deployment of either green hydrogen or biomethane for low-carbon heat. Early and clear policy decision-making would be needed to drive either option, and policy support for deployment of hydrogen and biomethane would be required to help co-ordinate all stakeholders in the rollout of either low-carbon gas. Section 7 of the present report outlines the step-by-step evolution of the gas network considered in both the Decarbonised Gas and Rapid Progress scenarios. Within the Decarbonised Gas scenario, the distribution grid is assumed to convert to hydrogen in a 'piecewise' fashion beginning in 2035. This conversion is assumed to proceed town-by-town and for some required changes, potentially building-by-building, as network infrastructure and appliances are checked and replaced if necessary, to be hydrogen-ready. This could incur significant additional costs if enough existing appliances are not hydrogen-ready by this point. *Figure 5* presents a conceptual schematic of this process. Biomethane is injected into the gas network before conversion begins in 2035 to assist in emissions reductions. Support to develop a market for off-gas grid biomethane use is needed in parallel in this scenario to encourage growth of the sector and minimise the risk of stranded assets. These aspects must be considered in the context of the costs and benefits of alternative pathways.

The Rapid Progress scenario assumes biomethane takes a more central role, becoming the primary fuel in the transmission network by 2050. The gas network is decommissioned in stages as the residential, commercial and public sectors are encouraged to decarbonise heating by other means. Meanwhile, biomethane and hydrogen (from 2030) are prioritised for high-temperature industrial use.

Figure 5: A schematic representing the piecewise conversion of the gas network in the Decarbonised Gas scenario, 2035-2050



Challenges

Significant investment in infrastructure would be needed for the deployment of hydrogen and biomethane before end users adopt the fuel. These upfront investments are likely to carry significant risks, as the assets would compete with each other and with other decarbonisation options.

To fully use the available biomass resource for the production of biomethane, supply chain infrastructure would need significant investment. Deployment of 60-250 anaerobic digesters with annual outputs between 15 and 60 GWh would be needed by 2030. Supporting transportation and injection infrastructure would also be needed. The cost of deploying this infrastructure could range from €1-2 billion.

Green hydrogen production infrastructure would need to be developed from the ground up, potentially including a new transmission network, and the entire existing gas distribution network would need to be re-purposed in a piecewise manner to be suitable for hydrogen. These infrastructure requirements would require significant investment, with up to €10 billion needed in infrastructure investment in scenarios with significant hydrogen deployment in industry or buildings connected to the gas grid, such as the Balanced or Rapid Progress scenario, depending upon uptake. If hydrogen is pursued as a key decarbonisation option for all on-gas consumers, these hydrogen infrastructure investment costs could exceed €20 billion before 2050. End users taking up hydrogen would also need to invest in new equipment capable of using hydrogen as a fuel, either hydrogen appliances or 'hydrogen-ready' appliances which use fossil gas but can be easily switched over to use hydrogen.

The deployment of the infrastructure in both pathways would require co-ordination across the entire supply chain and risks exist for both technology pathways. For green hydrogen production, end users are only likely to switch to using hydrogen for heating when there is a guarantee of a secure supply of hydrogen at a reasonable price, which would likely require a significant upfront investment from grid operators and through policy support. Unlike many electricity users, existing gas users have several fuel and technology options. If H_2 or biomethane do not deliver at a cost competitive with electricity or other fuel options, then there are significant risks of wasted investments. For biomethane, these risks also apply, as competing demands for biogenic resources after the investment in this infrastructure could lead to a reduced supply of biomethane. Furthermore, in a high-hydrogen scenario, all gas-connected consumers may switch to hydrogen instead, which could lead to this biomethane infrastructure becoming stranded before the end of its natural lifetime.

Resource constraints and competition for biogenic crops, and competition for renewable electricity generation sites, could increase the average cost of these fuels seen by the consumer. Competition for agricultural land use could result in low availability of biogenic crops for either hydrogen (gasification) or biomethane (primarily AD), and low-cost renewable generation faces competition between green hydrogen production and electricity generation for the power sector.

Biomass resources can generate various forms of energy and be used in other ways in the bioeconomy to produce biomaterials and other products. These competing demands for solid biomass could lead to limited use of land for AD crops suitable for biomethane. Imported biomass is potentially less resource-constrained, but there are risks and uncertainties around the emissions and overall sustainability of imported biomass.

Reliance on green hydrogen to decarbonise heat would most likely lead to a delay in decarbonisation efforts, and conflicts with 2030 decarbonisation targets and a focus on cumulative emissions reductions. Green hydrogen is only likely to be available for consumers from 2035 (2030 in the most optimistic case), and so does not offer any significant decarbonisation of emissions from heating before this date. While hydrogen blending could begin earlier, this is likely to be limited to 20% hydrogen by volume or 7% hydrogen by energy and therefore has quite limited potential for emissions reductions. Within the 2020s, there may be a role for the initial development of green hydrogen with dedicated wind generation in parts of the country where the electricity grid is limited. For example, in the northwest of Ireland, access to the electricity transmission grid is constrained, but access to the gas grid is not. The generation of hydrogen to blend into the gas grid, using lower-cost onshore wind in locations where wind farms achieve high-load factors, is a potential early deployment route. Alternatively, trucks or dedicated pipelines could transport hydrogen produced in these areas for use in transport or industry as pure hydrogen.

As hydrogen is not yet proven as a safe and reliable source for heat at any significant scale, there is a high risk of large sunk costs if hydrogen for heating is pursued and found unsuitable. This would also add to cumulative emissions in this case, and would represent a delay to decarbonisation efforts. If the green hydrogen produced in Ireland is not available to consumers at low enough costs to be competitive with other low-carbon heating options, this could lead to lower than expected hydrogen demand, further increasing the risk of sunk costs in hydrogen infrastructure.

Opportunities

Green hydrogen has the technical potential to decarbonise several key applications in Ireland, including replacing fossil gas use for heating buildings and in high-temperature industrial processes, as well as a long-term storage opportunity in the power sector.

If a hydrogen transmission grid is built and the distribution network successfully converted to support hydrogen distribution, green hydrogen could be used in significant quantities by existing gas network users, if available at a cost-competitive price with other decarbonisation options. It also presents an opportunity to decarbonise hard-to-electrify heat demands, such as space-constrained buildings unsuitable for heat pump deployment, or high-temperature industrial processes such as cement kilns. Without deployment of hydrogen, the need for gas infrastructure will significantly reduce by 2050, and so hydrogen provides an opportunity to avoid the decommissioning of a significant portion of this infrastructure.

Generation and storage of hydrogen (for use in the heat sector, or as a long-term storage mechanism in the power sector) offers an alternative to curtailment of renewable electricity, and could enable dispatchable power generation with low emissions. This potential has informed the energy storage assumptions for the power sector in the National Energy Modelling Framework (NEMF); for more information please see the *Net*

Zero by 2050 report [2] in this National Heat Study. Selling this hydrogen to a range of consumers could provide an alternative revenue stream for owners of renewable energy generation sites, which may become increasingly important in driving further renewable deployment as the penetration of renewables continues to increase out to 2050. If there is international demand for green hydrogen at the prices presented in this report then there could be the potential for the export of green hydrogen, either for heat, dispatchable power or for use of hydrogen in non-energy purposes such as for use as a chemical feedstock.

Grid blending of biomethane can lead to reductions in cumulative emissions by both 2030 and 2050. Biomethane offers potential for reduction in emissions in the 2020s and early 2030s from use of the gas via grid blending. However, this use depends on the realisation of resource potential and the deployment of AD infrastructure. This could provide the potential of emissions reductions before 2030, if the essential infrastructure is built and if the necessary crops are being grown in the required amounts in the agricultural sector, to appropriate and strict sustainability criteria. This could help Ireland meet its 2030 emissions reductions targets [4].

Biomethane can provide decarbonisation of heat with the lowest impact on consumers. Appliances currently using fossil gas require no adjustments to burn biomethane (either part-blended or pure biomethane). Gas combustion boilers (burning either fossil gas or biomethane) are less sensitive than heat pumps to the efficiency level of buildings, and so deployment of biomethane can be used as a decarbonisation option in inefficient buildings where energy efficiency measures may not be practical, for example, heritage buildings. However, the maximum estimated domestic biogenic resource potential for biomethane production is about 5 TWh, which is approximately 11% of current fossil gas demand for heat.

1 Introduction

Ireland's 2021 Climate Action and Low Carbon Development (Amendment) Act commits Ireland to reducing greenhouse gas emissions by 51% by 2030 and to achieving economy-wide carbon neutrality by 2050. This requires immediate emissions reductions in every sector. Energy used for heating and cooling accounts for 24% of Ireland's greenhouse gas emissions, but the current pace of decarbonisation falls short of the cuts required. Almost every sector of Ireland's economy uses heat energy, and decarbonisation efforts will need to be implemented by industry, businesses and households. This requires a comprehensive, robust and actionable evidence base that policymakers and other stakeholders can use to make decisions.

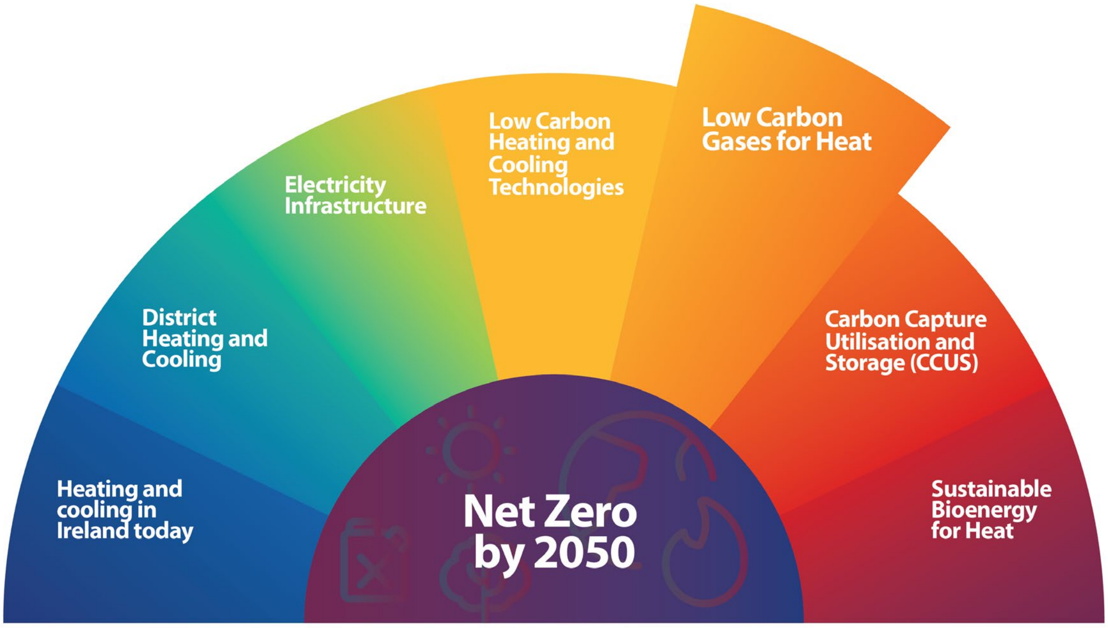
The Sustainable Energy Authority of Ireland (SEAI) commissioned Element Energy and Ricardo Energy and Environment to work with SEAI on the National Heat Study to provide this evidence base. The study evaluates the costs and benefits of various pathways that reach net zero by 2050. The evaluation was based on a comprehensive understanding of heating and cooling demand in Ireland and the deployment costs, potential and suitability of technologies, infrastructure and fuels to reduce emissions.

We have separated the insights and analysis from the study into eight reports (outlined in *Figure 6*)[2]. These reports provide a rigorous and comprehensive analysis of options for decarbonising heating and cooling in Ireland up to 2050. The findings support Ireland's second submission to the EU of a national comprehensive assessment of the potential for efficient heating and cooling, as required by Article 14 of the Energy Efficiency Directive [1]. There are seven major technical reports, each focusing on topics that form the overall analysis. The concluding report is called *Net Zero by 2050: Exploring Decarbonisation Options for Heating and Cooling in Ireland* [5]. It outlines the study's key insights across scenarios that achieve net-zero emissions from heating and cooling.

This report serves as a standalone document detailing the low carbon and renewable gases and the scenarios for possible future evolution of the gas network developed and analysed within the National Heat Study. It includes information on gas usage in Ireland today and how this demand may be met by low-carbon gases in the future. The costs of various production methods of hydrogen and biomethane and the resulting carbon content are estimated. Finally, this report includes a discussion on several potential trajectories for how the gas transmission and distribution networks may change over the years to 2050.

[2] All reports and supporting materials published as part of the National Heat Study are available from www.seai.ie/NationalHeatStudy/

Figure 6: Overview of the reports contributing to the National Heat Study



In the interest of clarity and brevity, detailed numerical inputs to the modelling of low-carbon gases conducted in the National Heat Study are available as an Excel workbook[3]. This includes details on the costs, efficiencies and fuel consumption of the low-carbon fuel production and storage methods considered.

1.1 Objectives and scope of this report

The objectives of the work done on low-carbon gases described in this report are:

- Review literature and consult with experts to gather information on the range of low-carbon gases and storage methods that could be deployed in Ireland to 2050, including both biological and non-biological energy carriers.
- Quantify the demand for gas in Ireland today and the potential future demand for low-carbon gases in the heat sector.
- Estimate the future cost of hydrogen and biomethane in Ireland, considering production routes, storage and delivery mechanisms, and the likely future hourly profile of demand.
- Develop possible trajectories for how the gas network may evolve to 2050, and comment on the actions and policies needed to realise these changes.
- Highlight challenges and opportunities relating to low-carbon gases and areas of uncertainty that will require further investigation in the future.

The results of this work are also essential inputs to the overall National Heat Study. The goals of the overall study are to:

- Develop a detailed understanding of heating and cooling demand in the residential, services and industrial sectors and the opportunities to reduce this.
- Assess the potential and costs of the low-carbon technologies and fuels that can decarbonise heat generation.

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[3] Supporting material for this report is available for download from the SEAI website. Available: https://www.seai.ie/data-and-insights/national-heat-study/low-carbon-gases-for-heat/.

- Explore pathways for technology and fuel deployment to reach net zero by 2050.
- Understand the perspectives of various stakeholders and seek to include data and information from a wide range of sources in the analysis.
- Provide detailed analysis and useful insights to policymakers, stakeholders and the public.
- Build modelling capacity to support further work on policy development.

This report begins with a description of the scenarios for heat decarbonisation investigated in the National Heat Study and the implications of these for low-carbon gases and the gas network (Section 2). Section 3 presents the full list of renewable and low-carbon gases initially explored and the shortlist carried forward for more detailed analysis. Section 4 discusses the current gas network demand and the future demand for low-carbon gases, including demand in buildings, industry and the power sector. Sections 5 and 6 present the method used to calculate future costs of green hydrogen and biomethane, respectively, and the volume of each that could be available in Ireland in 2050. Section 7 outlines the evolution of the gas network considered within the Decarbonised Gas and Rapid Progress scenarios. Section 8 discusses the challenges and opportunities presented by low-carbon gases in Ireland, followed by conclusions and next steps which are outlined within Section 9. For more information and discussion regarding the modelling results from this study, and how the findings in this report feed into the overall National Heat Study, please see the Net Zero by 2050 report [2], which is the main report on the scenario results of the National Heat Study.

2 Scenarios for heat decarbonisation

The National Heat Study considers five scenarios for the evolution of heat supply to 2050. *Table 2* describes these five scenarios, and how the gas network and gas network composition changes in each scenario. The Baseline scenario follows a 'business-as-usual' trajectory, while the four other scenarios explore different routes towards decarbonising heat, and are compatible with reaching net-zero emissions across the economy by 2050.

Table 2: National Heat Study scenarios and implications for low-carbon gases

Relationship to Overall Modelling

Baseline	Business-as-usual scenario where all sectors continue to use carbon-intensive practices.
	Limited deployment of heat networks, new technologies or fuel switching.
	Includes policy measures from the 2019 Climate Action Plan that had existing implementing measures such as funding and planning or legislation in place by the end of 2020.
	It does not achieve net zero by 2050.
High Electrification	Weighted towards electrification, coupled with minimal amounts of bio-derived gases, CCUS and green hydrogen.
	High levels of heat networks deployment and significant efficiency uptake.
	Achieves net zero by 2050.
Decarbonised Gas	Weighted towards green hydrogen use, CCUS infrastructure or bio-derived gases, or both, coupled with domestic and commercial fuel switching to green hydrogen or bio-derived gases, or both.
	Low levels of heat networks deployment and efficiency uptake.
	Achieves net zero by 2050.
Balanced	Progresses steadily and comprises a mix of cost-effective deployment of low-carbon technologies (electricity, bio-derived gases, green hydrogen).
	Medium level of industrial CCUS, heat networks and efficiency deployed.
	Achieves net zero by 2050.
Rapid Progress	Accelerated progress, driven by policy targets; all low-temperature applications are quickly electrified, while bio-derived gases are prioritised for industry sites.
	High levels of heat networks deployment and energy efficiency uptake.
	Achieves net zero by 2050.

High-level details of the Baseline and Scenarios examined

3 Low-carbon gas pathways considered

3.1 Hydrogen and other non-biological low-carbon gases

3.1.1 Hydrogen

This study considers three methods of hydrogen production and four methods of hydrogen storage, shown in *Table 3*. In line with Irish Government policy, the study considers only green hydrogen production routes.

Table 3: The production, storage and distribution methods considered for hydrogen in this study

Production	Description
Electrolysis – on-grid	Hydrogen production via grid-connected PEM and/or SOFC electrolysers
Electrolysis – renewables co-located	Hydrogen production via PEM and/or SOFC electrolysers co-located with renewable electricity production
Biomass gasification	Gasification of perennial energy crops with carbon capture
Waste gasification ✘	Gasification of waste – excluded from analysis as residual waste is expected to be absorbed in EfW plants and industry
SMR with CCS ✘	Hydrogen production from natural gas with carbon capture – excluded from analysis
Storage	**Description**
Pressurised containers	Medium or high pressure storage in tanks
Ammonia	Conversion to NH_3 for storage as liquid
Methanol	Conversion to CH_3OH for storage as liquid
LOHCs	Catalytic hydrogenation of liquid organic carriers
Delivery	**Description**
Gas network	Conversion of the gas network to hydrogen, with blending in the shorter term

Electrolysis using grid-connected electrolysers produces hydrogen using electricity from the grid during periods of generally lower electricity demand and electricity prices. We considered both PEM (proton-electron membrane or polymer-electrolyte membrane) electrolysers and solid-oxide fuel cell (SOFC) electrolysers to produce the hydrogen via this method, with the most cost-effective electrolyser type and sizing used in the modelling as per the method described in Section 5 below.

We also considered electrolysis when co-located with renewables, where renewable electricity generation technologies are built specifically to produce hydrogen, and hydrogen is produced from all generated electricity using electrolysers (again, both PEM and SOFC electrolysers were considered). The renewable generation options considered in this study for this method of hydrogen generation are:

- Onshore wind turbines;
- Fixed offshore wind turbines;
- Floating offshore wind turbines; and
- Solar photovoltaic panels.

Table 6 in Section 5.2 provides the available capacities for each type of renewable generation above, alongside the average capacity factor for each technology, and the date at which this technology is available for hydrogen production.

Another method considered for the production of hydrogen was through gasification of solid biomass, where biomass resources react with steam to become hydrogen. This biomass could come from domestic sources grown locally in Ireland and imported from other countries. Further details of the costs and availability of sustainable biomass resources are published in the *Sustainable Bioenergy for Heat* report [3] within the National Heat Study. A by-product of this biomass gasification is carbon dioxide, which could be captured to provide negative emissions from the production of hydrogen via this route.

We also considered two further options of hydrogen production not included in the final modelling. The first was waste gasification, similar to the biomass gasification described above, but using the biological content of municipal solid waste or biological waste from industry instead of purpose-grown biomass. It was deemed unsuitable for large-scale, long-term production of hydrogen, based on current regional waste management plans that see near-term use of energy from waste-to-energy technologies and a long-term reduction in waste volumes towards 2050 [6].

The other production option initially considered was production of hydrogen via steam methane reformation, where methane gas reacts with water to produce hydrogen and carbon dioxide, with 85-95% of the carbon dioxide captured directly after production and stored [5]. Hydrogen produced using this method with fossil gas is often known as ‘blue’ hydrogen, whereas ‘green’ hydrogen is hydrogen produced via electrolysis using renewable electricity or sustainable biomass fuels. We excluded this option based on the Irish Government’s commitment to green hydrogen [4].

This study considers the conversion of the existing gas network as the primary delivery method for green hydrogen, with blending in the nearer term. Large industrial sites may also produce hydrogen on site or receive hydrogen via purpose-built pipelines to nearby production sites, but these are not explicitly included.

3.1.2 Storage of hydrogen

Gas demand has peaks and troughs, with significant daily and seasonal variations. If demand for hydrogen replaces current gas demand, variation in gas demand is unlikely to change significantly. The methods of hydrogen production described in Section 3.1.1 are generally not fully dispatchable, with electrolysis using co-located renewable energy only producing hydrogen when there is renewable energy production (i.e. when the wind is blowing, for wind turbines). This is also the case with grid-connected electrolysers, for which production of hydrogen is generally cheapest when electricity prices are lowest. Any future hydrogen production profile is therefore highly unlikely to align to a future hydrogen demand profile, and so there would be a need for storage of hydrogen, especially seasonally.

Table 3 above shows the methods of hydrogen storage considered in this study. One major method of hydrogen storage is as a gas under pressure. This study considers both medium pressure (5-8 MPa) and high pressure (up to 43-50 MPa) metal storage tanks for hydrogen storage. Hydrogen can also be stored as a gas in significantly larger volumes in geological formations, where large underground caverns are built to store large volumes of hydrogen under pressure. We consulted with the Geological Survey of Ireland (GSI) about geological hydrogen storage in Ireland; current data available indicate that there is minimal known potential for geological storage within Ireland. Although there is some known potential in Northern Ireland (at Islandmagee for example [7]) that could be accessed as part of an all-island hydrogen strategy, consistent with the all-island energy market, but we have excluded this from the present analysis.

Hydrogen can also be stored chemically, where hydrogen is reacted with other elements or compounds to produce chemical compounds containing hydrogen. These methods of hydrogen storage are typically very stable, and can be stored as a liquid or as a solid. This study considered various chemical storage options for hydrogen, as detailed in *Table 3*. Ammonia, methanol and other liquid organic hydrogen carriers (LOHCs) were all considered for chemical storage of hydrogen in liquid form. These are all energy vectors in their own right and can be used as fuels themselves; for example, ammonia is considered as a potential fuel for low-carbon marine transport. However, this study only considers these as methods of hydrogen storage, as it only explores the decarbonisation of heating and cooling in Ireland. Chemical bonding has the advantage of creating a liquid that can be stored at near-ambient conditions. However, energy is required for both conversion to the storage medium and for re-conversion to hydrogen, which increases the costs of the hydrogen significantly as a proportion of the produced hydrogen is combusted to produce thermal energy for the conversion process. In addition, the storage compounds must be readily available or procured, and stored when not in use.

Hydrogen can also be stored chemically as a solid, with metal hydrides one potential option for this. Metal hydrides were initially considered for this study. However, this option was not included in the final modelling as we deemed the technology readiness level (TRL) too low for deployment at both the scales and on the timescales needed for hydrogen to help reach net-zero emissions in the heat sector by 2050.

If ammonia is widely used in Ireland as a storage method for hydrogen, ammonia emissions must be closely monitored to align with national emissions limits. The EU's National Emissions Ceilings Directive (2016/2284) (NECD) gives emission limits for EU member states for several air polluting gases, including ammonia. Figures from the national Ammonia Inventory (maintained by the Environmental Protection Agency) detail non-compliance with the ceilings set in the NECD. For example, in 2018, the ceiling for ammonia was 116 Kt and Ireland's emissions were 119.4 Kt.

3.1.3 Other low-carbon non-biological gases

Power-to-methane (also known as methanation) is a process that produces non-biological synthetic natural gas (SNG) by reacting carbon dioxide with water vapour to produce methane and oxygen.

We initially considered this as one way to use low-cost power after high-renewable energy deployment to produce methane for use for heat. It has the added benefit that existing gas transmission and distribution networks, as well as existing gas storage infrastructure, could be used without modification. Any heating equipment which currently uses fossil gas as a fuel would also not need to be modified if SNG replaces fossil gas as fuel.

Due to concerns surrounding the availability of a carbon dioxide stream to use for power-to-methane, and as significant proportions of carbon dioxide would be needed to produce SNG in large enough volumes to supply a significant proportion of Ireland's heat, we did not include non-biological SNG in the modelling carried out in the National Heat Study. However, the *Carbon Capture, Utilisation and Storage (CCUS)* report [8] identifies several sites in Ireland that are likely suitable for carbon capture. Further work could explore how SNG could integrate with these sites as part of a wider national CCUS strategy.

This study considered use of fossil gas alongside carbon capture and storage (CCS) in the heat sector and the power sector; the *Carbon Capture, Utilisation and Storage* report [8] within the National Heat Study provides more information on the use of fossil gas with CCUS.

3.2 Biological gases from sustainable feedstocks

As well as considering hydrogen, we also considered biomethane as a low-carbon gas to decarbonise the heat sector in this study. Production of biomethane via anaerobic digestion (AD) and biomass gasification were both considered, with information about these two production routes provided in *Table 4* and throughout this section of the report.

Table 4: Production, storage and distribution methods considered for biological gases in this study

Production	Description
Anaerobic digestion	Anaerobic digestion of animal slurries, silage, industrial food waste, and the biological component of municipal solid waste (BMSW)
Biomass gasification	Gasification of perennial energy crops to produce bioSNG
Storage	**Description**
Existing infrastructure	Existing natural gas infrastructure
Delivery	**Description**
Direct grid injection	Grid injection via pipeline from the site of production to gas grid
Centralised grid injection	Road transport to AGIs for centralised grid injection
Road transport + off-grid use	Road transport of containerised biomethane to off-gas grid end users

Note: *AGI is above-ground infrastructure.*

AD describes the breakdown of biodegradable material by micro-organisms in the absence of oxygen, with methane produced as a product among a mixture of other gases. This mixture of gases produced via AD is known as biogas, which can be combusted to produce heat, power or a mixture of the two. Biogas can also be further upgraded to biomethane (by removing the CO_2 and other impurities), which can then be grid injected or containerised for use by consumers. A large variety of biodegradable material can be used for this process, including animal slurries, silage, industrial food waste and the biological component of municipal solid waste. However, the use of some of these sources can cause significant upstream greenhouse gas emissions, and policy must ensure that only sustainable sources are used to produce biomethane.

Biomass gasification describes the process by which biomass is broken down by high temperature and high pressure in a low-oxygen environment to produce a variety of gases, which are then cleaned and further reacted with water vapour to produce methane. As this process also produces methane from biological feedstock, we also refer to methane produced in this manner as 'biomethane' in this report and throughout the rest of the National Heat Study; the term 'biogas' is also used interchangeably for biomethane produced via either AD or biomass gasification.

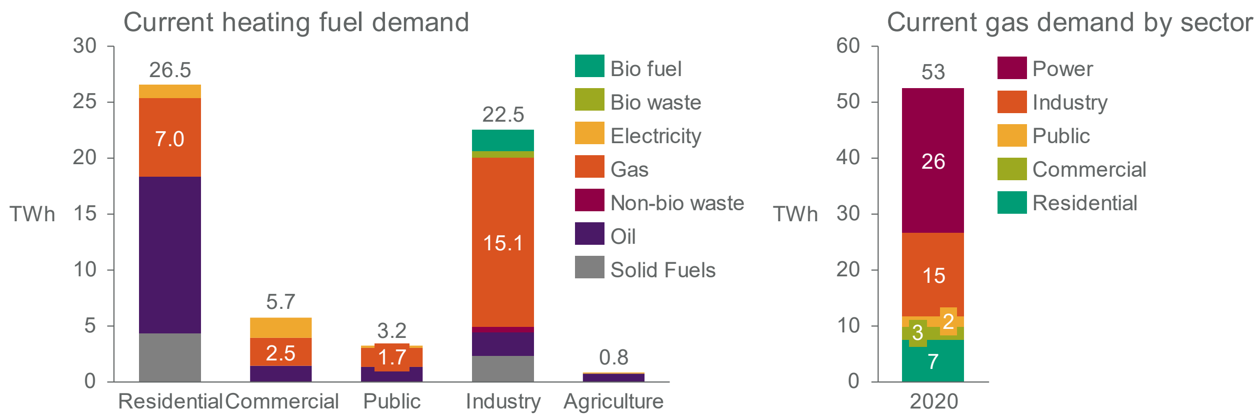
After production of biomethane either via AD or biomass gasification, the biomethane must be stored and distributed to end users. Fossil gas storage, transmission and distribution already exist in Ireland, with over 700,000 customers connected and over 14,000 km of existing pipelines [9]. As biomethane is chemically identical to fossil methane, all of this infrastructure can be used without modification to store and distribute biomethane throughout Ireland. However, additional infrastructure would be needed to either inject this biomethane into the grid to blend with existing gas supplies, or to distribute the biomethane to consumers directly if the existing gas infrastructure is re-purposed to distribute hydrogen in the future. The latter is also required if biomethane gas is used to decarbonise sites located away from the gas grid, currently fuelled by oil.

Table 4 shows the three methods of distributing biomethane considered for this study. The first two are both types of grid injection, with direct grid injection involving the injecting of biomethane directly into gas transmission or distribution network at the point of biomethane production. Centralised grid injection is the production of biomethane at dispersed locations, which is then transported by truck in pressured containers to existing AGI for more centralised grid injection. The third method of biomethane distribution considered, involves bottling the produced biomethane and transporting it via road freight directly for customers. The study considers infrastructure costs for all three methods, and the costs of transporting the crop to the biomethane production sites and any transportation of the biomethane to the grid injection sites or directly to customers. Appendix B explains this costing process.

4 Gas network demand

Today, the Irish gas network delivers about 53 TWh of energy to buildings, industry and power sector users each year [10]. *Figure 7* presents this volume as total sectoral fuel demand. While the residential sector consumes the most heating fuel, industrial demand for gas (15.1 TWh) is over twice that of the residential sector (7 TWh). The power sector consumes nearly as much gas as all other gas demands combined (25.8 TWh). Gas use in the power sector shows large variations from year to year depending upon commodity prices and wind generation. It peaked in 2010 at 32 TWh, before declining by 41% to 19 TWh in 2015, then increasing by 41% to the demand seen in 2020 [10].

Figure 7: Heating fuel (left) and gas demand (right) in 2020, by sector



Source: *Heating and Cooling in Ireland Today (National Heat Study)* [11] *and SEAI National Energy Balance data* [12]

The energy delivered via the gas network will change significantly over the course of the energy transition, both in terms of total energy and energy mix, with the potential expansion or reduction of the gas network both possible under different circumstances. Utilisation of the gas network in 2050 varies across the scenarios considered in the National Heat Study. The following sections describe the considerations and drivers that will affect the 2050 gas network demand in each sector. Note that, although in 2050 we assume low-carbon gases such as hydrogen and biomethane will meet this demand, we refer to it in this report as the 'gas' network.

4.1 Demand in buildings

The number of buildings sets the upper bound on the potential demand on the gas network for heating in buildings with access to the gas network. This includes buildings already connected as well as those within 30 m of the gas distribution network. In 2019, Ervia estimated about 300,000 homes currently using oil, solid or electric heating could use gas if provided with an 'in-fill' connection [9]. The gas penetration across Ireland's roughly 18,000 small areas was analysed to determine where in-fill connections are feasible. As shown in *Table 5*, about 213,000 buildings using oil and solid fuel could be connected to the gas network. A further 136,000 electrically-heated buildings are within 30 m of the gas network. However, these buildings are likely to incur additional capital costs and disruption as installation of a wet distribution system is required for conversion to gas, in addition to the network connection and new gas boiler.

If all oil and solid-fuelled buildings near to the gas distribution network are connected, the gas demand for buildings would rise from 11.7 TWh to 15.2 TWh. Electric buildings could contribute a further 1.7 TWh. There are about 750,000 oil and solid-fuelled buildings which are not near to the gas network. These buildings, particularly those using oil, may be suitable for use of containerised biomethane in the scenarios where that is available.

The lower limit on gas demand in buildings is less than 1 TWh, which we explore in the High Electrification scenario. Although space constraints and poor thermal efficiency limit the suitability of heat pumps in some buildings, there are very few buildings which can only be heated with gas. In those cases, there is also the option to deploy a hybrid heat pump, which would further reduce demand in buildings remaining on the gas network in this scenario. In this situation, there is the risk a low number of consumers and low gas demand may lead to high network costs for those remaining consumers. Some policy effort may be needed to address this. Potential options include Government subsidy of the network costs or a policy push to support alternative options.

Table 5: Potential in-fill gas network connections for buildings and associated gas demand

Existing fuel type	Residential buildings	Commercial buildings	Public buildings	Total buildings	Fuel demand (TWh)	Cumulative demand (TWh)
Existing on-gas	618,307	19,015	3,454	640,777	11.7	11.7
In-fill - oil	171,000	5,650	1,026	177,676	3.1	14.8
In-fill - solid	35,444	0	0	35,444	0.4	15.2
In-fill - electric	88,991	39,445	7,166	135,602	1.7	16.9
Off-gas - oil	542,040	17,909	3,254	563,203	12.7	N/A
Off-gas - solid	203,277	0	0	203,277	3.7	N/A
Off-gas – electric	118,085	52,342	9,509	278,551	1.8	N/A

4.2 Demand in industry

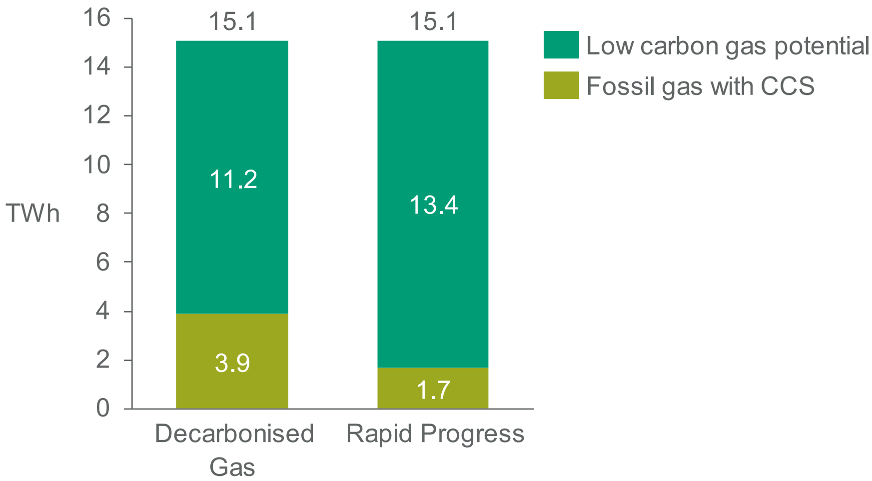
Hydrogen and other low-carbon gases are suitable for most industrial applications, especially where fossil gas is used today. There are a few important limitations to this, as follows:

- Kilns in the cement sector require biological or solid fuels;
- Sites already using biofuels are likely to continue where the biofuel is or can be low carbon;
- Industrial sites decarbonising via CCS technologies will not also require low-carbon gases.

For industry, the existing gas demand greatly exceeds existing oil demand for heating, with gas making up 73% of existing industry fuel use for heat, and oil only 10% [11]. Due to the developed nature of the gas network in Ireland, all industrial sites and processes with a need or strong economic incentive to switch to using gas for heating are assumed to have already done so. As such, we considered no further expansion of gas use for heating in industry beyond existing gas users.

The maximum industrial demand for low-carbon gases in 2050 considered in the Decarbonised Gas and Rapid Progress scenarios is less than the fossil gas demand today. This is because in these scenarios, some sites continue to use fossil gas, maintaining connections to a fossil gas transmission network and using CCS. The resulting potential for low-carbon gas usage for industry is the amount of existing fossil gas use without the gas use from sites which install CCUS and continue to use fossil gas. The potential for low-carbon gas usage is represented in dark green in *Figure 8*.

Figure 8: Maximum potential network demand in industry in two scenarios in 2050



4.3 Demand in the power sector

We have assumed that the net demand for low-carbon gases in the power sector will be near zero, representing a significant change from the situation today. Hydrogen may have a role in providing large-scale and flexible energy storage to the electricity network, but would not be used for baseload power generation, as is the case today. Given Ireland's commitment to green hydrogen, the power sector in the Decarbonised Gas scenario moves from being a consumer of fossil gas to a net producer of low-carbon gas.

The Decarbonised Gas scenario is likely to depend upon high deployment of hydrogen across the heat sector and within the power sector to decarbonise. Hydrogen is assumed to only be available for consumers in the heat sector in significant quantities from 2035. This reliance on hydrogen to decarbonise is likely to result in a high proportion of existing fossil fuel use not switching to hydrogen until the mid-2030s and beyond, so the cumulative emissions from the heat sector before hydrogen deployment in this scenario are likely to be higher than in other scenarios. To offset these higher cumulative emissions, large-scale BECCS is assumed to be required within this scenario. For more information, please see the *Net Zero by 2050* report [2] in this National Heat Study.

5 Green hydrogen production and storage

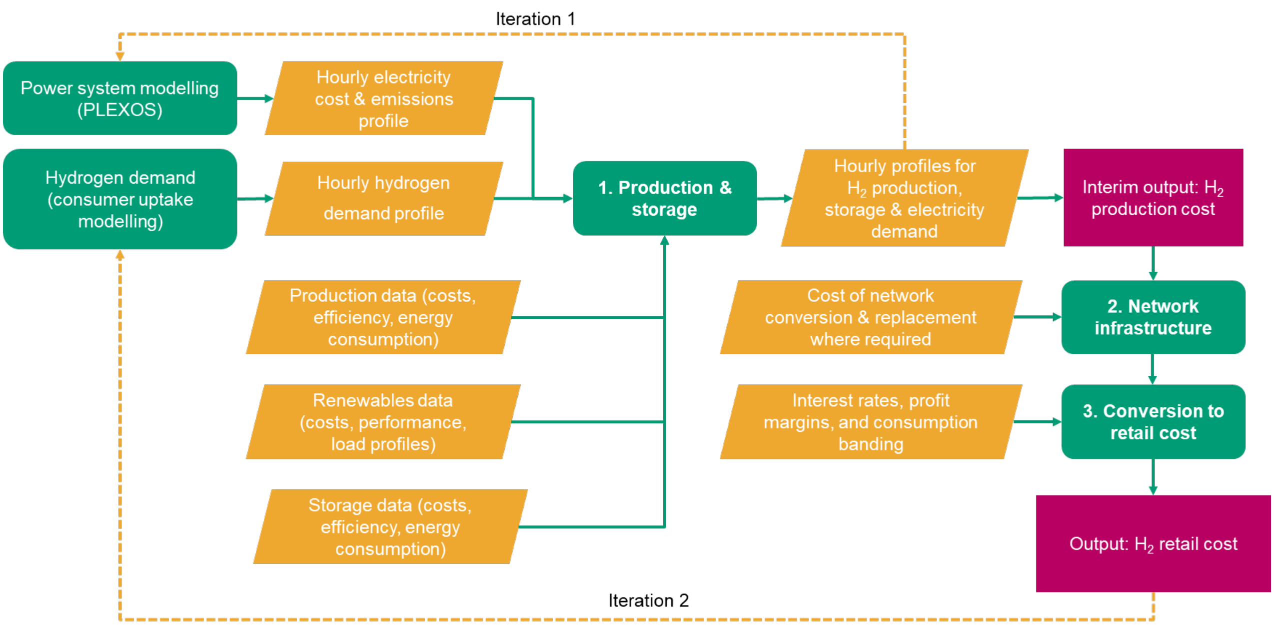
The most cost-effective method of supplying hydrogen depends upon the efficiency and cost of production, cost and efficiency of storage, and the supply and demand profiles of hydrogen. The biomass available for production of hydrogen via gasification may be resource-constrained, due to inherent limitations on sustainable resources and competition for these elsewhere within the heat and power sectors. The renewable electricity generation technologies presented in Section 3.1 are also limited in potential capacity for hydrogen production.

To model the cost-optimal mix of hydrogen generation and storage pathways, a Hydrogen Infrastructure Module was developed within the National Energy Modelling Framework (NEMF). This Module determines the cost-optimal storage solution, generation sizing and dispatch profile, for each hydrogen production method considered in this study. It also calculates the mix of hydrogen supplied by each production route if the demand for hydrogen exceeds the capacity of the cheapest production route, considering competing resource limitations and hydrogen demand from the other sectors modelled in the NEMF. Section 5.1 below outlines the method of calculation within this module, with further detail on the cost and performance assumptions of the technologies modelled in the Hydrogen Infrastructure Module presented in Appendix A and in the accompanying data workbook.[4]

5.1 Calculating the future cost of hydrogen

The Hydrogen Infrastructure Module has analysed the various production and storage methods listed above. The selection of cost-optimal combinations of production and storage requires iteration with other components of the NEMF, as shown schematically in *Figure 9*.

Figure 9: Schematic of the NEMF Hydrogen Infrastructure Module



All possible combinations of production and storage technologies are used to first calculate the cost of producing and storing hydrogen. The Hydrogen Infrastructure Module calculates five-year increments using the hourly demand for hydrogen projected by the NEMF and the hourly cost and emissions profile of high-resolution electricity modelling, also part of the NEMF. The Module combines these data with information on the cost and efficiency of each storage and production route. For electrolysis co-located with renewable

[4] Supporting material for this report is available for download from the SEAI website. Available: https://www.seai.ie/data-and-insights/national-heat-study/low-carbon-gases-for-heat/.

electricity generation, the cost and hourly production profile of the renewable generation are also included. This allows the hydrogen generation and storage capacity to be co-optimised to satisfy the demand profile from the NEMF at the lowest combined cost. For grid-connected electrolysis, this Module iterates with the Power System Module to capture the impact of electrolysers on the overall electricity demand profile, electricity generation mix, and cost and carbon emissions. Section 5.2 presents information on the availability of renewable generation for hydrogen production and on the cost and efficiency of production methods, with further details available in the accompanying data workbook.[5]

The Hydrogen Infrastructure Module determines the most cost-effective way to meet the hydrogen demand. For example, by examining a wide range of different production plant sizes and combinations of hydrogen storage, the Module may determine that a larger electrolyser is more cost-effective than a smaller electrolyser alongside the same co-located renewable generation plant, trading off the higher capital costs of the larger electrolyser against the lower running costs possible, as the larger electrolyser may more effectively utilise hours where low-cost electricity is available. Hydrogen storage plays an important part in this process, and different volumes of hydrogen are required to be stored for different lengths of time in each production method and production plant size considered. Because heating demand for hydrogen is seasonal, a large volume of storage is typically required to meet winter peak demands without over-sizing production plants relative to average demand throughout the year. The Module iteratively calculates the levelised cost of hydrogen using a wide range of production plant sizes and for each storage option.

The costs of hydrogen through each production route and size of production plant, and the volume potentially produced through that route, are then compared to determine the most cost-effective mix of production required to meet the total annual hydrogen demand. This is the interim output shown in *Figure 9*. The costs of network infrastructure are added to the cost of production and storage to produce the LRVC of hydrogen. In the final step, this is converted to a retail cost appropriate for each heat sector. This conversion takes into account the interest rates typically seen by infrastructure investors and reflects the differences in price bands for different consumer types present in the costs of fossil gas today. The following section presents the LRVC of hydrogen produced through the various routes considered and the volume available through each.

5.2 Renewables availability

Table 6 shows the resource potential for renewable electricity generation for hydrogen. The total potential additional capacity for onshore wind is based on a 2016 analysis performed for the DCCAE [13]. The potential capacities for fixed and floating offshore wind have been taken from the 2020 EirWind project [14]. The maximum additional capacity for solar is taken to be the highest deployment level within Eirgrid's 2019 Tomorrow's Energy Scenarios [15], which occurs in the Coordinated Action scenario. The capacity likely to be connected to the electricity grid for each type of renewable generation was estimated is based on the Centralised Energy scenario in Eirgrid's 2019 Tomorrow's Energy Scenarios [15].

Table 6: Renewable electricity production capacity beyond what is planned for electricity network connection

Renewable generation type	Total additional capacity	Capacity for grid connection	Capacity available for H_2 generation	Average capacity factor (%)	Earliest technology availability
Onshore wind	6.3 GW	1.7 GW	4.6 GW	40%	Available now

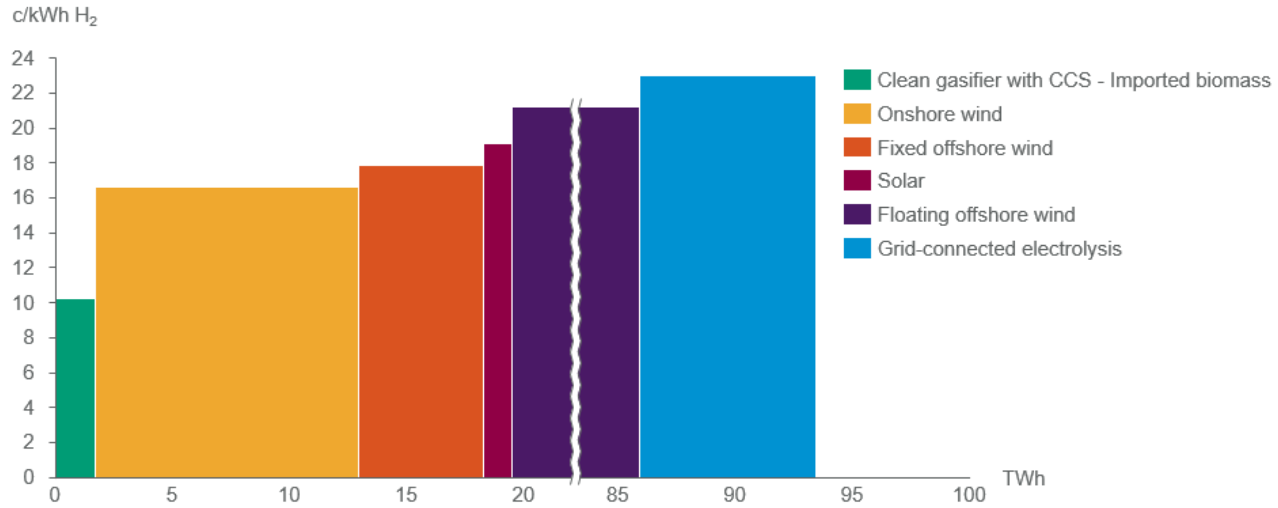
[5] Supporting material for this report is available for download from the SEAI website. Available: https://www.seai.ie/data-and-insights/national-heat-study/low-carbon-gases-for-heat/.

Fixed offshore wind	5 GW	3.3 GW	1.7 GW	50%	Available now
Floating offshore wind	20 GW	1.4 GW	18.6 GW	55%	2035
Solar	3.4 GW	1.4 GW	2 GW	11%	Available now

5.3 Cost and carbon intensity of hydrogen

Figure 10 shows the LRVC of hydrogen for each production route considered. The Hydrogen Infrastructure Module calculated the details within this graph for 2050 in the Balanced scenario, which includes the cost of storage, delivery and production. Note that the costs shown within this graph are calculated from the system's perspective. The costs include a social discount rate of 4% but do not include VAT, carbon pricing or other costs that end consumers may ultimately see.

Figure 10: LRVC of hydrogen production in 2050, Balanced Scenario



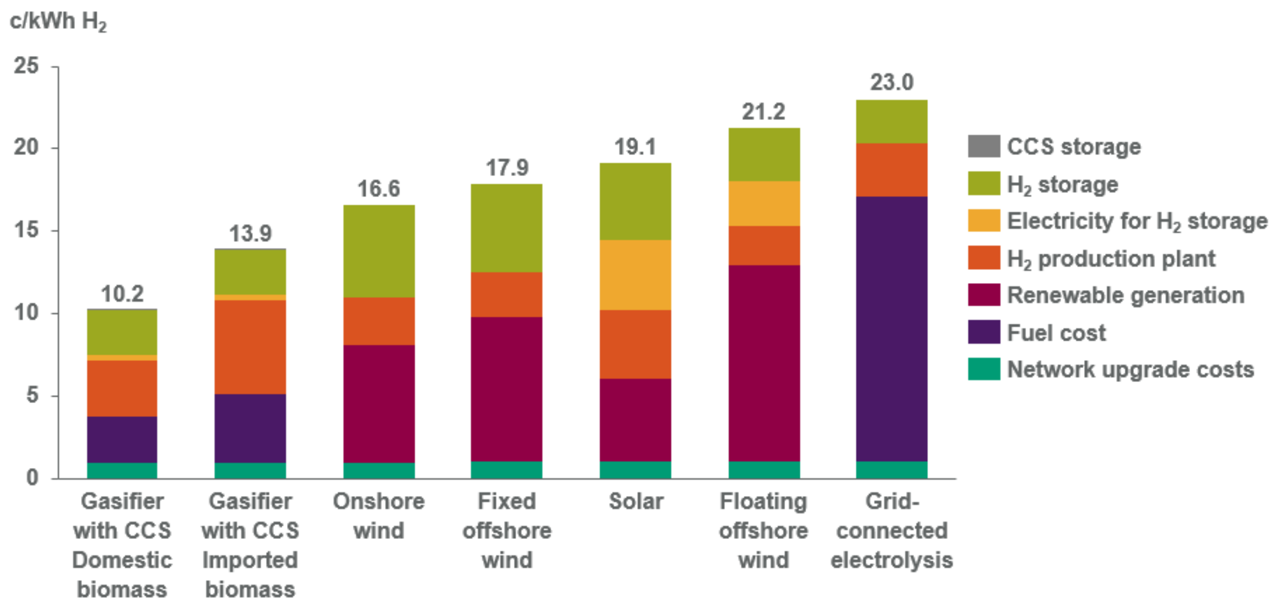
The x-axis in *Figure 10* shows the volume of hydrogen that may be produced in 2050 through each route in the Balanced scenario. For more information about the hydrogen demand in this scenario, please see the Net Zero by 2050 report [2]. The lowest cost production method is biomass gasification using imported solid biomass; the domestic biomass resource is fully used for other heat and power sector uses in 2050 in this scenario, and so is not available for hydrogen production. The volumes of biomass available limit the amount of hydrogen that can be produced through this method. As illustrated in this graph, grid-connected electrolysis is the least affordable option, however this is the cost calculated as being needed to produce the entire volume of hydrogen required in this scenario. This amount of grid-connected hydrogen production would cause significant additional electricity demand on the grid, and so this hydrogen production method is expensive. This is consistent with prior work conducted by ESRI [16]. Grid-connected electrolysis could meet lower levels of demand to provide hydrogen at a significantly lower cost when using cheap curtailed renewable electricity; however, this would not be the case if grid-connected electrolysis produces hydrogen at significant scale. There is also a risk that relying purely on curtailed renewables would not allow the production plant to achieve a sufficient annual load factor to be economical. The production volume available via grid-connected electrolysis is not fixed, and production via this route could be scaled to meet demand beyond that illustrated above.

Hydrogen production from electrolysers co-located with renewables varies by cost for the range of renewable generation technologies considered. The Hydrogen Infrastructure Module estimates production of hydrogen from onshore wind at 16.6 c/kWh, rising to 17.9 c/kWh for fixed offshore wind and 21.2 c/kWh for floating onshore wind. The potential volumes of production are based on the renewable resource capacity beyond what is likely to be connected to the electricity grid. *Table 6* above provides further details.

The carbon intensity of hydrogen also varies with the production method. The carbon intensity is zero where hydrogen is produced from dedicated renewables, in line with the assumption of renewable electricity in the electricity system model. For grid-connected electrolysis, the carbon intensity depends upon the emissions intensity of grid electricity emissions, which are calculated dynamically in the NEMF for the scenarios considered in this National Heat Study, and the efficiency of electrolysis. A net-zero power system would effectively lead to production of zero-emission hydrogen using grid-connected electrolysis.

Gasification of biomass has the potential to generate negative emissions depending on the carbon content of the biomass utilised. *Figure 11* presents the breakdown of each LRVC for each route analysed. The cost of fuel, or for co-located renewables, the cost of the renewable generation, dominates the cost in most cases. Biomass gasification and electrolysis co-located with solar photovoltaics (PV) are exceptions to this rule. For biomass gasification, the gasification plant itself is the highest single cost, particularly for domestic biomass which is assumed to be used in plants of smaller scale (relative to imported biomass) with higher capital cost per kWh hydrogen produced.

Figure 11: LRVC breakdown for each hydrogen production route in 2050



Many of the segments in the breakdown presented in *Figure 11* represent infrastructure investment costs, such as hydrogen storage infrastructure, hydrogen production plants (gasifiers or electrolysers), renewable electricity generation plants, and network upgrades. These infrastructure investments are levelised across the lifetimes of the infrastructure investments in the LRVC costs above and in the costs paid by consumers, and make up a significant proportion of the total hydrogen costs. Depending on hydrogen uptake in the modelled scenarios presented in the *Net Zero by 2050* report [2] in this National Heat Study, the total investment costs by 2050 in these components of hydrogen infrastructure could total up to €10 billion in scenarios, with a significant proportion of on-grid buildings or industrial consumers switching to hydrogen, such as the Balanced or Rapid Progress scenarios. In the Decarbonised Gas scenario, where hydrogen is the preferred low-carbon fuel for all consumers currently connected to the gas network with additional potential from consumers not currently connected to the gas network, these infrastructure investment costs could total over €20 billion before 2050.

Hydrogen storage contributes 2-6 c/kWh. The volume stored depends on the dispatchability of the generation plant. Less storage is required with gasification, as production can be ramped up in the winter months to match demand. Conversely, the most storage is required with solar, onshore wind and fixed offshore wind, due to the intermittency of renewable generation. In all cases, inter-seasonal hydrogen storage reduces the size of the hydrogen production plant required, allowing a lower levelised cost than without storage. The storage volumes required are equivalent to approximately 40% of the annual hydrogen demand. LRVCs with no hydrogen storage are 5-10 times more expensive than those shown in *Figure 11*.

Table 7 presents the hydrogen production and storage facilities required to meet an annual demand of 30 TWh, similar to the Decarbonised Gas scenario discussed above. The Module predicted chemical bonding with nitrogen to form ammonia to be the most cost-effective of the storage options considered, which is assumed in the figures above and *Table 7*. While the volume of storage required is significant, it is not unprecedented. *Figure 12* presents examples of existing ammonia storage tanks, 75 of which would be required to store 12 TWh. The number and size of the storage tanks are similar to those maintained to meet Ireland's obligation under EU legislation and International Energy Agency rules to hold a 90-day oil supply.

Table 7: Storage and production capacity required for Decarbonised Gas scenario

Factor	Quantity
Annual demand	30 TWh
Hydrogen production capacity	3-6 GW
Renewable electricity capacity (if co-located)	10 GW
Hydrogen storage	12 TWh
Ammonia storage volume	3 million m^3
Steel storage tanks	75

Figure 12: Existing ammonia storage tanks in Ireland

6 Biomethane production

6.1 Calculating the future cost of biomethane

We have explored several options for the evolution of land use for bioenergy production across the decarbonisation scenarios, as laid out in *Table 8*. The growth of resource for AD is of most relevance to biomethane production. Although perennial energy crops may be used for biomass gasification, there is competition for their direct use as pellets for heat and electricity production. The growth of energy crops is therefore maximised in the scenarios with less reliance on the gas networks (High Electrification), while AD crops are prioritised where the gas network is a key vector for decarbonisation (Decarbonised Gas and Rapid Progress). The biogenic resource potential and resulting feedstock costs in each of these scenarios is explored further in the Sustainable Bioenergy for Heat report [3] in this National Heat Study.

Table 8: Land use assumptions in the decarbonisation scenarios

Energy scenario	Decarbonised Gas	High Electrification	Balanced	Rapid Progress
Theme	**Maximise AD resources**	**Maximise perennial energy crops**	**Mix of AD and perennial energy crops**	**Additional AD resources**
Silage for AD	Silage grown on land released due to decline in national beef herd and improvements in productivity	No additional silage grown for AD	Half of land released used to grow silage for AD and half used to grow perennial energy crops	As decarbonized gas scenario, but additional land released, as national beef herd declines by more than in current projections
Perennial energy crops (SRC willow)	No expansion	Perennial energy crops grown on land released due to decline in national beef herd and improvements in productivity		
Afforestation	Afforestation target of 8,000 ha/ yr met every year to 2050			

The cost of biomethane is calculated within the National Energy Modelling Framework (NEMF). The volume of bioresource available for biomethane each year is determined based on the total crop resource and all crop volumes directed to other end-uses. The cost of biomethane depends on the bioresource cost, which varies with resource type, as well as the cost and efficiency of the production plant (see Appendix B for more information). The cost of delivery (through grid injection or compression, containerisation, and trucking) is added to the resource cost. In the final step, this is converted to a retail cost appropriate for each heat sector. This conversion takes into account the interest rates typically seen by infrastructure investors and reflects the differences in price bands for different consumer types present in the costs of fossil gas today. The following section presents the LRVC of biomethane produced through the various routes considered and the volume available through each.

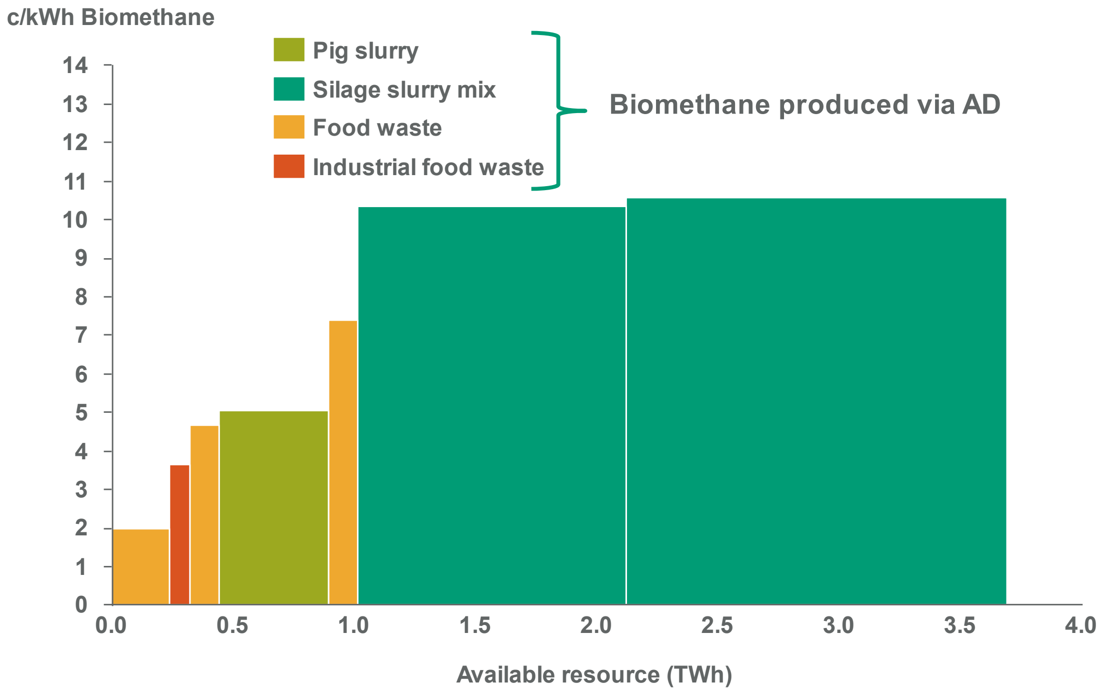
Biomethane blended into the existing fossil gas grid does not require fuel switching or a change of appliance by the end customers, as biomethane is chemically identical to fossil methane gas. There are a number of potential market and policy structures to support injection of biomethane into the grid. These may place the cost burden largely onto end consumers (for example using green gas 'certificates' which can be purchased from biomethane producers by gas users who wish to demonstrate that their gas consumption is low carbon) or may socialise the cost burden across all gas customers (for example an obligation on energy suppliers to procure a certain percentage of biomethane) or even across general taxation (as with the operational payments available under the Support Scheme for Renewable Heat (SSRH) [17] today). In the National Heat Study, it is assumed that biomethane injected into the grid is recovered through increased costs for all gas users. This allows the biomethane production capacity to develop without relying on early adopters who are prepared to accept a high fuel cost, and reduces the carbon content of the grid as a whole. Therefore, both the cost and carbon intensity of fossil gas are updated in the model to reflect the biomethane blending.

Off-gas grid customers who adopt biomethane must purchase a new heating appliance as they are replacing oil, solid-, or LPG-fuelled systems. These consumers also pay the additional cost to supply the containerised biomethane by truck.

6.2 Cost and carbon intensity of biomethane

Figure 13 presents the volume of biomethane available in the Decarbonised Gas scenario from domestic resources via AD. As noted in *Table 8*, this scenario this scenario assumes that silage for AD for biomethane is grown on land which becomes available as the suckler herd declines and the productivity of grassland is improved. The cost shown below is the LRVC.

Figure 13: LRVC of biomethane production in 2050 in the Decarbonised Gas scenario, by each type of crop being used for AD, for domestic resources only



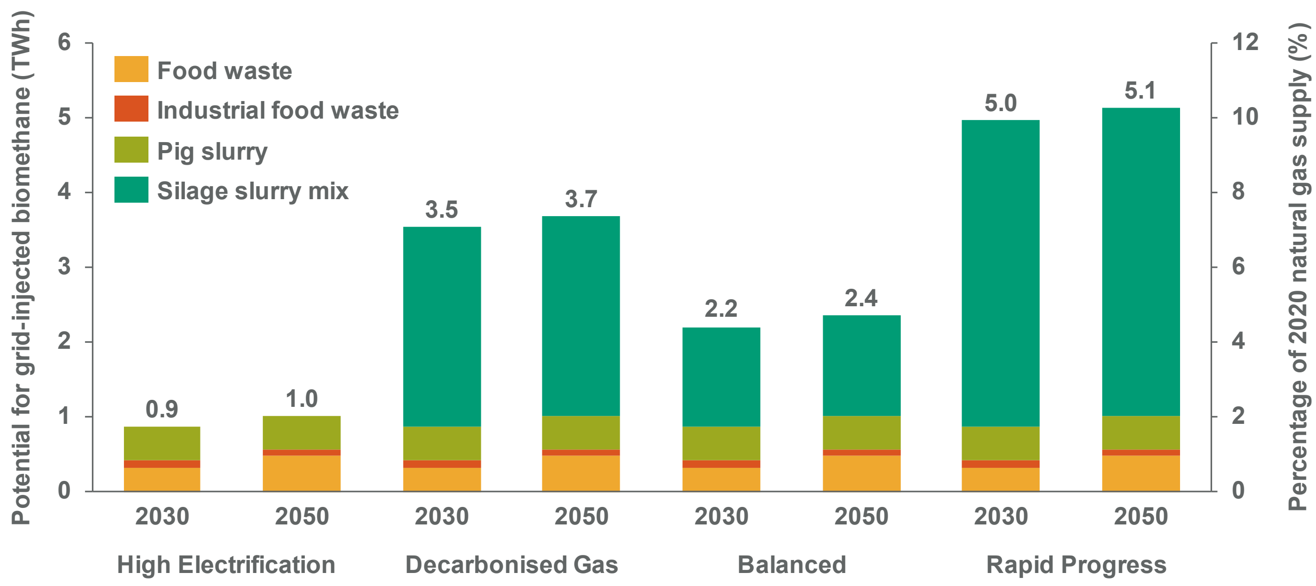
The bulk of the available biomethane (about 2.7 TWh) is produced from a 50/50 mix of silage produced from a red clover/ryegrass sward and cattle slurry. The LRVC of biomethane from the silage/slurry mix is 10.5 c/kWh. Approximately 1 TWh may be produced at relatively low cost (less than 7 c/kWh) from a mix of biological wastes. Gasification of imported wood pellets to produce biomethane may contribute significantly to the above volumes, adding a further 15 TWh at about 10 c/kWh.

Carbon emissions associated with biomethane production from domestic feedstocks vary as some feedstocks e.g. grass silage, have emissions associated with their production, whereas others such as food waste do not. Using slurry as a feedstock can even lead to a net reduction in carbon emissions due to emissions which are avoided by no longer having to store the slurry. So while the carbon emissions associated with biomethane production from a grass silage/slurry mix and its combustion are around 38 kg $CO_{2\ eq}$/MWh. For comparison, carbon emissions from the combustion of fossil gas are 185 kg $CO_{2\ eq}$/MWh.

The 5.1 TWh shown in Figure 14 is based on the ambitious assumptions for growth of grass silage for AD listed above. All scenarios apart from Rapid Progress assume a stable herd scenario, while in Rapid Progress there is a shift in land use, and there is a reduction of about 600,000 head of cattle. The biomethane volume drops to 3.7 TWh in the Decarbonised Gas and reduces to about 2.4 TWh in the Balanced scenario where newly available land is divided between silage crops and perennial energy crops for solid biomass.

The potential fossil gas demand for heat noted above (see Section 4 on Gas network demand) was as high as 30 TWh. The total existing fossil gas consumption in 2020 in Ireland in all sectors is 53 TWh. It is clear that domestic biomethane will not be available in sufficient quantities to meet the full scale of demand if the gas network is maintained or expanded as a key vector for decarbonisation. However, biomethane may have an important role in a more limited gas network primarily focused on supporting hard-to-decarbonise buildings and industrial sectors with fewer accessible decarbonisation options.

Figure 14: Potential volumes of biomethane available for grid injection in each decarbonisation scenario



7 Evolution of the gas network

Significant changes to the gas distribution and transmission networks will be required in the transition to a net-zero energy system in Ireland, regardless of the final energy mix. This section sets out the hypothetical scenarios describing the conversion of the existing gas grid to hydrogen (as assumed in the Decarbonised Gas scenario) and for curtailment of the distribution network and conversion of the transmission network to biomethane and hydrogen (as assumed in the Rapid Progress scenario). These gas network scenarios (Decarbonised Gas in Section 7.1 and Rapid Progress in Section 7.2) include both descriptions of the model assumptions relating to timelines and availability of resources, as well as the policy steps likely to be required if the gas network transforms in the way described. The actions and policies outlined below are not recommendations but rather an outline of the steps that could be undertaken to realise these scenarios, should one be selected as the preferred route for decarbonisation of heating in Ireland.

We developed the described steps based on discussion and feedback from key stakeholders including the Commission for Regulation of Utilities (CRU), Ervia and Gas Networks Ireland. We also received input from several university research groups working on low-carbon heating fuels, including the National University of Ireland in Galway and University College Cork.

7.1 Decarbonised Gas scenario

We assume the gas network will play a central role in the transition to a net-zero heating sector within the Decarbonised Gas scenario. Ireland's significant wind resource is used for the production of green hydrogen, and the network converts from fossil gas to hydrogen in a series of steps starting from 2030. Note that the 2050 network demand for low-carbon gas in this scenario is well beyond the domestic capacity for biomethane production (see Section 6), but containerised biomethane is available at sites off the gas network.

7.1.1 National decision and preparation: 2020s

Although large-scale hydrogen production and grid injection is unlikely to begin until the 2030s, significant action would be required within the 2020s to realise the Decarbonised Gas scenario, including:

- A clear national commitment to the development of a hydrogen grid to underpin policy, planning and investment in hydrogen.
- Identify the portions of the gas transmission network to be converted to hydrogen and those which will be maintained (to supply industrial or power sites using CCS technology), along with the timeline for piecewise network conversion.
- Carrying out an analysis of network capacity to determine where transmission network expansion/ reinforcement may be required to accommodate the lower energy density of hydrogen, which is about one-third that of fossil gas on a per kg basis. Hence, three times as much mass must be delivered through the transmission network to deliver the same amount of energy. Depending upon the current operational limits, spare capacity of the network, and the geographical distribution of hydrogen demand, it may be possible to accomplish this through higher flow rates or higher pressures, or both. Alternatively, if the transmission network is already operating at full capacity, a capacity expansion may allow the transmission network to meet the desired demand.
- Undertaking hydrogen appliance and network trials to understand, de-risk and cost full network conversion.
- Encouraging hydrogen uptake in high-value sectors, such as transport (HGVs, shipping, aviation), to increase production volumes and reduce costs.
- Introduction of hydrogen-ready boilers, which are expected to enter the market in the 2020s, to begin the process of making buildings hydrogen-ready.
- There is scope for biomethane to reduce the carbon content of the gas grid in the years before conversion to hydrogen. Clear timelines and policy supports are needed to encourage this rollout

while avoiding stranded assets after 2035. Support for AD should then focus on supply chain development and the off-grid market, beginning with industry.

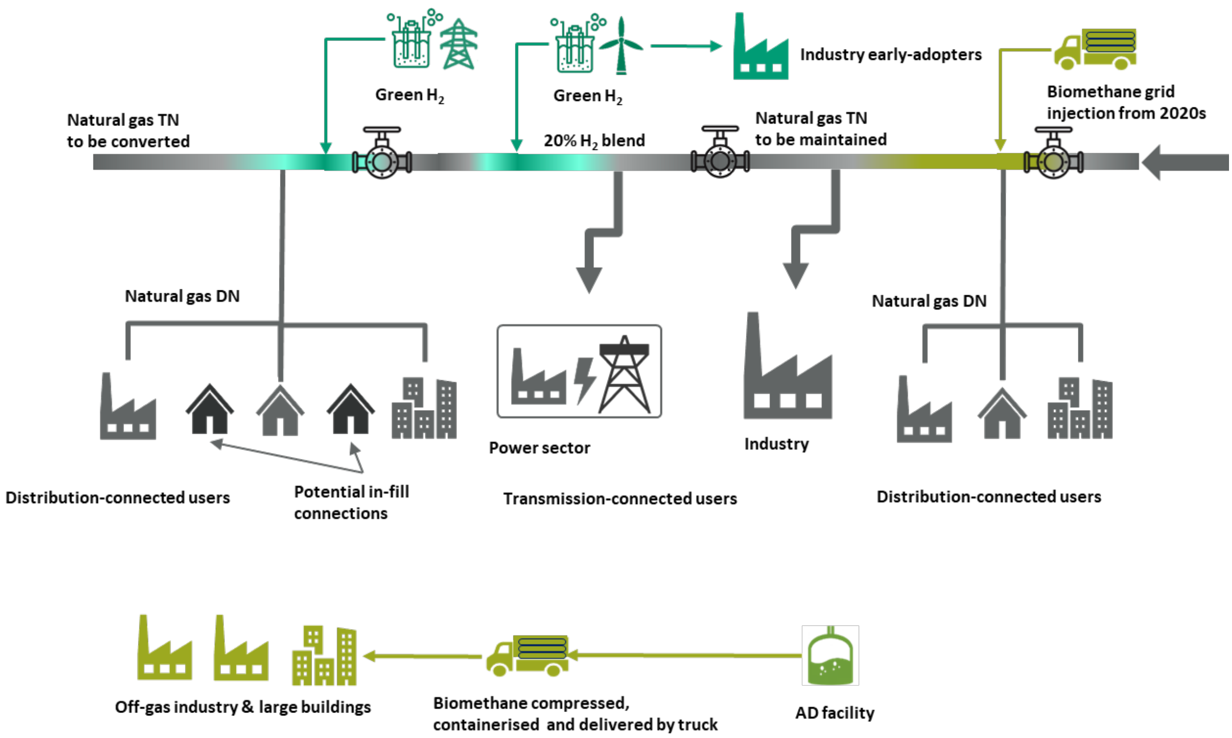
Based on assumed ramp-up rates of biomethane grid injection in this scenario, and assuming all available AD resource is used up to the technology deployment limit, 1.5 Mt CO_2 cumulative emissions could be abated through grid injection to 2030, with 0.4 Mt CO_2 abated in 2030. This is equivalent to 7% of the 2020 emissions from existing fossil gas use for heating in Ireland today [11].

As hydrogen is not yet proven as a safe and reliable source for heat at any significant scale, there is a high risk of large sunk costs if hydrogen for heating is pursued and found unsuitable; this would also add to cumulative emissions in this case, and would represent a delay to decarbonisation efforts. Conducting hydrogen appliance and network trials at a range of scales would be of paramount importance to fully understand the grid conversion process if this pathway is to be pursued.

7.1.2 Hydrogen blending: 2030-2035

Beginning in 2030 in the Decarbonised Gas scenario, hydrogen is blended into the gas transmission network at fractions up to 20% by volume (7% by energy). Early adopters in industry may develop production facilities on site or receive hydrogen via direct pipelines. This scenario assumes hydrogen-ready boilers become widespread by 2035. However, some policy support may be required to ensure that fuel-poor households in the areas for early conversion can replace or upgrade incompatible boilers, as well as to provide financial support to improve the energy efficiency of these buildings, to reduce underheating and exposure to high fuel bills. During this period, a detailed plan for conversion of the transmission and distribution networks is developed, focusing on the first regions to be converted beginning in 2035. *Figure 15* shows a conceptual schematic of the gas network in the early 2030s.

Figure 15: Schematic showing grid blending in the Decarbonised Gas scenario, 2030-2035



7.1.3 Piecewise grid conversion: 2035-2050

The first areas are assumed to fully convert to hydrogen beginning from 2035 in this scenario, beginning in the southwest and northwest of Ireland. The production and storage capacity in these areas must increase significantly to be sufficient to supply local demand. Distribution network conversion is assumed to take place town-by-town, including some building-by-building checks and upgrades. As further regions are converted, hydrogen production in the resource-rich areas (particularly in the west and southwest) would increase to supply the newly connected, higher-demand areas. CCS infrastructure is built to capture and sequester carbon at large industrial sites using fossil fuels and power sector sites converting to bioenergy. This period of the Decarbonised Gas scenario is shown conceptually in *Figure 16* and *Figure 17* presents one potential sequence for the piecewise conversion of the transmission network.

Figure 16: Schematic showing piecewise grid conversion in the Decarbonised Gas scenario, 2035-2050

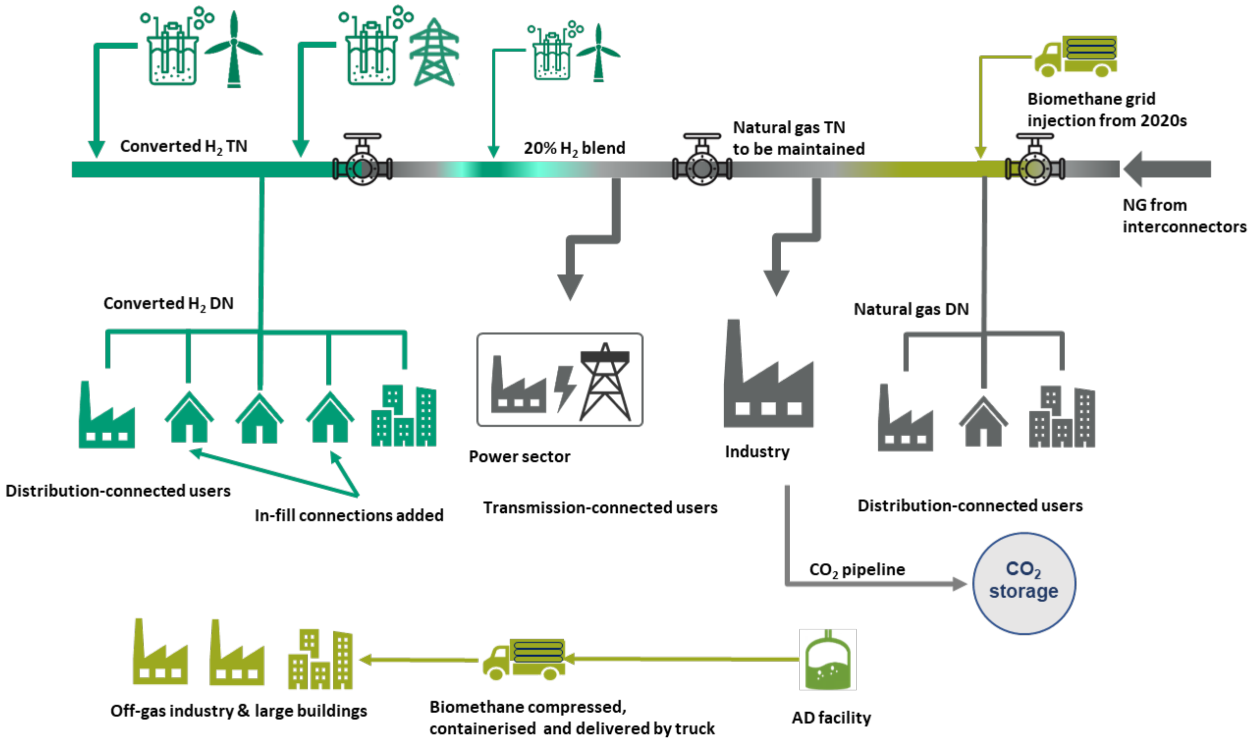
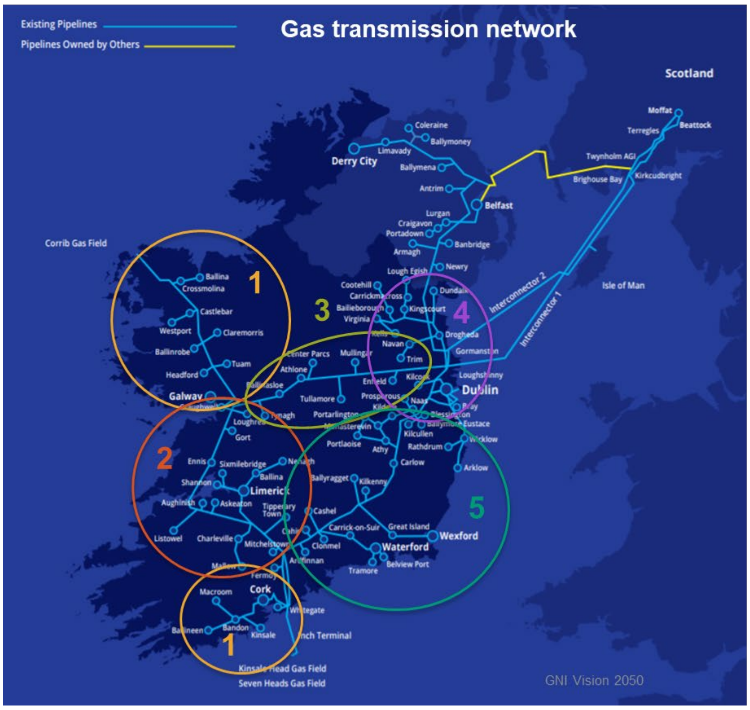


Figure 17: Potential sequence of the piecewise network conversion



1. First conversions in northwest and southwest – high resource potential
2. West coast – first H_2 legs now connected
3. Midlands – gas power plants decommissioned (or potentially converted)
4. Dublin and northern leg – significant demand to be supplied from H_2 generated elsewhere
5. Southeast – H_2 transmission grid constructed in parallel with NG transmission used by sites deploying CCUS

Background image source: *GNI Vision 2050 [9]*

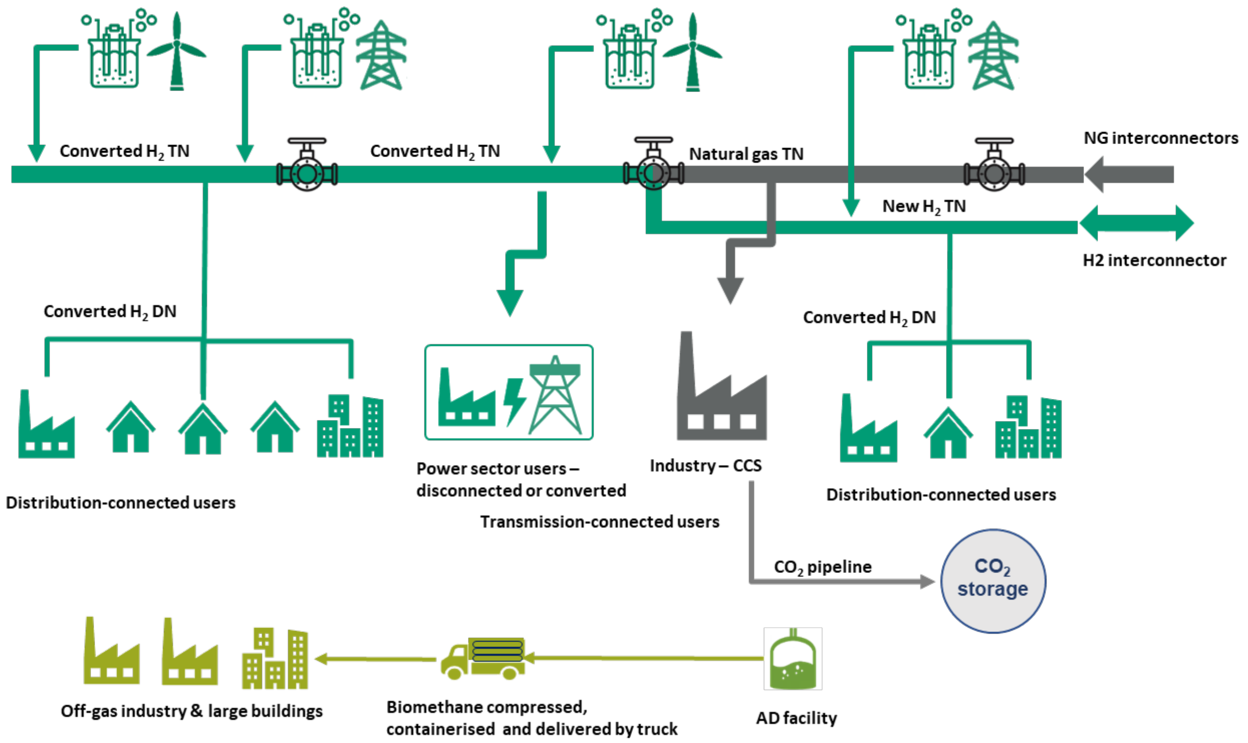
With hydrogen assumed to be a key route to heat decarbonisation in this scenario, homes and buildings adjacent to the network would be provided with the option to connect to the gas network. This may occur either before or after hydrogen conversion. This time period is also a critical period for clear messaging and support for the growth of AD crops and biomethane production. Grid injection of biomethane is assumed to cease by 2050 (although AD production of biohydrogen, currently being researched, may replace biomethane) but off-gas markets for biomethane are assumed to continue. Off-gas industry and non-domestic buildings with large energy demand are encouraged to adopt containerised biomethane supply.

7.1.4 Fully deployed hydrogen network: 2050

The Decarbonised Gas scenario assumes piecewise conversion of the transmission and distribution networks to be completed by 2050. It assumes fossil gas will remain only in selected parts of the transmission network for delivery to industry sites utilising CCS.

As noted above (see Section 4.3 Demand in the power sector), most large power sector gas users, chiefly large combined cycle gas turbines (CCGTs), would not continue to operate using fossil gas in 2050. The majority are decommissioned, although some may be converted to hydrogen to provide dispatchable electricity. At this point, Ireland's significant potential wind resource may allow hydrogen to be produced and exported, either via a dedicated interconnector or shipping by tanker. Biomethane continues to be produced and is containerised and delivered to non-domestic buildings and industry off of the gas network. Following the conversion period from 2030 to 2050, large-scale changes to the gas network cease and the network continues to operate as shown in *Figure 18*.

Figure 18: Schematic showing a fully deployed hydrogen network in the Decarbonised Gas scenario, in 2050



7.2 Rapid Progress scenario

The Rapid Progress scenario assumes a mix of technologies for deployment to decarbonise the heating sector. It assumes accelerated progress in the 2020s relative to the other scenarios considered in this

National Heat Study, with a focus on deployment of electric heating (primarily heat pumps) and building fabric efficiency measures, particularly in the residential, commercial and public sectors. The industry sector targets both low-carbon gases (hydrogen and biomethane) for use, and assumes development of a separate hydrogen transmission network from 2030 to supply hydrogen to industrial consumers. Biomethane production and grid injection infrastructure are assumed to be deployed from the early 2020s to allow for immediate emissions reductions from biomethane blending as well as from the direct delivery of containerised biomethane to industrial sites. At the same time, policy focus on the growth of a sustainable red clover/ryegrass silage that can be co-digested with cattle slurry aims to provide sufficient feedstock to provide meaningful emissions reductions by 2030 from biomethane use. As electrification and district heating deployment causes reduced gas demand in the residential, commercial and public sectors, and hydrogen replaces some gas demand in the industrial sector, the growth in biomethane availability allows it to eventually meet the total demand remaining on the fossil gas network, principally for industrial consumers. The phases of this transition are outlined below. As mentioned above, the actions and policies outlined below are not recommendations but rather an outline of the steps that could be undertaken to realise the Rapid Progress scenario considered within the National Heat Study.

7.2.1 Planning and AD deployment: 2020s-2030

As in the Decarbonised Gas scenario, the Rapid Progress scenario needs a clear decision from the Government on the direction of the gas network by the mid-2020s. The Rapid Progress scenario assumes a commitment to sustained support for domestic biomethane production and to reducing the demand on the existing gas grid and eventually decommissioning it. Policy support would be required for both buildings and industry (likely targeted by subsector) to encourage and enable the switch to electrification.

Farmers grow grass silage for AD on suitable agricultural land. The area available for silage for AD increases throughout the 2020s due to a reduction in the national beef herd and improvements in grassland productivity. If biomethane is to be widely taken up in this time period, significant policy support may be needed to reduce the costs of biomethane paid by industrial users to be cost competitive with other decarbonisation options, such as domestic solid biomass and electrification of heat. This could be in the form of direct subsidies to early adopters, further support for the agricultural sector to produce suitable crops for AD, or support to drive down the costs of biomethane production and distribution infrastructure.

Furthermore, significant and immediate action would be required in this scenario to promote the early development and deployment of hydrogen, as in the Decarbonised Gas scenario (see Section 7.1.1). This would include analysis of which industrial sites and processes would be most likely to decarbonise with either biomethane or hydrogen, hydrogen appliance and network trials to understand, cost and de-risk the network conversion, and an increase in hydrogen production volumes to prepare for grid blending and grid conversion to start by 2030. However, in the Rapid Progress scenario, these efforts would be focused on the industrial sector and development of a hydrogen transmission grid given the decision to reduce and eventually curtail use of the gas distribution network.

There are two assumed routes for biomethane to enter the gas network. Large production sites close to the transmission network may inject directly. Smaller production sites, many of which are likely to be on farms or in other rural locations, would compress and containerise the biomethane allowing it to be trucked to centralised injection points.[6] Unlike hydrogen, biomethane is chemically identical to fossil methane gas. Therefore, there is no limit on the fraction of the grid made up of biomethane at a given location. See *Figure 19* for a schematic depiction of the gas network at this stage of the Rapid Progress scenario.

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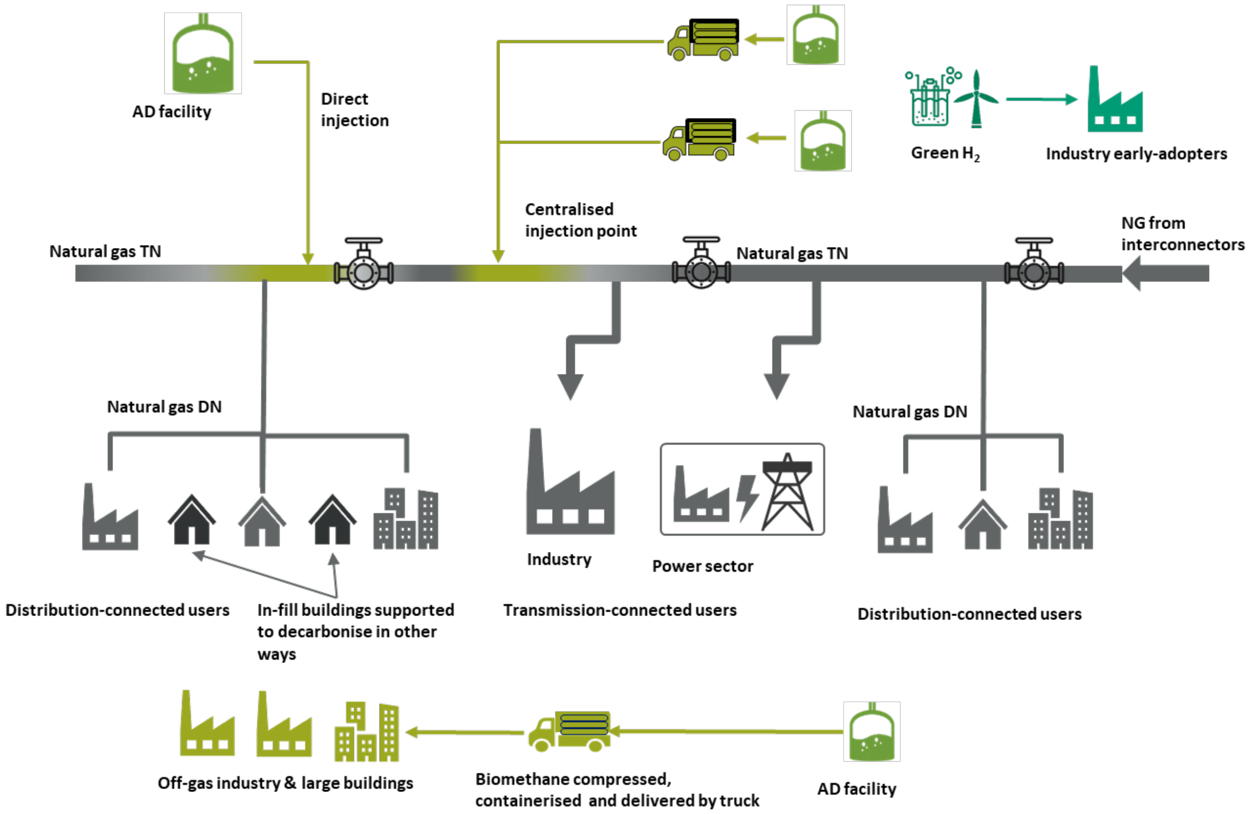
[6] GNI has identified eight potential locations for centralised injection points, located at existing network AGIs (above ground infrastructure).

Figure 19: Schematic showing planning for conversion and AD deployment in the Rapid Progress scenario, 2020s-2035



As noted above, it is important that Government and gas network stakeholders recognise that domestic biomethane production is limited and will not meet the demand currently met by the gas network. The Rapid Progress scenario therefore prioritises biomethane for use by industrial users which currently use fossil gas, to minimise unnecessary replacement of existing fossil gas equipment which is already suitable for biomethane use. As such, in this scenario, biomethane is only offered as a decarbonisation option in the industry sector to existing fossil gas users. Planning and co-ordination would be needed to support on-gas customers across the residential, commercial and public to ensure that they can decarbonise their heating systems via a variety of non-gas-based technologies (e.g. electrification, district heating or solid biomass), and prepare for the decommissioning of the distribution grid supplying on-gas consumers in these sectors from 2030.

7.2.2 Hydrogen deployment, continued growth in biomethane production, and distribution grid decommissioning: 2030-2050

Co-ordinated action would need to be sustained after 2030 in the Rapid Progress scenario to allow low-carbon gases to aid in the rapid decarbonisation targeted in this scenario. Biomethane demand could also continue to increase depending on the cost of biomethane available to industrial consumers, and production and deployment infrastructure would also need to continue growing to support this. Where industry demand for low-carbon solutions continues to increase, a policy focus on an expansion of the resource available from low-cost and sustainable grass silage, as well as on the delivery of biomethane infrastructure, could help meet this need. As such, for this pathway, ongoing policy support for the growth of energy crops and for increasing capacity of biomethane production routes is likely be needed. The distribution of biomethane may include centralised grid injection of compressed and containerised biomethane, direct grid injection at the production facilities, and distribution of containerised biomethane to end users, and so all distribution routes would need to be considered and supported.

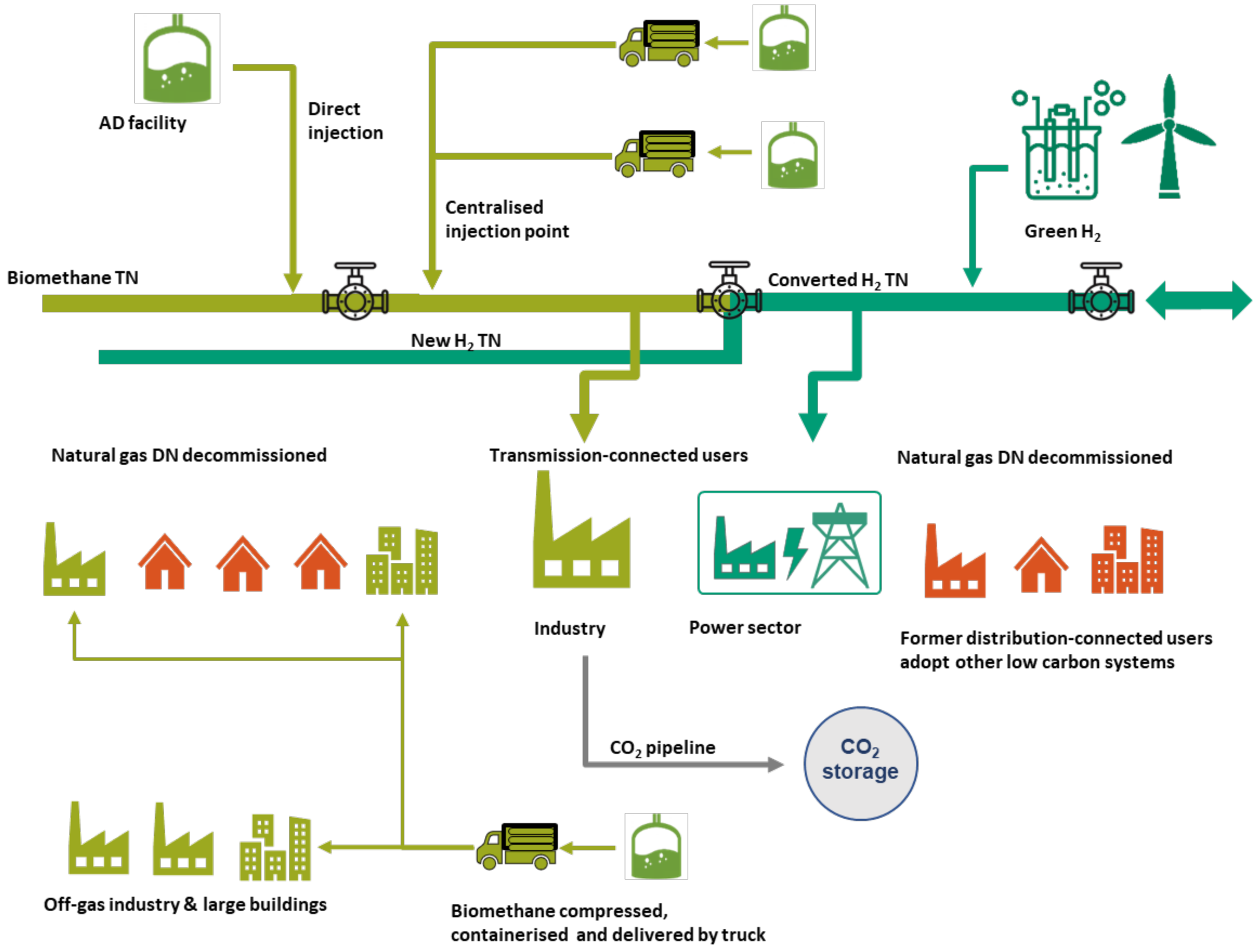
In this scenario, towards 2050, there may still be some fossil gas imports present in the methane transmission grid (blended with biomethane, as the two fuels are chemically identical), as the power sector or some industrial sites may continue to burn methane with CCUS. To ensure a net-zero use of this potential mixture of fossil gas and biomethane, some carbon accounting and sufficient biomethane production would be required to ensure any net emissions from combustion of blended methane gas by consumers in the heat sector balances against negative emissions from the power sector and industrial sites with CCUS using biomethane.

There is likely to be competition between biomethane and hydrogen as options for low-carbon fuels for industrial gas users in this time period, as hydrogen also becomes available for end users from 2030, with a separate developed hydrogen transmission grid. The projected costs of the two fuels (see *Figure 10* in Section 5 and *Figure 13* in Section 6) show that hydrogen and biomethane production costs are likely to be comparable, and so it is likely that both fuels would be present in 2050, given sufficient policy support. Whether an industrial site decarbonises through use of biomethane or hydrogen is likely to depend on process-specific and site-specific factors, and by proximity to the hydrogen or biomethane transmission grids.

The scenario assumes green hydrogen production will begin at scale from 2030, with upfront investment required initially to build a separate hydrogen transmission grid to allow the first consumers to connect to this grid and use hydrogen for heating from 2030. Initial construction of the hydrogen transmission grid is likely to connect production sites directly to large-scale early adopters. As considered in the Decarbonised Gas scenario, hydrogen deployment would begin in resource-rich hydrogen production areas (particularly in the west and southwest) and, as more hydrogen production capacity is connected, this new hydrogen transmission grid would extend throughout the rest of the country, connecting industry-heavy areas of Ireland according to projected demand. This process is assumed to continue throughout the 2030s and early 2040s, with hydrogen production ramping up smoothly over this time period to allow an increasing number of customers to connect. If green hydrogen production were to exceed hydrogen supply, there would be potential for Ireland to export excess green hydrogen or green ammonia.

In this scenario, distribution-connected consumers cannot continue using gas in the long term. Eventually, the gas distribution network would be decommissioned in a piecewise fashion, once most consumers in a given area have switched to other low-carbon alternatives. This decommissioning of the gas grid is likely to be driven by the ability of these 700,000 existing consumers to decarbonise via other methods, with strong policy support likely needed for this share of the population. As increasing amounts of the gas distribution network are decommissioned, fuel prices are likely to rise for customers remaining on the gas network as fixed infrastructure costs (which are levelised across all customers) are unlikely to reduce at the same rate as the number of customers. Therefore, the economic pressures on these customers to shift away from the gas network are likely to increase over time, independent of any other incentives offered to customers to encourage switching. *Figure 20* presents the steady-state operation of the gas network from 2050.

Figure 20: Schematic showing continued growth in biomethane production and a hydrogen parallel transmission network in the Rapid Progress scenario, 2035-2050



8 Low-carbon gas pathways: challenges and opportunities

8.1 Challenges

Significant and sustained co-ordination and policy support would be needed across the entire supply chain to enable the deployment of either hydrogen or biomethane for low-carbon heat. The following paragraphs describe the steps that would be needed to ensure that biomethane and hydrogen options are available. However, end consumers will make the final decision on which low-carbon heating technology to adopt based on which options are most attractive for their particular circumstances.

For a biomethane pathway, key stakeholders include:

- The agricultural sector to enable significant growth of sustainable grass silage crops necessary for AD in substantial amounts, with sustained policy support for producers in the agricultural sector and clear signals indicating that a market for biomethane would be available long term.
- The power sector, who are a key end user of fossil gas currently, and one of the sectors most likely to use fossil gas with CCUS in 2050 and beyond.
- The gas transmission and distribution network operator, who will need to understand the impact on fossil gas storage and distribution infrastructure, which would accompany the reduction in methane demand.

For a hydrogen pathway, these key stakeholders would remain significant; the agricultural sector, while less vital, can still play a key role if a significant proportion of hydrogen is produced via biomass gasification. Transmission and distribution network operators are likely to play a significant role in the deployment of hydrogen storage, transmission and distribution infrastructure, as well as in conversion of the existing distribution network. Network operators would also need to co-ordinate to provide a secure supply of green hydrogen for consumers across all sectors, and would need to ensure all connected consumers are ready for a switch to hydrogen appliances. Clear policy commitment would also help to drive demand for low-carbon gases by providing confidence to early adopters.

Reliance on green hydrogen to decarbonise heat would most likely lead to a delay in decarbonisation efforts, and conflicts with 2030 decarbonisation targets and a focus on cumulative emissions reductions. Hydrogen is only likely to be available for consumers from 2035 (2030 in the most optimistic case), so would not offer any significant decarbonisation of emissions from heating before this date. While hydrogen blending could begin earlier, this is likely to be limited to 20% hydrogen by volume or 7% hydrogen by energy and therefore has quite limited potential for emissions reductions. The conversion of the gas network to hydrogen and reaching the production levels of hydrogen to meet the entire 2050 demand will not happen overnight. As such, there are many users who, in a high-hydrogen scenario, would not experience significant emissions reduction until the 2040s, while waiting for the option of hydrogen for heating to become available. Buildings could have energy efficiency retrofits in the 2020s and 2030s in anticipation of hydrogen conversion to reduce final fuel costs for the customer and reduce cumulative emissions until hydrogen deployment. However, with such deep energy efficiency deployment, electrification of heat would become highly cost competitive.

As hydrogen is not yet proven as a safe and reliable source for heat at any significant scale, there is a high risk of large sunk costs if hydrogen for heating is pursued and found unsuitable; this would also add to cumulative emissions in this case, and would represent a delay to decarbonisation efforts.

Ireland has little known opportunity for geological storage of hydrogen, and may require significant volumes of hydrogen to be stored using other methods. For 20 TWh of annual hydrogen demand, over 300,000 medium-pressure steel containers could be needed. Alternatively, large volumes of ammonia, LOHCs or other chemical hydrogen carriers could store up to 40% of the annual demand of hydrogen. For an annual demand of 20 TWh, this represents 2 million cubic meters of ammonia (about the size of 50 typical above-ground oil storage tanks). This level of energy storage is not unprecedented in Ireland, but it is a significant infrastructure requirement. Further work would be useful to determine the potential of any geological storage available.

The potential domestic resource for biomethane production is too low to meet existing demand, so even at its maximum potential, biomethane cannot meet the entire gas demand in Ireland unless demand reduces significantly. The *Sustainable Bioenergy for Heat* report [3] in this National Heat Study explores the competing demands for land use in Ireland for resource production, but even prioritising resources for production of biomethane (via AD) with policy support and land use change policy reducing the national herd, only about 5 TWh of biomethane can be produced per year, representing only 11% of the 53 TWh of fossil gas consumed each year today. At these volumes, both cheaper and more expensive biomethane production routes are required (in terms of cost of biogenic feedstock), and so increasing demand to this level would increase the average cost of biomethane for heat, which could reach over 10 c/kWh.

Resource constraints and competition for biogenic crops, and competition for renewable electricity generation sites, could increase the average cost of low-carbon gases seen by the consumer. Competition for the agricultural land use could result in low availability of biogenic crops for either hydrogen (gasification) or biomethane (primarily AD), and low-cost renewable generation faces competition between green hydrogen production and electricity generation for the power sector.

A large-scale rollout of renewable electricity generation is expected by 2050 in line with decarbonisation efforts and will be well under way by 2030 to meet the target for up to 80% renewable electricity by this date. Dedicated renewables for production of hydrogen would therefore have to compete with demand for renewables to supply electricity for the wider power sector, which could increase the cost of these installations and the resulting cost of hydrogen. The renewable generation technologies which are cheapest for hydrogen production (onshore wind, fixed offshore wind; see *Figure 10*) are also the generation technologies with lower resource capacity than floating offshore wind, which is more expensive. This could increase the cost of green hydrogen seen by the consumer. However, some areas with high wind potential (for example in Mayo and Sligo) have low electricity transmission network capacity but significant gas transmission capacity. Further work is needed to understand the additionality of renewable installations for hydrogen generation.

Biomass is seen as a key fuel for decarbonisation in the power sector and by consumers in the heat sector, so competing demands for solid biomass could lead to limited use of land for AD crops suitable for biomethane. Biomass can provide low carbon, dispatchable electricity generation in the power sector, which becomes increasingly importantin a power system with high levels of variable renewable generation like solar PV and wind. When coupled with CCS, biomass combustion for power is also an opportunity to provide negative emissions in the power sector. For these reasons, biomass may be prioritised for use in the power sector, which may impact the use of land for AD crops and availability of solid biomass for gasification. Elsewhere in the heat sector, biomass offers a key pathway for decarbonisation when combusted directly for heat in solid biomass boilers. This provides an alternative to electrification, especially in off-grid homes and in industrial processes currently using solid mineral fuels for heat or which are unsuitable for electrification. Competition from direct users in the heat sector could therefore lead to further reduction in the availability of biomass for gasification. Imported biomass is potentially less resource-constrained, but there are risks and uncertainties around the emissions and overall sustainability of imported biomass.

Hydrogen for heat is likely to lead to an increase in annual fuel prices seen by the consumer, compared to fossil fuel use or electrification. As calculated in the Hydrogen Infrastructure Module within the NEMF (see *Figure 9* and *Figure 10)*, the LRVC of hydrogen is likely to be significantly higher for all production routes than that of fossil gas. For certain production routes, a limited volume of hydrogen may be comparable with electricity in terms of c/kWh of fuel delivered, however most production routes were estimated to have a higher LRVC than electricity. However, the high efficiency of heat pumps means that the cost to domestic and commercial consumers in terms of c/kWh of heat delivered may be significantly higher with hydrogen than with electrification. Fuel-poor consumers may be particularly at risk of high ongoing costs if they cannot afford the high upfront cost of a heat pump. Further, the Irish Government's commitment to green hydrogen [4] instead of blue hydrogen may be tested if cheaper blue hydrogen is available for import from other countries, such as the UK which is actively pursuing blue hydrogen as a decarbonisation fuel [18].

Deployment of hydrogen or biomethane requires significant investment in infrastructure, with the risk of stranded assets depending upon the success of these decarbonisation pathways. For biomethane deployment, as seen in the scenarios above, the infrastructure for AD and biomass gasification would need to be deployed at orders of magnitude greater than the currently existing infrastructure. This is also the case for grid injection points and facilities for compressing, containerising and trucking biomethane.

Green hydrogen production infrastructure would need to be developed from the ground up, potentially including a new transmission network, and the entire existing gas distribution network would need to be repurposed in a piecewise manner to be suitable for hydrogen. These infrastructure requirements would require significant investment, with up to €10 billion needed in infrastructure investment in scenarios with significant hydrogen deployment in industry or buildings connected to the gas grid, such as the Balanced or Rapid Progress scenario, depending on uptake. If hydrogen is pursued as a key decarbonisation option for all on-gas consumers, these hydrogen infrastructure investment costs could exceed €20 billion before 2050.

The deployment of the infrastructure required for significant availability of biomethane or of hydrogen would require co-ordination across the entire supply chain of these low-carbon gases, and risks exist for both technology pathways. For hydrogen production, consumers are likely to only convert when there is a guaranteed secure supply of hydrogen, which is likely to require significant upfront investment before uptake. If electrification of heat takes a greater than predicted share of heat in Ireland, this upfront investment may prove poor value for money. For biomethane, these risks also apply, as competing demands for biogenic resources after the investment in this infrastructure could lead to reduced supply of biomethane. Furthermore, in a high-hydrogen scenario, all gas-connected consumers may switch to hydrogen instead, which could lead to biomethane infrastructure becoming stranded before the end of its natural lifetime.

8.2 Opportunities

The technical potential of green hydrogen is estimated at around 90 TWh, more than the existing 53 TWh fossil gas use in Ireland. Green hydrogen therefore has the technical potential to decarbonise several key applications in Ireland, including replacing fossil gas use for heating buildings and in high-temperature industrial processes, as well as a long-term storage opportunity in the power sector. Green hydrogen could be used in significant quantities by existing gas network users, if available at a cost-competitive price. As shown in *Table 5*, in-fill of network connections could increase the demand from buildings on the distribution network from around 11 TWh today to 15-17 TWh. Final decisions on the uptake of low-carbon gases will be made by consumers based on the cost of the options available and their particular circumstances.

Hydrogen also provides an important decarbonisation option for high-temperature processes in the industry sector, for which electrification is more challenging. Additional hydrogen supply could help drive decarbonisation in the power and transport sectors, as well as create the opportunity for exporting green hydrogen.

In the transport sector, hydrogen is one key option for decarbonising road freight [19], as well as being considered in the decarbonisation of marine transport (either through the use of hydrogen directly as a fuel, or after conversion to ammonia). Hydrogen can be used in the power sector as a storage mechanism, with green hydrogen produced using excess renewable electricity and stored until periods of either peak demand or low intermittent renewable energy supply. This has been investigated at a high level within the National Heat Study and findings are included in the *Net Zero by 2050* report [2].

As potential hydrogen supply exceeds potential demands in these sectors, there is the potential to export green hydrogen or green ammonia to other countries with less developed hydrogen supply chains. Hydrogen export is beyond the scope of the National Heat Study and would benefit from further research.

Biomethane can provide decarbonisation of heat with the lowest impact on consumers. Appliances currently using fossil gas require no adjustments to burn biomethane (either part-blended or pure biomethane). Gas combustion boilers (burning either fossil gas or biomethane) are less sensitive than heat pumps to the efficiency level of buildings, and so deployment of biomethane can be a decarbonisation option in inefficient buildings which would require substantial costs to sufficiently improve the property's energy efficiency, for example, heritage buildings. However, the maximum estimated domestic biogenic resource potential for biomethane production is about 5 TWh, which is approximately 11% of current fossil gas demand for heat.

Biomethane can fulfil many key roles on the road to decarbonisation, including in hard-to-decarbonise processes and buildings across the heat sector, by providing emissions reductions by 2030 and negative emissions by 2050, and by allowing the agricultural sector to play a key role in decarbonisation. Although biomethane does not have the potential to meet the entire existing fossil gas demand today (27 TWh for heating and 53 TWh in total), it provides alternatives for consumers who may otherwise struggle to decarbonise effectively. One such example includes industrial processes such as cement manufacturing, which require high temperatures and cannot therefore electrify. Hydrogen is one potential option, but biomethane could also provide decarbonisation in these processes in Ireland. Containerised biomethane is an alternative low-carbon fuel in off-grid urban buildings in the commercial and public sectors, where biomethane is a cleaner-burning fuel than solid biomass or bioliquid.

Compared to hydrogen, biomethane offers much earlier potential for reduction in emissions from use of fossil gas via grid blending, with potential of emissions reductions before 2030 if the required infrastructure is built and the necessary crops are being grown in the required amounts in the agricultural sector. This can help Ireland meet its 2030 emissions reductions targets [4]. Biomethane can also be used alongside CCUS at either power generation or industrial sites to provide negative emissions in the 2040s, which can help offset any emissions from hard-to-decarbonise sectors. Both grid blending and use of biomethane with CCUS can lead to reductions in cumulative emissions by both 2030 and 2050, helping Ireland stay within its carbon budgets in these time periods.

Stakeholders across the agricultural sector would need to be heavily involved in the deployment of biomethane to grow the necessary crops to produce the required amounts of biomethane to offer emissions reductions. This affects land use in Ireland, which is explored in the *Sustainable Bioenergy for Heat* report [3] in this National Heat Study. Engaging with the agricultural sector to help provide emissions reductions in heat and power is an important way in which this sector can help lead decarbonisation efforts in Ireland.

Deployment of hydrogen may offer renewable generation sites the opportunity to generate additional revenue and provide an alternative use of existing fossil gas infrastructure. As deployment of renewable electricity generation technologies increases, there is likely to be an increasing amount of generation curtailed as renewable electricity supply may exceed existing demand and storage capacity more often. Generation and storage of hydrogen (for the heat sector, or as a storage mechanism in the power sector) offers an alternative to the curtailment of renewable electricity. Selling this hydrogen to a range of consumers could provide an additional revenue stream for the owners of renewable energy generation sites, which may become increasingly important in driving further renewable deployment, as the penetration of renewables continues to increase to 2050. However, the anticipated volume of curtailed electricity is likely to be significantly below the potential demands for hydrogen for heating shown in Section 4. The volumes of curtailed renewable electricity forecast for 2040 in Eirgrid's 2019 TES[15] could be used to produce approximately 1 to 2 TWh hydrogen, compared with the potential hydrogen demand for heating of around 30 TWh.

Use of hydrogen for heat provides an alternative use of existing fossil gas infrastructure. However, this would require investment to convert existing gas transmission and distribution infrastructure to enable the transportation of hydrogen. Investment in end-use appliances would also be required to ensure compatibility with hydrogen use. Without deployment of hydrogen, the need for gas infrastructure is likely to significantly reduce over the period to 2050.

9 Summary and next steps

This report of the National Heat Study has assessed the potential for green hydrogen and biomethane to contribute to the decarbonisation of heat in Ireland. Today the gas network delivers over 50 TWh of energy for heating, process use and electricity generation. Within all decarbonisation scenarios considered, the gas network evolves considerably between now and 2050. This evolution could include substantial changes to the fuel carried, number of connections and volume of energy delivered. If the gas network decarbonises to provide low-carbon gases to consumers, this will need a centrally-planned solution with significant support from all key stakeholders, as consumer uptake alone cannot drive decarbonisation of the gas network.

Hydrogen and biomethane both offer important opportunities for decarbonisation in Ireland. There is an estimated 90 TWh of potential for annual green hydrogen production, if the available renewable generation resource is fully utilised. This upper limit exceeds the existing gas demand in Ireland today, and offers the potential to fully decarbonise existing gas demand, or potential for green hydrogen exports, if there is sufficient demand internationally. However, significant challenges would need to be overcome. Significant investment and central planning by key stakeholders are likely to be required for network conversion and development of production and storage plants. These efforts would need to occur in advance of widespread hydrogen demand, and there is the risk of stranded assets for either of these low-carbon gases if fuel prices paid by consumers are not competitive with other decarbonisation options. Deployment of hydrogen would need to be preceded by significant testing of appliances, as well as pilot programmes to verify the suitability of gas distribution infrastructure for hydrogen.

Use of low-carbon gases for heat could enable the decarbonisation of heat for buildings and industrial applications that are hard to electrify, such as cement kilns or buildings with space constraints limiting heat pump deployment. Use of low-carbon gases could also allow the continued use of existing gas infrastructure.

Ireland's resource potential for green hydrogen production is significant, primarily due to the large potential offshore wind resource. In the most optimistic case, most of Ireland's hydrogen production capacity could be used for export rather than domestic consumption. However, further work is needed to refine our understanding of the offshore wind resource, the likely costs, and the additionality of supply beyond what will be required to meet Ireland's electricity needs. In addition, further analysis is needed on the use of hydrogen as a storage vector for electricity. Some form of long-duration storage and dispatchable low-carbon electricity generation would be needed to support a zero-carbon electricity grid. Hydrogen is a strong candidate for this role, while other competitors include power-to-methane, use of fossil gas with CCUS, and other novel forms of energy storage. However, reliance on green hydrogen to decarbonise heat would most likely lead to a delay to decarbonisation efforts, and conflicts with 2030 decarbonisation targets and the focus on cumulative emissions reductions.

The *Sustainable Bioenergy for Heat* report [3] in this National Heat Study has developed the most spatially detailed estimate to date of Ireland's potential for sustainable biomethane production from domestic bioresource. While the technical potential is significantly less than current gas network demand, biomethane can contribute to decarbonisation of the gas network in the 2020s and may have a long-term role to play as well. Further work is required to understand how biomethane and hydrogen might best work together in a decarbonised energy system, and to clarify the requirements and potential for off-gas delivery and use of biomethane in both buildings and industry.

A spatial (e.g. geographical) analysis of gas network capacity, heat demand and resource potential would enable development of a more detailed picture for how the gas network may evolve in different areas of the country. This could include assessment of the gas network's hydrogen delivery capacity (which would be lower than for fossil gas due to hydrogen's reduced energy density), the potential for green hydrogen production and gas network injection in each county, and the spatial distribution of heat demand. Such data are useful at both a local/regional level and nationally to improve understanding of the costs and benefits of different decarbonisation scenarios.

Glossary

Term	Description
AD	Anaerobic digestion
AGI	Above-ground infrastructure
Archetype	A simplified representation of a normally large number of real-world items, such as buildings.
BECCS	Bioenergy carbon capture and storage
BioSNG	Biosynthetic natural gas
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CCUS	Carbon capture utilisation and storage
CHP	Combined heat and power
CRU	Commission for Regulation of Utilities
DN	Distribution network
ETS	Emissions Trading Scheme (regarding the EU's emissions trading scheme)
GNI	Gas Networks Ireland
GSI	Geological Survey of Ireland
H_2	Hydrogen
kWh	Kilowatt hour; a unit of energy
LOHC	Liquid organic hydrogen carriers
LRVC	Long-run variable costs
MPa	Mega Pascal; 100,000 Pascals
NECD	National Emissions Ceilings Directive
NEMF	National Energy Modelling Framework
NG	Natural gas. This report also refers to natural gas as fossil gas and methane gas.
Non-ETS	This refers to industrial sites or other greenhouse gas emitters which are not part of the EU's emission trading scheme.
PEM electrolysis	Polymer-electrolyte membrane electrolysis, or proton-electron membrane electrolysis
PV	Photovoltaics

Term	Description
SEAI	Sustainable Energy Authority of Ireland
SNG	Synthetic natural gas
SOE	Solid-oxide electrolyser
SOFC electrolysis	Solid-oxide fuel cell electrolysis
SSRH	Support Scheme for Renewable Heat
TN	Transmission network
TRL	Technology readiness level

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Appendix A: Green hydrogen assumptions

Biomass availability

Table 9 presents the resource assumptions for biomass gasification. These are based on the analysis performed in the Sustainable Bioenergy for Heat report [3] in this National Heat Study.

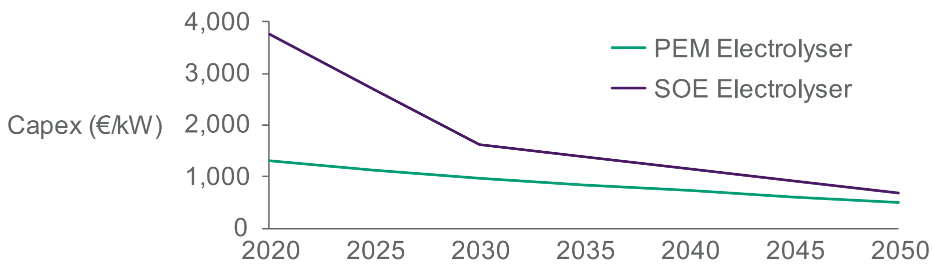
Table 9: Solid biomass resource available for hydrogen production in the Decarbonised Gas scenario

Bioresource for gasification	Max. bioresource available (TWh/year)	Average feedstock cost	Assumed plant size	Earliest technology availability
Domestic wood chips	1.2 to 1.8 TWh	1.2 c/kWh	50 MW	2035 (2030 in Rapid Progress)
Imported wood pellets	19 TWh	5.5 c/kWh	250 MW, 400 MW	2035 (2030 in Rapid Progress)

Cost and efficiency of green hydrogen production

Figure 21 to *Figure 24* present the costs and efficiency assumptions through time for each of the hydrogen technologies analysed. These data are taken from the Hydrogen Supply Chain Evidence Base [20] and the Future of Hydrogen [21], with further explanation of the method used to determine these values given in the accompanying data workbook published alongside this report[7]. Electricity prices were taken from the ENTSO-E Transparency Platform [22], and the processed renewables energy load factor data taken from the NASA MEERA database for wind [23] and solar [24], both normalised to match the projected average annual load factors in EirGrid's Tomorrow's Energy Scenarios [15] with data taken for Ireland from 2019.

Figure 21: Electrolyser cost over time to 2050; operating expense ranges 3-6% of capex for PEM electrolysers, and 1.5-7% for solid-oxide electrolysers (SOE)



[7] Supporting material for this report is available for download from the SEAI website. Available: https://www.seai.ie/data-and-insights/national-heat-study/low-carbon-gases-for-heat/.

Figure 22: Energy consumption for electrolysis: for SOE electrolysers, a proportion of the fuel consumption is from electricity, and a portion is from hydrogen; for PEM electrolysers, all fuel consumed is electricity

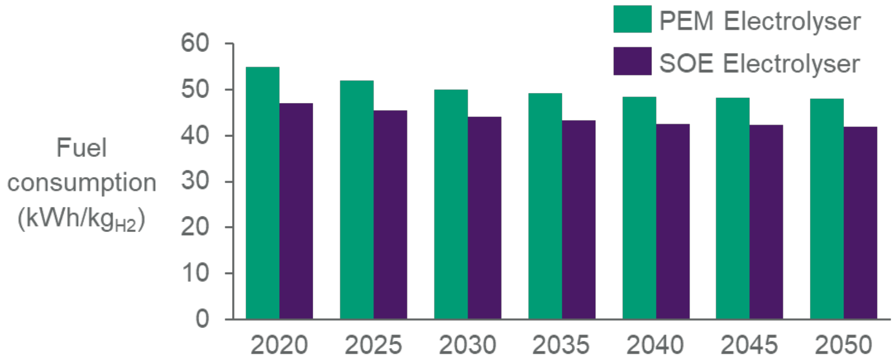


Figure 23: Projected capital cost (capex) of biomass gasifier for hydrogen to 2050

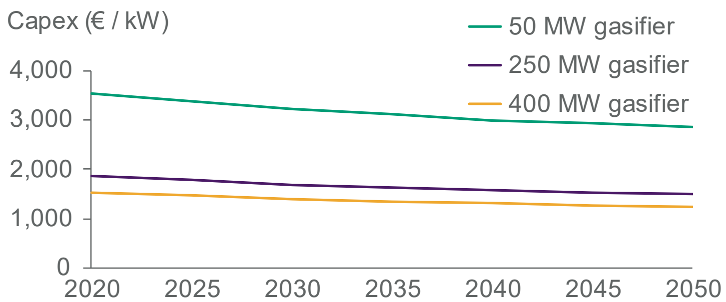
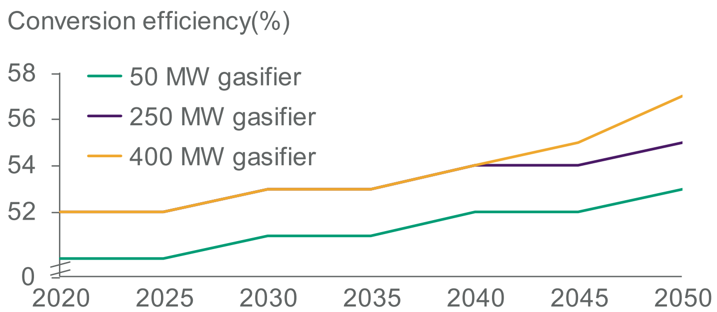


Figure 24: Efficiency of biomass conversion to hydrogen via gasification with CCS



Green hydrogen storage

The assumptions regarding the performance and costs of hydrogen storage as a gas in pressurised steel containers are taken from the Hydrogen Supply Chain Evidence Base [20]. The sources for cost and assumptions of the chemical storage of hydrogen as ammonia, methanol and other LOHCs are taken from several sources [21] [25] [26] [27] [28], with more information given in the accompanying data workbook[8].

[8] Supporting material for this report is available for download from the SEAI website. Available: https://www.seai.ie/data-and-insights/national-heat-study/low-carbon-gases-for-heat/.

Appendix B: Biomethane assumptions

Cost and efficiency of production

Figure 25 and *Figure 26* present the capital costs (capex) and operating costs (opex) for anaerobic digestion (AD) facilities. The biomethane plant costs in *Figure 25* are based on previous analysis by Ricardo for SEAI [29] and analysis by KPMG for the Renewable Gas Forum Ireland [30]. The costs depend on type and scale of the plant, and tend to be higher for food waste processing as de-packaging equipment must be included. The efficiency of AD is 87-89%. Both efficiencies and costs are expected to be stable over time as the technology is already mature.

Figure 25: Capex and opex of biomethane production plants, which are expected to be stable over time

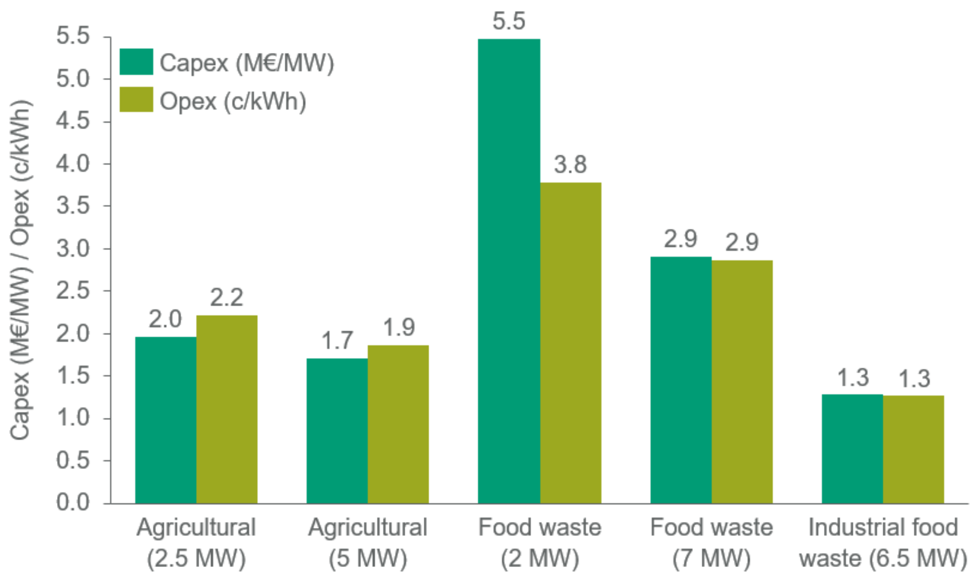
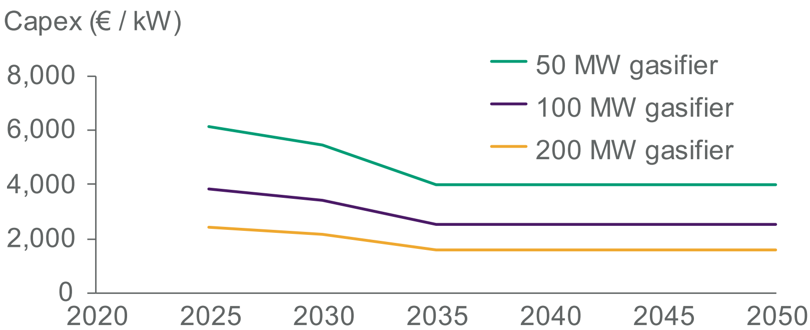


Figure 26: Capex of biomass gasifier for SNG to 2050



The costs shown in *Figure 26* for biomass gasification are based on two academic papers [31] [32]. The efficiency of biomass gasification shown in *Figure 27* was developed using the same sources. The cost assumptions for the biomethane transport options considered are presented in *Table 10* below.

Figure 27: Efficiency of biomass conversion to SNG via gasification

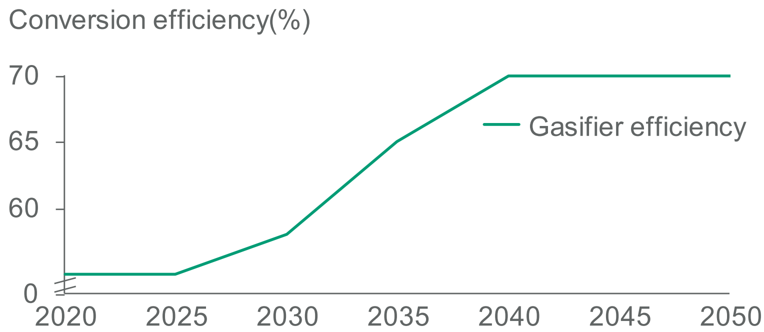


Table 10: Cost assumptions for biomethane transport options

Characteristic	Direct grid injection	Centralised grid injection	Road transport + off-grid use
Description	Grid injection via pipeline from the site of production to gas grid	Compression of biomethane into specialised container at production site followed by road transport to centralised injection point (hub and spoke model)	Compression of biomethane into specialised container at production site followed by road transport to off-gas grid end users (e.g. industry, transport)
Location	BioSNG plant and larger AD plant (e.g. food waste) which can be located relatively close to gas network	Likely to be used for most agri-led AD plant. Gas Networks Ireland (GNI) considering 7 or 8 'hubs' which with a 50 km radius would cover most of country	Concept been used with fossil gas to supply gas to four distilleries in Scotland; should be transferrable to biomethane. Storage vessel and pressure reducing installation necessary at end-user site
Costs	€1.5 million for pipeline and gas entry unit	0.8 c/kWh (0.35 c/kWh for road transport; 0.45 c/kWh for injection at hub – includes capex of injection hub)	0.7 c/kWh (assumed to be twice the cost of road transport to a hub)
Data source	Data from previous analysis on biomethane for SEAI, data from UK RHI reviews (Renewable Heat Incentive), and site data	Data from GNI based on Project GRAZE [33]	Detailed cost data unavailable; estimated at twice costs for road transport

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