National Heat Study

Net Zero by 2050

Exploring Decarbonisation Pathways for Heating and Cooling in Ireland

SEAI SUSTAINABLE ENERGY AUTHORITY OF IRELAND

Net-zero by 2050:

An exploration of decarbonisation pathways for heating and cooling in Ireland

Final report of the National Heat Study

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Final Report of the National Heat Study

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The National Comprehensive Assessment for Ireland was 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.

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Sustainable Energy Authority of Ireland

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Key insights

- **Heat-related CO_2 emissions are rising.**

  The current total CO_2 emissions from fossil fuel consumption for the heating of all buildings and industrial applications (including upstream emissions from the electricity used for heating) in Ireland is 14.1 $MtCO_2$. This represents 38% of total energy-related CO_2 emissions or 24% of total national greenhouse gas emissions. Despite many homes and businesses taking up government grants over the last decade, the emissions from heating are up 13% from the post-recession lows of 2014.

- **Ireland aims to reduce emissions by 51% from 2018 levels by 2030. The current Climate Action Plan measures are unlikely to deliver enough heat-related CO_2 cuts to meet a proportional share.**

  Current policy measures are unlikely to deliver the Climate Action Plan goals. The modelling shows an unprecedented level of additional policy effort, that goes beyond current heat related Climate Action Plan goals, is required to ensure heat related emissions stay within the proposed carbon budget limits. The findings provide direction as to the prioritisation of effort and the need for extended measures to decarbonise heat as quickly as possible.

- **District heating is a technology that offers additional potential. It is proven and available now. The analysis suggests it could provide as much as around 50% of building heating demand in Ireland.**

  The analysis shows that heat supplied to buildings through district heating networks is a competitive option that can be widely deployed. The potential identified is more than that considered in recent policy planning and offers the chance for additional emissions cuts. Heat networks are a mature infrastructure that a variety of heat energy sources can supply. The Climate Action Plan measures that seek to address the market and regulatory gaps that exist in Ireland can address the regulatory, planning and financial barriers to deployment.

- **Heat pumps are a prominent technology in all scenarios and in all sectors. Rapid emissions cuts require deploying the technology at scale.**

  Heat pumps are widely used to decarbonise space and water heating in buildings and low-temperature heat at industrial sites. Capital costs are a barrier in the residential sector, and additional policy support is needed to drive uptake. The economics are more favourable in other sectors. Awareness-raising, marketing campaigns and supply chain support can aid the uptake of heat pump technologies in the services and industry sectors.

- **Evolving existing policy supports to focus on replacing fossil fuels in buildings can have a more significant and immediate emissions reduction impact than a fabric-first approach.**

  The current support scheme incentives are designed based on the ‘fabric-first’ principle, which asks consumers to use the available fabric technologies and financial budgets to reduce heat demand before installing a renewable heating system. However, this approach may not be consistent with the rapid decarbonisation needed to meet the goals of the Climate Action Legislation. It is also not financially viable for a large proportion of consumers in the analysis. Support scheme design that focuses on meeting the minimum levels of fabric performance to support a switch away from fossil fuel heating sources is likely to see more uptake and require less investment. Additional fabric improvements can happen if higher fuel costs or lower technology costs provide more attractive paybacks.

- **Available domestic solid and gaseous biomass fuels are used in all scenarios. Nationally appropriate sustainability governance is required to minimise upstream emissions, align with circular and bioeconomy goals, and avoid increasing emissions in non-energy sectors.**

  Bioenergy supplies between 7-17% of heat demand by 2030 and a similar proportion in 2050. Sites that are sized below the mandatory EU threshold for sustainability governance use most of this energy. The resource assessments for the biomass feedstocks considered upstream greenhouse gas emissions and other important sustainability aspects, such as biodiversity. Hence, the resource estimates are based on specific good practice approaches to their cultivation, harvesting, collection and use. Energy crops grown in ways that depart from these assumptions risk causing environmental damage, leading to more greenhouse gas emissions in the land use and agricultural sectors. Nationally appropriate sustainability governance measures and other market development supports can help biomass supply chains contribute to their full potential and reduce the risk of emissions increases in other sectors.

- **The availability of sustainable biomethane links to land-use choices and requires increased productivity in the agricultural sector. It can be a competitive option if the costs and benefits are shared across all gas grid users or used off grid to displace oil.**

  The biomethane resource is estimated based on a detailed spatial analysis of the potential for red clover, grass silage and cattle slurry, and national estimates of food and other waste streams. The resource is an estimated 4-8% of current gas fuel use. It is lower than previous estimates for two reasons: grass silage feedstock is limited to environmentally suitable and accessible land, and farmer uptake is considered. If a reduction in the size of the national herd was to occur, the resource estimate would increase to 11%. Biomethane from waste is the lowest cost. Biomethane generated from sustainable slurry and grass silage mixes at the estimated volumes can also be competitive if the costs and benefits are shared across all gas customers or if it is transported directly to off-grid sites using more expensive and higher-carbon oil fuels.

- **Net-zero emission pathways with the lowest cumulative emissions use more electric heating technologies. Scenarios focused on a hydrogen gas grid have more cumulative emissions.**

  Green hydrogen is a potential large-scale solution for gas-based industry and power generation.[1] The potential hydrogen resource is much greater than Ireland's heat demand. However, it is unlikely to be commercially available until the 2030s, whereas electrification technologies are available now. This means that hydrogen plays a smaller role in rapid decarbonisation scenarios than electrification. The Climate Action Plan contains measures to build the regulatory infrastructure required to deploy hydrogen. Further effort to accelerate the commercial availability of competitively priced green hydrogen can enhance its role in the heat sector and allow the fuel to contribute to reducing emissions sooner.

- **A decarbonised electricity grid helps cut heat-related emissions.**

  The analysis shows that electricity use for heating has a prominent and increasing role in all the scenarios examined. Delivery of renewable capacity and supporting grid flexibility must stay ahead of demand growth to realise the benefits of emissions savings from this demand-side electrification of heat. The high-resolution electricity modelling shows power sector emissions reducing by about 50% by 2030 (relative to 2018), while demand increases by 61-69% in the same period - driven by data centre demand growth, heat electrification, and electric vehicles. The power sector modelling sees a total of 10-11 GW of wind capacity installed by 2030 to meet a renewable electricity percentage of at least 70% in all scenarios. The Climate Action Plan is targeting an 80% renewable electricity share by 2030, and the delivery of this will further enhance the heat sector savings shown here.

- **A timetable for fossil fuel phase-out in all sectors is needed as soon as possible to meet net zero by 2050.**

  The results indicate some consumers are likely to choose fossil fuel technologies, even with high-carbon and fossil fuel prices. This suggests that additional policy is needed to ensure full phase out. The following fossil fuel phase-out dates have been estimated based on technology lifetimes and other assumptions.

  No new fossil fuel appliances can be installed in buildings post-2035 if net-zero heating emission is to be reached by 2050.

  For industry, given longer technology lifetimes, this timeframe would either need to be sooner (circa 2025), or else unabated fossil fuel technologies will need to be retired before the end of their useful life. This analysis assumes the latter.

- **The future role of carbon capture, utilisation and storage (CCUS) and negative emission technologies (NETs) as part of economy-wide carbon neutrality is important to define.**

  The analysis identified several heat and power generation sites that are likely to be suitable for CCUS abatement. Should these sites switch to hydrogen or electricity, they would no longer need CCUS, and the potential for negative emissions would be reduced. However, cement and some other industries are likely to have limited abatement options for their process emissions. Should Ireland wish to have the option to deploy this technology over the long-term, then advanced planning around the role of CCUS and NETs such as bioenergy carbon capture and storage (BECCS) is needed. Decisions are required on where and how the clustering of sites and infrastructure might be achieved. The role of biomass fuels, where they come from, and in what quantities are also important factors to consider.

[1] In line with government policy, green hydrogen produced from renewable sources was the only hydrogen production route considered in the analysis.

Version Control

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February 2022	V1.0	Published
January 2023	V1.2	Updated Section 7.7 to reflect Table 5 being domestic and imported biogenic sources.

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1 Introduction and background

1.1 Introduction

Ireland's Climate Action legislation has set legal requirements for greenhouse gas emissions reductions. By 2030, emissions must be 51% less than in 2018, and by 2050, the Irish economy must be carbon neutral [1]. The carbon budgeting process described by the legislation will set out the annual emissions reduction trajectory and set greenhouse gas limits for each sector of the Irish economy to meet these targets. These limits represent Ireland's contribution to the principal aim of the Paris Agreement: to curb global temperature increases by restricting the total amount of greenhouse gas emissions emitted into the atmosphere.

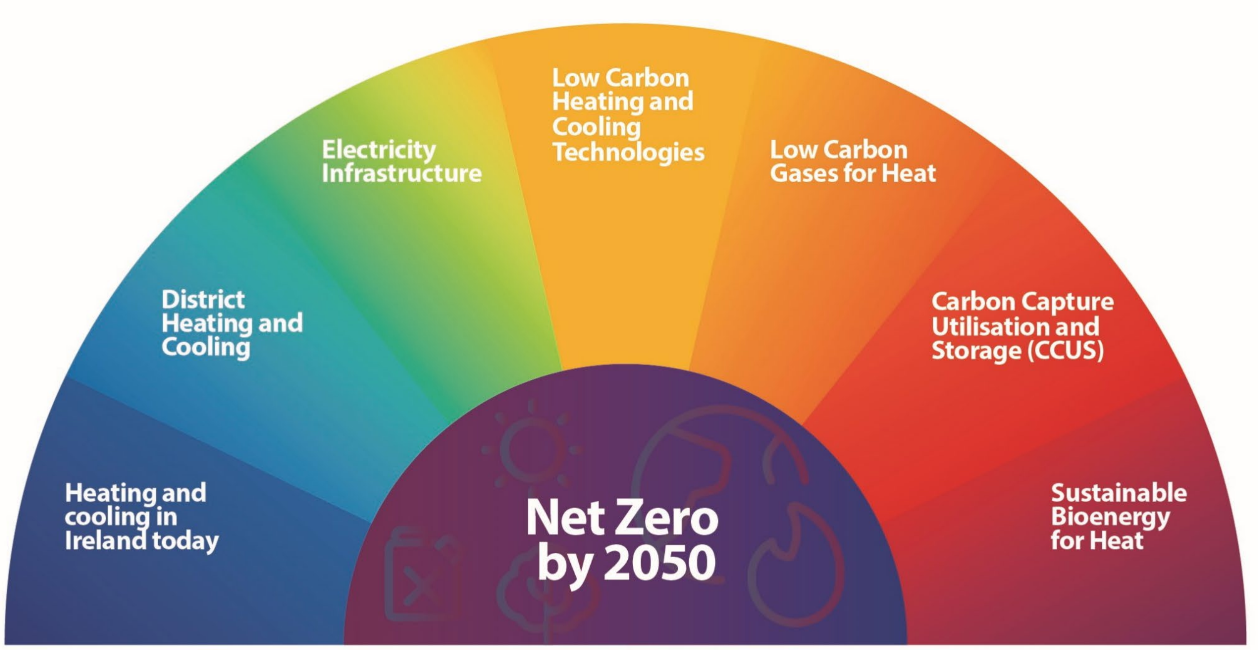
Reducing and removing heat energy emissions is a difficult challenge. Over the last decade, many businesses and households have added insulation, installed more efficient technology and used less solid fuel. However, annual emissions from energy used for heating have been on an increasing trend since 2014, when Ireland emerged from the effects of the global 2008 recession. Annual CO_2 emissions from energy used for heat (excluding electricity generation) were 12% higher in 2020 than in 2014; emissions from the residential sector were up 18%, services were up 13% and industry increased by 9%.

The Irish Government has published a Climate Action Plan that identifies actions to turn these trends around. The Plan, revised annually, specifies actions that aim to keep emissions within the carbon budget limits for each sector. The first Plan required under the Climate Legislation was published in late 2021 [2]. Several of the measures identified in the Plan rely on the outcome of the work of this National Heat Study to inform the policy ambition.

The National Heat Study aims to provide a rigorous and comprehensive analysis of the options to reduce CO_2 emissions associated with heating in Ireland. The Sustainable Energy Authority of Ireland (SEAI) commissioned Element Energy and Ricardo Energy and Environment to work with SEAI on the study. The project was carried out in close collaboration with the Department of the Environment, Climate and Communications. As well as contributing to national policy, the findings also supported 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.[2] The data, assumptions and outcomes of the National Heat Study are detailed in eight technical reports (*Figure 1*).[3] The project leaves SEAI with an enhanced modelling and analysis capability to continue providing insights and tackling further work. It has enabled a comprehensive stakeholder engagement that has delivered insights and information and started many new important discussions. It also provides a detailed set of data and information to inform broader research efforts in Ireland.

[2] SEAI, Element Energy and Ricardo Energy and Environment (2021) The Comprehensive Assessment of the potential for efficient heating and cooling in Ireland, report to the European Commission. DECC
[3] Available at SEAI webpage: https://www.seai.ie/data-and-insights/national-heat-study/

Figure 1: Framework of reports



This report is the last in a series of eight reports produced as outputs from the National Heat Study. It uses the detailed background data and analysis for the seven technical reports and details the outcome of the energy system modelling of five scenarios. It explores the challenges faced by consumers in different sectors, the technology options they favour and what they cost to deploy and run. It also evaluates the annual and cumulative emissions of the scenarios and highlights policy actions and decisions that can support net-zero pathways.

1.2 Objectives

The objectives of this work on the pathways to decarbonise heating demand in Ireland are to:

1. Explore a diverse set of potential heat decarbonisation pathways (across viable fuel options) to reach net zero by 2050.
2. Present sectoral, building-level and/or subsector-level insights across potential key decarbonisation driving factors (such as electrification and heat pumps, hydrogen, biomethane, solid biomass etc.) geared towards policymakers, stakeholders and the public.
3. Provide insight into the potential impacts for government policy to 2030 and to 2050.
4. Quantify the relative costs of carbon abatement via energy-efficiency measures and low-carbon heating systems across Ireland's heating sectors.

The goals of the National Heat Study are to:

1. Develop a detailed understanding of heating and cooling demand in the residential, services and industrial sectors and the opportunities to reduce this.
2. Assess the potential and costs of the low-carbon technologies and fuels that can decarbonise heat generation.
3. Explore pathways for technology and fuel deployment to reach net zero by 2050.
4. Understand the perspectives of various stakeholders and seek to include data and information from a wide range of sources in the analysis.
5. Provide detailed analysis and useful insights to policymakers, stakeholders and the public.
6. Build modelling capacity to support further work on policy development.

1.3 Structure of this report

This report follows the subsequent structure:

- **Overview of Ireland's existing climate action targets and policies** – Ireland's 2021 Climate Action Plan (CAP) and Low Carbon Development Bill [1].
- **Approach to decarbonisation pathways** – methodology and key modelling assumptions taken to develop the different decarbonisation scenario pathways to 2030 and to 2050.
- **Key scenario results** – temporal pathways for annual CO_2 emissions.
- **Key policy challenges** – assessment of the policy effort levels needed to drive uptake of low carbon technologies to meet CAP targets
- **Consumer journey** – contextualised overview of possible key archetype journeys to decarbonisation per sector and their drivers.
- **Technology and fuel considerations** – breakdown of heating demand throughout the decarbonisation process, heat pump uptake, district heating, key fuel switching (electricity, hydrogen, biomethane, biomass) and CCUS.
- **Costs of decarbonisation** – an overview of the cost benefit analysis (CBA) outcomes.
- **Energy system context** – district heating, electricity system modelling, hydrogen supply and usage, and biomethane supply and usage.
- **Key actions** – summary of key trends and observations.

2 Overview of Ireland's existing climate action targets and policies

Ireland has enacted legally binding climate targets to achieve net zero by 2050 and cut emissions by 51% from 2018 levels by 2030 [1]. These align with Ireland's commitments under the Paris Agreement. They also align with the European Union's objectives to cut emissions by 55% from1990 levels by 2030 and achieve climate neutrality by 2050.

The Climate Change Advisory Council recently published proposed carbon budgets for the Irish economy consistent with these requirements [4]. The Council was established under Ireland's Climate Action legislation, and it has an independent expert advisory role. The Council has proposed budget limits for two five-year periods. From 2021 to 2025, the budget limit proposes capping total carbon emissions at 295 $MtCO_{2eq}$, representing an average annual reduction of 4.8%. From 2026 to 2030, the proposed budget is set at 200 $MtCO_{2eq.}$ equivalent to an 8.3% annual emissions reduction. In line with the Climate Legislation, the Oireachtas considers the Council's proposals for approval, and the Government divides the overall carbon budgets into sectoral emissions ceilings.

Part of the amended Climate Action legislation requires Ireland to produce a Climate Action Plan and update it annually. The first required under the legislation was published in October 2021 [2]. The Plan sets out a roadmap to deliver the legally binding targets. The 2021 publication updates and supersedes the 2019 Climate Action Plan [5]. Subsequent plans from 2022 will incorporate the sectoral emissions ceilings that come from the carbon budgeting process.

The National Development Plan 2021-2030, also published in October 2021, sets out a ten-year capital expenditure framework to fund the plans [6]. The Plan is supported by a climate and environmental assessment and incorporates an investment package of €165 billion across all sectors of the economy.

Ireland has reporting and emissions reduction requirements arising from EU legislation. Ireland's 2020 National Energy and Climate Plan (NECP) was prepared according to the Governance Regulation to incorporate all planned policies and measures identified up to the end of 2019 [8]. The NECP aims to reduce emissions that fall outside of the EU Emissions Trading Scheme (ETS) by 30% from 2005 levels by 2030. Non-ETS emissions include the transport, residential, services, some industry and manufacturing, agriculture and land use and waste sectors. The national legislation described above goes beyond the ambition outlined in the NECP.

The Energy Efficiency Directive also includes a requirement for each EU member state to complete a National Comprehensive Assessment for the potential of energy-efficient heating and cooling every five years [9]. Ireland submitted the first cycle of reports to the EU Commission in 2015 [10]. The second cycle includes an updated methodology that focuses more on renewable sources of energy to satisfy heating and cooling demands [11]. The Department of the Environment, Climate and Communications (DECC) asked SEAI to carry out the analysis supporting the submission.

Ireland had mixed success in reaching its 2020 renewable energy share targets. It achieved its transport target and just missed its electricity target. However, the significant shortfall to the renewable heat target meant Ireland missed its overall renewable energy share target of 16% [12]. Working closely with DECC, SEAI developed a scope of work that meets the needs of the National Comprehensive Assessment method and puts in place a foundational evidence base to help policymakers address the challenges facing the Irish heat sector.

Ireland's second National Comprehensive Assessment report was published in August 2021.[4] This report, the seven supporting technical reports, background data and modelling capacity are available to support the Climate Action process in Ireland. The National Heat Study provides insights into the opportunities and challenges that the emissions reduction trajectories present to the homes, businesses, public sector organisations and industries that use heat energy. The scenario analysis looks at how current policy helps address these challenges and where more action is needed.

[4] SEAI, Element Energy and Ricardo Energy and Environment (2021) The Comprehensive Assessment of the potential for efficient heating and cooling in Ireland, report to the European Commission. DECC

3 Approach to decarbonisation pathways

This section details the modelling approach to developing viable decarbonisation pathways for Ireland to 2050. It covers an overview of the archetype and scenario modelling, the key modelling factors and assumptions, and a high-level overview of the five scenarios developed.

3.1 Archetype and scenario modelling

The scenario-based analysis allows for a detailed investigation of a diverse set of possible outcomes or futures. This study leverages key bottom-up evidence-based data, in-depth stakeholder engagement, and sector knowledge to develop different pathways to a net-zero future. In turn, this allows stakeholders to review key aspects of each possible pathway, identify risks, challenge current thinking, aid planning, enable decision-making (including investment considerations) and understand the potential impact and results of key drivers along the way.

SEAI's National Energy Modelling Framework (NEMF) is a tool that examines aspects such as the variation in technology readiness, technical suitability, cost data and performance data to assess various scenarios (including potential decarbonisation paths) in Ireland. The archetype model developed for the NEMF contains data on over 680 individual heat demand archetypes, representing a combination of physical and consumer attributes, which in turn provide a detailed description of demand in residential, services, and industry sectors. The NEMF maps technology suitability and performance to each archetype. The model contains representations of bioenergy and hydrogen resources and fuel supply chains, and an infrastructure module that calculates the costs of infrastructure deployment linked to technology uptake. The model uses this techno-economic data to generate payback and lifetime cost estimates for the various technology options available, accounting for policy incentives, taxes and regulations. This payback and lifetime cost information, along with other data on consumer decision-making behaviour, allows a deeper understanding of understand how much uptake may result in various scenarios and in response to policy measures. We use this simulation approach in this analysis to examine what impact a given set of policy measures can have on the energy system.

Where technology deployment is based on centralised decisions, we account for these outside of the consumer decision-making framework. This includes industrial carbon capture, utilisation and storage (CCUS) and district heating. Industrial sites utilising CCUS/BECCS abatement technologies are not considered for other abatement technologies (such as electrification or hydrogen) and we calculated relevant parameters for their decarbonisation off model. This includes an analysis conducted for CCUS technologies separately for each of the industrial sectors. The analysis has assessed energy and fuel requirements, costs, and emissions reductions from CO_2 capture on the relevant industrial sites, including costs related to CO_2 transport and storage. We took a similar approach for the allocation of district heating, determined by a geographical approach based on linear heat density. We integrated the results of this analysis with the NEMF to assign district heating to relevant proportions of archetypes, where most cost effective in the highest heat-dense areas. These aspects are then integrated into the NEMF outputs and fed into the results of the wider project.

3.2 Modelled scenarios

Each of the alternative net-zero scenarios seeks to reflect a plausible pathway to a decarbonised heat supply by 2050. They consider a variety of relevant factors including, but not limited to, the speed of transition, energy efficiency, heat networks, gas grid extent, CCUS/BECCS deployment, renewables deployment, the evolution of the power system, transport system considerations and a mix of low-carbon technology uptake. The *High Electrification* and *Decarbonised Gas* scenarios intend to capture two different pathways to net zero by 2050. The *Balanced* scenario aims at a middle ground between these two. It accounts for a technology mix that is cost effective, feasible to implement and aims to minimise the risk of over-dependence on any single technology. As the most ambitious scenario, *Rapid Progress* reflects a future where decarbonisation measures are achieved earlier. It explores how soon net zero in the heat sector might be achievable and what the challenges are, paying particular attention to the period to 2030.

Figure 2 summarises the scenarios.

Figure 2: High-level details of the Baseline and net-zero scenarios

Relationship to Overall Modelling

Scenario	Details
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

Further to the above, *Table 1* provides some of the key modelled parameters and how they vary by scenario and sector. For example, it illustrates how some technologies or fuels are modelled to only certain scenarios (such as high-temperature (High T) heat pumps in *High Electrification*; no hydrogen in the *Baseline*) or how some sectors see limited options for technology uptake to fit the scenario narrative (such as in *Decarbonised Gas*, buildings on the gas network only switch to hydrogen boilers and hybrid heat pumps (HHPs) with hydrogen).

Table 1: Modelled high-level scenario narrative parameter variation

Scenario	Residential / Commerical / Public	Industry
Baseline	• Low amounts (all) biomethane blended into the grid • No H_2 techs. • No in-fill gas grid connections • Solid biomass & bioliquid available off grid (elec. CF cannot switch to this) • No elec. resistive/storage on-grid	• No CCS/BECCS • 25-year tech. lifetime • ETS carbon price target of €150 by 2050
High Electrification	• Low amounts (all) biomethane blended into the grid • No uptake of gas-based technologies • Solid biomass & bioliquid available off grid (elec. CF cannot switch to this) • High T HPs offered only in this scenario • DH to supply limited to 30% of heating demand in buildings (resi/com/pub)	• Limited power BECCS / industry • Limited fossil CCS • All suitable HPs are taken up if feasible and cost effective • Cost-effective electrification prioritised • All others choose most cost effective • No biomethane; allow biomass / H_2 • 15-year tech. lifetime (early retire) • ETS CO_2 price target of €350 by 2050
Decarbonised Gas	• Biomethane blended into grid until 2035 • Gas and in-fill buildings take up H_2 boilers and HHP • H_2 blended in grid from 2030, piecewise conversion from 2035 • Solid biomass & bioliquid available off grid (elec. CF cannot switch to this) • No elec. resistive/storage on-grid • Biomethane avail. off grid post-2035 for com/pub • DH to supply limited to 10% of heating demand in buildings (resi/com/pub)	• High power BECCS, medium in Industry • High fossil CCS/H2GTs in power • Cost-effective hydrogen prioritised • All other choose most cost effective • Biomethane available off grid post-2035 • 15-year tech. lifetime (early retire) • ETS CO_2 price target of €350 by 2050
Balanced	• Biomethane blended into grid until 2035 • H_2 not available for in-fill gas grid connections • On-gas move to H_2 boiler, HHP or HP • Solid biomass & bioliquid available off grid (elec. CF cannot switch to this) • No elec. resistive/storage on-grid • Biomethane avail. off grid post-2035 for com/pub • DH to supply limited to 20% of heating demand in buildings (resi/com/pub)	• Medium power BECCS / cement • CCS in core large industrial sites and some in power • Cost-effective uptake; no enforced priority • Biomethane available off grid post-2035 • 15-year tech. lifetime (early retire) • ETS CO_2 price target of €350 by 2050
Rapid Progress	• Biomethane prioritised for industry • Gas distribution grid decommissioned in 2040s • Solid biomass & bioliquid available off grid (elec. CF cannot switch to this) • No elec. resistive/storage on-grid • DH to supply limited to30% of heating demand in buildings (resi/com/pub)	• Medium power BECCS, high in industry • High fossil CCS, limited in power • Cost-effective biomethane prioritised; when resource runs out, move to electrification • On-gas can uptake biomethane and off-gas can take up biomass • 15-year tech. lifetime (early retire) • ETS CO_2 price target of €350 by 2050

Resi = residential; com = commercial; pub = public; DH = district heating; CF = counterfactual; elec = electrical; tech = technology; HP = heat pump; HHP = hybrid heat pump; CCS = carbon capture and storage; BECCS = bioenergy carbon capture and storage.

3.3 Key factors and assumptions

This subsection details some of the main modelling drivers and assumptions. It covers the use of counterfactual (that is, the existing system used in a building or technology archetype) fossil-based phase-out dates, outlines how consumer decision-making is modelled and illustrates how the existing stock of counterfactual heating technologies is turned over. As this work leverages SEAI's comprehensive NEMF, this list is non-exhaustive; rather, it highlights the key relevant factors to allow for easier interpretation of the modelling results.

3.3.1 Fossil fuel/counterfactual phase-out date

The fossil fuel phase-out date or counterfactual phase-out date (used interchangeably within this report) is the date from which fossil-based counterfactual heating system technologies are no longer available for consumers when they decide to replace their existing heat technology.

Table 2 outlines the modelled fossil-based counterfactual phase-out dates. The latest phase-out date is set leaving a minimum of 15 years until 2050. The aim of this is to ensure that the vast majority of existing stock will turn over and so be required to replace existing heating systems at end of life by 2050 (at the latest) with a low-carbon alternative. A 15-year lifetime is assumed for heating systems, based on known lifetimes of existing counterfactual and low-carbon technologies (for more information, see the Low Carbon Heating and Cooling Technologies report[5] in this National Heat Study). However, it is important to note that, in reality, imposing a phase-out may cause consumers to attempt to prolong existing fossil lifetimes. This type of consumer behaviour needs to be included in considering effective policy, and the scenario results should be interpreted as representing a well-designed policy context that avoids this.

A fossil-based counterfactual phase-out is one method of effectively enforcing the transition to net-zero emissions by 2050. However, it is only one tool that can be utilised. As described elsewhere in this report, additional policy and support need to play a key role in ensuring this is an economically feasible, timely and just transition. Apart from this type of phase-out date, other levers available to policy makers include (but are not limited to) grants, loans, marketing campaigns, carbon taxes, and mandatory annual services linked to certification for continued use.

Table 2: Modelled fossil-based counterfactual phase-out dates, by sector and scenario

Sector	Baseline	Balanced, High Electrification, Decarbonised Gas	Rapid Progress
Public	No phase-out timeline	2031	2026
Residential		2032	2027
Commercial		2034	2029
Industry		2035	2030
Agriculture		2035	2030

3.3.2 Consumer decision-making

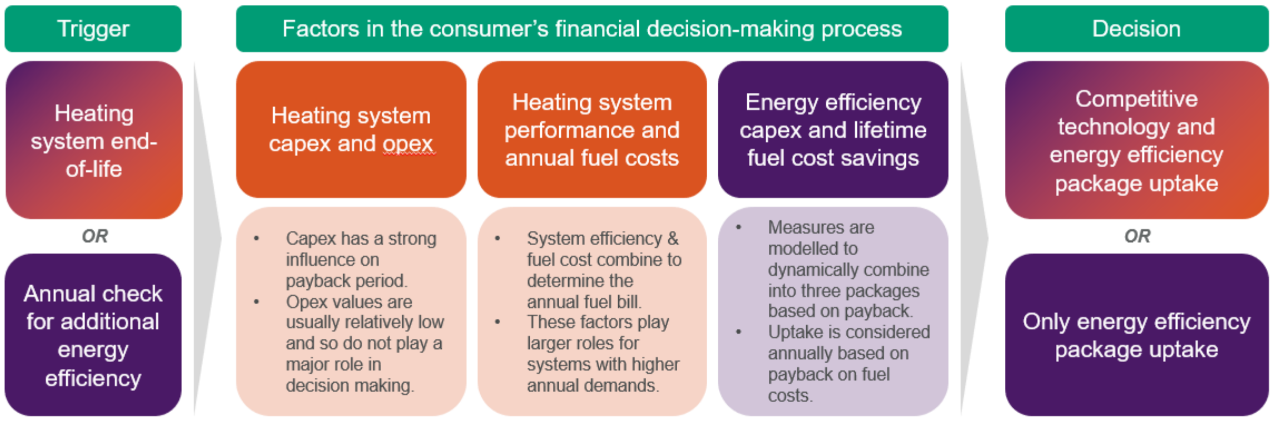
The modelled technology and energy-efficiency uptake process simulate consumer decision-making. It accounts for various consumer approaches to energy-related decisions that happen in different sectors and circumstances. Engagement levels, budget limits and payback preferences are specified and used to simulate consumer uptake and policy impact out to the early 2030s. Further out in the time horizon, post-fossil fuel phase-out, the lifetime

[5] SEAI, 'Low Carbon Heating and Cooling Technologies'. 2022 [Online]. Available: www.seai.ie/publications/Low-Carbon-Heating-and-Cooling-Technologies.pdf

costs of competing technologies in individual archetypes are used to determine uptake based on the lowest-cost option for the archetype.

Figure 3 visually highlights the key modelled triggers and factors that consumers consider when determining uptake. They undertake the same process before and after the fossil fuel phase-out date. However, prior to the phase-out date, aware and engaged consumers focus on their immediate financial situation and utilise payback period as the key decisive variable to determine cost effectiveness. This mindset shifts to a more long-term view once fossil-based options are no longer available; consumers then switch to deciding based on total lifetime cost as they consider joint options for investment into low-carbon heating systems and energy efficiency.

Figure 3: High-level overview of modelled consumer decision-making process – triggers, factors and decision



Notes:

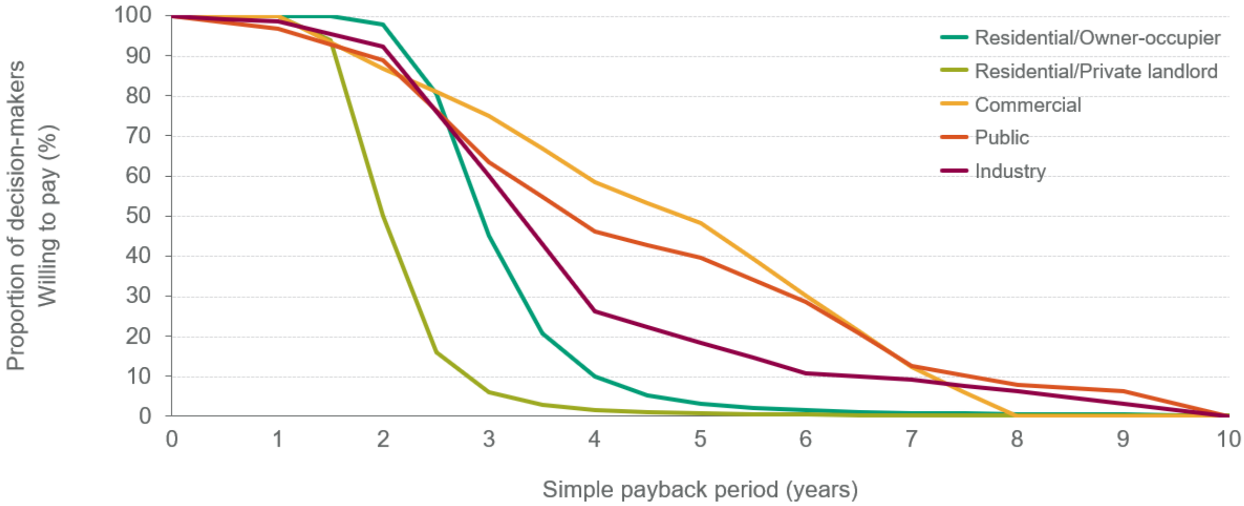
- Orange blocks represent items associated with heating system decision-making.
- Purple blocks represent items associated with energy-efficiency decision-making.
- Purple-to-orange gradient blocks represent items jointly associated with energy efficiency and heating system decision-making.

Consumers are split into engagement levels (such as laggards, consumers who think they have done enough, consumers who need more information, and aware and engaged consumers) and budget levels (that is, with or without capital budget limits). We derive the information for these splits from the results of a prior survey of consumer behaviour in the commercial sector in Ireland [13] deployed as part of a previous SEAI study [14] and prior retrofit research [6] [15] [1][16] [2][17] [3][18] [19]. Aware and engaged consumers with no budgetary restrictions are more likely to embark upon the process to switch to a low-carbon technology and uptake further energy efficiency [13]. These consumers are the early adopters that have the potential to make the switch to decarbonised heat within the next five to ten years. Less engaged consumers are modelled to start making decisions at later points in time, with the slowest uptakers only being included in the decision-making stock in 2030 (in the *Baseline*) or 2025 (in the decarbonised scenarios). Policy efforts focusing on behavioural, informational and regulatory interventions can help raise the engagement levels of less engaged consumers. For the budget-restricted consumers, they are modelled to have varying levels of capital constraints, with different budget levels based on the subsector and other archetype-based factors. Budget-constrained consumers need low-cost finance and other financial solutions to help these consumers adopt a low-carbon option.

The key costs considered in the modelled decision-making process are the capital expenditure (capex; including cost of technology, installation of the technology, and the cost of any transitional components if necessary, such as required radiator upgrades), operational expenditure (opex) and fuel costs (or savings). Financial policy incentives, such as upfront grants or ongoing operational support, are simulated. These act to lower consumer investment or operating costs and improve the relative costs of low-carbon technologies and energy efficiency, leading to shorter payback times. The number of hours that space and water heating systems need in buildings is generally higher in the winter months. Therefore, the initial capital and installation costs are more influential on payback periods and consumer choices in these circumstances. In contrast, for many industrial sites and heating systems and some buildings with high load factors, fuel costs are a larger proportion of total heating costs, and so the price of fuel is a more dominant factor in consumer decision-making. When making decisions based on total lifetime cost, the annual costs start to play an increased role, but typically, the initial investment still dominates, especially in buildings with lower load factors.

For the payback period calculation, the model calculates the proportion of uptake modelled using the willingness-to-pay curves derived for each sector. *Figure 4* below illustrates the five different willingness-to-pay curves used in the uptake modelling, one for each sector, apart from residential, where there is a distinction between tenure types. These curves are based on consumer surveys of consumer preferences in the residential, commercial, public and industrial sectors [13] [14].

Figure 4: Willingness-to-pay curves used in the uptake model



Based on this study's findings, consumers generally find it more cost effective to take up energy-efficiency measures when they also need to switch to a low-carbon heating system. This can be because improvement to the operating efficiency of the low-carbon heating system usually needs energy-efficiency improvements. Consumers can also see the benefits of reduced energy demand (via the installation of fabric measures) more clearly when considering the potential for lowered heating system sizing, the efficiency gains of a new system and the lowered fuel costs of a new system. If not considered cost effective, consumers can opt not to take up new energy-efficiency measures (that is, 'do nothing').

3.3.3 Stock turnover rate

For the purposes for this report, stock turnover is the replacement of counterfactual heating systems (turnover) by buildings or industrial sites (stock). We use a 15-year stock turnover rate for all consumers as this generally matches observed technology lifetimes for both existing counterfactual heating technologies and low-carbon heating technologies.[6] *Figure 5* presents an example timeline of how this stock turnover is modelled for the specific case of residential oil boilers. The critical point here is that chosen heating system options become locked in for 15 years and follow a cycle of turnover based on heating system end of life. A maximum of two turnovers is available to facilitate decarbonisation prior to 2050 – unless policy enables consumers to retire existing technologies before the end of their life.

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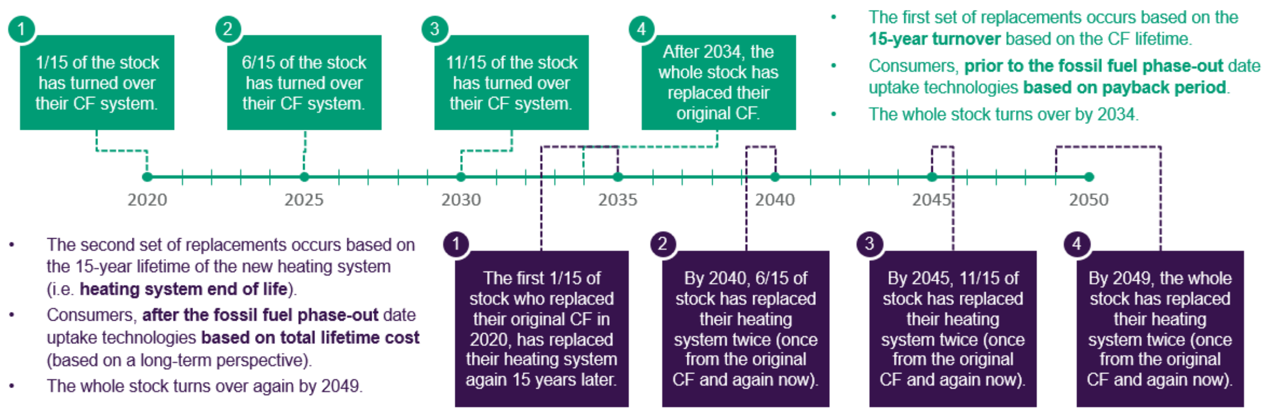
[6] SEAI, 'Low Carbon Heating and Cooling Technologies'. 2022 [Online]. Available: www.seai.ie/publications/Low-Carbon-Heating-and-Cooling-Technologies.pdf

Figure 5: Illustrative example of the modelled stock turnover rate timeline for residential oil boilers



Note:

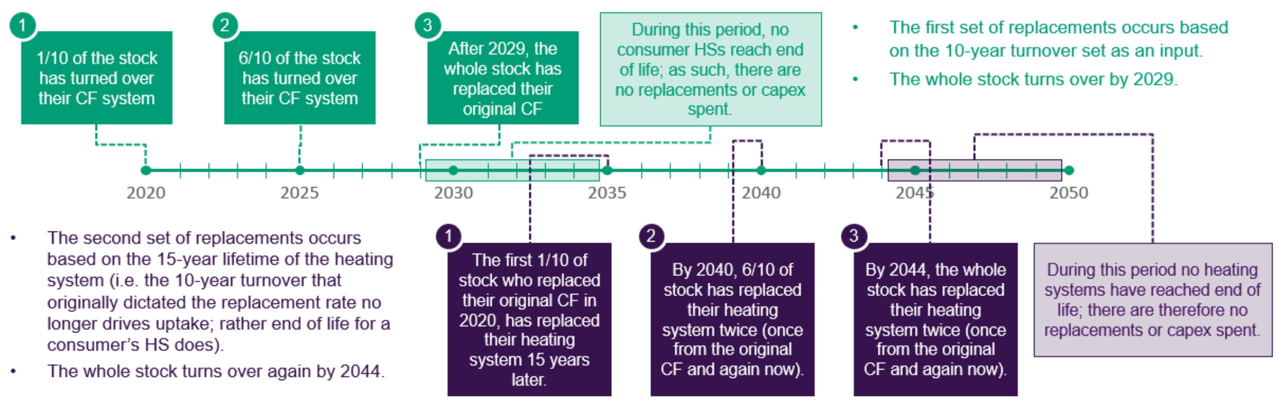
- CF = counterfactual

As *Figure 5* shows, the first set of replacements (represented by the green boxes) occurs on a 15-year turnover timeline based on the lifetime of the counterfactual heating system (in this case, residential oil boilers), with one-fifteenth of the stock being replaced each year. Before the fossil fuel phase-out date, consumers decide to take up technologies (fossil-based or renewable/low carbon) based on payback period. By 2034, the whole stock turns over. The second set of replacements occurs based on the assumed 15-year lifetime of the new heating system (that is, as before, the heating system end of life). Consumers, after the fossil fuel phase-out date, uptake low-carbon technologies based on total lifetime cost (based on a long-term perspective). By 2049, the whole stock turns over again.

A key shift away from the methodology above is modelled in the *Rapid Progress* scenario, where residential counterfactual gas and oil boilers are set to have an initial ten-year turnover rate. This contrasts with the other scenarios where they have a 15-year turnover (based on their lifetime). This lower turnover rate in *Rapid Progress* is consistent with either a significant, widespread shift in consumer engagement with climate change and the climate-related issues regarding fossil fuel heating, or sustained policy support encouraging the high rollout of low-carbon heating options and promoting the early replacement of heating systems for all consumers.

Figure 6 below presents an example timeline of how this stock turnover is modelled. The purpose of this change in assumption is to model what could be possible in *Rapid Progress* to more quickly decarbonise this large proportion of stock (and emissions).

Figure 6: Illustrative example of the modelled stock turnover rate timeline for residential gas and oil boilers in the Rapid Progress scenario



Note:

- CF = counterfactual

In this scenario, the first set of replacements occurs based on the set ten-year turnover rate. The whole stock turns over by 2029. The second set of replacements initiates based on the 15-year lifetime of the heating system (that is, similar to other scenarios). Therefore, the second set of turnover begins from 2035, 15 years after 2020. This is because the ten-year turnover that originally dictated the replacement rate no longer drives future uptake; rather, this is driven by the heating system's end of life. As such, the whole stock turns over again by 2044.

Due to the ten-year turnover rate not aligning with the 15-year lifetime of the heating system being replaced, the model results do not see an evenly distributed yearly pattern by consumers. For example, there are drops in uptake during the period after the whole stock turns over (such as after the first ten years) but before the lifetime of the heating systems purchased by the first one-tenth of consumers ends (such as 2030-2034). We see a similar pattern after the second turnover from 2045-2049. In reality a turnover rate of ten years is likely to be an average over several years, and hence the overall uptake profile is likely to be more smoothly distributed.

3.3.4 Cost of carbon

One key lever to increase the rate of decarbonisation of heat is to apply a cost to all CO_2 emissions resulting from use of fuels. This price (typically expressed as a € per tonne of CO_2 emissions) can by policy and provides a financial incentive for consumers to switch to heating systems with fewer emissions per unit of heat provided. The model used three main separate carbon prices across the modelled scenarios: a low-carbon price for ETS sites; a high-carbon price for ETS sites; and a carbon price for non-ETS sites. *Figure 7* shows the time variation of these three carbon prices.

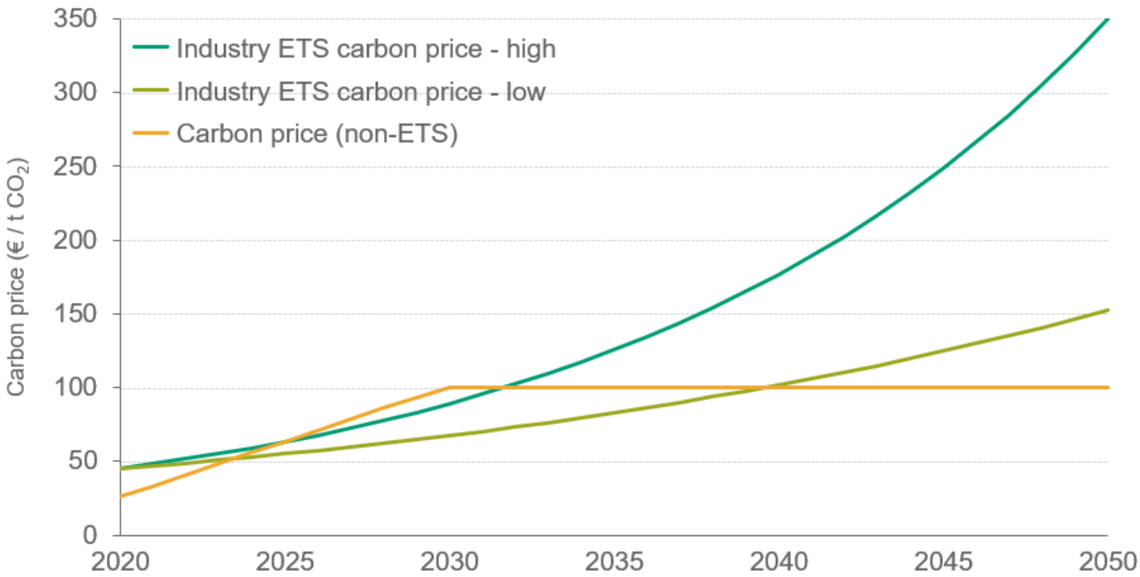


Figure 7: The cost of carbon used in the modelled scenarios; two different ETS carbon prices are shown, and the carbon price used for non-ETS archetypes

The lower industry ETS carbon price, paid by sites included in the ETS scheme in the industry sector in the *Baseline* scenario, increases from just below €50 / tonne CO_2 in 2020 to €153 / tonne CO_2 in 2050, in line with the EU Reference scenario 2020 [20]. To accelerate decarbonisation in the industrial sector in the decarbonisation scenarios, the model used a higher industry ETS carbon price; this carbon price increases from just below €50 / tonne CO_2 in 2020 to €350 / tonne CO_2 in 2050, in line with analysis from the European Commission supporting COM(2018) 773 [21]. For more information regarding the industrial sites included in the ETS scheme, please see the Heating and Cooling in Ireland Today report[7] in this National Heat Study.

The model also applied a carbon price to non-ETS consumers. This price increases from €26 / tonne CO_2 in 2020 to €100 / tonne CO_2 in 2030, and then stays constant to 2050. This carbon price is based on three carbon taxes in Ireland – the Natural Gas Carbon Tax (NGCT) [22], the Solid Fuel Carbon Tax (SFCT) [23] and the Mineral Oil Carbon Tax (MOT) [24] – with a full nominal rate of €33.50 per tCO_2 equivalent in 2020. The model assumes an increase of €7.5 per tCO_2 equivalent per year until 2030, after which the price stays at €100 per tCO_2 equivalent.

[7] SEAI, 'Heating and cooling in Ireland today'. 2022 [Online]. Available: www.seai.ie/publications/Heating-and-cooling-in-Ireland-today.pdf

3.4 Macro-economic projections calibration

The growth in industrial demand for heating in Ireland is projected forward using the SEAI National Energy Projections scenarios. These are underpinned by a macro-economic perspective of recent relationships between energy use, economic growth, energy prices and energy policies. These relationships provide the basis for projecting how energy use trends may develop into the future following changes in fossil fuel prices, economic growth and high-level cross-cutting energy policies. The Economic and Social Research Institute (ESRI) provided the macro-economic data based on their latest economic outlook from the COSMO (Core Structural Model of the Irish economy) and I3E (Ireland Energy, Economy and Environment) models.

The macro-economic projections used to calibrate industry energy demand for the heat project anticipate strong growth in energy demand over the period to 2050. This growth is in line with projected economic growth in the Irish economy and an assumed low global energy price environment. As a small and open economy, Ireland is strongly susceptible to both the changes to the macro-economic environment and the energy demand changes that accompany global energy prices. In particular, industry energy demand can notably fluctuate depending on the global energy price assumptions.

The 'low' energy prices underpinning the heat project industry demand are from the UK's Department for Business, Energy & Industrial Strategy (BEIS) 2019 Fossil Fuel Price Assumption (last updated on 6 February 2020) [25]. The ESRI model results referenced projects growth of just over 3.2% per annum overall economic activity measured by real gross domestic product (GDP).

4 Key scenario results

4.1 CO_2 emissions trajectories

All the scenarios analysed, except for the *Baseline*, meet net zero by 2050, but some do so with less cumulative emissions than others. *Figure 8* shows the annual CO_2 emissions trajectory for each scenario, and *Figure 9* shows the cumulative CO_2 emissions from 2020 to 2050 for each scenario. The CO_2 emissions come from all fuels used to generate heat energy, including electricity. The scenarios that rely on technologies that are commercially available now perform best as they reduce CO_2 emissions sooner. The scenarios that wait for promising technologies to mature have more CO_2 emissions in the near term and thus have higher cumulative emissions over the period to 2050.

The *Balanced*, *High Electrification* and *Rapid Progress* scenarios reduce emissions quicker. The availability of low-carbon technologies for heat that are powered by low-carbon electricity in these scenarios is a primary driver of this outcome. The large-scale deployment of heat networks (district heating) and the use of bioenergy also make significant contributions to the CO_2 reduction trends. The *Decarbonised Gas* scenario relies more heavily on green hydrogen and biomethane to achieve net zero. Green hydrogen is unlikely to be available at scale to consumers until the 2030s, and the biomethane resource is not large enough to drive emissions reductions sooner. The *Decarbonised Gas* scenario takes longer to make deep cuts in emissions than the other scenarios. Emissions savings from CCUS technology, including bioenergy CCUS, deployed from the mid-2030s cannot offset this. These factors mean the *Decarbonised Gas* scenario achieves net zero by reducing emissions later than the other scenarios. This delay causes the scenario to have the highest cumulative emissions overall.

Figure 8: Annual carbon dioxide emissions ($MtCO_2$ / annum) by scenario, 2020-2050

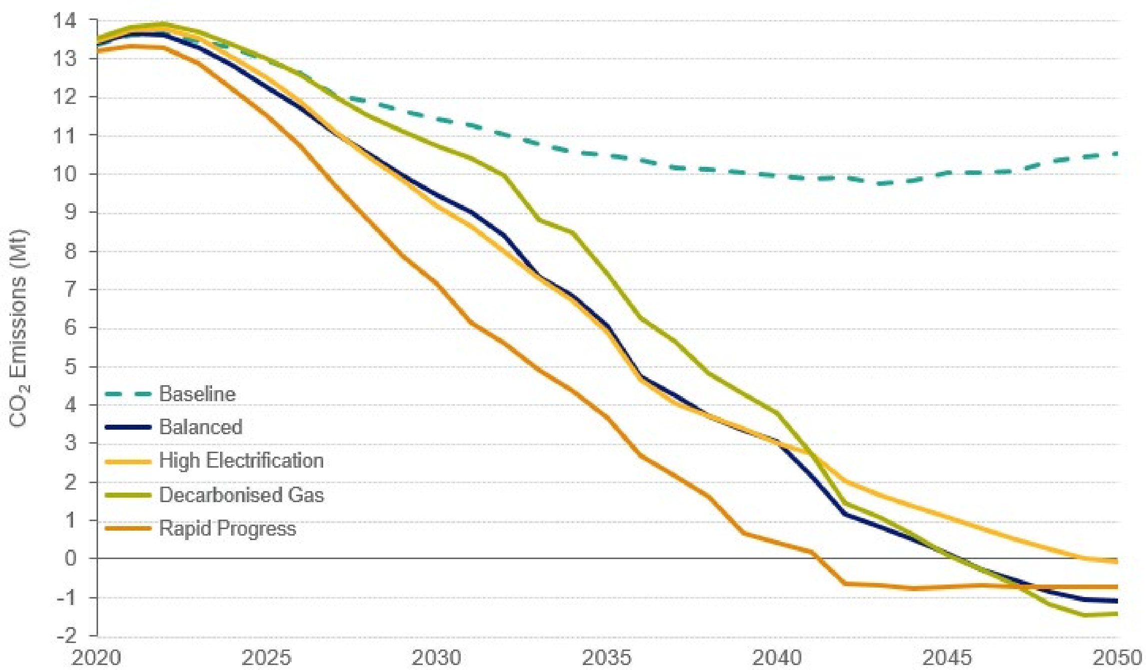
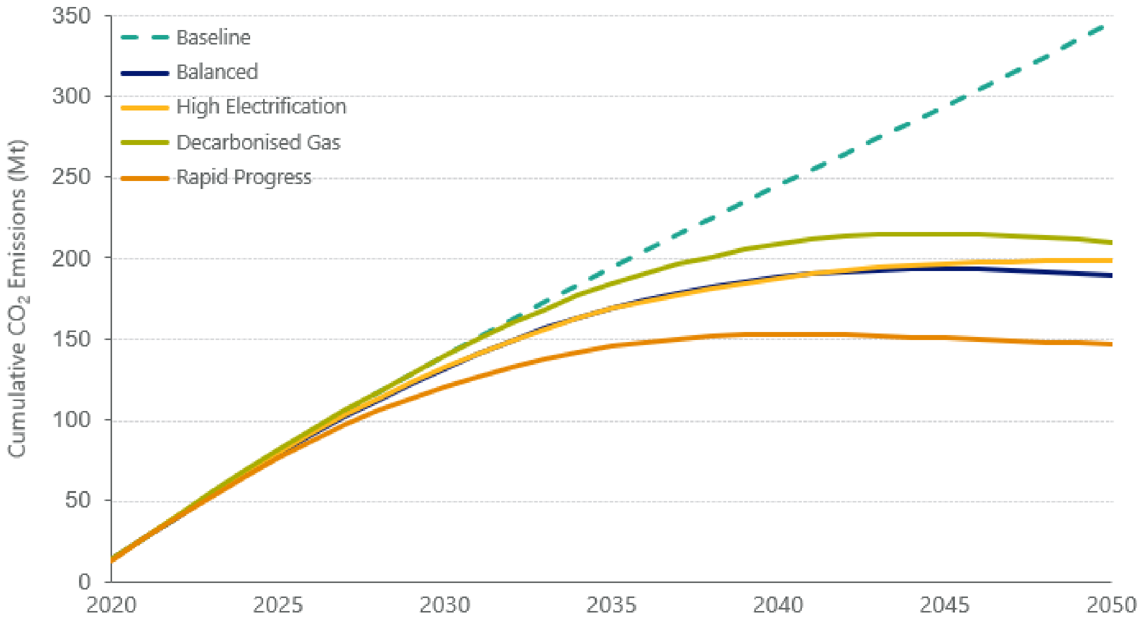


Figure 9: Cumulative carbon dioxide emissions ($MtCO_2$ since 2020) by scenario, 2020-2050



4.2 Carbon budgets and trajectory to 2030

As *Figure 8* and *Figure 9* show, an early effort reduces total cumulative emissions. The recent carbon budget proposals put forward by the Climate Change Advisory Council set economy-wide budgets across two periods to 2030 [4]. From 2021 to 2025, the budget limit proposes capping total carbon emissions at 295 $MtCO_{2eq}$, representing an average annual reduction of 4.8%. From 2026 to 2030, the Council set the proposed budget at 200 $MtCO_{2eq.}$ equivalent to an 8.3% annual emissions reduction.

The National Heat Study scenarios present insights into the challenges ahead and the efforts required to stay within carbon budget limits. While the budget limits are not applied to energy end uses, heat energy use contributes to emissions in several economic sectors where emissions ceilings will apply. Comparing the emissions trajectories from the scenarios to the carbon budget limits provides insights into the challenge ahead for those sectors that generate a large proportion of their emissions through the use of heat energy.

Figure 10 shows how the scenarios examined in the National Heat Study compare to the carbon budget proposals. The emissions shown include all CO_2 directly released from the combustion of fossil fuels, the indirect CO_2 emissions related to electricity use as a source for heat and the upstream emissions from the use of bioenergy. All scenarios fall short of emissions limits in the first budget period. Only the *Rapid Progress* scenario meets the reduction threshold in the second. No scenario stays under the implied overall emissions limit from 2021 to 2030.

The *Baseline* scenario falls short of the Climate Action Plan sub-targets because the policy measures[8] do not achieve sufficient low-carbon technology and fuel uptake. The *Balanced, High Electrification* and *Decarbonised Gas* scenarios apply additional policy effort to achieve the Climate Action Plan activity level targets. For targets such as retrofitting 500,000 homes to a building energy rating (BER) of at least B2 and the installation of 600,000 heat pumps requires significant additional incentives. Meeting these, however, does not ensure a sufficient reduction in CO_2 emissions to meet cuts targeted in the Climate Action legislation.

[8] In the *Baseline,* current policy measures are those from the Climate Action Plan 2019 that had existing implementing measures such as funding and planning or legislation in place by the end of 2020.

Figure 10: Cumulative emissions ($MtCO_2$) since 2020 by scenario, relative to carbon budget targets in 2025 and 2030

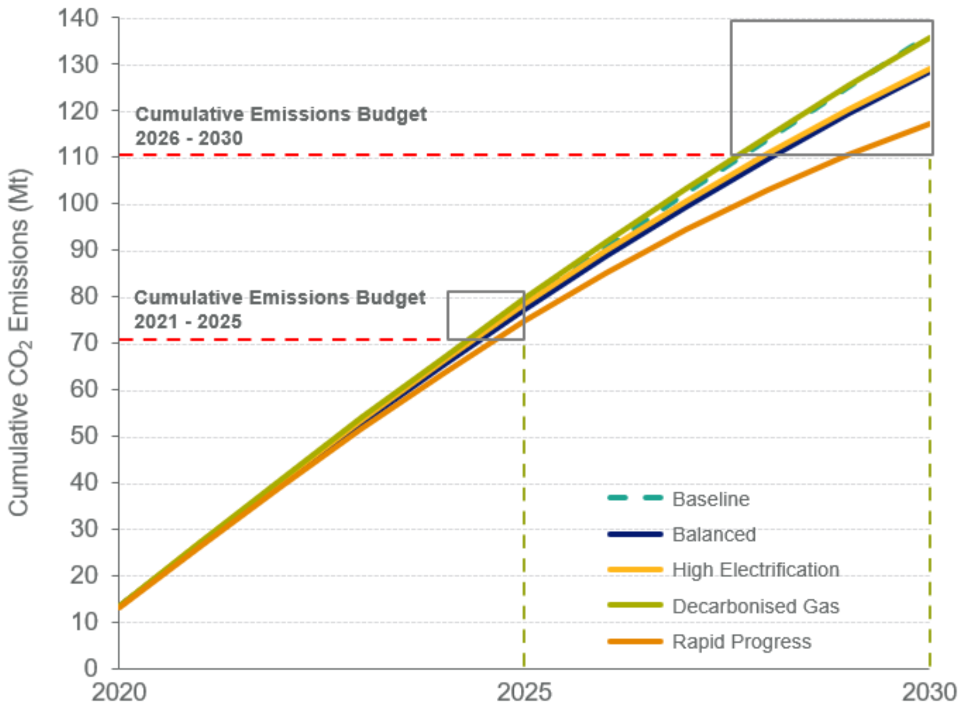
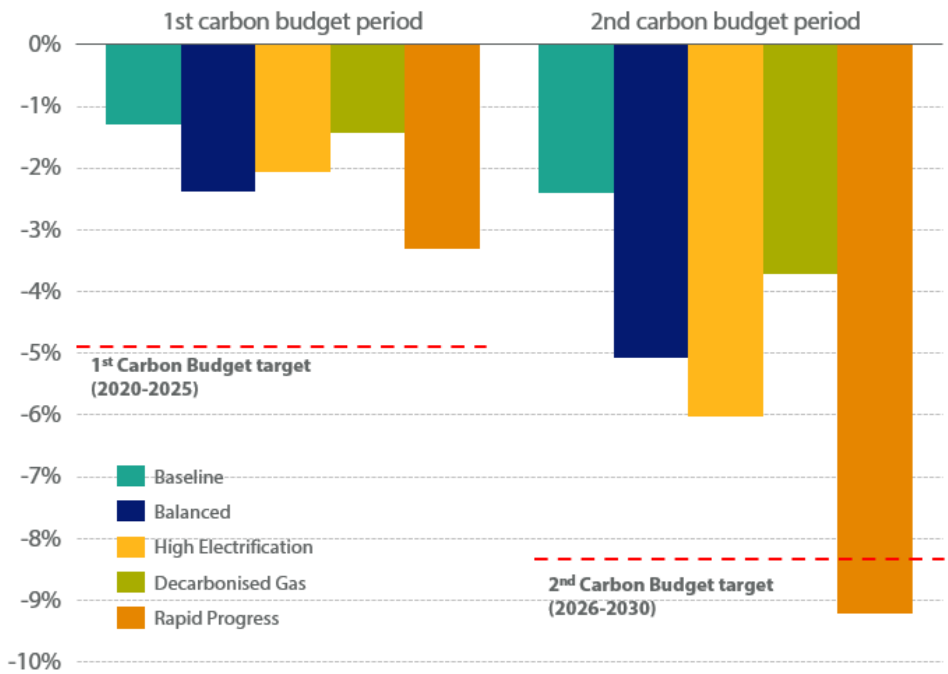


Figure 11: Average annual emissions reductions (% compared to the previous year's emissions) by scenario, compared to carbon budget targets



5 Key policy challenges

5.1 Policy effort and Climate Action Plan targets

The Climate Action Plan [2] targets that apply to heat decarbonisation focus on the buildings sector. These targets have a policy incentive or regulation that supports their delivery in most cases. The supporting policy incentives drive uptake by closing the investment cost gap. The policy support available for industry provides ongoing payments for some technologies and upfront support for others.[9]

The *Baseline* scenario captures the impact of current policy. The modelling approach represents how consumers make decisions. It simulates how various incentives, regulations and other policies, fuel prices and other factors influence their energy-related investment decisions. The results suggest that existing policy measures fall short of delivering the uptake targeted in the Climate Action Plan and that more effort is required.

To quantify this additional effort, we used the model to simulate how consumers are likely to react to increases in policy incentives. This approach provides some insight into the challenges facing policymakers. It does not represent a recommendation nor an optimal approach to the detailed policy design required to achieve the uptake targeted. Further in-depth policy and dedicated policy design work is required to establish the specific approach. *Table 3* details how the scenarios perform against some key activity targets published in the 2021 Climate Action Plan.

We have used a subjective scale of 1-3 to categorise and illustrate the additional policy effort required to meet the Climate Action Plan targets:

1. **An extension of existing policy.** These involve actions, such as the extension of timelines or budgets. They also include activities that increase consumer awareness of the options available and other measures that simplify and reduce the hassle of making a technology switch. Examples include: communication campaigns, demonstration events and pilots; simplifying administration, design, installation and financing processes; training programmes; and awareness-raising for heat technology supply chains. Technology and installation standards also have an essential role in supporting quality and market development.

2. **Additional policy effort.** These policies include actions that improve the payback of energy efficiency and renewable energy technologies, such as via increased grant rates. This category may also have some light regulation that requires consumers to consider the sustainable energy options available at key decision points, such as when replacing a boiler. Other policy support that may also have a play include renewable and low-carbon heat obligations and measures that allow the value of providing electricity grid flexibility to be captured by end users.

3. **Stretch policies.** These policies may include regulations and requirements aimed at bringing forward more consumer decisions, sharing the cost of decarbonisation across all energy sources emitting CO_2 and making the cost of installing fossil options less attractive. Examples may include: roadmaps with hard dates for the phase-out of fossil fuels; minimum standards for energy efficiency and carbon intensity of products and buildings; and transferring some decarbonisation cost from the electricity sector to oil, gas and coal.

Table 3: Progress towards key Climate Action Plan targets in the Baseline and Balanced scenarios

Objective / Target	Baseline ('BAU') scenario vs target	Balanced scenario vs target	Level of additional policy effort required
500,000 homes retrofitted to a B2 BER or cost-optimal or carbon equivalent by 2030.	~15% of target - residential buildings are reaching BER B2 between 2020 & 2030.	~80% of target - residential buildings are getting BER B2 between 2020 & 2030.	2-3
600,000 heat pumps to be installed over 2021-2030 (of which 400,000 in existing buildings).	~25% of the target for heat pumps in existing buildings.	~92% of the target for heat pump uptake in existing buildings met.	2-3

[9] More detail available in the assumptions document that accompanies this report. Available: www.seai.ie/data-and-insights/national-heat-study/Net-Zero-by-2050/ .

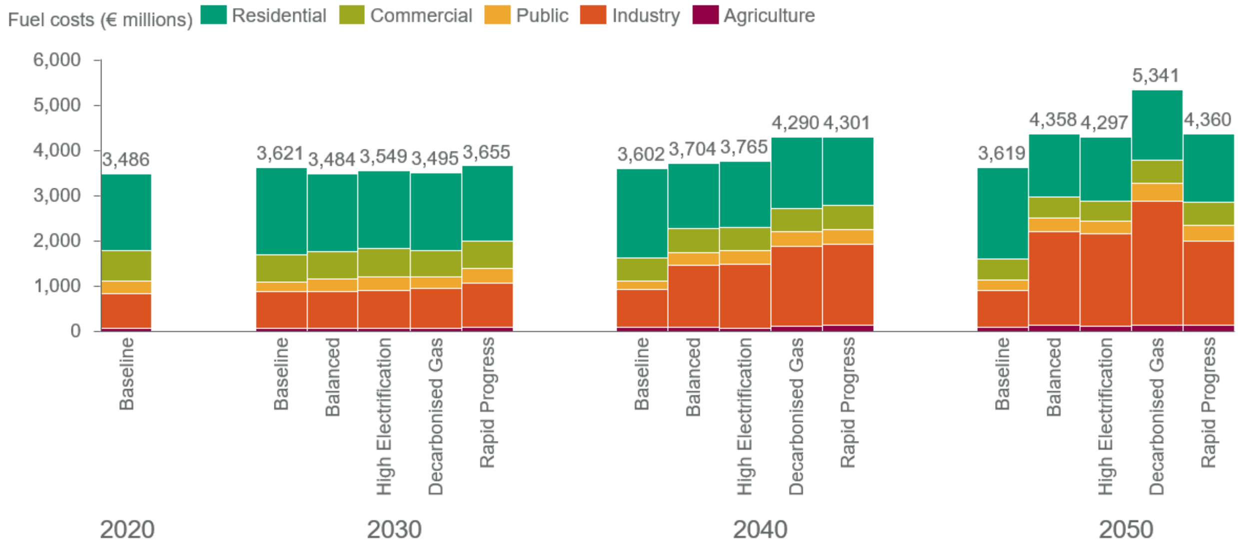
Objective / Target	Baseline ('BAU') scenario vs target	Balanced scenario vs target	Level of additional policy effort required
	Target met for heat pumps in new builds.	Target met for heat pumps in new builds.	
Public bodies' Climate Action Roadmaps will target at least a 50% overall contribution from renewable space heating (heat pumps, biomass & district heating) by 2030. The target contribution for the school sector will be confirmed as part of the School Sector Climate Action Roadmap.	~43% of public sector buildings' space heating demand is met by renewable technologies by 2030.	~57% of public sector buildings' space heating demand is met by renewable technologies by 2030.	2-3
Deploy zero-carbon heating to meet the needs of 50,000 typical commercial buildings by 2030.	~29,000 commercial sector buildings have installed zero-carbon heating systems by 2030.	~44,000 commercial sector buildings have installed zero-carbon heating systems by 2030.	2
Additional 1,600 GWh of renewable heat via SSRH.	~80% of target	Target achieved	1
1.6 TWh of indigenous biomethane by 2030.	Target achieved	130% of target achieved	2
Deliver up to 2.7 TWh of district heating, with the exact level to be informed by the outcome of the National Heat Study.	The target of 0.12 GWh from 2019 Climate Action Plan achieved.	~ Target achieved	2

5.2 Policy challenges for the industry sector and the buildings sector

The differences in circumstances and decision-making approaches across the sectors are the basis for the various challenges faced by policymakers aiming to achieve economy-wide decarbonisation. For the buildings sector, tackling the challenges of upfront cost and new technology adoption is paramount. Finding ways to reduce the ongoing fuel costs of renewable and low-carbon options is key in the industry sector.

Figure 12 shows the annual fuel costs for all sectors, including the residential and industrial sectors. Households see a long-term benefit from decarbonisation investment, with all scenarios showing lower household fuel spend than in the *Baseline* across the whole time period. The higher efficiency of low-carbon technologies means they need less fuel to satisfy their heating demand. Conversely, the industry sector faces cost and competitiveness challenges in decarbonisation scenarios. Currently, most industry sectors use low-cost gas to meet their heat demand needs. While low carbon and renewable technologies are available now, these are generally more expensive to run, as are those technologies that become available later. Green hydrogen is approximately twice as expensive as fossil gas, and the efficiency penalty from carbon capture technologies also increases costs.

Figure 12: Total annual ongoing fuel costs for key milestone years (€$_{2019}$ million)



6 Consumer journey

The ability to view decarbonisation of the entire heat sector in Ireland through the impact on specific consumer groups is one strength of the modelling conducted for this National Heat Study. This section contextualises the model results through a range of example archetypes that provide insights into consumer decisions. This focus on the consumer perspective of decarbonisation can support policy design by determining the effectiveness of policy support at aiding decarbonisation in specific targeted groups.

Table 4 below outlines the four archetypes selected and detailed throughout this section. It also notes their significance in terms of relative proportions of stock, heating demand and emissions. CO_2 emissions include direct emissions from fuels combusted to produce heat and the emissions associated with electricity generation, which is calculated as the grid average for the year in which they are generated. For example, residential oil boilers in detached homes make up a large proportion of sectoral heating demand (40%) and a slightly lower proportion of sectoral emissions (39%). This is due to oil's relatively high emissions factor, but also illustrates that other heating fuels may have higher per unit emissions (such as solid mineral fuel heating).

Table 4: Overview of selected archetypes and their relative sectoral significance in terms of stock, heating demand and emissions

Sector	Archetype	Proportion of sectoral stock (or pieces of industrial equipment)	Proportion of sectoral heating demand	Proportion of sectoral CO_2 emissions
Residential	Detached home with oil boiler	27%	40%	39%
Commercial	Retail business with electric heating	40%	16%	16%
Public	Healthcare facility with gas boiler	22%	35%	28%
Industry	Food and drink production site with gas heating	4%	16%	17%

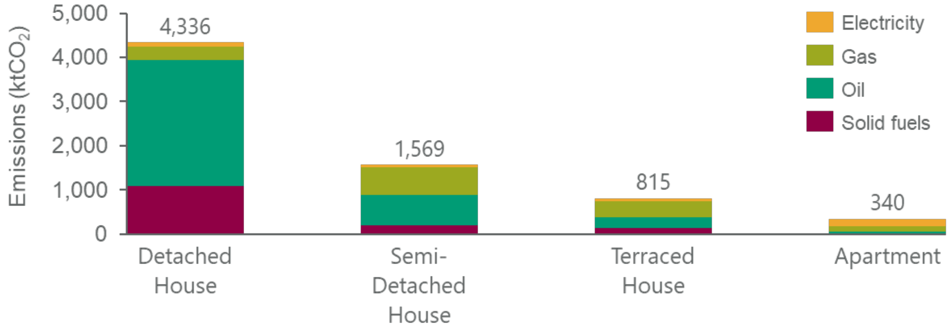
The selected archetypes correspond to significant segments of the Irish stock (in terms of the relatively high percentage of either stock, heating demand or emissions), which we chose as exemplars to illustrate possible pathways for decarbonisation. However, it should be noted that they are not representative of the diverse spectrum of the Irish heating demand and 680 of these achetypes are includedin the modelling analysis.

6.1 Residential

6.1.1 Background

In the Irish residential sector, 62% of fuel-based emissions for heating come from detached houses, which make up 42% of the residential stock. Of those detached homes, there are approximately 474,000 with oil boilers. Most emissions (65%) from Irish detached houses result from the consumption of oil. This archetype is responsible for 39% of total residential heating emissions. *Figure 13* below shows the breakdown of the residential emissions, by fuel and building type, illustrating the importance of detached oil boiler homes in terms of their proportion of CO_2 emissions.

Figure 13: Total emissions ($ktCO_2$) from fuel use for heating in the residential sector, by building and fuel types



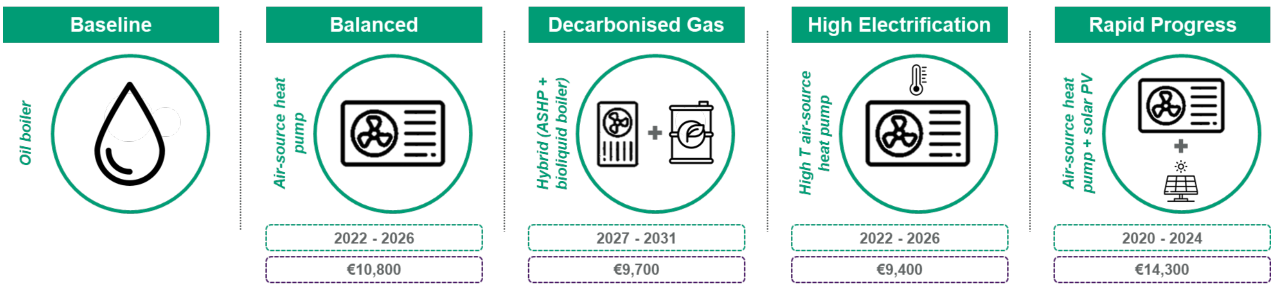
Additionally, when considering a path to full decarbonisation, it is important to consider many households in Ireland rely on secondary fossil-based heating systems – stoves, ranges and open fires. To fully decarbonise, renewable heating systems must replace both primary and secondary heating systems. Secondary heating is a potential area for further exploration as it is out of scope for this study, which is focusing on a household's primary heating system.

6.1.2 Decarbonisation pathways - example archetype

For large detached houses with oil boilers, consumers in the decarbonised scenarios generally leverage grant support to switch to various heat pump options, including possible hybrid configurations. The specific heat pump chosen by this consumer group in each decarbonised scenario depends on the relative cost of fuels (including electricity and hydrogen) in each scenario, as well as availability in given scenarios; for example, high-temperature (High T) air source heat pumps (ASHPs) are only available in the *High Electrification* scenario, and hydrogen is only made available for consumers with counterfactual oil boilers in the *Decarbonised Gas* scenario.

Figure 14 illustrates the range of renewable heating systems, the period over which this archetype would likely take up this technology and the required capital expenditure to decarbonise.

Figure 14: Most financially favourable renewable heating system options to decarbonise a large (138 m² average floor area) residential house with a counterfactual oil boiler, by scenario



Notes:

- Costs noted above are total system costs and any additional transition costs (such as radiator upgrades if necessary), without accounting for potential grant support.
- Green outlined dates represent a possible timeframe for when a significant proportion of this archetype may choose to uptake to the stated renewable energy system (note, this will be different for all consumers, particularly in relation to the counterfactual system lifetime).
- Purple outlined cost figures represent the total capex required to switch to the new low-carbon heating system, including any cost-beneficial energy efficiency and transition costs.

As noted above, in the *Baseline* scenario, this archetype chooses to replace their existing system with a new oil boiler (€3,300) at each 15-year decision point with no further energy-efficiency uptake. This archetype already has energy efficiency equivalent to a BER rating of D1-D2, and the available energy-efficiency measures do not have good enough payback periods for the consumer to install. As a result, this large residential house's oil boiler continues to emit ~5.5 tCO_2/yr.

In the decarbonised scenarios, prior to any support, the new heat pump configuration system capex is a multiple of three times higher than that of the counterfactual. To support the consumer to overcome this initial payment differential, financial support via a grant (such as covering 60-80% of the system capex) is modelled to be available until 2032 to switch to a heat pump or a hybrid heat pump system. With this available incentive, prior to 2032, many homes within (and similar to) this archetype take advantage of this support and switch to an ASHP or hybrid heat pump system. In the *Balanced* scenario, a pure ASHP is taken up. In *Decarbonised Gas*, where hybrids are available, a bioliquid boiler hybrid is chosen. In *High Electrification*, this archetype takes advantage of the option to take up a high-temperature ASHP and forgoes the need for a radiator upgrade. Lastly, in *Rapid Progress*, an ASHP with solar panels (PV) is chosen to offset some future electricity costs via the connected PV panels. Though not shown above (as this archetype switches prior to the phase-out date, post 2032), solid biomass boilers and pure ASHPs become the most cost-effective option, dependent on the fuel costs and availability by scenario.

By switching to the new heating system, consumers take advantage of the annual fuel cost drop of 55-70%. This reduction in fuel costs provides the long-term incentive for consumers' willingness to pay (that is correlates to a sufficiently low payback period). Additionally, though this archetype has limited potential for further cost-effective energy-efficiency uptake; it utilises available support modelled (such as 60% energy efficiency grant) and installs €1,700 worth of fabric energy-efficiency measures to further upgrade their already partially insulated home prior to 2032, decreasing the home's heating demand by 6.3%.

Though this archetype's journey is not unique, there is a wide range of options and relative costs in the residential sector. For example, to decarbonise, capex values range from €6,000-30,000 in the residential sector, with €12,000 being the approximate average for a detached oil boiler house. A significant drop in annual fuel costs offsets the upfront heat pump expenditure. The result is a payback period from one to five years relative to the re-purchase and operation of the existing fossil-based system. Particularly for consumers who see longer payback period options, the modelled upfront grant is a substantial aid to reduce the barrier to entry and lower the payback period into a range where a consumer is more likely to switch (that is, has a higher willingness to pay) and significant uptake across the stock is evident.

6.1.3 Energy-efficiency uptake

Heat demand determines the amount of energy that heat generation technologies must provide. It is a key driver of amounts of fuel usage and CO_2 emissions. Heat demand rises in each scenario. The deployment of energy-efficiency measures in all sectors is not enough to offset the impact of economic and population growth. Additional demand comes from the estimated new builds needed to house an expanding population in the residential sector, which increase from approximately 22,000 new homes per year in 2021 to around 40,000 in 2030 and 56,000 in 2050. New buildings also drive demand growth in the services sector. In the industry sector, heat demand grows in line with the projections for increased economic activity.

The deployment of energy-efficiency technologies in the net-zero decarbonisation scenarios reduces demand relative to the *Baseline*. The residential sector sees the most considerable difference by deploying fabric measures that reduce the heat lost from dwellings. But even in this sector, anticipated savings are modest. Heat demand is 3% more in the *Baseline* scenario than in the net-zero scenarios by 2030 and 5% more by 2050.

Consumers are likely to choose fabric measures that are low cost and low hassle. *Figure 15* and *Figure 16* depict the uptake of fabric measures and their resulting savings, respectively. As seen, cavity wall insulation, draught proofing, and roof insulation are taken up in the highest quantities, as they are the most cost effective (low cost, low payback period) measures. In contrast, solid wall insulation and high-efficiency window glazing have higher payback periods and are not widely deployed; however, it should be noted that though deployment of solid wall insulation is relatively low, there is a significant saving seen from archetypes who do find it cost effective to install. Additionally, due to the even higher payback period of floor insulation, uptake of this measure is not seen. Lastly, both graphs illustrate the higher uptake of low-cost measures in the early years. This uptake slows as time goes on as the most cost-effective installations are performed first, and the remaining options become less cost effective.

Figure 15: Cumulative uptake of fabric measures in the residential sector (Balanced scenario, number of installed measures)

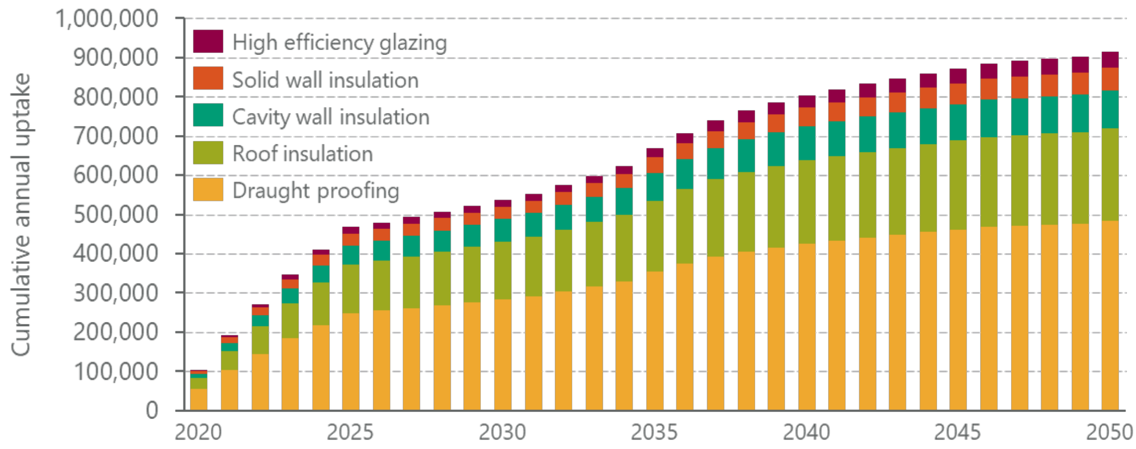
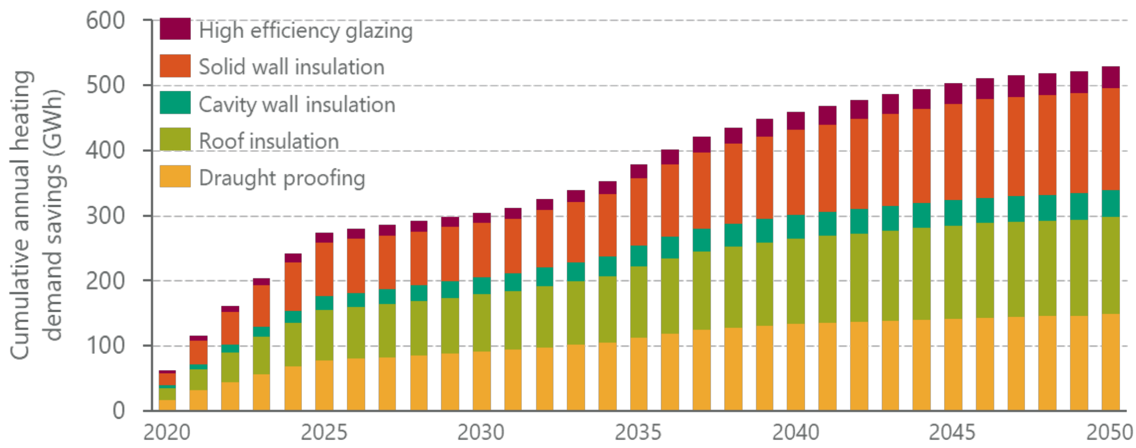


Figure 16: Cumulative heating demand savings due to fabric measure uptake in the residential sector (Balanced scenario, GWh)



Once a household installs a low-carbon heat supply option, fabric measures do not deliver additional end-use CO_2 emissions reductions. However, in many cases, it makes sense for a household to improve the building fabric to reduce their fuel bills, improve their comfort levels or improve the suitability of their building for low-temperature heating technologies such as heat pumps. The modelling shows that 83% of the residential building stock install some form of heat demand reduction measure in the *Balanced* scenario. As *Figure 15* and *Figure 16* illustrate, consumers are likely to favour the low-cost and low-hassle fabric measures such as draught proofing, roof insulation and cavity wall insulation, with other measures seeing limited uptake.

There are several underlying reasons for this:

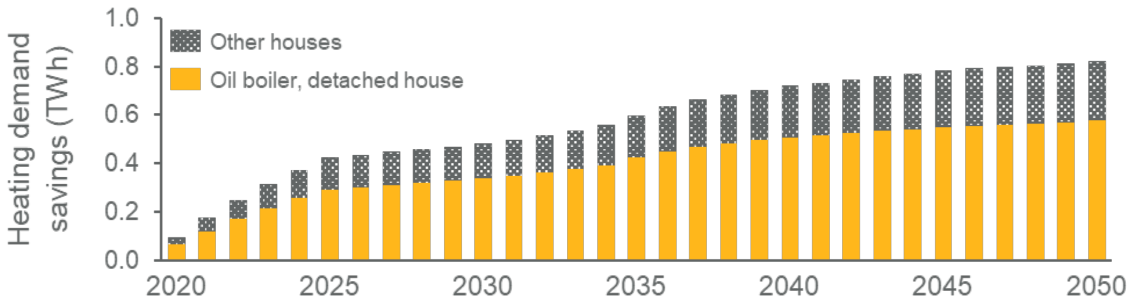
- Other measures, such as solid wall insulation, floor insulation and high-efficiency glazing, can bring significant energy savings, but are also the most expensive, have the longest payback periods (see Section 7.1) and have the most consumer hassle associated with their installation. These factors limit uptake among consumers.
- The NEMF calculates the energy saving and the cost of installing each measure in each building archetype. It also includes estimates of how much potential exists in the building stock for each fabric upgrade type. This data allows a calculation of payback periods and total energy reduction potentials for each measure in each building archetype. Section 7.1 describes the average payback periods for all detached dwellings heated by oil in 2030. The most expensive measures have significantly longer payback periods and are prohibitively long for many building archetypes.
- The potential theoretical savings for energy-efficient measures are unlikely to be seen due to the rebound effect. Most people have a limited budget for heating. Occupants of dwellings with poor thermal performance tend to underheat their dwellings to limit their fuel costs. Upon improving the thermal

performance of a dwelling, the occupants can benefit from either reduced energy use and fuel costs, or higher indoor temperatures, or a combination of both. Though increased internal temperatures bring significant health and wellbeing benefits, a significant portion of the theoretical energy and CO_2 savings are often not realised. This is the rebound effect, and we account for it in the modelling presented here.

- In the NEMF, the payback calculations for each fabric measure include the value of the comfort to the consumer. The energy used in an upgraded dwelling to increase the internal temperature, rather than being taken as a reduction in energy demand with the associated fuel bill savings, is included as a notional economic benefit seen by the occupants. This approach captures the value of comfort and wellbeing seen by the bill payer. However, the actual realised energy savings in ***Error! Reference source not found.***(and associated CO_2 emissions savings) are adjusted down to account for the comfort-taking rebound.
- In most circumstances, the payback periods for fabric measures become longer when more efficient, lower running cost heat sources are installed. For example, the running costs of a well-installed heat pump are lower than for an oil boiler in most circumstances. Therefore, after a dwelling has a heat pump installed, the payback period for adding additional demand reduction measures increases, all else being equal. Should fuel prices rise in the future for the low-carbon heating options, then the deep fabric upgrades are likely to become more financially attractive to building occupants.

Relating these energy savings back to the chosen residential detached house with an oil boiler, *Figure 17* illustrates the importance of energy-efficiency measures in detached oil homes with oil boilers, relative to all other dwelling types. By 2050, 70% of the total heating demand savings in the residential sector (in the *Balanced* scenario) are seen in detached houses with oil boilers. This implies that (i) there is higher potential for savings in these archetypes considering the higher existing heating demands, and (ii) it may be more cost effective for these types of houses to install fabric efficiency measures.

Figure 17: Residential heat demand savings from energy-efficiency uptake (Balanced scenario, TWh)



6.1.4 Heating demand and emissions

Though energy efficiency is a key tool to reduce existing heating demand and lower the need for the existing heat supply, to fully decarbonise the Irish heat sector, a full stock switch to low-carbon heating systems is necessary. To support this switch, energy efficiency will play a key role in enabling buildings to be eligible for the uptake of certain technologies (such as heat pumps). Additionally, energy efficiency brings wider benefits (such as economic, health and comfort). However, historically, residential heating demand has outpaced savings from efficiency improvements for several reasons, including the growth in existing stock, lowering reliance on secondary heating fuels and a rise in disposable income. This trend, besides anticipated economic growth trends and the development of new building stock (albeit largely adopting heat pumps), is expected to result in continued growth in residential heating demand, as seen in *Figure 18*. This highlights the central role of technology and fuel switching to the decarbonisation objective.

Figure 18: Residential heating demand breakdown, by fuel and technology (Balanced, TWh)

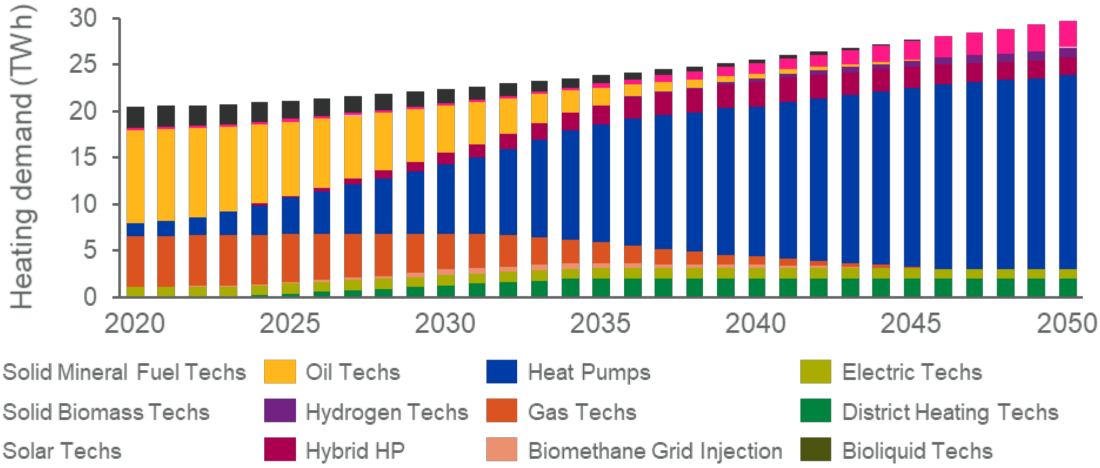
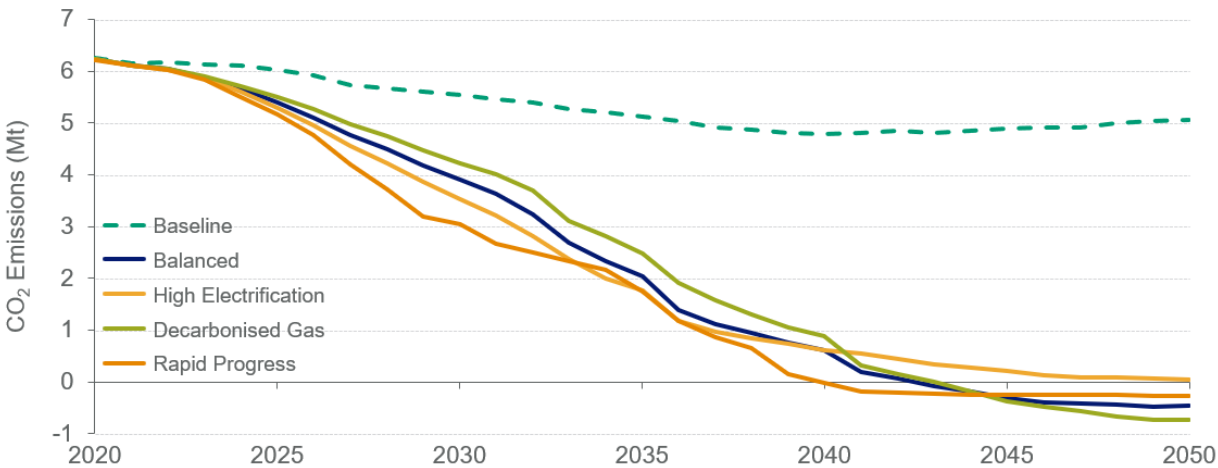


Figure 19 below illustrates the scenario pathways for the annual CO_2 emissions in the residential sector. These are aligned with technology and fuel switching trends (as seen for the *Balanced* scenario in *Figure 18*). While the *Baseline* scenario sees minor decreases from existing levels, the other scenarios all achieve full decarbonisation by 2050. The deployment of bioenergy carbon capture and storage in the power sector in some scenarios results in a negative emissions intensity for electricity by the mid-2040s. Section 9.2 has further details on the power system modelling and scenario assumptions.

Figure 19: Residential direct heating emissions (all scenarios, annual $MtCO_2$)



Rapid Progress achieves full decarbonisation first, having the steepest reduction trends amongst all scenarios. In this scenario, we assume residential houses with oil and gas boilers will turnover their counterfactual heating systems after ten years, rather than the full 15 years seen in other scenarios. Due to the higher turnover rate in this scenario, 10% of the fossil fuel technologies are turned over each year, representing 73% of the residential emissions. The earlier turnover of these systems, and the assumption that residential consumers can only choose a low-carbon technology option from 2027, results in a sharper drop in emissions from the onset in the *Rapid Progress* scenario. For further detail regarding how the stock turns over in this scenario, see section 3.3.3.

The other decarbonised scenarios follow a pattern where *High Electrification* is the second quickest, followed by *Balanced* and finally *Decarbonised Gas*. This relative speed of decarbonisation is primarily driven by the level of hydrogen and deployment of district heating present in each scenario. Hydrogen, because it is not available until 2035 (or 2030 in *Rapid Progress* scenario), delays the decarbonisation of the residential segments of stock poised to switch over to this fuel. This is driven by the modelled assumptions to fit the scenario narrative; for example, the modelling prevents residential customers, who are on the gas grid, from uptaking other technology options such as a heat pump. As such, these scenarios with higher levels of hydrogen switching may cause elongated periods where these buildings remain on their counterfactual technology in place of switching to other decarbonisation options.

Additionally, as *Decarbonised Gas* has the lowest level of planned low-carbon district heating, which is deployed prior to 2035, a larger proportion of stock must decarbonise individually.

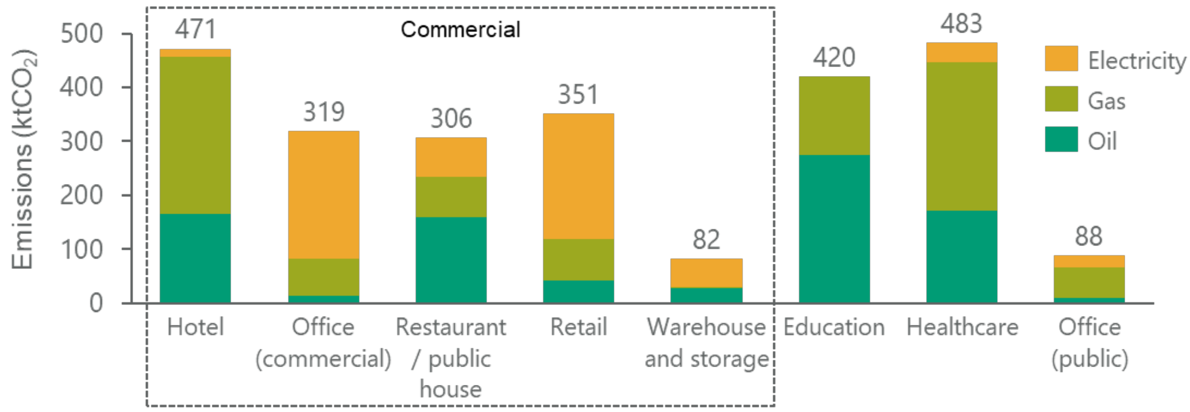
6.2 Commercial

6.2.1 Background

In the Irish commercial sector, 31% of the existing heating demand is attributed to offices and retail buildings. Within these building types, electricity is the dominant existing heating fuel and represents the highest share of existing total emissions. There are approximately 53,000 retail buildings and 35,000 office buildings with counterfactual direct electric heating in Ireland and these buildings are responsible for 16% and 15% respectively of Ireland's total commercial heating demand.

Figure 20 below shows the breakdown of commercial sector emissions by fuel and building type, illustrating the significance of electricity use in this sector.

Figure 20: Total annual emissions from fuel consumption for heating in commercial and public buildings, by building type and main heating system ($ktCO_2$)

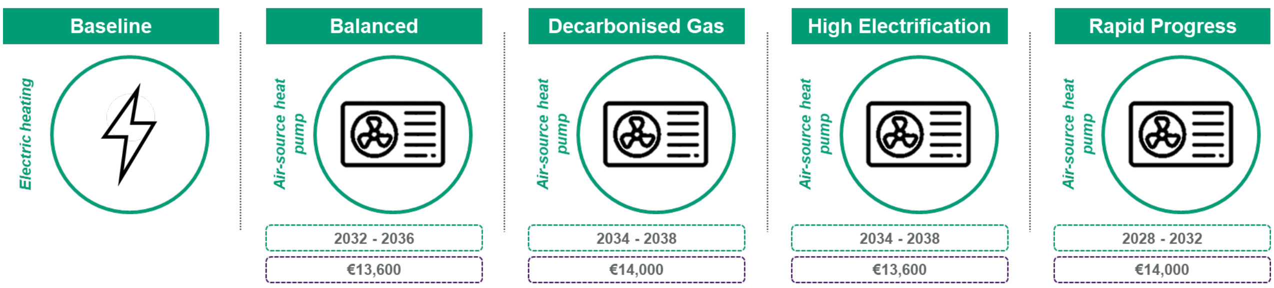


To illustrate a consumer journey within the Irish commercial sector, a small retail business with electric heating is studied.

6.2.2 Decarbonisation pathways - example archetype

For small retail businesses with direct electric heating, their most cost-effective route to decarbonisation is to utilise grant support to switch to an ASHP. *Figure 21* illustrates this uniformity across the scenarios, highlighting the chosen heating system, the period over which this archetype would likely take up this technology in each scenario, and the required capital expenditure to decarbonise.

Figure 21: Most financially favourable renewable heating system options to decarbonise a small commercial retail business with counterfactual electric heating, by scenario



Notes:

- Costs noted above are total system costs and any additional transition costs (such as radiator upgrades if necessary), without accounting for potential grant support.
- Green outlined dates represent a possible timeframe for when a significant proportion of this archetype may choose to uptake to the stated renewable energy system (note, this will be different for all consumers, particularly in relation to the counterfactual system lifetime).

- Purple outlined cost figures represent the total capital expenditure required to switch to the new low-carbon heating system, including any cost-beneficial energy efficiency and transition costs.

As noted above, in the *Baseline* scenario, this archetype chooses to install a replacement equivalent to their counterfactual electric heating system (€2,700) with no further energy-efficiency uptake. As a result, this small electrically heated retail business continues to emit ~2.2 tCO_2/yr, declining in line with the carbon intensity of the electricity grid.

In the decarbonised scenarios, prior to any support, the new heat pump system capex is a multiple of five times higher than that of the existing direct electric heating system. Minor differences in the final cost are due to slightly more favourable modelled cost assumptions for radiator upgrades included in the *Balanced* and *High Electrification* scenarios, based on improvements to the supply chain and installation processes in these scenarios. To support businesses in overcoming this initial payment differential, financial support via a grant (such as covering 30% of the system capex) is modelled to be available until 2034 to switch to this heat pump system. With this available incentive, prior to 2034, some businesses within (and similar to) this archetype take advantage of this support and switch to an ASHP. However, even after 2034, this heating system remains the most cost-effective option across all scenarios, although grant support is no longer available and direct electric systems are no longer supported.

This switch to the new heating system is the most financially favourable option for this archetype as this business decreases its annual fuel bill by up to 75%. Most businesses that are likely to switch from either existing commercial electric heating (or oil boilers) to ASHPs have annual heating demands within 15-35 MWh (a relatively low demand). In this range, the heat pump system sizes required are correspondingly relatively low as well (and in the higher-end range of domestic households). As such, for the general case, though the capex can be up to five times higher, the fuel use and fuel cost reductions compensate for this, resulting in payback periods of one to five years. Within this range, a commercial consumer is likely to have a relatively high willingness to pay.

However, note that this type of rapid/significant uptake is not seen in practice in today's market. There are several possible reasons for this, including the potential disruption involved in replacing electric heating (in particular with heat pumps), the split incentives between landlords and tenants, the prospect that there is only a low level of awareness and knowledge in the sector of the potential to switch, and available funding. If non-financial barriers can be effectively tackled and overcome, the financial case for switching is promising.

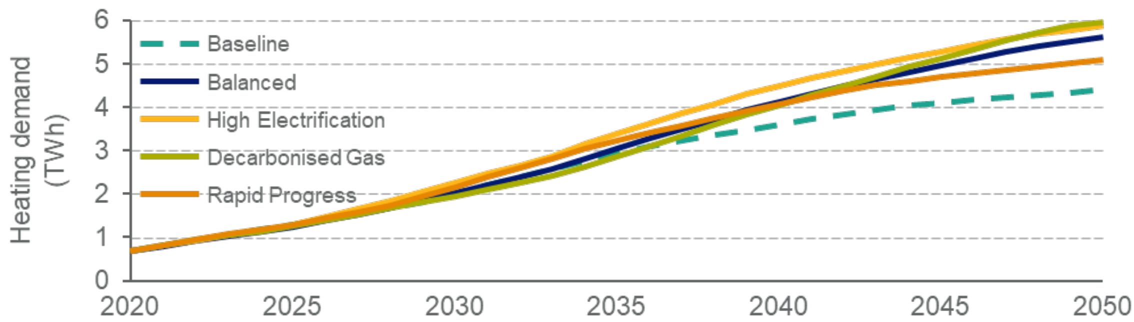
Additionally, this archetype chooses not to uptake any further energy-efficiency measures apart from in the *Rapid Progress* scenario. In *Rapid Progress*, with the support modelled (a 35% energy efficiency grant), this business only spends €600 for a shallow energy-efficiency package (prior to 2029), decreasing their heating demand by 7%. In other scenarios, the slightly lowered grant value creates a situation where this archetype no longer finds themselves willing to uptake further efficiency. This relationship indicates the usefulness of grant support in this context and the sensitivity of the amount provided.

In the commercial sector, there is a very wide range of building types and sizes, resulting in an equally wide range of relative costs to decarbonise. For example, capex values range from €3,500-210,000 in the commercial sector, with €23,000 being the approximate average for a retail business on counterfactual electric heating. This initial expenditure, combined with the significant drop in annual fuel costs, results in an average payback period of three to five years relative to the re-purchase of the existing system. However, in contrast to the residential sector, this sector has a higher tolerance for longer payback periods. As such, the modelled upfront grant incentivises the consumer to uptake the heat pump system, but even without grant support, the ASHP becomes the most favourable option across all scenarios when decarbonisation is required.

6.2.3 Commercial heat pump uptake

Heat pumps are likely to play an important role in decarbonising the commercial sector. *Figure 22* depicts the total commercial sector heating demand that switches to heat pump systems across all modelled scenarios. As illustrated, all scenarios see a significant increase in heat pump uptake. To put this into perspective, of the total 131,000 stock in the commercial sector, 62-77% choose to uptake a heat pump or hybrid heat pump by 2050. Even in the *Baseline* scenario, 24% of all stock choose to switch to some form of heat pump configuration.

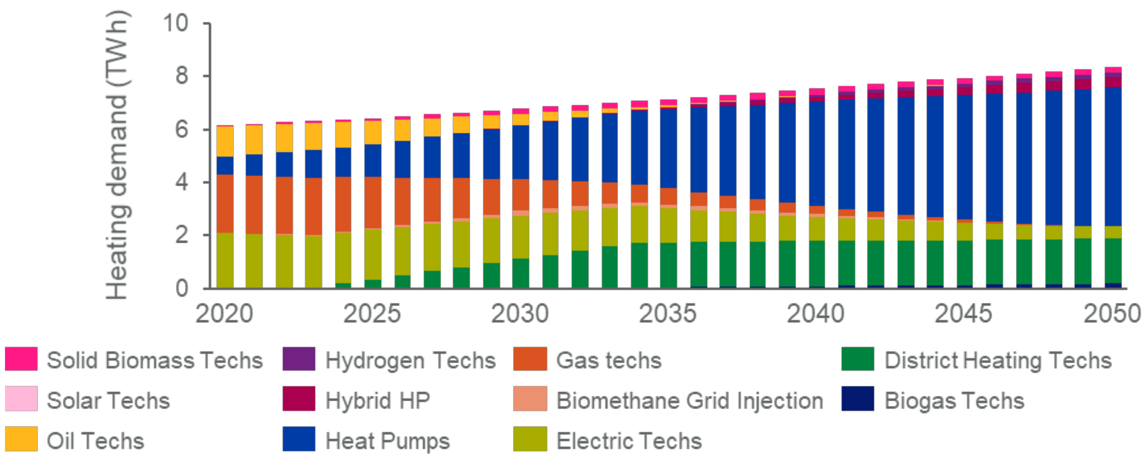
Figure 22: Commercial heat pump heating demand uptake (TWh)



6.2.4 Heating demand and emissions

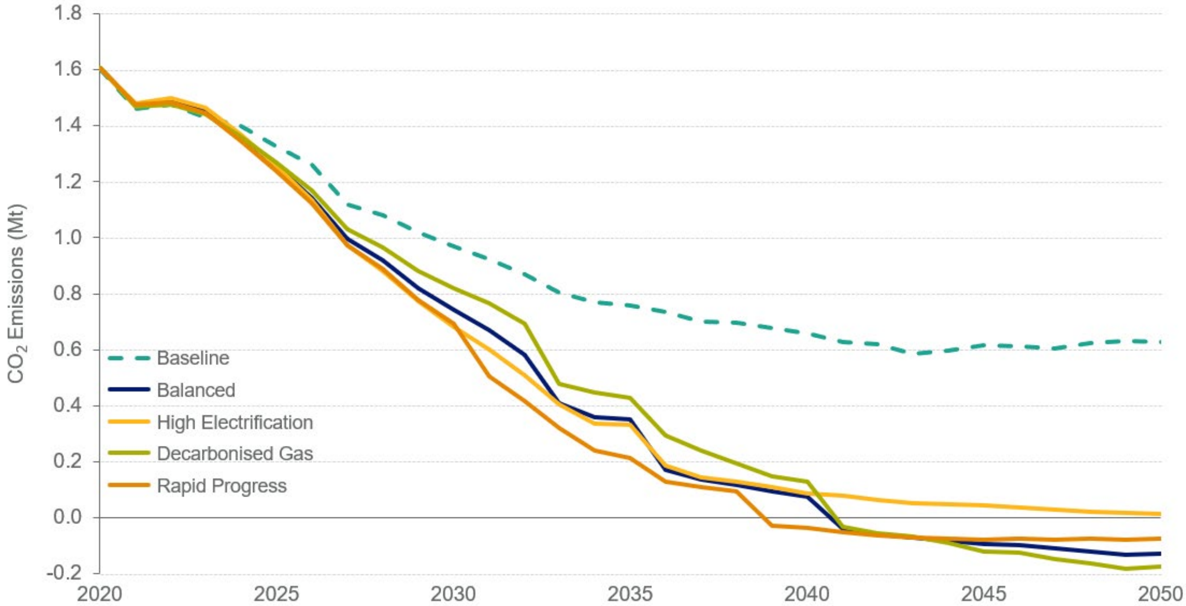
In the commercial sector, the uptake of heat pumps and district heating dominates the heating demand switches. *Figure 23* illustrates the changing heating demand mix to 2050 (for the *Balanced* scenario), including additional new buildings into the stock. The important role of heat pumps in the commercial sector is clear. Additionally, the low-carbon district heating represents 16% and 21% of all commercial heating demand by 2030 and 2050. However, it is important to note that there is further economic potential for increased district heating uptake; the modelling currently limits this uptake to the most cost-effective 10-30% of residential, commercial and public heating demand. As such, additional cost-effective district heating may be possible.

Figure 23: Commercial heating demand breakdown by fuel and technology (Balanced, TWh)



Like the residential sector, the emissions reduction pathway aligns with the technology and fuel switching trends (as seen for the *Balanced* scenario in the above graph). *Figure 24* below illustrates the scenario pathways for the annual CO_2 emissions in the commercial sector. In contrast to the residential sector, where the *Baseline* sees only a minor decrease, the commercial sector in the *Baseline* scenario sees CO_2 reductions of 30% by 2030 and 54% by 2050. This is largely due to the uptake of cost-effective heat pumps, based on leveraging existing grants in the early years.

Figure 24: Commercial direct heating emissions (all scenarios, annual $MtCO_2$)



The other scenarios see full decarbonisation by 2050. In this sector, *Rapid Progress* and *High Electrification* achieve this first, having the steepest reduction trends amongst all scenarios. As these two scenarios see the highest early rollout of heat pumps and district heating, they decarbonise quicker than *Decarbonised Gas* and *Balanced*, where some stock decide to wait for hydrogen-based technologies to become available in 2035. Notably, there is a slight uptick in emissions in the *Baseline* scenario in the later years towards 2050. This increase is explained by some commercial stock deciding to switch back to fossil-based systems (once their existing renewable system comes to its end of life during the second turnover period) as previously available grant support is no longer modelled to be available during this period, in line with the funding commitments horizon in current government plans. This results in a situation for some archetypes where the available fossil-based system then again becomes more cost effective, resulting in an increase in emissions. This should be avoided in reality by ensuring new fossil-based systems are no longer available in later years.

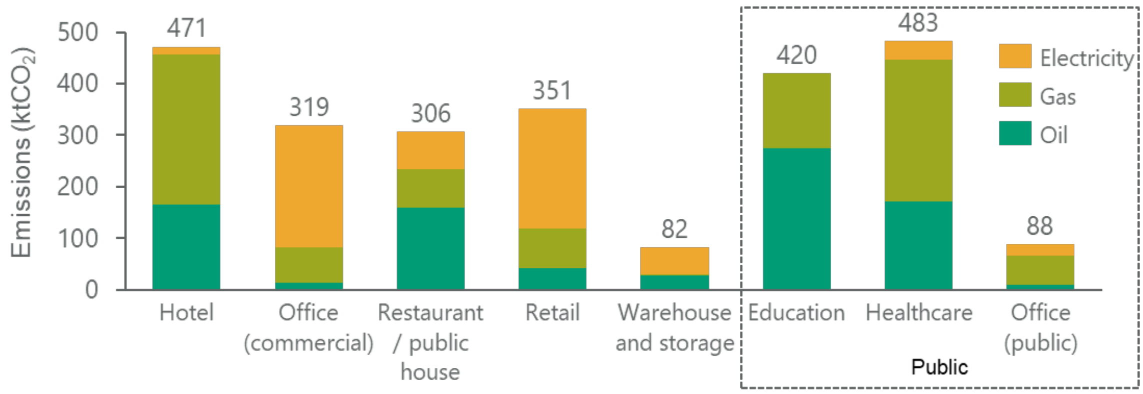
6.3 Public[10]

6.3.1 Background

Gas and oil-based emissions are the majority contributor to heat-related emissions in the Irish public sector (94%). *Figure 25* below shows the breakdown of public sector emissions by fuel and building type, illustrating the significance of gas and oil use in this sector. There are 5,400 healthcare facilities with counterfactual gas boilers; these buildings are responsible for 35% of Ireland's total public heating demand. Another key segment of this sector is educational buildings – there are 5,000 with counterfactual oil boilers in Ireland, and these buildings are responsible for 20% of Ireland's total public sector heating demand. To illustrate a consumer journey within the Irish public sector, a healthcare facility with a gas boiler is analysed.

[10] The NEMF uses the NACE classification system to define the different sectors. NACE is a common classification system for economic activity for statistical purposes, used widely internationally and by the CSO, and by SEAI for the national energy balance. Under the NACE classification, public services include a wider range of activities than just the state-run public sector. For example, the NACE classification for healthcare includes all healthcare-related units, including non-HSE health buildings, for example GPs, dentists, nursing homes, creches and physiotherapists. Therefore, the public services sector described here includes, but is not limited to, the state-run public sector.

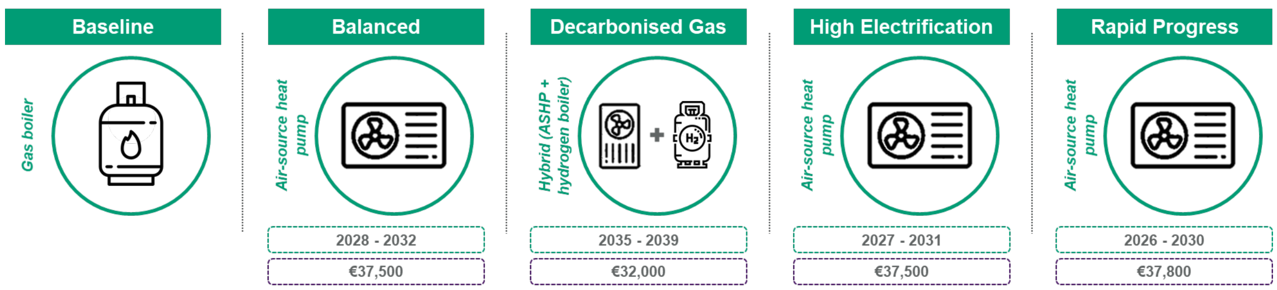
Figure 25: Total annual emissions from fuel consumption for heating in commercial and public buildings, by building type and main heating system ($ktCO_2$)



6.3.2 Decarbonisation pathways - example archetype

For healthcare facilities with gas boilers, their most cost-effective route to decarbonisation is to utilise grant support to switch to an ASHP or hybrid heat pump configuration. *Figure 26* illustrates the chosen range of renewable heating systems, the period over which this archetype would likely take up this technology and the required capital expenditure to decarbonise.

Figure 26: Most financially favourable renewable heating system options to decarbonise a healthcare facility with counterfactual gas boiler, by scenario



Notes:

- Costs noted above are total system costs and any additional transition costs (such as radiator upgrades if necessary), without accounting for potential grant support.
- Green outlined dates represent a possible timeframe for when a significant proportion of this archetype may choose to uptake to the stated renewable energy system (note, this will be different for all consumers, particularly in relation to the counterfactual system lifetime).
- Purple outlined cost figures represent the total capex required to switch to the new low-carbon heating system, including any cost-beneficial energy efficiency and transition costs.

As noted above, in the *Baseline* scenario, this archetype chooses to install a replacement equivalent to their counterfactual gas boiler heating system (€22,500) with no further energy-efficiency uptake. As a result of remaining on a gas boiler, this healthcare facility continues to emit ~86 tCO_2/yr.

Compared to the large counterfactual gas boiler, the low-carbon heat pump system taken up in the decarbonised scenarios is only 40-70% more expensive upfront, with the hybrid system in *Decarbonised Gas* being on the lower end and the pure ASHP system in other scenarios on the upper end of the range. Initial financial support (such as via a 30% grant) is modelled to be available until 2031. In *Balanced*, *High Electrification* and *Rapid Progress* scenarios, this facility makes use of the grant and switches to an ASHP. In *High Electrification*, some stock chooses to move to a high-temperature ASHP. In *Decarbonised Gas*, this archetype can only make the switch after hydrogen becomes available in its area, post-2035.

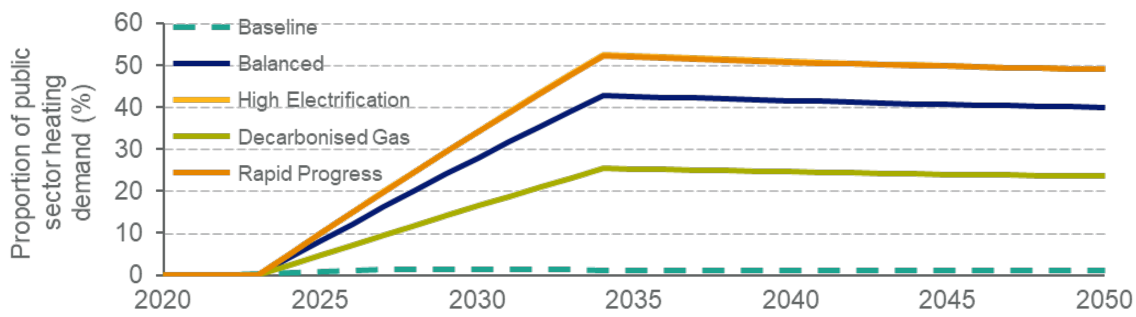
By switching to the new heating system, this facility reduces its annual fuel bill. For the switch to the pure ASHP, we see a reduction of 40-50%. However, we see a reduction of <20% by switching to the hybrid system due to the relatively high costs projected for hydrogen use. Similarly, stock that switches to a high-temperature heat pump in *High Electrification* may benefit from higher-temperature heat output and potentially lower upfront capex and transition costs, but will also likely operate at lowered efficiencies (compared to the standard low-temperature heat pump configuration), resulting in lower fuel bill savings. Lastly, unlike both the residential and commercial sectors, where in at least one scenario the chosen archetype decides to install additional energy efficiency, this public sector healthcare facility decides to stick with its existing fabric level.

Similar to the commercial sector, there is an extensive range of heating demand needs, resulting in an equally wide range of relative costs to decarbonise. Capex values range from €2,000 to €260,000 in the public sector, with €81,000 being the approximate average for a public healthcare facility on a counterfactual gas boiler. However, unlike the commercial sector, the initial capex differential is not as substantial. Coupled with the reasonable drop in fuel costs, facilities are likely to see an average payback period of one to three years relative to the re-purchase of their existing system.

6.3.3 Low-carbon district heating uptake

Low-carbon district heating is a key, low-regrets technology that can be deployed early and at scale; this is evident in its cost-effective uptake seen in the public sector across all decarbonised scenarios. *Figure 27* depicts the modelled linear uptake pathway of district heating in the public sector (shown as the proportion of total public sector heating demand) across all scenarios. The decarbonised scenarios see significant uptake, ranging from approximately a quarter to a half of all public sector heating demands. To put this into the perspective of stock uptake, of the total 24,400 stock in the public sector, 20-42% move to district heating by 2034, illustrating the high heat density of these types of buildings based on their propensity to be located in dense urban areas. Further, as noted previously, district heating uptake is restricted to a limited proportion of the total heating demand in these scenarios. Therefore, cost-effective district heating uptake could be higher than modelled here under more ambitious district heating deployment. This presents an opportunity for early and efficient reduction in existing emissions in this sector.

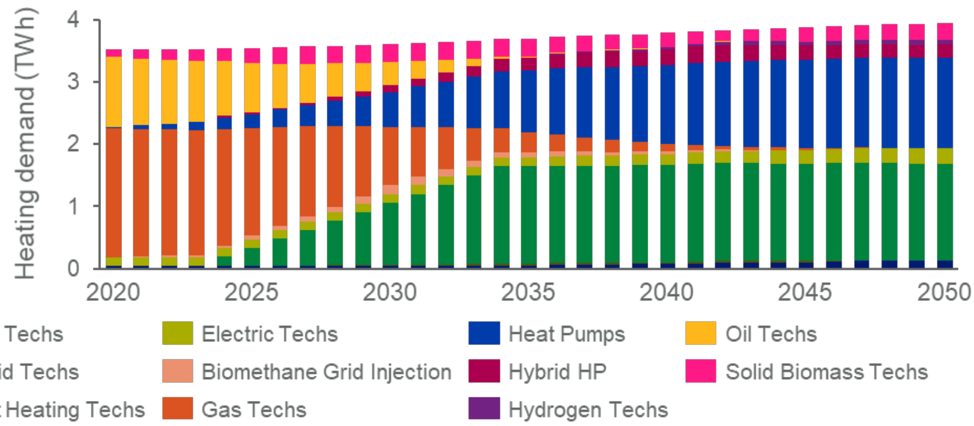
Figure 27: Proportion of public sector heating demand attributed to low-carbon district heating networks (all scenarios, %)



6.3.4 Heating demand and emissions

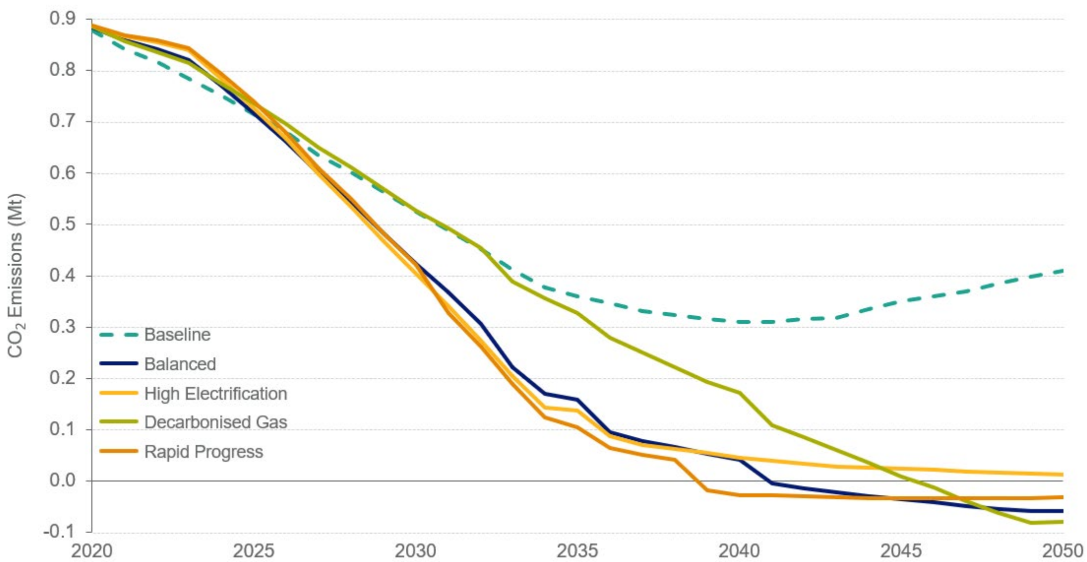
Similar to the commercial sector, the public sector sees heating demand switches dominated by the uptake of heat pumps and district heating. *Figure 28* illustrates the changing heating demand mix to 2050 (for the *Balanced* scenario), including additional new buildings into the stock. As outlined in the previous section, district heating networks play a large role here in decarbonising much of the sector. Additionally, heat pump uptake represents 19% and 43% of all public heating demand by 2030 and 2050, respectively.

Figure 28: Public heating demand breakdown, by fuel and technology (Balanced, TWh)



As discussed in previous sections, the emissions reduction pathway aligns with the technology and fuel switching trends (as seen for the *Balanced* scenario in the above graph). *Figure 29* below illustrates the scenario pathways for the annual CO_2 emissions in the public sector. Similar to the commercial sector, the *Baseline* scenario sees significant CO_2 reductions over time (48% by 2030 and 58% by 2050). This is largely due to the early uptake of cost-effective heat pumps, based on leveraging existing grants and the decarbonisation of the electricity grid in parallel. The other scenarios see full decarbonisation by 2050.

Figure 29: Public direct heating emissions (all scenarios, annual $MtCO_2$)



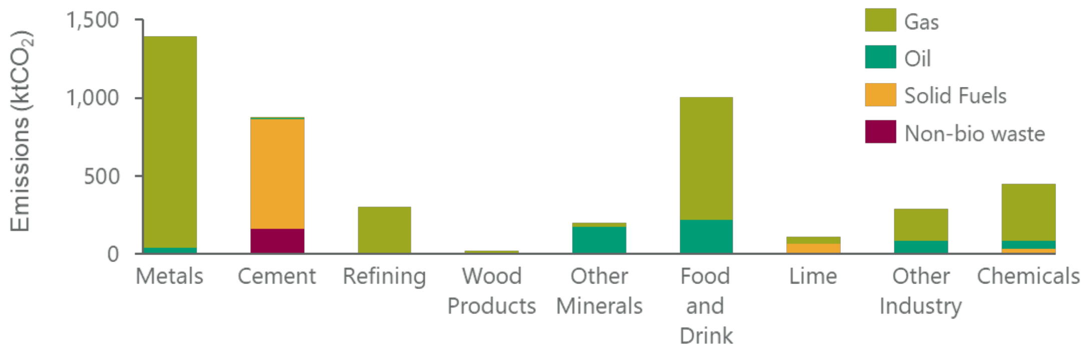
In this sector, *Rapid Progress* and *High Electrification* achieve this first, having the steepest reduction trends amongst all scenarios, quickly followed by the *Balanced* scenario. As these scenarios see the highest early rollout of heat pumps and district heating, they decarbonise quicker than *Decarbonised Gas* – where relatively larger proportions of stock wait for hydrogen-based technologies to become available in 2035 – by being prevented from taking up other low-carbon technologies. Again, similar to the commercial sector, we see the trend of switching back to fossil-based systems (during the second turnover period, when existing grant support is no longer available) and resulting increase in emissions in the *Baseline*.

6.4 Industry

6.4.1 Background

In the Irish industrial sector, the majority (67%) of emissions from fuel consumption for heating come from gas consumption, though this is not the case in every subsector (exceptions include cement and lime subsectors where solid fuels are more common). There are 580 food and drink facilities with gas-based heating systems in Ireland. These sites are responsible for 16% of Ireland's total industry heating demand. *Figure 30* below shows the breakdown of the industrial emissions, by subsector and fuel type, illustrating the significant use of gas in terms of its proportion of CO_2 emissions.

Figure 30: Total annual emissions from fuel consumption for heating in industry subsectors, by fuel type ($ktCO_2$)

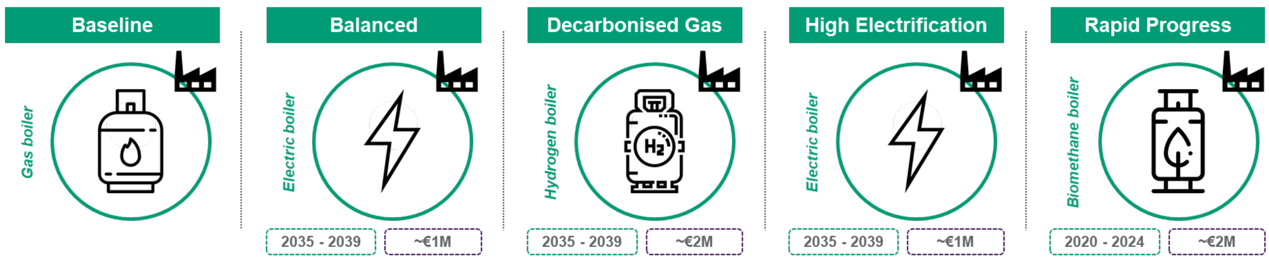


The overall food and drink industry (being a part of the agri-food sector) contributes over €9 billion in gross value added (GVA) to the Irish economy. This represents almost 3% of the overall economy's GVA in Ireland [26]. To illustrate a consumer journey within the Irish industrial sector, a food and drink facility with a gas-based heating system is studied.

6.4.2 Decarbonisation pathways - example archetype

For industrial food and drink sites with gas-based heating, their most cost-effective route to decarbonisation varies by scenario based on fuel cost trends and the availability of low-carbon fuels. Industry sites need heat for their manufacturing processes. They operate the heat generation technologies in the summer and winter to meet these needs. This means they use more fuel than other sectors and the industry sector has significantly higher annual fuel costs in most cases. Therefore, energy-related decisions at industry sites are strongly influenced by ongoing costs (particularly fuel costs). The heat generation technology capex is less important because it contributes a much smaller part of the financial expenditure over the working life of the technology. For industry technologies, a typical lifetime is ~25 years, which further weights financial decisions towards the ongoing costs. *Figure 31* illustrates the varied cost-effective options chosen by this archetype across the scenarios, showing the chosen heating system, the period over which this archetype would likely take up this technology in each scenario, and the required capex to decarbonise.

Figure 31: Most financially favourable renewable heating system options to decarbonise a food and drink facility with counterfactual gas heating, by scenario



Notes:

- Costs noted above are total system costs and any additional transition costs (such as radiator upgrades if necessary), without accounting for potential grant support.
- Green outlined dates represent a possible timeframe for when a significant proportion of this archetype may choose to uptake to the stated renewable energy system (note, this will be different for all consumers, particularly in relation to the counterfactual system lifetime).
- Purple outlined cost figures represent the total capex required to switch to the new low-carbon heating system, including any cost-beneficial energy efficiency and transition costs.

In the *Baseline* scenario, this archetype chooses to install a replacement equivalent to their counterfactual gas-based heating system (~€2 million) with no further energy-efficiency uptake. As a result, this gas-heated food and drink facility continues to emit ~6,300 tCO_2/yr.

Apart from the electric boiler option (seen in *Balanced* and *High Electrification*), which saves this site 42% upfront, switching to other options (hydrogen boiler, biomethane boiler) requires about the same upfront investment as the gas boiler counterfactual. In terms of uptake periods, these industry sites wait as long as possible to take up a low-carbon option in the decarbonisation scenarios. When the fossil fuel option is removed in the 2030s, these sites choose a low-carbon option out of necessity. Before the phase-out date, the paybacks offered by low-carbon options are too long for most industry consumers, even with the high-carbon prices assumed in the decarbonisation scenarios. In these scenarios, progress towards decarbonisation comes from grid-injected biomethane, which acts to reduce the overall emissions intensity of the gas fuel. All gas consumers in all sectors share the costs, so each sees a small increase in price. So too are the benefits, so each sees a slight reduction in the CO_2 intensity of the gas fuel. The extent of biomethane resources depends on agricultural activity and productivity. The total resource is less than the current gas use demand in the industry sector. In addition, if a single site pays the total price of the biomethane fuel in order to capture the full extent of the emissions benefits, the competitiveness of the fuel reduces significantly.

The exception to this is the *Rapid Progress* scenario where this archetype takes advantage of the availability of low-cost biomethane derived from cattle slurry mixed with specifically grown crops (such as red clover) and the prioritisation of biomethane fuel for use in industry. The archetype becomes an early adopter of biomethane, either through trucked shipments of containerised biomethane or by paying for biomethane to be produced and injected into the gas grid to meet the archetype's gas demand. More biomethane is available in this scenario and at lower cost because of the land-use assumptions made in the resource assessment analysis that explore a reduction in the animal herd, consistent with rapid decarbonisation, that allows more land to be used to grow red clover grass silage.[11] The co-ordinated action across the biomethane supply chain assumed in this scenario allows farmers to reduce the production cost of biomethane and offer it to industry sites at a competitive price that is lower than in the other scenarios. In later years, the transmission network delivers biomethane to transmission-connected industry sites. In the *Rapid Progress* scenario, separate transmission networks exist for the transmission of hydrogen and for biomethane; more information is provided in the Low Carbon Gases for Heat report[12] in this National Heat Study.

The industry sector generally sees increased annual fuel costs across all decarbonised scenarios compared to the *Baseline* overall. The higher costs of low-carbon fuels relative to fossil gas is the main reason for this. However, the changes in fuel costs vary significantly depending on the low-carbon technology and fuel chosen; for example, for sites where a heat pump is suitable, we see cost decreases based on the increased system efficiency. However, in general for this archetype, in the *Balanced* and *High Electrification* scenarios, by switching to the cheaper upfront electric system, annual costs increase by 51% compared to the *Baseline*. However, in *Rapid Progress*, by leveraging the subsidised biomethane prioritised for the industrial sector, assuming production cost support at a farm producer level, the fuel costs paid by consumers reduce by 29% by 2050 relative to the *Baseline*. In contrast, *Decarbonised Gas*, due to the use of green hydrogen, sees annual costs increase by 91% compared to the *Baseline*. This increase in fuel cost is not unique to this archetype. Rather, the industrial sector generally sees increased annual fuel costs across all decarbonised scenarios compared to the *Baseline* overall.

Only in *Rapid Progress*, with the support of a 30% grant (via EXEED), does this facility spend €250,000 on a deep energy-efficiency package (alongside the take up of the biomethane boiler) prior to 2030, decreasing its heating demand by 15%. In other scenarios, as the business stays on its counterfactual system until the phase-out date (after which energy efficiency grants are no longer available), the business only takes up additional energy-efficiency measures in later years as fuel prices increase.

6.4.3 Carbon capture, utilisation, and storage (CCUS)

CCUS is a key decarbonisation solution for use in industry to reach net zero. Each scenario assumes differing deployment at the existing industry sites identified as having suitable potential.[13] Its modelled potential aligns with the evolution of the energy system in each scenario and accounts for sites, such as cement manufacturers,[14] that have process emissions that are difficult to abate by other means. The deployment timing is based on an

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[11] The Sustainable Bioenergy for Heat report contains further background on the biomethane resource assessment. Available: www.seai.ie/publications/Sustainable-Bioenergy-for-Heat.pdf

[12] SEAI, 'Low Carbon Gases for Heat'. 2022 [Online]. Available: www.seai.ie/publications/Low-Carbon-Gases-for-Heat.pdf.

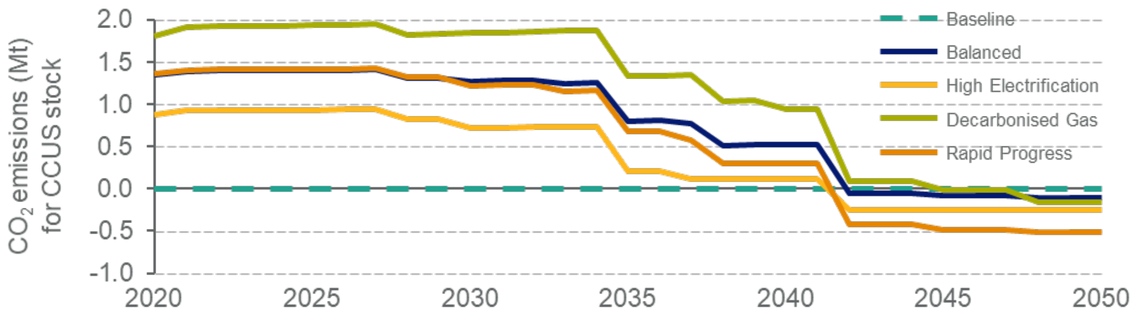
[13] See the supporting technical report on Carbon Capture, Utilisation and Storage for details on the suitable potential. Available: www.seai.ie/publications/Carbon-Capture-Utilisation-and-Storage-(CCUS).pdf

[14] Cement manufacture (and other industrial activities) are assumed to continue to operate as they do currently. Hence, all scenarios use some carbon capture and storage (CCS) to abate the process emissions from these industries.

assessment of the technology readiness levels (TRLs) and the current policy backdrop in Ireland. Sites that eventually switch to electricity or hydrogen to fuel their heat demands are no longer suitable for carbon capture and storage (CCS). In conjunction with the use of sustainable biomass fuels, the technology offers the potential for negative emissions. These may be required to offset emissions elsewhere in the energy system and in the wider economy or, in the case of a delayed transition, to claw back emissions that occurred before the technology was available. The consideration of these factors contributes to the difference in the quantity of abated emissions across the scenarios. The deployment of the technology requires central planning and national policy to deploy – the deployment trajectories reflect potential policy approaches with different perspectives on the role of the technology, capturing a range of ambition across the potential identified.

Figure 32 depicts the emissions profile of the stock, which eventually move to CCUS as their decarbonisation method by 2050. As illustrated, this occurs in a piecewise method, as individual sites are modelled to convert over time, particularly after the mid-2030s. By 2050, all decarbonised scenarios see a net negative emissions value as some sites switch to bioenergy (become BECCS sites). CCUS is not modelled in the *Baseline* scenario.

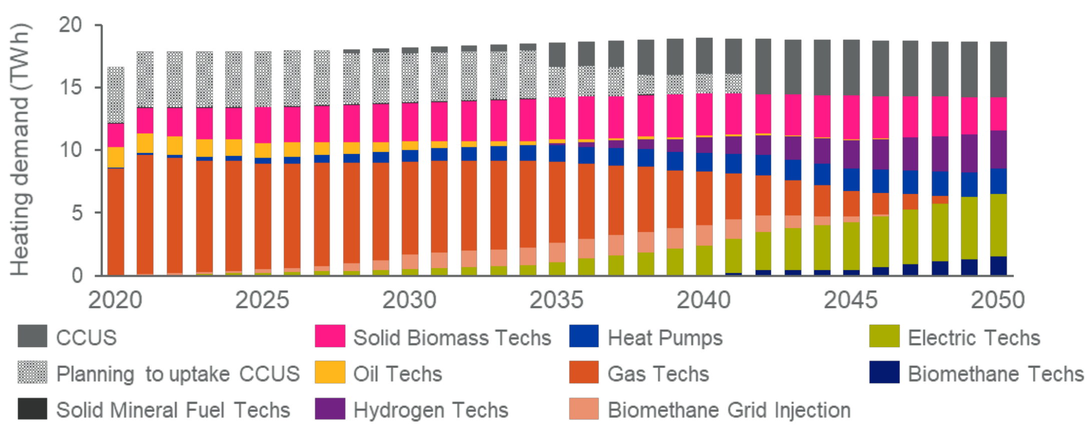
Figure 32: Annual emissions (in $MtCO_2$ / annum) from stock taking up CCUS in the industry sector, by scenario



6.4.4 Heating demand and emissions

In the industry sector, the heating demand switches are scenario dependent, varying based on fuel cost and availability. *Figure 33* illustrates the changing heating demand mix to 2050 (for the *Balanced* scenario). As outlined in the previous section, CCUS plays a key role here in decarbonising a significant proportion of heating demand, particularly in otherwise hard-to-decarbonise applications (such as cement production). By 2050, these sites operate with the CCS abating predominantly gas-based fuel use. In the *Balanced* and *Decarbonised Gas* scenarios, sites also use solid and waste fuels; whereas in *Rapid Progress* and *High Electrification*, there is significant additional use from bioenergy and waste fuels. The remaining mix is supplied via hydrogen, solid biomass, biomethane and electric technologies. Additionally, the following graph is different to the other sectors presented in that it showcases the likely delay in decarbonisation (that is, persistence of fossil-based fuels into the later years). This is a pivotal area for policymakers to review to ensure this sector's pathway to a decarbonised future is appropriately planned and incentivised to align with national targets and industrial policy.

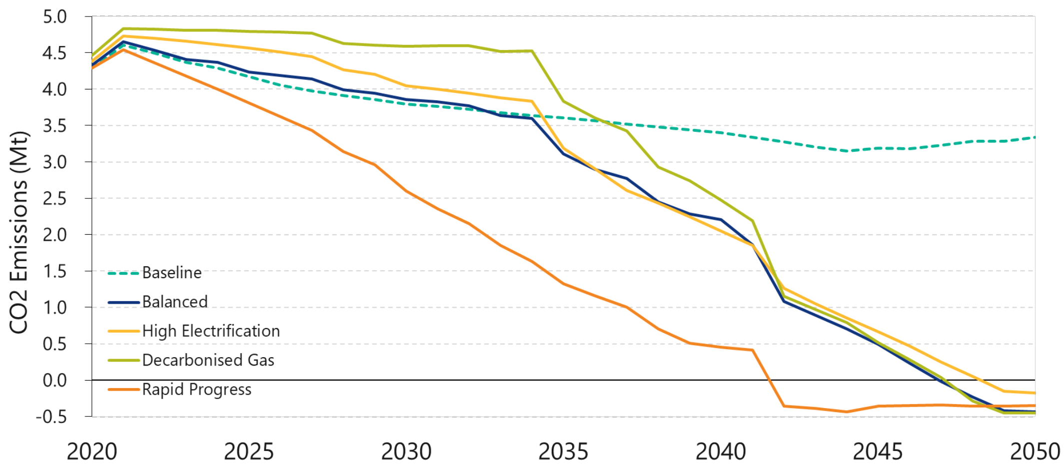
Figure 33: Industrial heating demand breakdown by fuel and technology (Balanced, TWh)



As seen in *Figure 34*, the emissions reduction pathway follows a similar pattern to including CCUS (and its emissions pathway presented in *Figure 32*). The general drift downward in heating emissions in all scenarios is caused by:

modelled uptake of energy-efficiency measures and grid-injected biomethane reducing the emissions intensity of gas use; gradual electrification of industrial processes (via both direct electrification and uptake of heat pumps); and the simultaneous reduction in power grid emissions intensity. Compared to the other sectors, this graph depicts a delayed transition where emissions continue in the near term due to several factors: the inclusion of CCUS, the delayed uptake of hydrogen technologies (only once they become available); and the general lack of financial favourability based on the potential for increased running costs seen across many industrial archetypes. These aspects will need sufficient thought and planning to ensure a smooth transition in this sector.

Figure 34: Industrial direct heating emissions (all scenarios, annual $MtCO_2$)



The *Rapid Progress* scenario decarbonises relatively quickly compared to the other scenarios and it also assumes CCUS in later years. In addition, this scenario assumes a higher availability of biomethane because of the land-use and herd size reduction assumptions included in the background resource assessment. The more significant amounts of biomethane are also prioritised for use in the industry sector, and allow decarbonisation for existing gas users who may struggle to decarbonise via fuel switching or electrification of heat. Making use of this allocation of resources, many of the technically and economically suitable industrial sites move to biomethane, causing the initial steeper drop in emissions compared to the other scenarios.

The *Baseline* scenario decarbonises slightly quicker than the *Balanced*, *High Electrification* and *Decarbonised Gas* due to the lack of deployment of CCUS in this scenario. In the modelling, industrial sites designated for the installation of CCUS generally do not switch heating fuels before installing the carbon capture equipment. Therefore, in the *Baseline* scenario, some industrial processes on large industrial sites (designated for CCUS in other scenarios) may switch to low-carbon heating technologies such as heat pumps. The *Decarbonised Gas* also prioritises many on-gas industrial sites for hydrogen, which prevents many sites from switching to other low-carbon technologies before hydrogen becomes readily available, therefore decarbonisation before hydrogen is ready for deployment in 2035 is slower than in other scenarios. These trends illustrate some of the potential trade-offs involved in a shift to centrally planned energy system options.

7 Technology and fuel considerations

This section summarises some of the key results from the four scenarios showing the decarbonisation of the heat sector. A summary of the existing heating demand across the entire heat sector is in Section 7.1. The following sections highlight the major differences between the decarbonised scenarios, including heat pump and district heating deployment, consumption of hydrogen and electricity for heat, and consumption of solid biomass and biomethane across the heat sector.

7.1 Heating demand

The technologies that supply heating in Ireland will need to change significantly as the heat sector decarbonises; the resulting technology split varies across the decarbonisation scenarios presented. *Figure 36* on the next page shows the total heating demand in each scenario across all sectors between 2020 and 2050 by technology type. The overall differences in trends between scenarios are visible in this figure; however, a comparison in the trends of key technology groups is presented throughout the rest of Section 7 under the various sub-headings below. Note that *Figure 36* does not include the heating demand of new builds, but does account for growth in heating demand in the industry sector based on projections of macro-economic sector growth.

7.2 Heat pumps

Heat pumps play a significant role in decarbonising heat in all scenarios, and dominating heat demand in new builds in the residential, commercial and public sectors, with significant numbers deployed in retrofits in all scenarios. *Figure 35* ***Error! Reference source not found.*** shows the total annual heating demand met by heat pumps by scenario from 2020 to 2050. The total scenario (solid) lines show the heating demand from both heat pumps retrofitted in existing buildings (which varies by scenario) and from heat pumps installed in new builds. The dashed line shows the heating demand from heat pumps in new builds (the same in each scenario). The heating demand in retrofits (which varies by scenario) is the difference between the solid lines and the dashed line.

Figure 35: Total annual heating demand met by heat pumps by scenario, between 2020 and 2050

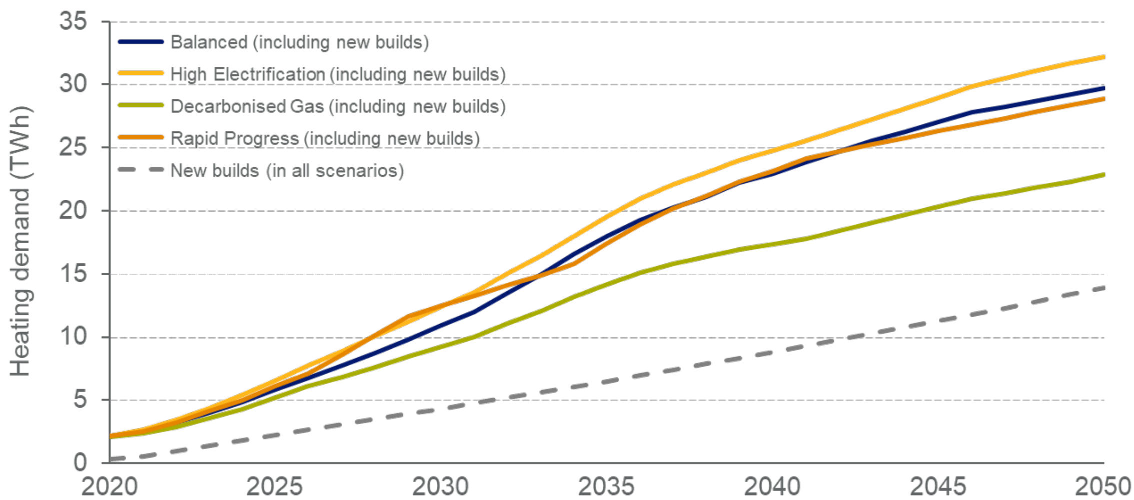
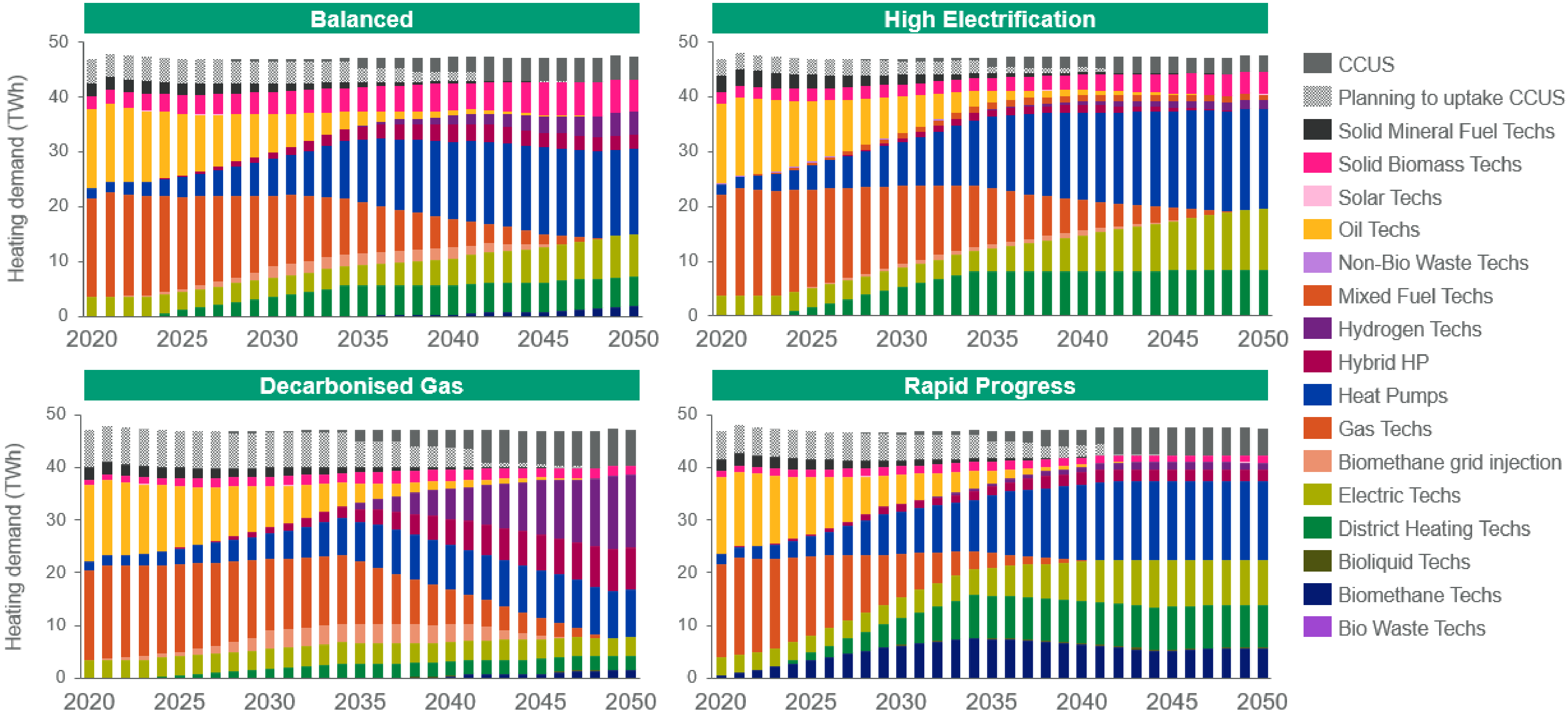


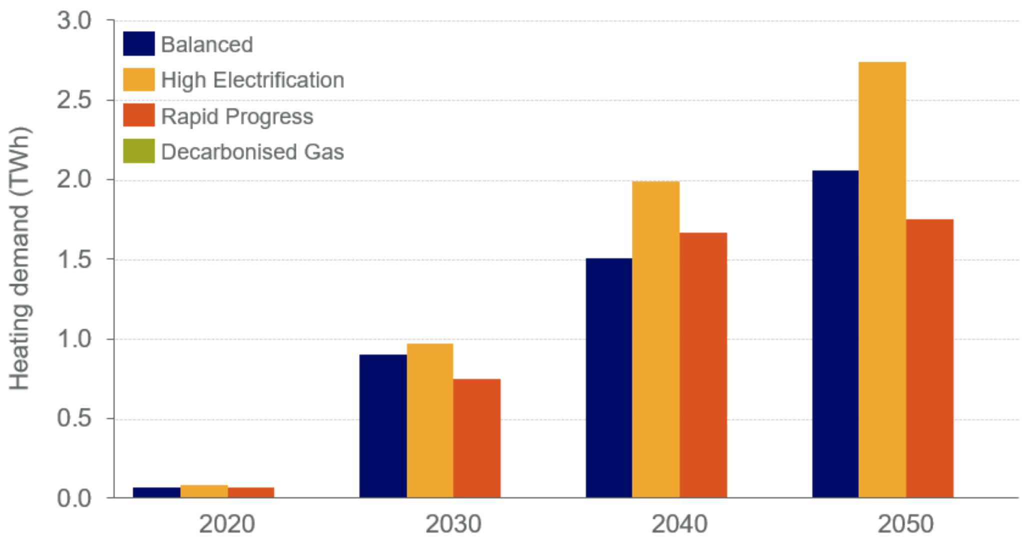
Figure 36: Breakdown of total existing annual heating demand by scenario and by technology type, 2020-2050, across all sectors



High Electrification has the highest heating demand met by heat pumps, due to including high-temperature heat pumps particular to this scenario. High-temperature heat pumps in buildings are defined as those which can produce flow temperatures above 60 °C (for more information please see the Low Carbon Heating and Cooling Technologies report[15] in this National Heat Study). This inclusion opens further suitability options for properties that would otherwise exceed the threshold of heating demand per unit floor area (either before or after energy efficiency) to be suitable for a standard low-temperature heat pump. *Rapid Progress* and *Balanced* scenarios have high levels of heat pump deployment as well; both scenarios have over 25 TWh of heating demand met by heat pumps in 2050 across all sectors. Lastly, *Decarbonised Gas*, despite being focused on low-carbon gas use, also has a significant proportion of heating demand met by heat pumps, in both new builds and retrofits.

Figure 37 shows the total annual heating demand met by industrial heat pumps in the industry sector by scenario, between 2020 and 2050. Note that this heating demand is not added to the heating demand met by heat pumps shown in *Figure 36*, but instead shows the portion of heating demand from *Figure 36* that is met by heat pumps in the industry sector. Industrial heat pump uptake is largely similar in the *Balanced*, *High Electrification* and *Rapid Progress* scenarios, with over 10% of industrial heating demand met by heat pumps. The uptake of heat pumps in the *High Electrification* scenario is higher than in the other two scenarios due to electrification of heating being prioritised in this scenario. There is no uptake of heat pumps in the industrial sector in the *Decarbonised Gas* scenario, as these industrial sites are planned to decarbonise using hydrogen as a heating fuel instead, based on the modelled scenario narrative.

Figure 37: Total annual heating demand met by industrial heat pumps in the industry sector, 2020-2050, by scenario



Note: *Decarbonised Gas* scenario is not visible in the graph as no heat demand is met by industrial heat pumps.

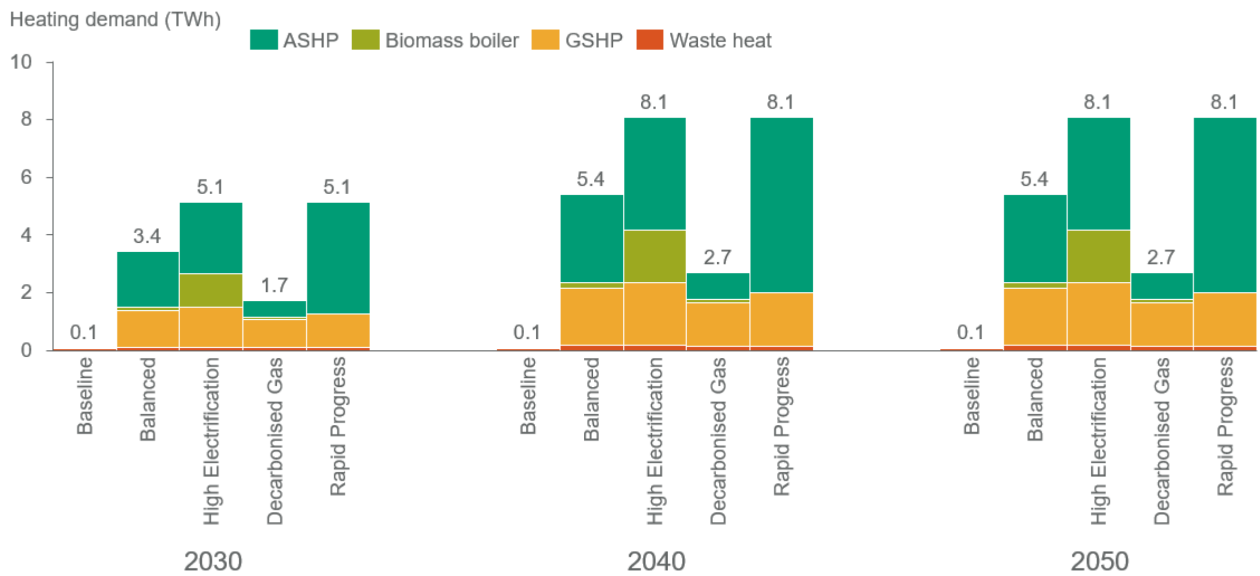
7.3 District heating

District heating has the potential to play a significant role in heat decarbonisation, especially in heat-dense areas, but would require significant deployment throughout the 2020s and the early 2030s and supported by policy on regulation, planning and financing. *Figure 38* shows the modelled annual heating demand met by district heating in all sectors by scenario, from 2020 to 2050. For all scenarios, growth in heating demand met by district heating occurs linearly between 2023 and 2034. It is deployed in the most cost-effective small areas throughout Ireland, based on the linear heat density analysis coupled with the modelled cost comparison with each building's counterfactual heating system technology. Heating demand met by district heating in *Rapid Progress* and *High Electrification* is 51% higher than in *Balanced*, and over three times as high in *Decarbonised Gas*. Note that the heating demand met by district heating is the same in both *Rapid Progress* and *High Electrification*. In all scenarios, district heating is competitive and taken up to the modelled limit. For further details regarding a feasibility

[15] See footnote 6.

assessment for the uptake of district heating, see the District Heating and Cooling report[16] in this National Heat Study.

Figure 38: Total annual heating demand supplied by each district heating technology by scenario, in 2030, 2040 and 2050, including heating demand in all sectors suitable for district heating (residential, commercial, public)



We considered several options for heat extraction and waste heat recovery to feed into district heating networks. These included heat extraction from existing power stations and heat recovery from industrial sites, geothermal sources and data centres. Extraction of heat from existing power stations requires the most capital investment of all the options as it requires replacement of the existing turbines. It should be noted that this analysis focused on heat extraction from existing power stations, with the costs of retrofitting power stations to extract heat being substantial. Should new power stations be built in the coming decades that are CHP-ready (combined heat and power), these costs would be notably much lower.

In addition, due to limited data on the suitability of the geothermal resource at depths below 400 m, the analysis focused on the potential for geothermal via ground source heat pumps (GSHPs) up to a depth of 400 m. It should be noted that data from Geological Survey Ireland (GSI) shows that geothermal energy has significant potential in Ireland. Further characterisation and definition of this data in terms of source suitability will allow further analysis to take place to fully investigate the potential of geothermal energy across Ireland.

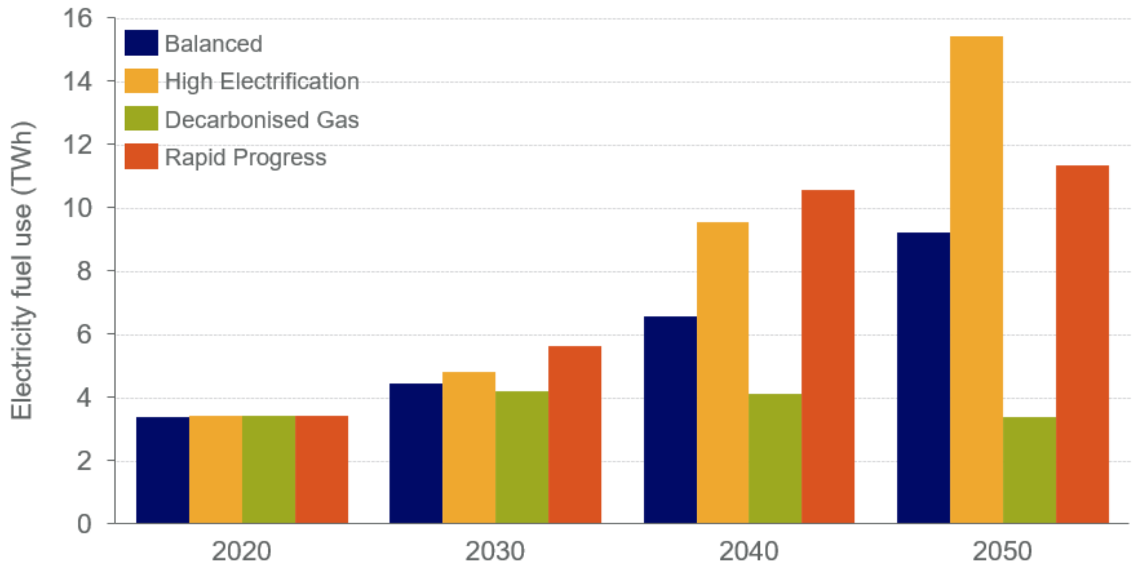
Furthermore, the analysis also covered low-grade heat recovery from data centres. Analysis shows there is significant potential for heat recovery from around 20 data centres across Ireland. We estimated the amount of heat available based on generic data and benchmarks from the literature. It is recommended that site-specific data for data centres in Ireland are gathered hereafter to allow full characterisation of this resource.

Figure 38 also shows the total annual heating demand supplied by each district heating technology for each of the four scenarios in 2030, 2040 and 2050. GSHPs supply a similar amount of heating demand in all scenarios except the *Baseline* scenario in 2030, 2040 and 2050. The amount of district heating heat demand supplied by ASHPs varies significantly by scenario, with the highest deployment being in the *Rapid Progress* scenario. *High Electrification* is the only scenario with significant amounts of heat supplied by biomass boilers. Furthermore, waste heat contribution to the total district heating demand is negligible in all scenarios due to the modelled assumptions being conservative. We did not consider heat extraction from deep geothermal and from power stations in-planning for district heating in this study as explained above, but there is the potential for significant amounts of low-cost heat to be provided via these two options.

7.4 Electricity use for heat

Electricity use for heat will increase significantly as the heat sector decarbonises, both through an increase in heat pumps and due to direct electrification of heating, including in industrial processes. *Figure 39* shows the total direct electricity consumption for heat between 2020 and 2050 for each scenario, not including the electricity used by heat pumps (Section 7.2 covers the heating demand of heat pumps by scenario).

Figure 39: Total annual electricity fuel use for heat (excluding by heat pumps) by scenario, 2020-2050, for all sectors



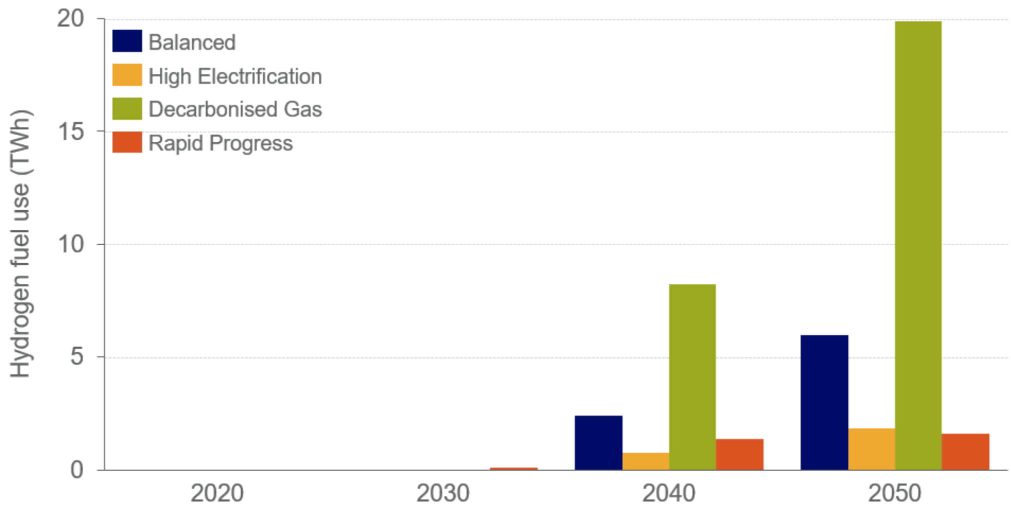
All scenarios have a higher electricity use for heat in 2030 than today. The *Balanced, High Electrification* and *Rapid Progress* scenarios show a significant increase in electricity use for heating in 2050 compared to 2020. This is caused by a significant increase in direct electric heating in buildings (most significant in the *High Electrification* scenario) and due to the electrification of heat in the industry sector. The *Decarbonised Gas* scenario has comparable electricity use for heat in 2050 and 2020, with a large portion of heat supplied by hydrogen (see Section 9.3). However, significant portions of this hydrogen are produced via electrolysis and so this scenario sees a significant increase in overall electricity consumption for heating purposes. We explore the effects of this increase in electricity fuel use for heating on the electricity networks in Section 9.2. However, as a general note, to support a full economy-wide decarbonisation (and prevent a possibility of increased emissions), it is important that the decarbonisation of the power sector be aligned to (or ideally come before) the electrification of heat or other sectors.

7.5 Hydrogen

Hydrogen has the potential to play a significant role in the decarbonisation of heat in Ireland, but the extent of deployment of hydrogen for heat depends significantly on the future of the gas distribution network. *Figure 40* shows the total annual hydrogen fuel use for heating by scenario across all sectors, between 2020 and 2050. Hydrogen use for heating first becomes available for *Rapid Progress* in 2030, and in the other scenarios from 2035. Hydrogen fuel use for heating in *Decarbonised Gas* is significantly higher than in other scenarios, due to the conversion of the gas distribution network to hydrogen between 2035 and 2050 in this scenario. The future evolution of the gas network in each scenario is explained further in the Low Carbon Gases for Heat report[17] in this National Heat Study.

[17] See footnote 12.

Figure 40: Total annual hydrogen fuel use for heat in all sectors, 2020-2050, by scenario



In the *Balanced* scenario, there is also some uptake of hydrogen for heating in the residential, commercial and public sectors. However, this is in a reduced gas distribution grid, such that the 2050 hydrogen demand is significantly lower than the 2020 methane gas demand.

In the *Rapid Progress* scenario, the hydrogen fuel use for heating is only in the industry sector, using a purpose-built hydrogen transmission network to supply key industrial sectors with hydrogen in this scenario. The distribution gas network is decommissioned by 2050 in *Rapid Progress*, and therefore archetypes with existing gas boilers take up a variety of other heating technologies, generally heat pumps, direct electrification of heat, solid biomass boilers or off-grid biomethane in the commercial and public sectors.

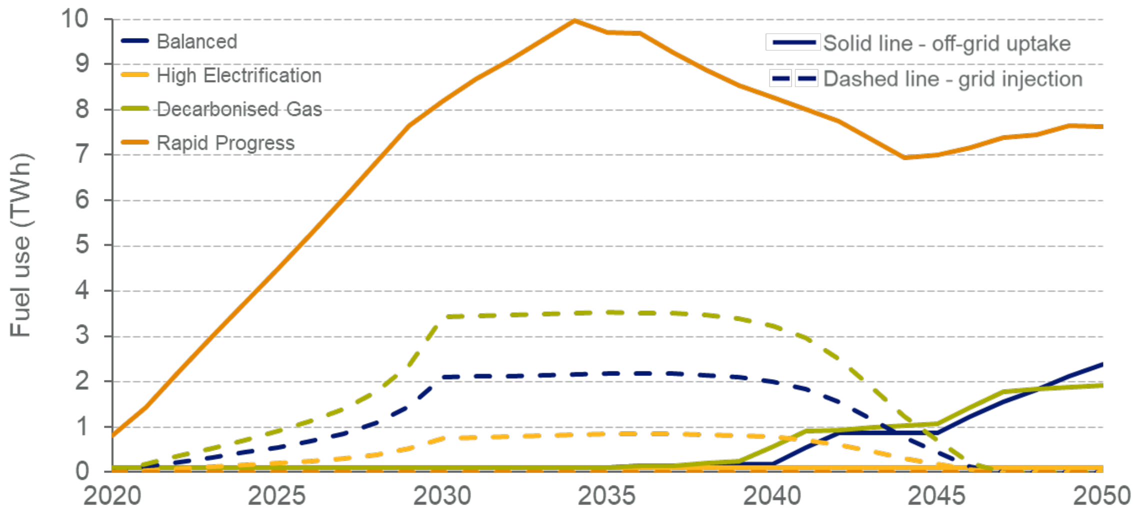
In the *High Electrification* scenario, the gas distribution network is decommissioned between 2031 and 2050, following the counterfactual technology phase-out dates. A dedicated hydrogen transmission network is used to supply hydrogen to key industrial sites which can only decarbonise through hydrogen use, but hydrogen demand in 2050 in industry is much lower than the 2020 industry gas demand in this scenario. Outside of industry, technologies with existing gas boilers must convert to non-gas technologies, with over 50% of such buildings converting to heat pump systems, and most of the remainder installing direct electric heating technologies.

7.6 Biomethane

Figure 41 shows the total biomethane fuel use for heating by scenario between 2020 and 2050. The solid lines show the off-grid biomethane fuel use, with the dashed lines showing the amount of biomethane injected in each scenario. Note that in the *Rapid Progress* scenario, the solid line represents both grid injection and off-grid distribution of containerised biomethane. The background resource assessment of the biomethane resource is based on implementing good sustainability practices. The modelling analysis accounts for the upstream emissions' impacts in the CBA. Should actual uptake and use of biomass resources deviate from these good practice assumptions, the upstream greenhouse gas (GHG) emissions and environmental impacts are likely to be more damaging than accounted for in this analysis. The background technical report, Sustainable Bioenergy for Heat,[18] has further details of the availability and upstream emissions' impacts.

[18] SEAI, 'Sustainable Bioenergy for Heat'. 2022 [Online]. Available: www.seai.ie/publications/Sustainable-Bioenergy-for-Heat.pdf.

Figure 41: Total biomethane fuel use for heating in all sectors, 2020- 2050, by scenario; includes fuel use from both grid injection (dashed lines) and direct off-grid consumption (solid lines)



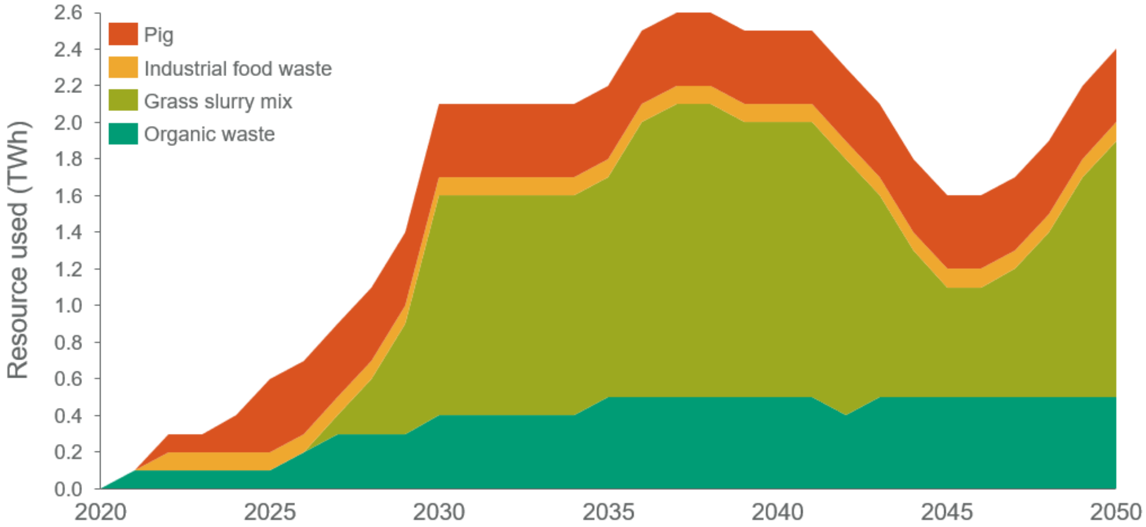
In the *Balanced, High Electrification* and *Decarbonised Gas* scenarios, between 2020 and 2030, the infrastructure for both anaerobic digestion (AD) and grid injection is expanded up to a maximum level by 2030. Production is then maintained at a level that maximises use of the available resources and ensures that the new infrastructure continues to be used productively. Injecting biomethane into the gas grid lowers the carbon intensity of the methane within the gas distribution network. Each grid-connected consumer in each sector shares this benefit. They also see a slight increase in the price of gas because biomethane is more costly than fossil methane gas. In the early- and mid-2030s, AD uses all suitable available bioresources, and the produced biomethane is injected into the grid. From the late 2030s, the volume of biomethane injected into the grid reduces as the gas distribution grid either converts piecewise from methane to hydrogen in the *Balanced* and *Decarbonised Gas* scenarios, or as the gas distribution network is decommissioned in *High Electrification*.

From 2035, any remaining available resource (that is, availability above the amount required for grid injection) is made available for delivery to off-grid commercial and public archetypes as containerised biomethane in the *Balanced* and *Decarbonised Gas* scenarios. The cheapest bio-resource is prioritised for grid injection and so uptake of this off-grid biomethane is low for the first few years. But as grid injection decreases, more of the cheaper resource becomes available to produce cheaper containerised biomethane for these off-grid consumers and so uptake increases. This off-grid consumption of biomethane is not available in the *High Electrification* scenario, as land becoming available through improved agricultural efficiency is utilised for perennial energy crops and solid biomass rather than crops suitable for AD.

The hypothetical land-use change assumption in the *Rapid Progress* scenario implies a significant departure from current and planned agriculture practices. For farmers to move away from raising beef and into growing a specialised red clover/ ryegrass sward for energy would require a coordinated policy effort across the entire supply chain. Farmers would have to take on new practices, invest in crop establishment and knowledge development, and replace their current income from beef farming. Heat users would require access to competitive and secure fuel supply. One way of achieving both aims would be to focus on reducing the cost of fuel production. Supporting farmers through measures such as knowledge transfer, crop establishment support and land premiums can lower crop production costs and may help bring about the herd reduction assumed in the *Rapid Progress* scenario. It can also offer a means to support the best environmental practices to ensure energy crops are grown sustainably. Support for the capital investment in the supply chain can also lower biomethane prices. In the *Rapid Progress* scenario, the cost of biomethane fuel available to end users is based on a subsidised basis that reduces the cost to an average of ~7.5 c/kWh. This is competitive with other low-carbon options.

Figure 42 shows the total resource used to produce biomethane in the *Balanced* scenario by resource type, including for both grid injection and for off-grid containerised biomethane. The cheapest resources are used initially, up to the available supply limit, at which point the more expensive resources are used to produce biomethane for grid injection. As grid injection biomethane ramps down in the 2040s, this resource becomes available for AD to provide containerised biomethane for off-grid properties.

Figure 42: Total resource used to produce biomethane for grid injection in the Balanced scenario, 2020-2050, by resource type



In the *Balanced*, *High Electrification* and *Decarbonised Gas* scenarios, the biomethane production and distribution infrastructure (both AD and grid injection infrastructure) is constrained within the model. This deployment constraint represents the ramping up of these technologies, from the existing infrastructure in 2020, to the infrastructure necessary to use the full available AD resource in 2030. This amount of grid injection is maintained from 2030, before ramping down in the 2040s as the methane distribution grid is decommissioned (in *High Electrification*) or converted to hydrogen (in *Balanced* and *Decarbonised Gas*). Each AD plant is operated for at least 15 years before being phased out as methane demand reduces in the *Balanced*, *High Electrification* and *Decarbonised Gas* scenarios, with some plants remaining to provide containerised biomethane for off-grid use.

This constraint is removed in the *Rapid Progress* scenario, allowing much more significant uptake of biomethane in the early- and mid-2020s, as seen in *Figure 41*. This represents early and concerted effort across the entire biomethane supply chain to allow the rapid mobilisation of the agricultural sector, and deployment of AD and injection infrastructure (Section 9.4 provides more information). This biomethane fuel use in the *Rapid Progress* scenario is represented in *Figure 41* by a solid line (indicating off-grid use) but is modelled as technology-ambivalent distribution of this biomethane, either through grid injection as in the other scenarios or via distribution of containerised biomethane by road. This biomethane is only available to sites currently connected to the gas network to allow them to continue using their existing equipment, and so it is not available for off-grid industrial sites. Further, biomethane production in *Rapid Progress* is supplemented by gasification of up to 5 TWh of imported solid biomass to produce around 3 TWh of biomethane via gasification technology. The combination of faster infrastructure deployment, increased availability of crops for AD (more information given in the Sustainable Bioenergy for Heat report[19] in this National Heat Study), and use of gasified solid biomass leads to *Rapid Progress* having significantly higher biomethane uptake than in other scenarios.

Competition from direct electric and hydrogen heating technologies in the industrial sector reduce biomethane fuel use in this scenario after 2035.

7.7 Solid biomass and other biogenic fuels

Table 5 shows the primary energy consumption of domestic and imported biogenic fuels in 2030 and 2050 in each scenario. All scenarios make use of the biomass available from the forestry by-products, food and other biodegradable wastes. The differences between the scenarios are based on land use for energy crop cultivation. The *Rapid Progress* scenario has the highest availability of domestic resources because of the assumption that there are additional land-use changes from beef farming to growing a red clover/ ryegrass mix for silage for biomethane production, while also having the highest level of imports. This scenario also prioritises biomethane for use at sites currently using methane gas as a heating fuel, allowing rapid decarbonisation without needing to change equipment or heating systems.

[19] See footnote 18.

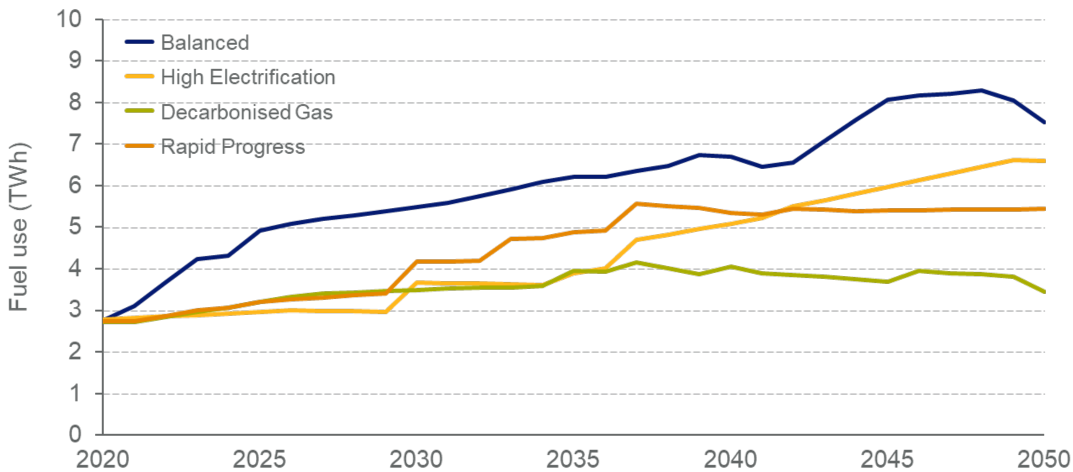
The *High Electrification* scenario uses the available land to grow willow. The *Balanced* scenario also allocates some land use to grow willow. These crops only become available later because of the current immature supply chain. However, over the long term, the crop produces more energy because of its higher per hectare energy density. Willow also has a more favourable upstream GHG emissions profile than biomethane produced from grass silage, although when slurry is added to the production process, the upstream emissions profiles for the two fuels are similar.

Table 5: Total primary energy consumption (TWh) of domestic and imported biogenic fuels for each scenario in 2030 and 2050, by end fuel use

Scenario	Wood chips/pellets		Biomethane/biogas		Other (incl. bioliquids & bioLPG)	
	2030	2050	2030	2050	2030	2050
Baseline	6.3	5.3	2.2	2.2	0.3	1.1
Balanced	5.5	7.5	2.8	2.4	0.4	1.1
High Electrification	3.7	6.6	1.1	0.1	0.1	1.1
Decarbonised Gas	3.5	3.4	4.6	2.0	0.4	1.1
Rapid Progress	4.2	5.4	8.2	7.5	0.4	1.1

Figure 43 shows the total annual solid biomass consumption (including domestic resources and wood pellet imports) for direct heat by scenario in 2020 and 2050. Of the 2020 consumption present in all scenarios, 80% is in the industry sector, with the residential sector the next largest sector. The base year consumption aligns to the 2019 Energy Balance data [27]. Solid biomass has a role in all scenarios and maintains a constant average annual share of 13% of heat demand to 2050. The resource assessment assumes that the resources are grown, harvested, processed and combusted in line with good sustainability practices. The domestic resources are generally taken up by consumers before pellet imports; however, when domestic resources are being fully taken up by consumers in the heat and power sector, pellet imports are used in the heat and power sectors. See *Figure 44* below for a further breakdown in the *Balanced* scenario. The upstream supply chain emissions' impacts and the air quality impacts are included in the assessment of the total costs and benefits of each scenario. The background technical report, Sustainable Bioenergy for Heat,[20] has further details of the availability and upstream emissions' impacts.

Figure 43: Total solid biomass fuel use for heating by scenario, 2020-2050, inclusive of all sectors



In the *Decarbonised Gas* and *Rapid Progress* scenarios, consumption of biomass increases between 2020 and 2035, to fuel solid biomass boilers installed in off-grid commercial, public and agriculture sites. Consumption of biomass

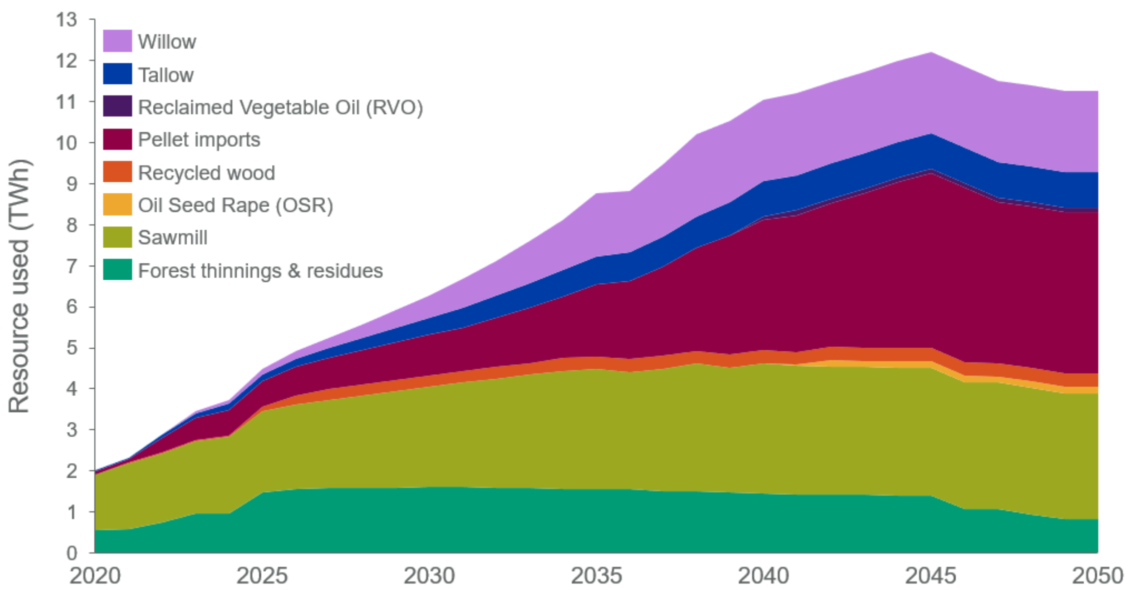
[20] See footnote 18.

in industrial CCUS stock also increases from 2031 due to some fuel switching at the CCUS sites in these scenarios. Between 2037 and 2050, the biomass consumption reduces, as some archetypes which installed solid biomass boilers before this time choose to electrify instead, especially in the public and agriculture sectors. This switching away from biomass is due to constraints on the available resources of the cheapest biomass crops due to increasing consumption across the CCUS stock, the power sector and provision to supply district heating. There is, therefore, little cheap crop available for uptake by other consumers in the heat sector.

In the *High Electrification* and *Balanced* scenarios, biomass consumption for direct heat increases from 2020. In the *Balanced* scenario, this is due to a significant uptake of biomass for heating in industry from 2020, alongside further uptake in the commercial, public and agriculture sectors. The *High Electrification* scenario sees less uptake of biomass in industry (caused by more electrification of heat), but otherwise sees similar uptake of biomass in the other sectors before 2035. From 2035, biomass consumption in the commercial, public and agriculture sectors generally decreases in these scenarios. However, this demand is replaced and exceeded by significant uptake from 2035 of solid biomass boilers in the residential sector, which continues the overall growth in solid biomass use for heat until 2050 in both scenarios.

Figure 44 shows the biomass resources and imported refined fuels used in the *Balanced* scenario. Note that this includes crops used for combustion of biomass fuels in the heat sector (see *Figure 43*) as well as bioliquid fuels used in the heat sector. All the available low-cost domestic resources that arise as by-products from the forest and wood industries are used. Sawmill residue availability increase over time in line with projections of sawmill throughput. The growth in domestic resources comes from the use of short rotation coppice (SRC) willow grown by Irish farmers. This resource is available in the *Balanced* and *High Electrification* scenarios, where some of the available agricultural land is used to grow the crop. In *Decarbonised Gas* and *Rapid Progress* scenarios, this land is used to grow a red clover/ ryegrass mix for silage for biomethane production and so is unavailable for SRC willow. The remaining domestic resource used comes from recovered waste wood, tallow and solid biodegradable waste, primarily used to fuel cement manufacture in the industry sector, as well as off grid use of wood chips and pellets in the residential sector. Wood fuel imports have an increasing role over time. They are used in industrial biomass boilers and CHP plants across all industrial sectors, where consumption of domestic biomass in the industry, residential and power sectors limits the availability of cheap domestic resource.

Figure 44: Total resource used for solid biomass and bioliquid fuels in the Balanced scenario, 2020-2050, by resource type

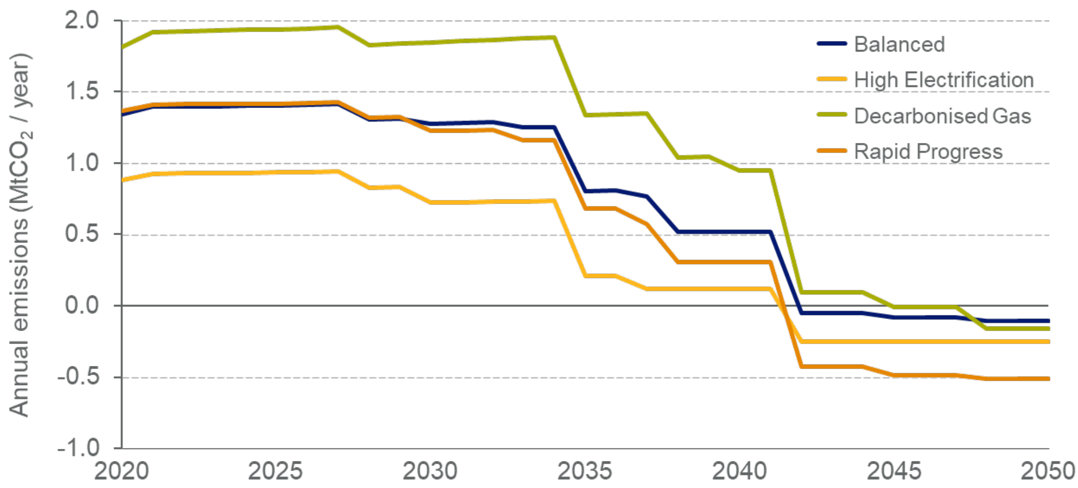


7.8 Carbon capture, utilisation and storage (CCUS)

CCUS plays a significant role in reducing industrial heating emissions in all scenarios, with significant emissions reductions expected from its use from the mid-2030s. Each scenario assumes differing deployment at the existing industry sites identified as having suitable potential.[21] The use of the potential aligns with the evolution of the energy system in each scenario and accounts for sites, such as cement manufacturers, that have process emissions difficult to abate by other means. The deployment timing is based on an assessment of the TRLs and the current policy backdrop in Ireland. Sites that switch to electricity or hydrogen to fuel their heat demands are not suitable for CCS. With the use of sustainable biomass fuels, the technology leads to negative emissions. These may be required to offset emissions elsewhere in the energy system and in the wider economy or, with a delayed transition, to claw back emissions that occurred before the technology was available. The consideration of these factors contributes to the difference in the quantity of abated emissions across the scenarios.

Figure 45 shows the total annual emissions in the industry stock designated for uptake of CCUS by scenario, between 2020 and 2050. The initial emissions vary by scenario as each scenario deploys CCUS to varying levels, with the highest CCUS deployment in the *Decarbonised Gas* scenario and the lowest deployment in *High Electrification*, with the *Rapid Progress* and *Balanced* scenarios having CCUS similar deployment rates that fall between the high and low scenarios.

Figure 45: Total annual emissions from industry stock designated for CCUS by scenario, 2020-2050



The significant step changes in emissions seen in all scenarios occur when large industrial sites (with correspondingly significant emissions) deploy CCUS. The model assumes that an industrial site installs the CCS technology completely within one year, leading to these significant annual changes in overall emissions. The slight increases in emissions between drops visible in *Figure 45* are caused by the macro-economic adjustments modelled to account for sectoral economic growth; Section 3.4 explains this further.

From 2042 in the *Balanced*, *High Electrification* and *Rapid Progress* scenarios, and from 2045 in the *Decarbonised Gas* scenario, the total annual emissions in the stock designated for CCUS becomes negative. This is due to the use of biomass for fuel in addition to the capture of the emissions from combustion (BECCS). As this biomass has removed CO_2 from the atmosphere during its growth, capture and permanent storage of the emissions from its combustion leads to this carbon being permanently removed from the carbon cycle; thus, these are modelled as negative emissions. The greater amount of negative emissions in the *Rapid Progress* scenario represents a higher proportion of the CCUS stock using biomass for fuel for heating than the other scenarios.

Figure 46 shows the total upfront cost (capex) of installation of CCUS on industrial sites in each scenario, between 2020 and 2050. We modelled the upfront cost of installing CCUS technology in an industrial site to be paid entirely in one year, leading to the step-change nature of the costs seen in *Figure 46*. Until 2037, CCUS is installed on the same sites in each scenario, and so the upfront cost paid in each scenario for CCUS is the same; after 2037, the CCUS deployment differs by scenario, and hence so do the costs. More information about which industrial subsectors deploy CCUS in which scenarios, and in which years, is in the Carbon Capture, Utilisation and Storage (CCUS) National Heat Study report.[22]

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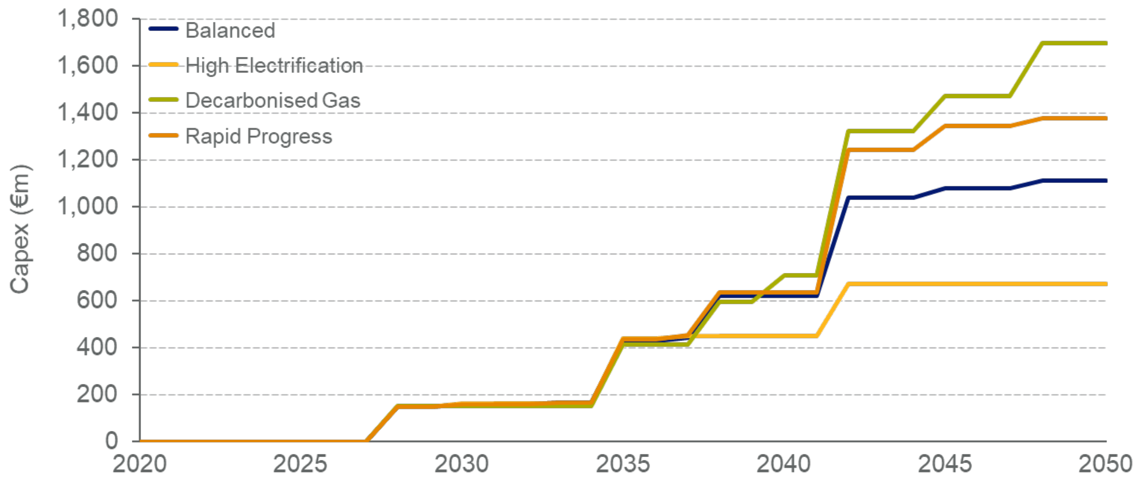
[21] For more information about this process, please see the Carbon Capture, Utilisation and Storage (CCUS) report in this National Heat Study, available atwww.seai.ie/publications/Carbon-Capture-Utilisation-and-Storage-(CCUS).pdf. For more information on hydrogen production, please see the Low Carbon Gases for Heat report in this National Heat Study, available at www.seai.ie/publications/Low-Carbon-Gases-for-Heat.pdf
[22] See footnote 21.

Figure 46: Total annual upfront cost (capex) for CCUS installations in industry, 2020-2050, by scenario



The variation of CCUS deployment across scenarios reflects a range of probable levels for the development of CCUS in Ireland, and the deployment in each scenario depends on both the assumptions specific to CCUS deployment within each scenario, but also on the wider energy context within each scenario. For example, *High Electrification* has the lowest CCUS deployment across the decarbonised scenarios, reflecting both limited adoption of this technology across key industrial sectors and in the power sector, but also increased direct electrification of industrial heating processes across the sector. *Decarbonised Gas* is the scenario with the highest levels of CCUS deployment, which is also accompanied by high uptake of low-carbon hydrogen in industry. *Rapid Progress* has the highest amount of negative emissions by 2050, representing a focus on increasing the availability of energy crops across Ireland in this scenario, as well as the use of biomass imports for use with CCUS to provide negative emissions. We explore the scenario differentiations in deployment further in the Carbon Capture, Utilisation and Storage (CCUS) report in this National Heat Study.[23]

Across all scenarios, large-scale deployment (> 0.5 $MtCO_2$ / annum) will begin in the 2030s, partly caused by the long lead times needed to develop new CCUS infrastructure. This is particularly the case with the current availability of CO_2 shipping infrastructure, both domestically and internationally. If CCUS infrastructure capacities are available in the late 2020s, adoption of the CCUS technologies by industrial sites in Ireland is generally not considered a barrier for the uptake of this technology.[24]

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[23] See footnote 30.
[24] See footnote 21.

8 Costs of decarbonisation

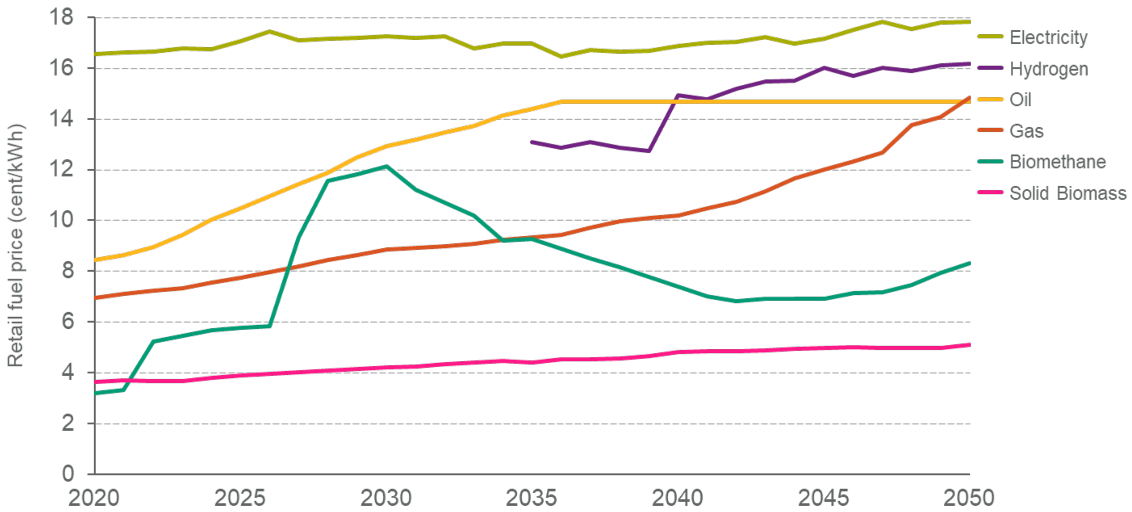
This section summarises the fuel costs, total upfront heating system costs, and additional capital investment costs by scenario. It also covers a scenario-level CBA and briefly touches on energy-efficiency cost effectiveness. For the main cost data presented, they are first broken down by sector and then by installed site technology grouping, across all scenarios. The costs presented in this section are total investment costs, inclusive of costs paid by the consumer and costs covered by financial policy support (such as grants); costs for new builds do not vary by scenario so are excluded.

8.1 Fuel costs

Changes in annual fuel prices are one important way in which the decarbonisation of heat will impact consumers' uptake decisions and annual fuel bills. Although total heating fuel costs are higher in 2050 than in 2020 in all scenarios, with the decarbonised scenarios having higher fuel costs than the *Baseline* scenario, decarbonisation offers a route to lower emissions coupled with lower fuel costs (compared to the *Baseline*) in some sectors, such as the residential sector. However, in the industry sector, the move to low-carbon heating results in an increase in fuel costs for the sector as compared to the *Baseline*.

Figure 47 shows the average retail fuel price paid by consumers (including the carbon tax) in the *Balanced* scenario between 2020 and 2050 for electricity, hydrogen, oil, gas, biomethane and solid biomass. The fuel costs shown are weighted-average figures across all sectors; consumers in each sector pay sector-specific fuel prices instead of the fuel prices shown in this figure. However, we used these average fuel prices to illustrate the overarching fuel price trends.

Figure 47: The average retail fuel prices seen by consumers in the Balanced scenario, 2020-2050, for a selected set of fuels

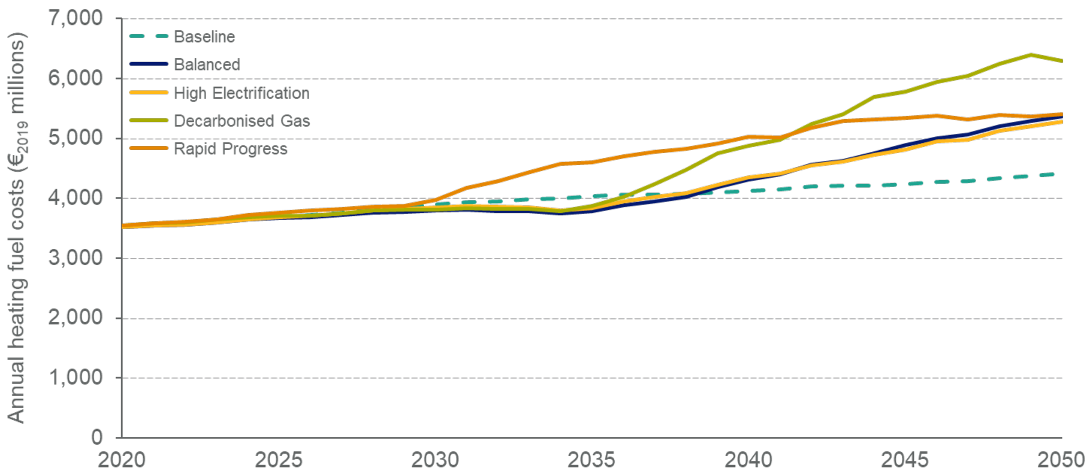


Based on this study's modelling, the electricity price is likely to increase in line with increasing electricity demand as more of the heat consumers electrify their demand. There are also projected increases in other sources of demand such as data centres, EVs and appliances. The hydrogen price increases from when it becomes available in 2035 to 2050. The cheapest routes of hydrogen production are used first, and then as hydrogen demand increases further, the more expensive hydrogen production routes must be used, leading to an increase in the average fuel price.[25] The oil price increases out to 2050 based on projections of the oil wholesale price [25]. The gas price increases due to both increasing wholesale gas prices and to the reducing demand for fossil gas. As more consumers electrify and stop using fossil gas, the total network costs are levelised across a smaller customer base, leading to higher costs per unit of fuel supplied. The slight increase in the biomass price by 2050 is caused by an increasing proportion of more expensive biomass as the total demand increases. In the *Balanced* scenario, the biomethane price rises in 2020s while the necessary production and distribution infrastructure is being deployed. The biomethane price decreases from 2030 due to electrification of heat reducing demand, and increasing availability of cheaper production resources. These both lead to a greater proportion of biomethane production using cheaper resources,

[25] For more information on hydrogen production, please see the Low Carbon Gases for Heat report in this National Heat Study. Available: www.seai.ie/publications/Low-Carbon-Gases-for-Heat.pdf

which results in a lower levelised cost. *Figure 48* shows the total annual heating fuel costs for all sectors between 2020 and 2050, by scenario.

Figure 48: The annual total heating system fuel costs (in €$_{2019}$ millions) for all sectors, 2020-2050, by scenario



Similar to the trends in the previous subsection, the fuel costs by scenario are largely similar out to 2030; thereafter, fuel prices start diverging. Between 2026 and 2036, the *Balanced*, *High Electrification* and *Decarbonised Gas* scenarios all have lower fuel costs than the *Baseline* scenario. This is generally caused by increased heat pump uptake in these sectors across the residential, commercial and public sectors compared to the *Baseline* scenario. The gain in heating system efficiency due to the uptake of these heat pumps leads to lower fuel costs overall.

From 2035, the total fuel cost increases due to significant uptake of green hydrogen, a relatively expensive fuel per kWh, as seen in *Figure 47* in the *Balanced, High Electrification* and *Decarbonised Gas* scenarios. This increase begins in 2030 in *Rapid Progress* due to the modelled scenario-specific assumption that hydrogen becomes available for the industry sector in 2030. The higher increase seen in *Decarbonised Gas* correlates directly with a more significant uptake of hydrogen for heating in this scenario compared to the other scenarios, particularly in the industry and residential sectors.

By 2050, the fuel costs in the *Balanced, High Electrification* and *Rapid Progress* scenarios are all comparable. The *Baseline* scenario has lower costs by 2050 due to minimal use of hydrogen for heat, lower proportions of direct electric heating, and high remaining proportions of cheaper fossil fuels. The *Decarbonised Gas* scenario has higher costs from 2037 due to a much higher proportion of hydrogen for heating, particularly in industry.

Figure 49 shows the total annual fuel costs paid in the entire heat sector at millstone 10 year increments by sector for each scenario. *Figure 50* shows the same data but by technology type.

Figure 49: The total annual fuel costs paid in each scenario (in €$_{2019}$ millions) by consumers at milestone years, by sector

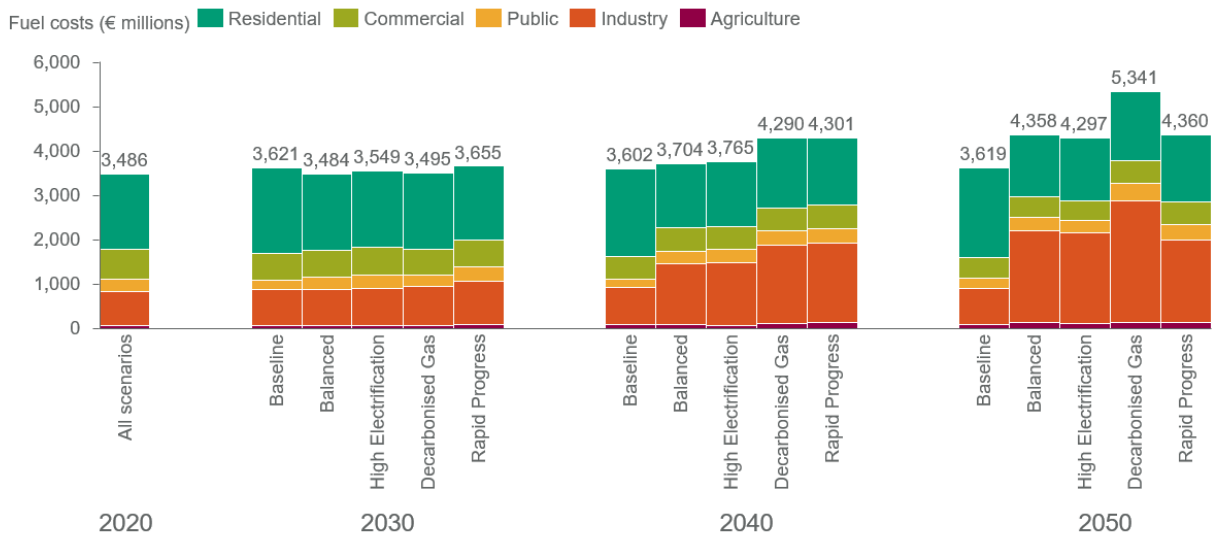
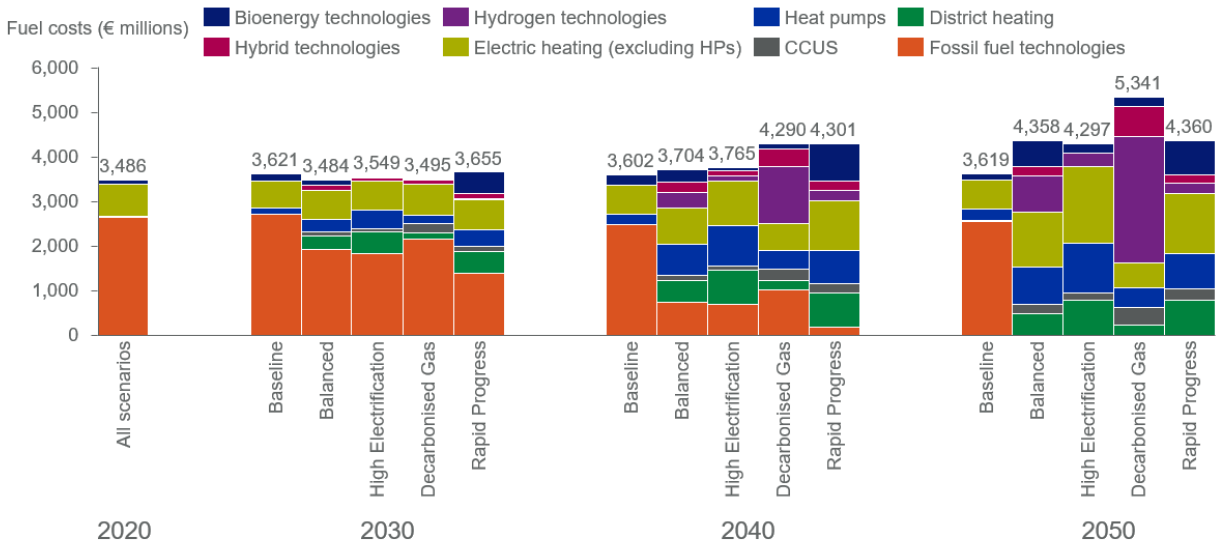


Figure 50: The total annual fuel costs paid in each scenario (in €$_{2019}$ millions) by consumers in at milestone years, by technology type



Fuel costs are projected to increase in the residential sector in all scenarios to 2050. However, the *Baseline* scenario, where many consumers remain on fossil fuels, sees the largest increase. In 2050, fuel costs in the *Baseline* scenario are 52% higher than 2020. The decarbonised scenarios also see an increase in fuel costs compared to 2020, with the lowest increase of 22% seen in the *Balanced* scenario and the highest increase of 29% seen in the *Decarbonised Gas* scenario (due to high uptake of hydrogen boilers). Note that these fuel prices include those in new-build properties; although the total fuel prices increase in all scenarios, the average price of heat per kWh in the residential sector falls in all decarbonised scenarios as the growth rate of heating demand exceeds the growth rate of total annual residential fuel costs.

Decarbonisation of heat in the commercial sector does not significantly impact fuel costs seen by consumers, with total fuel costs projected to be 1-10% lower in all scenarios in 2050 than in 2020, with the lowest fuel cost in the *Baseline* scenario and the highest in *Rapid Progress* and *Decarbonised Gas*. High heat pump uptake leads these reductions in fuel costs in all scenarios, which, due to their high efficiencies, use significantly less fuel than conventional combustion or direct electric technologies. The relatively higher costs in *Decarbonised Gas* are caused by more hydrogen uptake, and in *Rapid Progress* by an increased proportion of direct electric heating than in other scenarios, which is more widely available in this scenario to allow for rapid decarbonisation.

In contrast to the commercial sector, decarbonisation of heat in the public sector leads to increases of 11-44% in fuel prices (depending on the route taken) compared to an 8% projected reduction in *Baseline* scenario fuel prices by 2050. Higher uptake of hybrids and hydrogen boilers in the *Decarbonised Gas* scenario causes the highest increase in fuel costs, whereas the increased uptake of heat pumps in *Balanced* and *High Electrification* leads to lower fuel prices than the other decarbonised scenarios. The *Baseline* scenario sees a decrease in fuel prices due to heat pumps replacing oil boiler archetypes where fossil fuel heating is most expensive, with a large proportion of gas boilers still remaining (which generally have lower fuel prices).

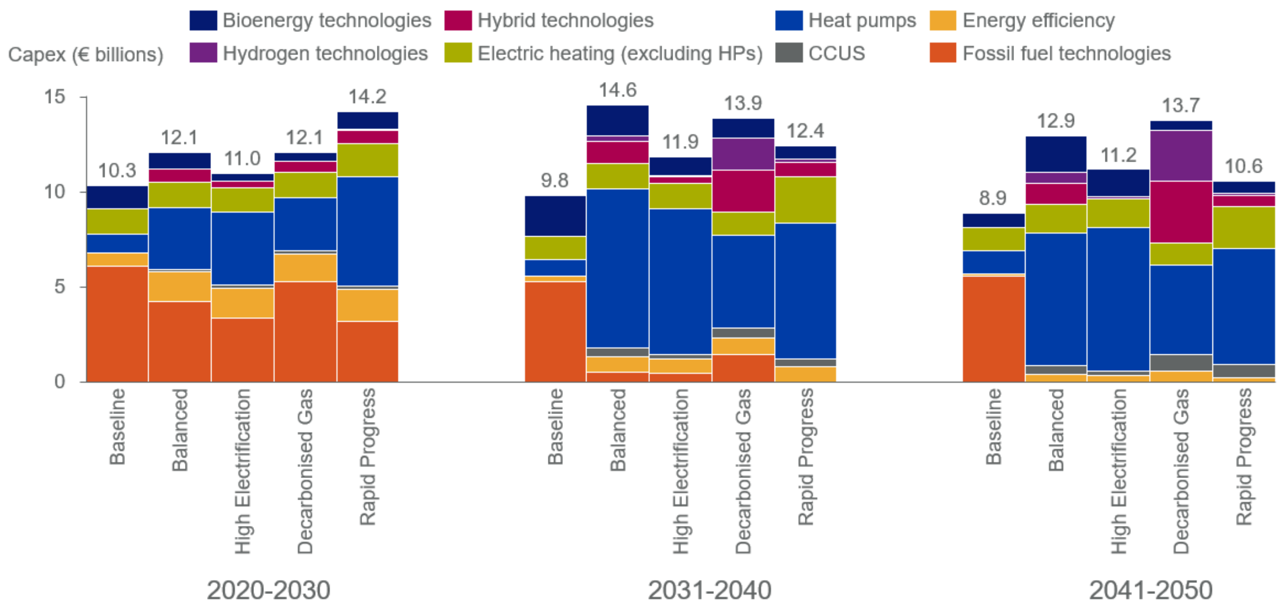
The industry sector sees the largest increase in fuel prices between 2020 and 2050; this effect is most significant in scenarios with high hydrogen use in industry. The *Baseline* scenario sees a 5% increase in total industry fuel costs (caused by slightly increasing fossil fuel prices), but the increases in costs in the other scenarios range from 157% in *Rapid Progress* to 267% in *Decarbonised Gas* by 2050. Coupled with the relatively high fuel use seen across intensive industrial sectors, significant uptake of hydrogen in the *Balanced*, *Decarbonised Gas* and *Rapid Progress* scenarios is a major factor in this fuel cost increase. An increase in electrification of heat in industry also leads to higher annual fuel costs compared to the counterfactual technology (that is, prior to technology / fuel switching). In contrast, in the *Rapid Progress* scenario, the availability of large volumes of biomethane (which is relatively cheaper than hydrogen or electricity) prioritised for industry leads to the lowest scenario fuel costs by 2050.

8.2 Capital costs (capex)

The total upfront investments for heating systems and energy-efficiency improvements vary significantly between the scenarios, as each scenario decarbonises heat at different rates and with differing technology mixes. This section aggregates the upfront capex as the total costs of the heating technologies, including costs paid by both the consumer and the upfront costs covered by policy support (such as grants), and including the upfront costs for both heating system replacements and energy-efficiency improvements. Lastly, the costs presented are for on-site investment costs so, for example, district heating upfront costs are excluded as they are included in end users' fuel bills, hence consumers pay for district heating as continuous fuel costs (see Section 8.3).

Figure 51 shows the total upfront costs paid for heating system replacements and energy-efficiency improvements in each decade for all scenarios by upfront investment type. *Figure 52* shows the same but by sector.

Figure 51: Total upfront costs paid for heating system replacements and energy-efficiency improvements in each scenario and decade, by upfront investment type (€$_{2019}$, millions)



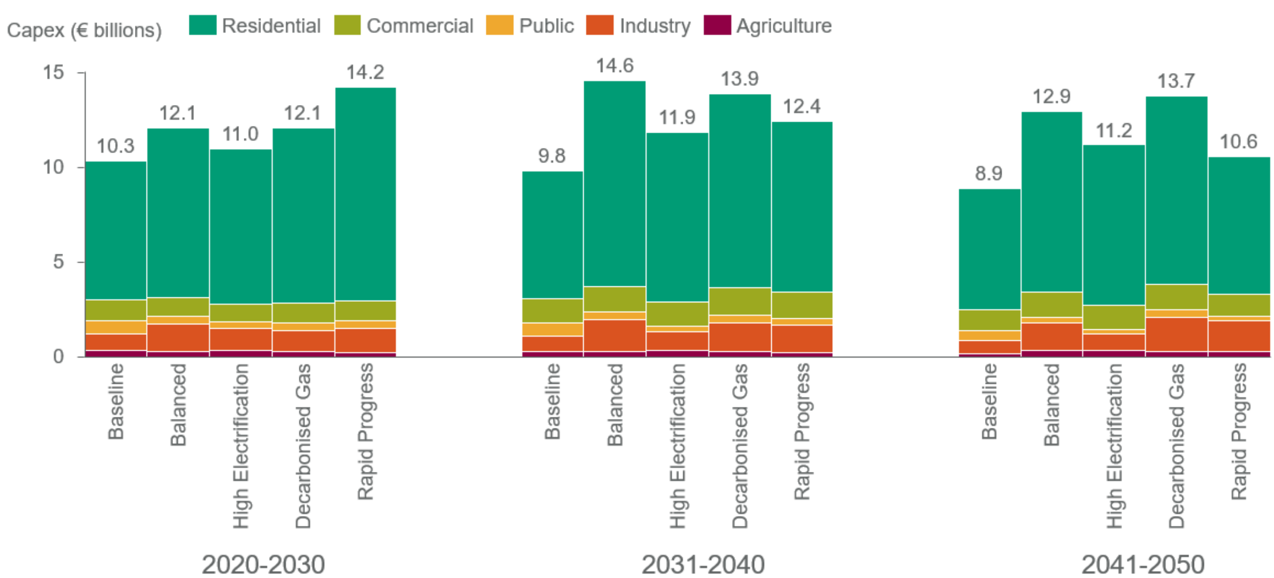
Between 2020 and 2030, the *Baseline* scenario has the lowest total investment costs for on-site technologies, mainly due to lower investment in energy-efficiency improvements and significantly less investment in higher capex renewable technologies than in the decarbonised scenarios. The scenarios with the highest and most rapid deployment of heat pumps (*Rapid Progress*, then *High Electrification*) result in the lowest investment costs in fossil fuel technologies. The *Baseline* scenario has significantly higher fossil fuel technology costs due to less switching to low-carbon heating technologies, caused by the lower level of grant and other policy support for low-carbon heating modelled in the decarbonised scenarios. Costs for electric heating and energy efficiency are largely similar across all decarbonised scenarios between 2020 and 2030, as are investment costs in bioenergy technologies (except for the *High Electrification* scenario, where this is lower). The total costs between 2020 and 2030 are highest in *Rapid Progress* due to the higher initial turnover of residential gas and oil boilers, and the significant increase in heat pump investment in this scenario compared to all other scenarios. *High Electrification* has the lowest costs in this time period of the decarbonised scenarios due to its lower levels of installed hybrids and bioenergy technologies, particularly compared to the *Balanced* and *Decarbonised Gas* scenarios.

Between 2031 and 2040, the *Baseline* scenario remains the lowest cost, as fossil fuel technologies generally still have lower upfront costs than renewable technologies, and there is no fossil fuel technology phase-out modelled in this scenario. There is, however, significant uptake of bioenergy technologies in the *Baseline* scenario driven by low fuel prices of solid biomass and bio wastes. Of the decarbonised scenarios, *Rapid Progress* is no longer the scenario with the highest upfront costs; the increased technology turnover rate (explained in Section 3.3.3) and the earlier fossil fuel phase-out date led to an increased number of technology replacements in the 2020s, and so fewer technologies need to be replaced in the 2030s in this scenario. The *Balanced* scenario has the highest upfront costs in this period, led by high deployment of heat pumps and hybrid technologies. In contrast, *Decarbonised Gas* still sees high investment in fossil fuel technologies (especially in the residential sector), while also seeing significantly higher deployment of hybrid technologies than in the other decarbonised scenarios. The higher costs in these technologies in *Decarbonised Gas* make up for the lower deployment of heat pumps in the 2020s and 2030s compared to the other decarbonised scenarios. *High Electrification* is again the decarbonised scenario with the lowest upfront costs in this decade due to lower investment costs in hybrid and bioenergy technologies than the other decarbonised scenarios.

From 2041 to 2050, *Decarbonised Gas* is now the scenario with the highest upfront investment due to high deployment in hybrid and hydrogen heating technologies, as hydrogen becomes available to an increasing number of consumers. The *Balanced* scenario follows based on deployment of hybrid and hydrogen heating technologies accompanied by a large amount of bioenergy technologies in off-grid properties. The *Rapid Progress* scenario has the lowest investment in on-site technologies in this decade of all the decarbonised scenarios, partly due to high deployment of direct electric heating technologies in buildings unsuitable for heat pumps.

Figure 52 compares these same total upfront costs between scenarios in each decade, but instead disaggregated by sector. The residential sector dominates costs across all scenarios in each decade, which is expected, as this sector has the highest number of buildings. The significant variation between scenarios and decades in upfront costs in the residential sector is aligns to the scenario variation explained in the above paragraphs. The higher industrial upfront costs beyond 2030 in the *Balanced* and *Decarbonised Gas* scenarios result from higher CCUS deployment, as also seen in *Figure 51*.

Figure 52: Total upfront costs paid for heating system replacements and energy-efficiency improvements in each scenario and decade, by sector (in €$_{2019}$, millions)



8.3 Additional capital investment in net-zero scenarios

An additional €4.2-8.7 billion of investment is required to decarbonise the buildings sector. For the industry sector, an additional investment of €0.6-2.1 billion in low-carbon technologies is required. Investments are also required in hydrogen, district heat and electricity infrastructure. *Table 6* details the investments estimated for various sectors and infrastructure options by scenario.

Table 6: Total capital investment required by scenario, for energy-efficiency improvements (by sector), heating technologies (by sector) and renewable fuel production infrastructure, in €bn, based on the total sum of in-year investments (not discounted)

Investment type	Baseline	Decarbonised Gas	High Electrification	Balanced	Rapid Progress
Energy-efficiency improvements					
Residential	0.39	2.04	1.86	1.95	1.85
Services	0.62	0.70	0.62	0.66	0.63
Industry	0.11	0.16	0.19	0.19	0.18
Heat technology					
Residential	20.16	27.37	23.79	27.48	25.73
Services	4.69	4.40	3.75	4.11	3.96
Industry	2.34	2.66	2.20	3.31	2.81
Infrastructure					
District heating infrastructure*	0.07	3.53	12.14	7.55	11.74
Hydrogen infrastructure and production*	0.00	23.07	2.24	6.21	3.15
Electricity infrastructure*	10.51	16.27	25.41	21.01	23.87
CCUS infrastructure	0	1.55	0.62	1.04	1.30
Total	**38.88**	**81.74**	**72.82**	**73.51**	**75.22**

*In this analysis, consumers pay these network costs in their fuel bills.

8.4 Cost benefit analysis (CBA) summary

This section details the high-level scenario results of the economic CBA, aligned to Annex VIII of the Energy Efficiency Directive [9]. It takes a societal point of view by incorporating socio-economic factors, such as a suitable social discount rate (SDR), and environmental externalities in determining net present cost (NPC). The key assumptions and inputs used to produce the total lifetime cost of each scenario, via the CBA, are noted below:

- Plant and equipment capital investments (including that provided by policy support, such as grants).
- Associated energy networks capital investments.
- Variable and fixed opex (excluding energy costs).
- Long-run variable energy costs (variable wholesale and network costs).
- Carbon costs (based on traded shadow prices of carbon provided in the Public Spending Code).
- Damage costs of non-GHG pollutants (PM, NOx, SOx, VOC costs) as set out in the Public Spending Code.

- SDR of 4% as specified by the Public Spending Code.

The benefits considered in the NPC calculation are the value of outputs to the consumer and external benefits, such as environmental benefits and GHG emissions reductions. It was not possible to consider other benefits, such as labour market effects, energy security and competitiveness, and health and safety benefits. Consumers typically experience lower fuel costs after switching to renewable heating technologies (apart from the industry sector, as discussed in Section 8.1 ; this benefit is captured via a lower net present value of fuel costs in the decarbonised scenarios compared to the *Baseline* scenario. The shadow price of carbon is used to estimate the environmental impact, by placing a monetary value on CO_2 emissions. As emissions reduce in the decarbonised scenarios, this approach results in a lower cost of carbon in those scenarios compared to the *Baseline* scenario. Non-GHG pollutants A similar approach is taken for non-greenhouse gas pollutants.

Table 7 and *Figure 53* below present a summary of the results of the economic CBA. At a high level, three of the four decarbonised scenarios show a decrease in NPC compared to the *Baseline* scenario. The costs of the *High Electrification* scenario are 6.3% lower than the *Baseline* scenario, with the *Balanced* and *Rapid Progress* scenarios showing total discounted costs that are 1.4% and 0.3% lower. The *Decarbonised Gas* scenario has the highest cost of all the energy systems, 4.5% higher than the *Baseline* scenario.

Hydrogen and CCUS infrastructure investments, the higher cost of installing hydrogen technologies and the relatively high price of green hydrogen fuels are the main differences that cause the *Decarbonised Gas* scenario to have the highest overall costs. These factors, and the speed of decarbonisation, also influence the costs in the *Rapid Progress* scenario. The technology and infrastructure investments occur earlier and benefit less from the discounting effect than other scenarios. As shown in *Table 6*, the costs in the *Rapid Progress* scenarios are comparable to other scenarios before adjusting the costs for the future value of money. The *High Electrification* scenario has the lowest deployment of CCUS and hydrogen use. It also sees some benefits from the increased efficiency of electric heating, which offsets the higher unit costs of electricity, mainly where heat pumps are used.

The declining role of fossil fuel in the net-zero scenarios reduces CO_2 emissions costs. This decline also reduces those emissions that negatively affect air quality and helps reduce costs. However, the combustion of solid biomass in the net-zero scenarios reduces the overall benefits seen. The *Rapid Progress* scenario reaches net zero sooner so emits less overall. It also gains from emissions removals through the use of BECCS from the mid-2040s. This leads to fewer emissions overall and a lower cost of carbon. Conversely, the *Decarbonised Gas* scenario has the highest emissions costs of the other decarbonised scenarios due to the higher cumulative emissions in this scenario. The shadow price of carbon has a large influence on the overall outcome. An overall price increase, as well as a faster rise in the earlier years, would improve the relative cost outcome of the scenario that decarbonise quickest.

Decarbonised Gas is the scenario with the highest infrastructure costs, due to the large additional investment required for the high levels of deployment of hydrogen for heating in this scenario. The scenario with the highest non-infrastructure fuel costs is the *Baseline* scenario, due to the continued reliance on fossil fuels and low deployment of district heating, and low additional electrification of heat. All decarbonised scenarios show a significant increase in fuel infrastructure costs, due to investment in hydrogen and district heating infrastructure, as well as additional electricity infrastructure investment.

Figure 53: Economic CBA – summary of NPCs (€bn) across scenarios

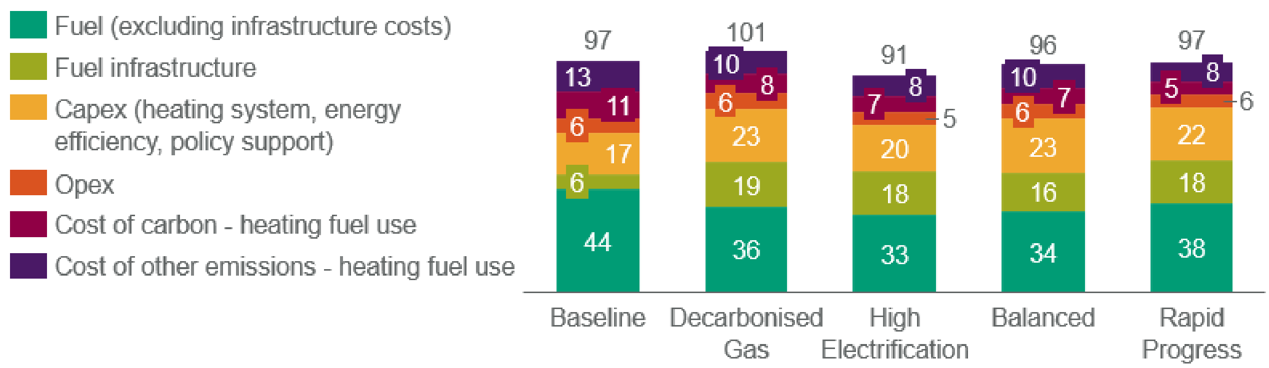


Table 7: Change, relative to Baseline, of the NPCs by cost category, across scenarios based on an economic CBA

NPC change (relative to Baseline)	Baseline	Decarbonised Gas	High Electrification	Balanced	Rapid Progress
Fuel (excluding infrastructure costs)	0%	-19%	-28%	-23%	-16%
Fuel infrastructure	0%	221%	221%	177%	218%
Capex (heating system, energy efficiency, policy support)	0%	32%	14%	32%	29%
Opex	0%	3%	-15%	-4%	-9%
Cost of carbon - heating fuel use	0%	-28%	-38%	-37%	-52%
Cost of other emissions - heating fuel use	0%	-23%	-34%	-23%	-38%

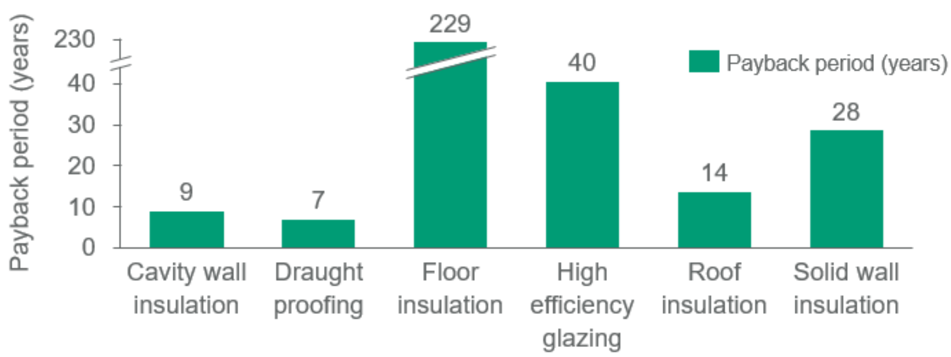
It should be noted that in the *Rapid Progress* scenario, an additional NPC of €3.8 billion would be required outside of the energy sector to lower the production costs of biomethane so it can be available at a competitive price and in more significant quantities to drive the uptake of biomethane utilised in the industry sector. As these costs are not in the energy sector, they are excluded from the CBA results presented here.

8.5 Energy-efficiency cost effectiveness

The uptake of energy-efficiency measures is determined based on payback period, as described in the 'Energy-efficiency measures' section in the Low Carbon Heating and Cooling Technologies report[26] in this National Heat Study.

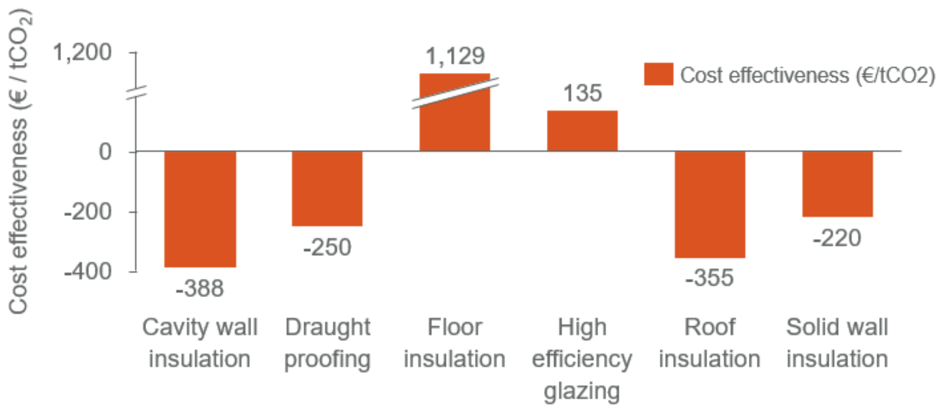
Figure 54 shows the average payback period of fabric improvement energy-efficiency measures, using the example of a residential detached home with an oil boiler (the combination of residential building structure and counterfactual heating system with the highest number of buildings). *Figure 55* shows the average cost of decarbonisation (in terms of €/tCO_2) for fabric improvement energy-efficiency measures in the same buildings.

Figure 54: The average payback period of fabric improvement energy-efficiency measures available in the residential sector in residential detached houses with oil boilers



[26] See footnote 5.

Figure 55: The average cost effectiveness of fabric improvement energy-efficiency measures available in the residential sector in residential detached houses with oil boilers



The payback periods in *Figure 54* show that in residential detached homes with oil boilers, only cavity wall insulation and draught proofing have average payback periods below ten years, with roof insulation the only other measure with a payback period less than 20 years. The floor insulation measure has a very poor cost effectiveness in terms of € / tonne CO_2, caused by the high costs and low savings, which lead to its high-payback period (see *Figure 55*). As the uptake of energy efficiency by consumers is determined using these payback periods (along with a consumer's willingness to pay), uptake of measures other than cavity wall insulation and draught proofing is generally low. However, note that these payback periods are not inclusive of any energy efficiency grants, which effectively support the consumer by lowering the payback period of these measures, thereby driving increased uptake.

Figure 55 shows the average cost of abated emissions of the same fabric improvement energy-efficiency measures (over the lifetime of their use) in the same portion of the stock, using typical lifetimes of these energy-efficiency measures (for more information, please see the Low Carbon Heating and Cooling Technologies report[27] in this National Heat Study). As the lifetimes of these energy-efficiency measures are typically significantly longer than the payback period thresholds (>35 years), significant carbon emissions can be abated alongside net cost savings for most of these measures over their lifetime. The negative € / tonne CO_2 values alongside high-payback periods show that energy-efficiency measures have the potential for significant financial and carbon savings, but the long-term nature of the savings may cause generally low uptake.

If a low-carbon heating technology is installed alongside energy-efficiency measures, then the carbon emissions savings of the combined energy efficiency and low-carbon heating technology will be greater than the savings from either installed alone. This is due to low-carbon heating alongside fuel savings, although the difference between these emissions savings and the savings resulting from the installation of a low-carbon heating technology alone is marginal. However, additional benefits from installation of both include increased comfort seen by the consumer and consumer fuel cost savings. Widespread energy efficiency will also improve security of energy supply due to lower fuel consumption, although significant deployment of energy efficiency will be required for this to be impactful.

[27] See footnote 5.

9 Energy system context

The decarbonisation of the heat sector occurs in parallel and integrates with other components of the energy system; for example, potential district heating networks, the electricity system, hydrogen supply and usage, and biomethane supply and usage.

9.1 District heating

We have analysed the heating and cooling demand of each sector spatially to produce a national map of heat demand. This map also includes data on potential waste heat sources and the potential geothermal energy resource at different depths. The data were linked to Ireland's 18,641 small geographical areas. The national map of heat demand is available on the SEAI website [28].

9.1.1 Existing spatial thermal demand

A detailed spatial analysis of heat demand and potential heat sources forms the foundation of the analysis of the potential for district heating in Ireland conducted as part of the broader National Heat Study.[28]

Table 8 shows the total annual heat and cooling consumption by sector; these results are of the magnitude expected and are consistent with the 2015 Irish Heat Demand Map. The overall current thermal demand of heating for Ireland at SA resolution covers an area of 70,264 km^2 over 18,641 small areas of variable size.

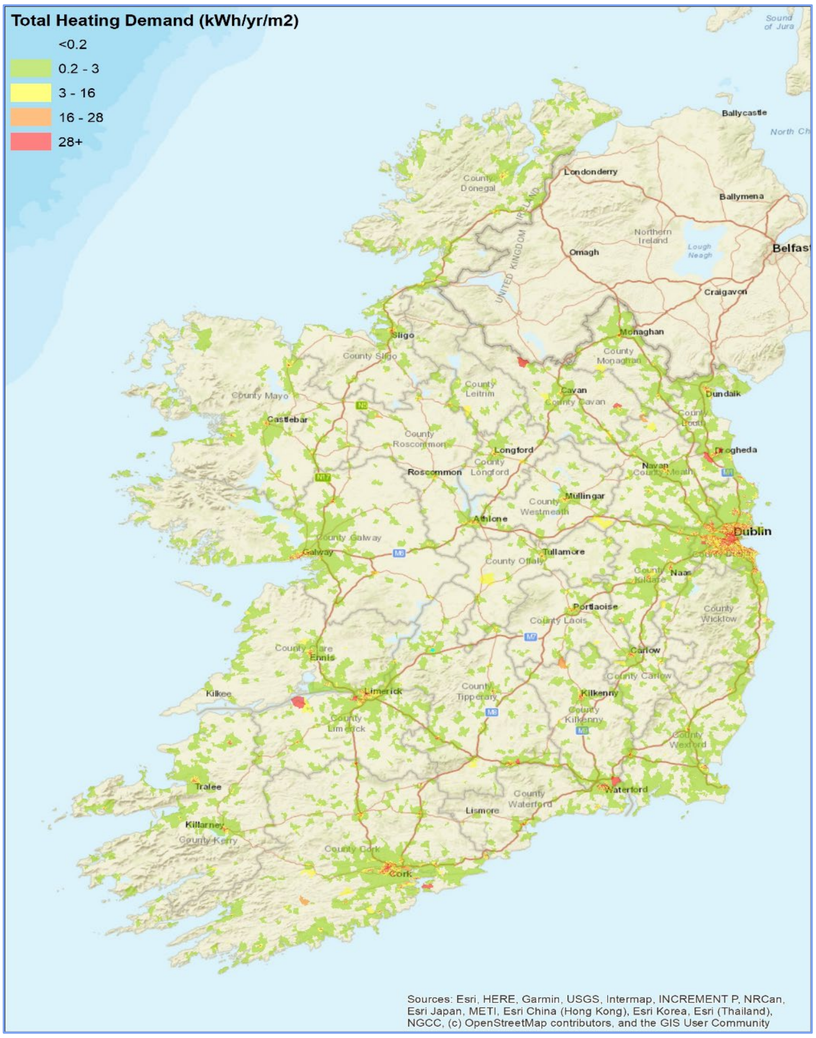
Table 8: Total demand by sector [MWh/year]

Requirement	Residential	Commercial	Public	Industrial (ETS only)
Heat MWh/year	19,411,123	5,677,295	3,543,041	12,740,213

Out of the 18,641 areas, all have a 'thermal heat demand' and 4,053 areas returned 'no thermal cooling demand'. The area heat density range was from 3.1 x 10^{-6} kWh/m^2 to 3,571 kWh/m^2 with an average value of 17.0 kWh/m^2 and a median of 9.0 kWh/m^2. *Figure 56* shows a sample of results.

[28] For more information on the spatial analysis of heating and cooling in Ireland, please see the Heating and Cooling in Ireland Today report of this National Heat Study. Available: www.seai.ie/publications/Heating-and-cooling-in-Ireland-today.pdf.
For more information on potential heat sources for district heating, please see the District Heating and Cooling report of this National Heat Study. Available: : www.seai.ie/publications/District-Heating-and-Cooling.pdf

Figure 56: Heat density map (all sectors)



9.1.2 Current status of district heating in Ireland

In order to understand the current state and future potential of district heating in Ireland, we combined existing literature on district heating in Ireland with consultation and interviews with key stakeholders. This exercise confirmed limited deployment of district heating in Ireland, and that heat networks in operation tend to be small scale. However, previous work has suggested that district heating has the potential to play a more prominent role. More recently, larger municipal scale projects such as the Dublin City District Heating scheme, Tallaght District Heating scheme and the Clongriffin District Heating Network have made progress towards construction.

9.1.3 District heating model considerations

The district heating model, developed as part of the District Heating and Cooling report[29] in this National Heat Study, analyses the cost of constructing a district heating network and operating the heat generation plant in every small geographic area in Ireland. The model aims to provide a high-level analysis of which small areas in Ireland show the greatest economic viability for district heating. The profile and characteristics of heat demand at a small area (SA) resolution in Ireland are key inputs to this model. Through pairing the domestic, commercial and public heat demand for all 18,641 SAs in Ireland with the district heating model, we determined the capex and opex of implementing a district heating network for each SA.

There are four key costs within the model: the generating technologies, thermal storage, the pipe network (trenching costs differ for city and rural areas) and the connection of consumers to the network. The model includes the following technology options for providing heat to the networks:

[29] See footnote 19.

- Option 1 – Heat extraction from power stations and industrial waste heat recovery (including data centres)
- Option 2 – Biomass boiler
- Option 3 – Biomass CHP with biomass boiler backup
- Option 4 – Air source heat pump (ASHP)
- Option 5 – Ground source heat pump (GSHP)
- Option 6 – Low-carbon gas CHP
- Option 7 – Geothermal at depth up to 400 m.

In order to understand the potential that heat extraction/recovery (Option 1) and geothermal (Option 7) had within Ireland, these two options received a detailed analysis.

9.1.4 Heat extraction from power stations and industrial waste heat recovery potential

Power stations produce large amounts of low-temperature heat as a by-product of generating electricity. This low-temperature heat energy is often unsuitable for district heating networks, which typically need higher-temperature heat inputs. Adding additional equipment allows these power stations to provide heat at a temperature suitable for heat networks. Potential exists in Ireland for converting some existing power stations to extract heat and for building new stations as CHP-ready plant. We evaluated the potential for heat extraction from these sources, and excluded power stations operating at peak load – open cycle gas turbines – and others closing in the next couple of years.

The total heat extraction and waste heat recovery potential is estimated at 10.9 TWh_{th}/year (1.8 GW_{th}), which equates to 38% of national heat demand for the domestic, commercial and public sectors:

- Heat extraction from six power stations – 9 TWh_{th}/year.
- Heat extraction from two energy-from-waste (EfW) sites – 0.4 TWh_{th}/year.
- Heat recovery from 17 industrial sites – 1.5 TWh_{th}/year.

Data centres show promising potential, but more publicly available data is required regarding the operation of Irish data centres to fully assess this option.

9.1.5 Geothermal potential

Other countries use geothermal energy to power district heating networks. These systems access heat energy available under the ground. Where suitable, it has the potential to provide abundant, low-cost heat. GSI has carried out several detailed evaluations of geothermal energy potential [4]; these recent studies and data provided by GSI were reviewed in detail as part of the National Heat Study, and provided key inputs into this analysis. High resolution and robust data are available in Ireland to depths of 400 m. Beyond this depth, significant further potential may exist, but there is great uncertainty about the suitability of sites; research funded by GSI and SEAI is ongoing. However, at the time of writing, there is no robust framework for geological suitability at depths below 400 m; hence, the focus of this report is on geothermal potential up to 400 m. It should be noted that using geothermal energy for heat at depths up to 400 m requires heat pump technology, so it is considered under GSHP (Option 5) rather than in a separate category for geothermal energy.

9.1.6 Key results from the initial spatial analysis

An important variable when assessing the potential for district heating in an SA is heat density. Linear heat density was first considered, which is total heat demand divided by the road length in each SA [MWh/km]. The analysis of district heating potential in Ireland indicates that 311 SAs out of 18,641 have a heat density greater than 10,000 MWh/km; it is these locations that show the greatest potential for district heating. While the 2015 SEAI district heating study [10], carried out by AECOM, proposed that SAs with a heat density less than 10,000 MWh/km are not viable for district heating, the results from this work suggest that the crucial cut-off is in fact lower, with construction costs (€/MWh) plateauing at 1,000 MWh/km. Hence, the cost (€/MWh) of constructing a network with a heat density of 1,000 MWh/km is very similar to a heat density of >10,000 MWh/km. This is important because 51% of all SAs in Ireland have a heat density between 1,000 and 10,000 MWh/km. To put this into perspective, this analysis shows that around 2.5% of the total heat demand from the residential, commercial and public sectors has a high economic viability for district heating (>10,000 MWh/km). However, district heating could potentially serve up to 54% of heat demand (>1,000 MWh/km).

Results suggest that, in terms of capital costs, biomass boilers and ASHPs are the cheapest options for district heating, although CHP and GSHPs are not substantially more expensive. It is also worth noting that CHP provides the ability to generate and sell electricity, which provides additional revenue. The analysis shows that extraction of heat from power stations and waste heat recovery from industrial sites is notably more expensive than the other generation options considered. However, note that we only considered existing power stations in the analysis, and the costs of retrofitting power stations to extract heat are substantial. Should new power stations be built in the coming decades that are CHP-ready, this would likely be notably cheaper.

If every property in a SA is provided with heat, the cost of connecting each property to the network is the greatest component of the total capital cost. Therefore, the number of consumers being connected to a district heating scheme should be carefully optimised. Public sector buildings can have a key role in improving the economics of heat networks by providing anchor heat loads.

9.2 Electricity system

9.2.1 Retail electricity price estimation

Heat technologies fuelled by electricity are available in all sectors. The retail price of electricity is a crucial component in determining the cost effectiveness of these technologies, and it is therefore highly influential in electrified heat uptake decisions.

The retail electricity price is charged per unit of electricity consumption (€/kWh). It comprises several factors including wholesale costs, system services costs, transmission and distribution (network) costs, supplier costs, value-added tax (VAT), and the Public Service Obligation (PSO) levy, which supports special categories of generation, including renewables [29]. The modelling approach seeks to capture the annual evolution of these costs, which in a competitive market should reflect the retail price of electricity, by applying an annual growth rate for total costs to scale the current retail electricity prices for electricity customers. The change in wholesale, system services, and PSO components are captured via calculating the annuitised investment cost of system resources. These include generation, storage, interconnection and demand-side units, as well as their short-run variable costs (such as, fuel, ETS) costs, which is simulated using the PLEXOS unit commitment and economic dispatch software [30].

The change in network cost, which aims to reflect the costs of developing, maintaining and operating the transmission and distribution electricity networks, is captured via components that are fixed, dependent on peak and total demand, and variable renewable installed capacity. Further detail on the methodology used for network costs is in the Electricity Infrastructure report[30] of this National Heat Study.

9.2.2 Electricity demand

The heat sector expects electricity demand will grow strongly between now and 2030, with data centres being a key driver in the short-to-medium term [31]. The electrification of heat and transport, while removing emissions from these sectors, will drive further electricity demand growth and hence the need for investment in the electricity system. *Figure 57* presents the total electricity demand for each scenario. Electricity demand, depending on the scenario, grows by 56-64% between 2020 and 2030, and 62-80% between 2030 and 2050.

Figure 58 shows the electricity demand from the main drivers of this growth. Data centres are the dominant form of electricity demand growth between now and 2030, followed by electric vehicle growth. Heat sector electrification, in contrast, occurs later in the horizon. By 2030 there has been only a small growth in total electrified heat; however, by 2050, heat electrification is the dominant growth area in all scenarios except the *Baseline*.

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[30] SEAI, 'Electricity Infrastructure'. 2022 [Online]. Available: www.seai.ie/publications/Electricity-Infrastructure.pdf.

Figure 57: Total electricity demand, 2020-2050, by scenario

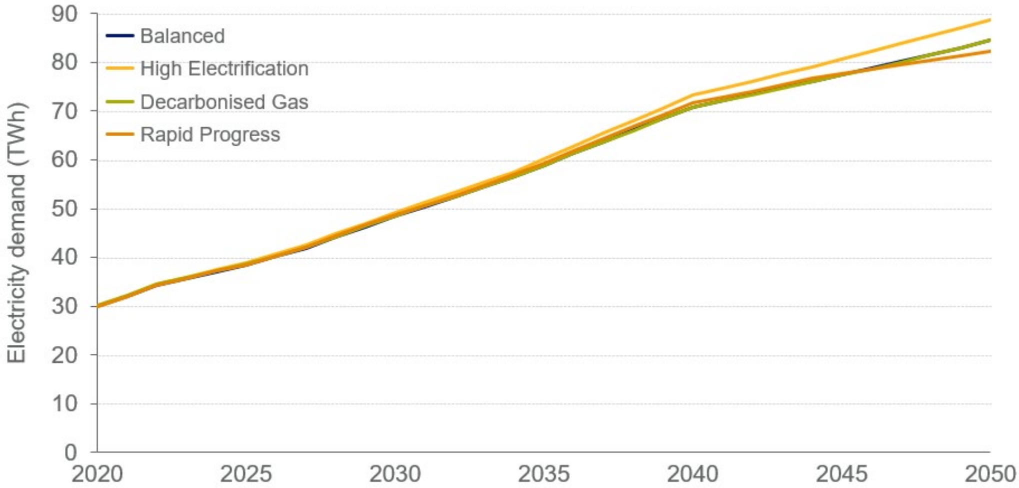
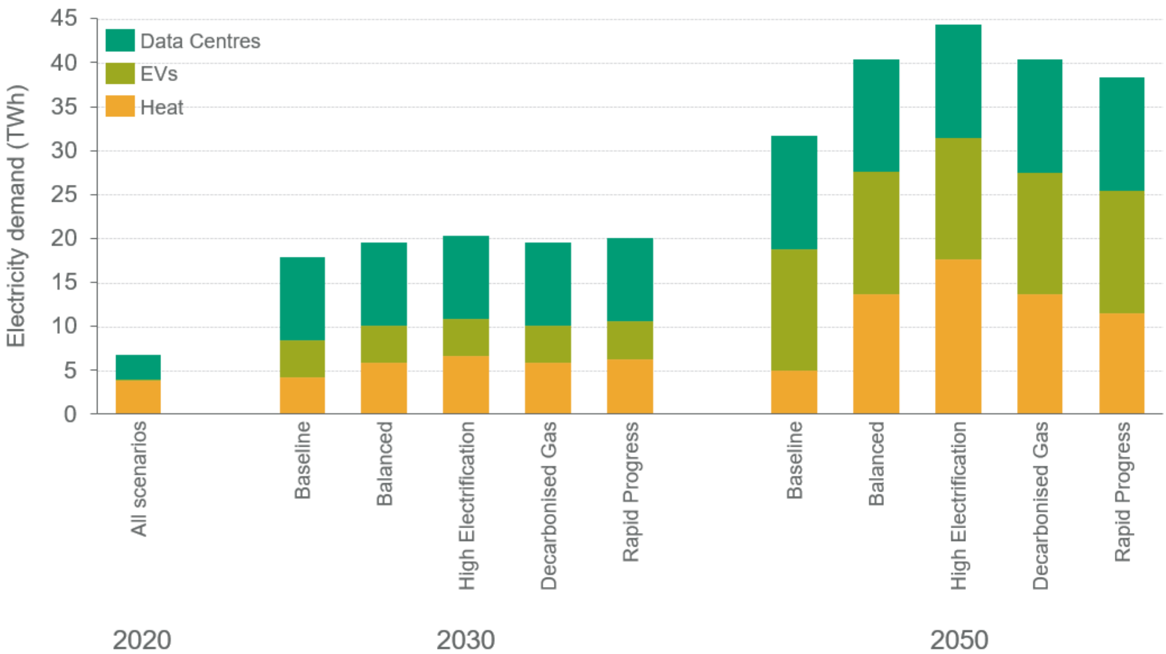


Figure 58: Electricity demand from primary growth sectors for electricity demand in 2020, 2030, and 2050, by scenario



9.2.3 Electricity supply

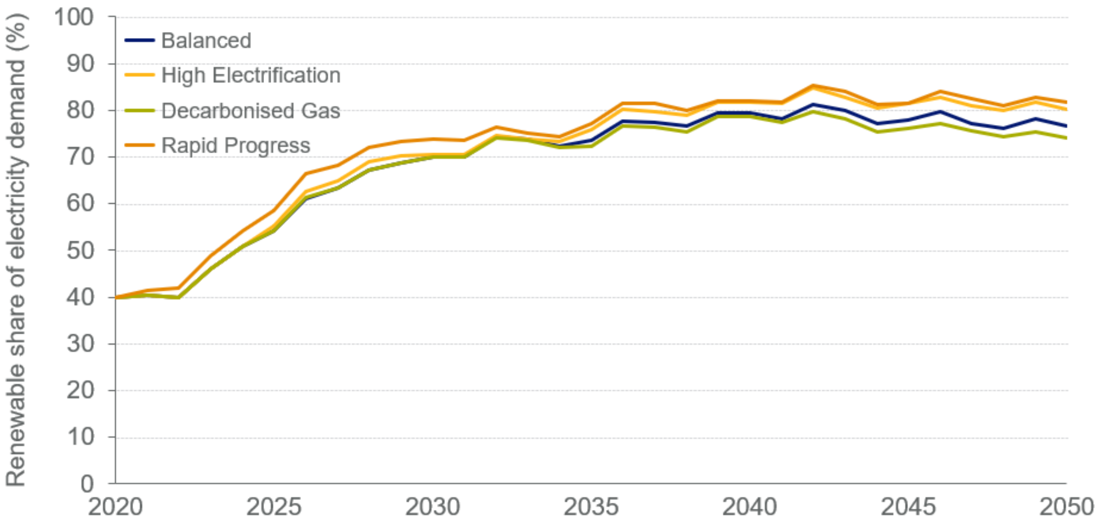
The consequences of demand growth include the need for a higher deployment of renewable generation capacity to meet a given renewable electricity (RES-E) target. The deployment of renewables and the associated flexibility and network investments lead to increased investment costs but reduced fuel and emissions costs. However, electricity demand growth may also require further investment in conventional, firm generation capacity[31] to meet security of electricity supply standards. The ambition for net zero by 2050 implies that firm power generation needs to fuel switch in the coming decades. This introduces the possibility of hydrogen, CCS and negative emissions technologies.

The share of electricity from renewable generation has increased fivefold between 2005 and 2020 [32]. The heat sector expects variable renewables to continue playing a primary role in electricity supply decarbonisation in Ireland, with a growing focus on diversifying the renewable energy mix, for example solar PV and offshore wind,

[31] 'Firm' generation capacity refers to power plants that are able to supply energy as needed up to a given constant rate [21], which is not the case with variable renewable energy sources due to its weather dependency.

within a cost-competitive framework. *Figure 59* shows the share of electricity demand met by renewable electricity. Flexibility levers such as interconnection with neighbouring jurisdictions, storage and demand-side management are assumed to increase in order to integrate higher shares of variable renewable electricity generation.

Figure 59: Share of electricity demand met by renewable electricity sources



Three low-carbon firm generation archetypes are modelled, namely:

- Combined-cycle gas turbines with CCS;
- BECCS (as a negative emissions technology); and
- Hydrogen-blended/fuelling for the remaining gas turbines.

The model maps the deployment of these decarbonisation archetypes to the scenario storylines. For example, *Decarbonised Gas* assumes stronger uptake of gas CCS and BECCS, whereas *High Electrification* and *Rapid Progress* assumes a higher usage of hydrogen to decarbonise firm electricity generation.

The gas CCS and power BECCs modelling is informed by the Carbon Capture, Utilisation and Storage (CCUS) report[32] in this National Heat Study. We assume an individual power BECCS unit has a capacity of 300 MW, with the operating hours set to meet each scenario's negative emissions volume. *Table 9* shows the number of gas CCS power generation sites. Note that gas CCS is not a zero-carbon generation technology as the capture rate is less than 100%.

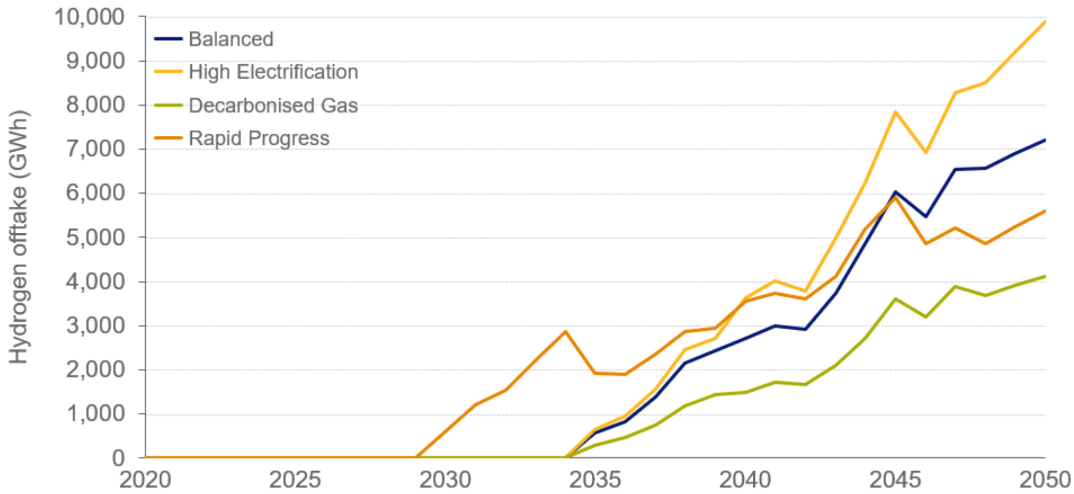
Table 9: CCS deployment

	Baseline	Balanced	Decarbonised Gas	High Electrification	Rapid Progress
# of gas power CCS sites	0	2	5	0	1

Green hydrogen is used to fuel the remaining firm generation capacity to achieve the net-zero targets, with the modelling informed by the Low Carbon Gases for Heat report[33] in this National Heat Study. *Figure 60* shows the green hydrogen offtake in the power sector.

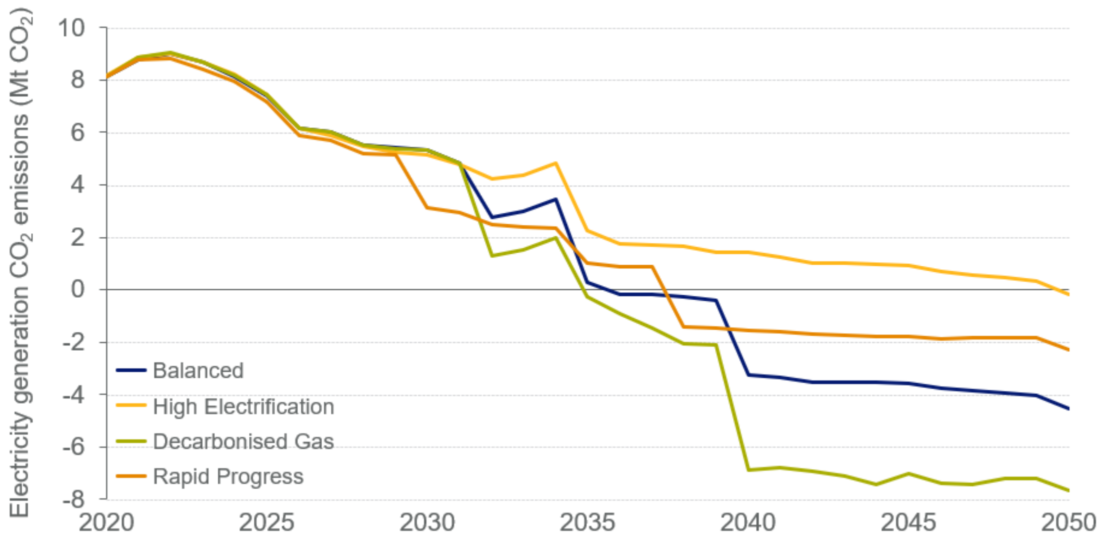
[32] See footnote 13.
[33] See footnote 12.

Figure 60: Hydrogen consumption in the power sector



Power sector CO_2 emissions are a function of total demand, the net carbon intensity of dispatched generation, and the net import or export behaviour of interconnector trades. Careful power system planning is required to ensure that electricity supply decarbonisation does not lag behind electrification and other sources of demand growth, otherwise power sector emissions are likely to increase, arising from an increase in fossil fuel-fired generation output. This will have an onward negative impact on the emissions associated with electrified heat demand.

Figure 61: Total CO_2 emissions from electricity generation



9.3 Hydrogen

Hydrogen contributes to the supply of energy for heating in all scenarios considered in the National Heat Study. Hydrogen-fuelled heating appliances directly use 2-12 TWh, with further demand in the power sector for dispatchable generation supplied by hydrogen and additional use in the transport sector modelled. This also varies by scenario, as described in Section 9.2.

The following section provides an overview of the modelling approach and assumptions; for more information and a further description of the methodology, please see the Low Carbon Gases for Heat report[34] in this National Heat Study.

We considered three methods of hydrogen production for this study: electrolysis using electricity-grid-connected electrolysers, electrolysis using electrolysers co-located with purpose-built renewables, and biomass gasification

[34] See footnote 12.

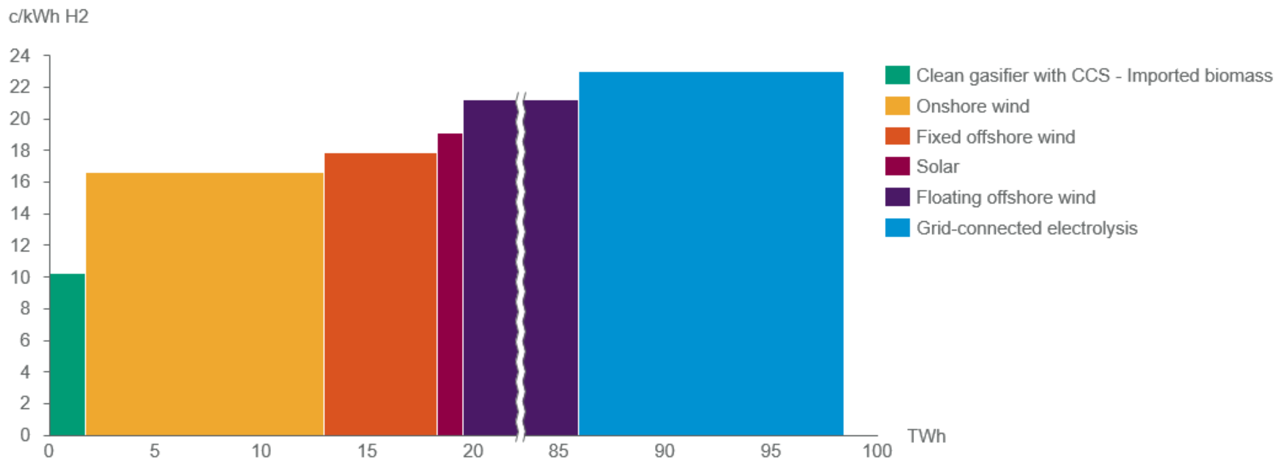
with CCS. Renewables considered for co-located renewable generation include onshore wind, solar, fixed offshore wind and floating offshore wind. Each renewable generation type was limited based on the potential for renewable generation deployment in Ireland. *Table 10* gives the renewable electricity hydrogen production capacity for the renewable generation types considered.

Table 10: Renewable electricity production capacity beyond what is planned for electricity network connection

Renewable	Total additional capacity	Capacity for grid connection [33]	Capacity available for H_2 generation	Average capacity factor (%)	Earliest technology availability
Onshore wind [34]	6.3 GW	1.7 GW	4.6 GW	40%	Available now
Fixed offshore wind [35]	5 GW	3.3 GW	1.7 GW	50%	Available now
Floating offshore wind [35]	20 GW	1.4 GW	18.6 GW	55%	2035
Solar [33]	3.4 GW	1.4 GW	2 GW	11%	Available now

The model calculated the cost of producing hydrogen via each method, using assumptions about the costs of each hydrogen production method and the storage and distribution of the necessary hydrogen. *Figure 62* shows the long-run variable costs (LRVC) of producing hydrogen via each method in 2050 for the *Balanced* scenario.

Figure 62: LRVC of hydrogen production in 2050 in the Balanced scenario, by each method



The cheapest option is production of hydrogen via gasification of imported biomass, although the potential hydrogen resource via this method is relatively small compared to other methods. Electrolysers collocated with purpose-built onshore wind renewable generation are the next cheapest, followed by fixed offshore wind, solar and floating offshore wind. Grid-connected electrolysis is the most expensive method to produce hydrogen, however this is because *Figure 62* shows the LRVC cost of hydrogen if each production route were used to produce enough hydrogen to meet the full hydrogen demand. In 2050 in the *Balanced* scenario, hydrogen fuel use in the heat and power sectors is approximately 14.4 TWh (*Figure 64*), and so the grid-connected electrolysis is costed to produce the full 14.4 TWh. This amount of grid-connected hydrogen production will result in significant additional electricity demand on the grid, and so this hydrogen production method is expensive. Lower levels of demand could be met by grid-connected electrolysis to provide hydrogen at significantly cheaper cost when using cheap curtailed renewable electricity; however, this will not be the case if hydrogen is produced via grid-connected electrolysis at significant scale.

9.3.1 Production and uptake

There are two principal routes of green hydrogen production within the National Heat Study:

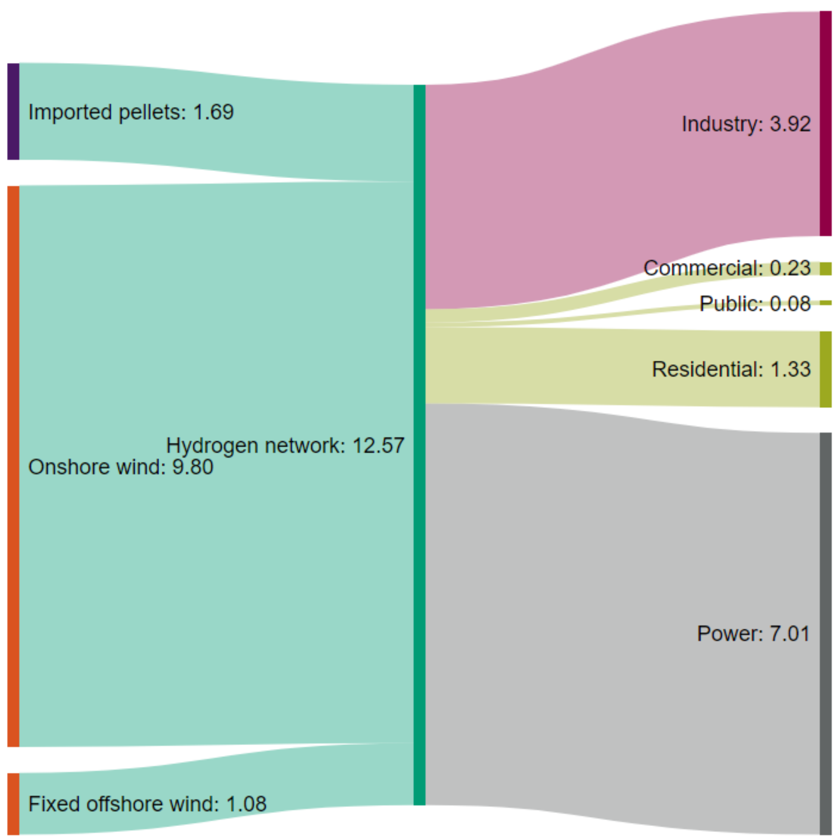
1. Electrolysis co-located with renewable electricity generation; and

2. Gasification of wood pellets with carbon capture.

Figure 63 presents a Sankey diagram of hydrogen production and consumption in the *Balanced* scenario in 2050. Note that this presents a snapshot of fuel production and consumption, but does not include losses and inefficiencies from production and storage of hydrogen. As shown in *Figure 63*, most of Ireland's hydrogen demand is met through electrolysis co-located with onshore and fixed offshore wind, while around 10% is produced using biomass gasification. The production mix below was determined considering the available resource (including for renewable electricity and imported pellets) and the relative cost of hydrogen produced through each route. The model considers grid-connected electrolysis but does not select it for uptake due to its higher cost. While gasification of imported biomass is the most cost-effective source of hydrogen (see the report on Low Carbon Gases for Heat[35] for further information), its uptake is limited to less than 2 TWh. This reflects the current TRL of gasification technology and takes a conservative view on the quantity of sustainable biomass that may be available for import. Domestic biomass is unlikely to be available for hydrogen production via gasification in significant amounts due to competing demands for domestic biomass resource across the heat and power sectors, based on the modelling conducted here. The 4.5 GW of onshore wind capacity, beyond that planned for connection to the electricity grid, is estimated to produce just over 10 TWh of hydrogen per year [33]. Fixed offshore wind with electrolysis is the next most affordable production route; around 0.8 GW offshore wind capacity is required to meet the remaining demand in the *Balanced* scenario.

While Ireland's capacity for fixed offshore wind beyond the needs of the electricity system is sufficient to supply the demand in the *Balanced* scenario, floating offshore wind is also required in the *Decarbonised Gas* scenario where total hydrogen demand is approximately 23 TWh. Floating offshore wind is projected to become available in Ireland by 2030, in time for hydrogen rollout in the 2030s [36]. Ireland's total capacity for offshore wind is estimated to be around 20 GW and would be capable of supplying far more hydrogen than what is required domestically, even within the *Decarbonised Gas* scenario. There is therefore considerable potential for export of hydrogen or related fuels (such as green ammonia), although this is beyond the scope of the National Heat Study.

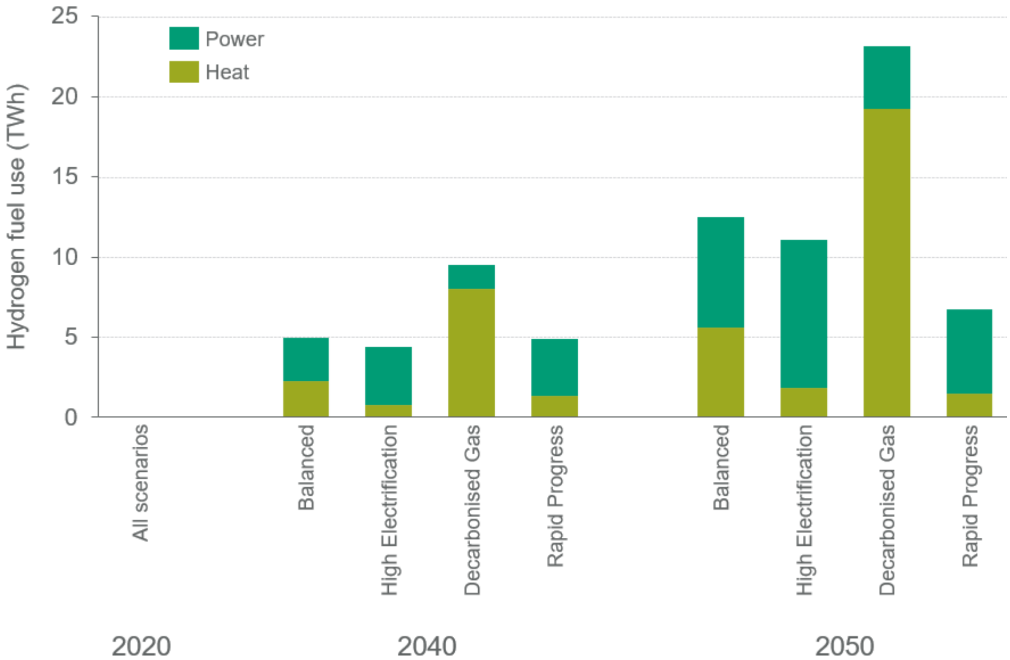
Figure 63: Sankey diagram for hydrogen production and use in 2050 in the Balanced scenario (TWh)



35 See footnote 12.

The power sector and industry dominate hydrogen demand in the *Balanced* scenario, with residential, commercial and public buildings requiring about 2 TWh out of the total 14 TWh supply. As discussed in the previous section, about 50% of the total hydrogen demand is from the power sector in the *Balanced* scenario. Although ultimately supplied largely from variable renewables, this represents a demand for flexible and dispatchable power generation that cannot be met directly from such as wind resource. The power sector demand for hydrogen is largest in the *High Electrification* scenario (around 9 TWh) due to assumptions made on the availability of BECCS and other dispachable plants in that scenario. Although 7 TWh of hydrogen for power will require over 7 TWh of renewable electricity to generate due to inefficiencies in the conversion processes between electricity and hydrogen, the production of hydrogen from renewable electricity provides dispatchable use of renewable electricity stored as hydrogen.

Figure 64: Total hydrogen consumption in each scenario in 2020, 2040 and 2050, by use in heat and power sectors



In the *High Electrification* and *Rapid Progress* scenarios, hydrogen consumption for heating is limited to use in the industry sector, with a hydrogen transmission network developed in the 2030s and 2040s to supply industrial consumers who wish to decarbonise using hydrogen for heating (more information is in the Low Carbon Gases for Heat report[36] in this National Heat Study). Typically, these are industrial sites already using hydrogen for heating and those not planning to install CCUS. Hydrogen is typically used for decarbonisation in industrial sites with demand for high-grade heat (>500 ° C); in the *Balanced* scenario, 65% of industrial processes using high-grade heat decarbonise using hydrogen. As residential, commercial and public consumers currently connected to the gas distribution network switch to alternative heating technologies, the gas distribution network is scaled back in size and eventually decommissioned. This process is outlined in greater detail in the Low Carbon Gases for Heat report[37] in this National Heat Study.

In the *Balanced* and *Decarbonised Gas* scenarios, industry demand for hydrogen still exists, however consumers currently connected to the gas distribution network can also decarbonise using hydrogen for heating. In the *Balanced* scenario, this is typically in buildings with poor initial insulation but also with lower heating demands (and so heat pumps are not cost effective due to their high upfront cost). Some buildings also decarbonise using a hybrid heating technology, with an ASHP providing the base load heating demand and a small hydrogen boiler providing peak heating demand. As the number of consumers connected to the gas distribution network decreases in the *Balanced* scenario, the gas network will be gradually scaled back to match the reduction in demand. In the

[36] See footnote 12.
[37] See footnote 12.

Decarbonised Gas scenario, all buildings currently connected to the gas distribution network decarbonise using hydrogen, either with standalone hydrogen boilers or with ASHP-hydrogen hybrid heating technology.

In the *Decarbonised Gas* scenario, consumers within close proximity of the gas distribution network but currently without an existing gas connection can connect to the gas distribution network and decarbonise using hydrogen for heating. Further information about the method to determine the number of homes which can connect to the gas distribution network to use hydrogen, and the cost of doing so, is in the Low Carbon Gases for Heat report[38] in this National Heat Study. Uptake of hydrogen by these consumers is generally low in this scenario, due to the additional cost of connecting to the gas distribution network and due to competition from heat pumps and direct electric technologies, as well as biomass, bioliquid and biomethane boilers.

9.3.2 Key actions and time points for hydrogen

This section sets out the process that would be required for conversion of the methane gas grid to hydrogen, as in the *Decarbonised Gas* and *Balanced* scenarios, should the decision be made to pursue a hydrogen-led pathway. We developed the described steps based on discussion and feedback from Ervia, Gas Networks Ireland and the Commission for Regulation of Utilities (CRU). As part of the consultation process of the National Heat Study, we received input from several university research groups working on low-carbon heating fuels, including the National University of Ireland in Galway, Dublin City University, and the Science Foundation Ireland Research Centre for Energy, Climate and Marine at University College Cork.

2020s: National decision and preparation

Although the deployment of hydrogen for heating will not be possible at a large scale before 2030, significant action from the Government will be required already in the 2020s to make this a reality. A clear national commitment to the future evolution of the gas network is needed to underpin the policy, planning and investment in hydrogen in the 2020s. To get to this point, further investigation is required in several areas:

- Technical assessment of the gas network capacity out to determine where network expansion and/or reinforcement may be required to accommodate the lower energy density of hydrogen relative to methane gas.
- Identifying any areas of the transmission network to be maintained as methane gas for use with CCUS.
- Hydrogen appliance and network trials to understand, de-risk and cost full network conversion.
- Public engagement to gauge attitudes to hydrogen and determine key risks and pitfalls from the consumer and industry perspective.

2030-2035: Hydrogen blending

Beginning in 2030 in the *Balanced* and *Decarbonised Gas* scenarios, hydrogen is blended into the methane gas transmission network at fractions up to 20% by volume (7% by energy). This can take place in all areas except those where the gas transmission network will be maintained. 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.

Early adopters in industry may develop production facilities on-site or receive hydrogen via direct pipelines. Hydrogen-ready boilers become widespread by 2035, but some policy support may be required to ensure that fuel-poor households in the areas for early conversion can replace or upgrade incompatible boilers.

2035-2050: Piecewise grid conversion

In the *Balanced* and *Decarbonised Gas* scenarios, the first areas are fully converted to hydrogen beginning in 2035, potentially 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. Floating offshore wind is expected to be commercialised by the early 2030s [36], in time to support the up-scaling of green hydrogen production.

Distribution network conversion takes 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) will increase to supply the newly connected, higher demand areas. CCS infrastructure is built to

[38] See footnote 12.

capture and sequester carbon at large industrial sites using fossil fuels and power sector sites converting to bioenergy.

This is a critical period for clear messaging and support for the growth of AD crops and biomethane production. Grid injection of biomethane will cease by 2050, but off-gas markets for biomethane will continue in these scenarios. Off-gas industry and non-domestic buildings with large energy demand are encouraged to adopt containerised biomethane supply.

2050: Fully deployed hydrogen network

The piecewise conversion of the transmission and distribution networks is completed by 2050. Methane gas remains only in selected parts of the transmission network where it is delivered to industry sites utilising CCS.

In the *Decarbonised Gas* scenario, 4 TWh hydrogen provides dispatchable electricity, rising to 7 TWh in the *Balanced* scenario due to lower deployment of BECCS. In all scenarios, the gas network supply to the power sector is significantly reduced from the 2020 demand of about 25 TWh.

At this point, Ireland's significant wind resource may allow hydrogen to be produced and exported, via either 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 a hydrogen network.

9.4 Biomethane

Biomethane contributes to heating decarbonisation in all scenarios, with its role depending on the volume of suitable biogenic resources and the use of hydrogen or methane in the gas network. While domestic biomethane cannot be produced in quantities sufficient to supply the gas network fully, it can reduce the average carbon content of the gas network beginning in the 2020s and in later years may supply off-gas industry and services, or a much-reduced gas network. The resource estimates suggest that the available biomethane resource could be between 4-8% of Ireland's current gas fuel demand. If changes to land use in agriculture occurred and if the freed-up land is used to grow a red clover/ ryegrass mix for silage, then this could rise to 11% of current gas demand by 2030.

The technical background and supporting information for this section is available in the Low Carbon Gases for Heat[39] and the Sustainable Bioenergy for Heat[40] reports.

9.4.1 Resource availability and uptake

The domestic biogenic resource suitable for biomethane production varies by scenario as shown below in *Figure 65*. In the *Decarbonised Gas* and *Rapid Progress* scenarios, newly available land is dedicated to grass silage. Under the *High Electrification* scenario, a perennial energy crop (SRC willow) is grown instead of grass silage for AD). In the *Balanced* scenario, half the available land is used for grass silage and half for SRC willow. All scenarios assume that the national cattle herd evolves in line with the projections detailed in Ireland's National Energy and Climate Plan [37]. The *Rapid Progress* scenario is the exception as it assumes a shift in land use and a reduction of about 600,000 head in the herd. Hence, *Decarbonised Gas* and *Rapid Progress* have the highest volume of domestic resource for biomethane, equivalent to 3.7 and 5.1 TWh biomethane, respectively.

In the *Balanced* and *Rapid Progress* scenarios, the domestic biogenic resource is supplemented with imported wood pellets, which can produce biomethane through gasification. This results in a 2050 production of about 8 TWh biomethane in the *Rapid Progress* scenario. This volume is significantly less than the energy delivered annually through the gas network today, which is approximately 50 TWh.

[39] See footnote 12.
[40] See footnote 18.

Figure 65: Domestic and imported biomethane resource and 2050 uptake, by scenario (TWh)

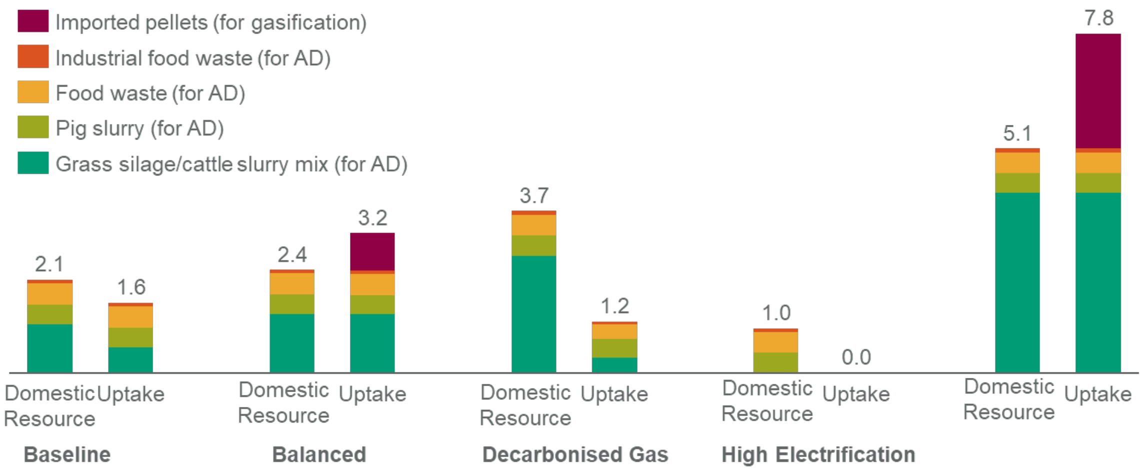
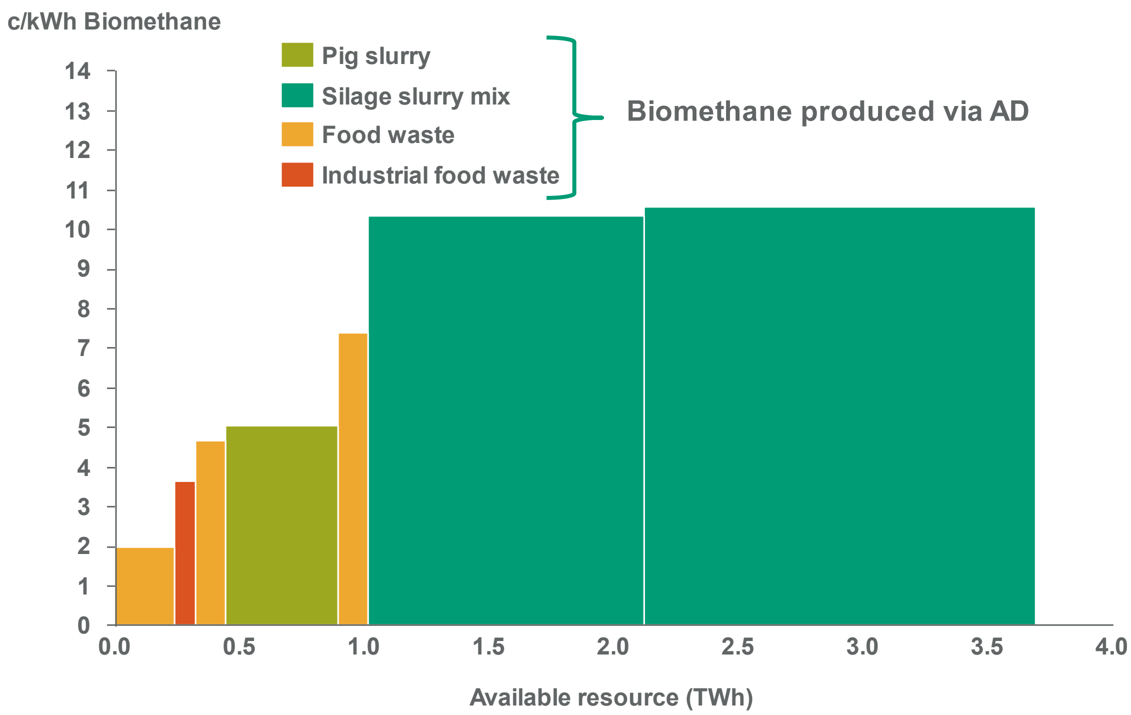


Figure 66 shows the LRVC for production of biomethane from domestic resources in the *Decarbonised Gas* scenario.

Figure 66: 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 technical potential for biomethane supply is significantly lower than the existing gas demand across all sectors of 52 TWh. Prioritisation or allocation of biomethane for specific end users may, therefore, be necessary. Grid injection of biomethane reduces the average emissions intensity for all gas users and, if done in large volumes and early enough, this can provide significant reductions in emissions while scaling up alternative technologies such as heat pumps or hydrogen production. Grid injection has the potential to motivate rapid development of biomethane given the large demand for gas, if an appropriate market structure is put in place to provide an acceptable return on investment for biomethane production. However, in scenarios where the gas grid is decommissioned or converted to hydrogen before 2050, early and sustained policy support is required to reduce and manage the risk of stranded biomethane production and grid injection assets. If a biomethane transmission grid is available for consumers in 2050 (for example, for industrial consumers as in the *Rapid Progress* scenario), then centralised production and distribution provides an opportunity to utilise existing methane gas storage and distribution infrastructure. Furthermore, this offers sites with CCUS infrastructure the opportunity to provide negative emission through the combustion of biomethane.

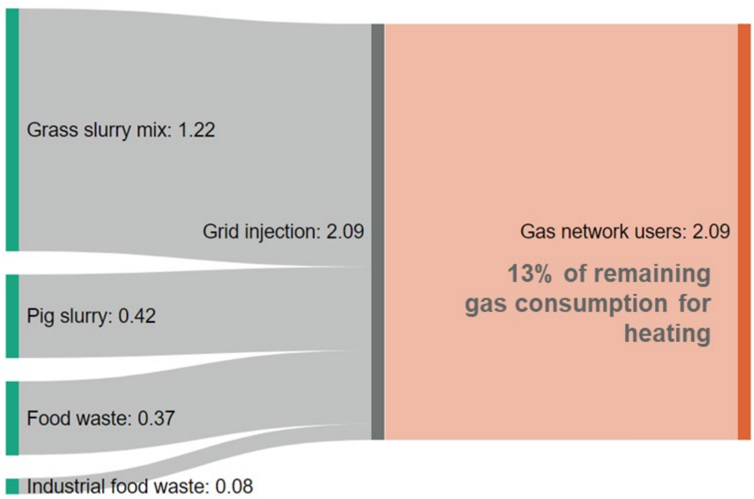
Distribution of containerised biomethane offers the opportunity for biomethane production infrastructure to stay in use beyond any decommissioning or conversion of the gas distribution network, and can provide a low-carbon heating option for buildings and industrial sites which are unsuitable for electrification of heat. It also offers the opportunity to replace oil and solid fuel boilers, which have higher emissions per unit heat supplied than gas boilers, and so have greater CO_2 savings potential per home in off-grid properties. These heating systems are also typically more expensive than gas boilers in terms of total lifetime costs and so consumers could be more likely to take up biomethane in off-grid properties. Prioritising biomethane for off grid users could lead to uncertainty around the demand for off-grid biomethane, and so sustained policy support would provide consumers with confidence that this is a viable long-term decarbonisation option for heating. With competition from electrification and other heating technologies, the market for biomethane deployment is potentially smaller in off-grid homes, and the lack of a centralised gas network used to supply biomethane to customers means that the costs of emissions abatement via biomethane use cannot be socialised across the entire consumer base.

9.4.2 Key actions and time points for biomethane sector

Biomethane can contribute to heat decarbonisation both in the short and long term, but will require joined-up policy across agriculture, supply and demand to create a market and avoid stranded assets. There is a supporting role for biomethane even in scenarios where the gas network is earmarked for conversion or curtailment if near-term policy considers the risks to the sector from the uncertain future of the gas network. Grid injection can provide a large and attractive market for biomethane, assisting scale-up in the 2020s, if the agricultural sector and investors are confident that there will be a market for biomethane for at least 15-20 years, that is longer than the economic life of AD and grid injection plants.

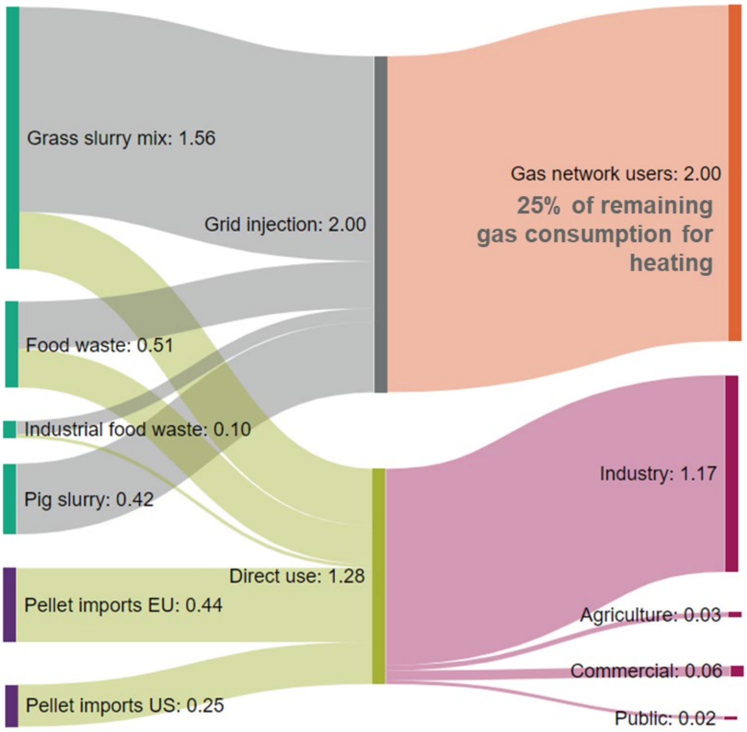
Both the feedstocks and delivery routes for biomethane are likely to vary over time, as shown in *Figure 67* to *Figure 69*. In 2030 (*Figure 67*), just over 2 TWh biomethane is produced in the *Balanced* scenario using only domestic biogenic resources, chiefly a grass silage/ cattle slurry mix. Within the 2020s, policy support for AD crops and plant are required, along with a clear decision on the future of the gas distribution network, timeframe for its conversion to hydrogen or curtailment, and the long-term future of biomethane. This will give a clear signal to the sector on how best to develop biomethane infrastructure, such as by connecting to parts of the gas network which will be maintained or by cultivating demand from off-gas grid users.

Figure 67: Sankey diagram for biomethane production and use in the Balanced scenario in 2030 (TWh)



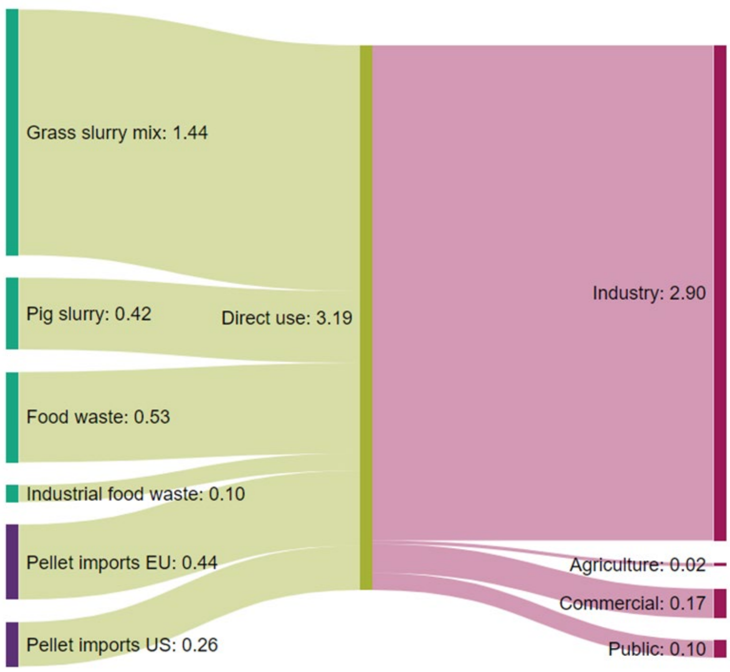
By 2040, in the *Balanced* scenario (*Figure 68*), the piecewise conversion of the gas distribution network to hydrogen is already underway. Around 2 TWh are still injected into the remaining gas network, and growth in biomethane production since 2030 is focused on the off-gas market, principally industry; this is typically in higher-heat grade processes. Around 0.7 TWh biomethane is now produced from imported wood pellets from the US and the EU. At this point, biomethane makes up one-quarter of the remaining gas demand for heating, reducing the carbon content of the gas network by 18%.

Figure 68: Sankey diagram for biomethane production and use in the Balanced scenario in 2040 (TWh)



Support for off-gas industry and larger commercial sites to adopt containerised biomethane will be critical to enable the biomethane sector to transition away from the gas grid by 2050. As shown in *Figure 69*, only off-gas consumers use biomethane in 2050 in the *Balanced* scenario, for example in rural office and retail buildings, as well as education and healthcare buildings.

Figure 69: Sankey diagram for biomethane production and use in the Balanced scenario in 2050 (TWh)



9.5 Solid biomass

The technical background and supporting information for this section is available in the Sustainable Bioenergy for Heat report.[41]

9.5.1 Resource availability and uptake

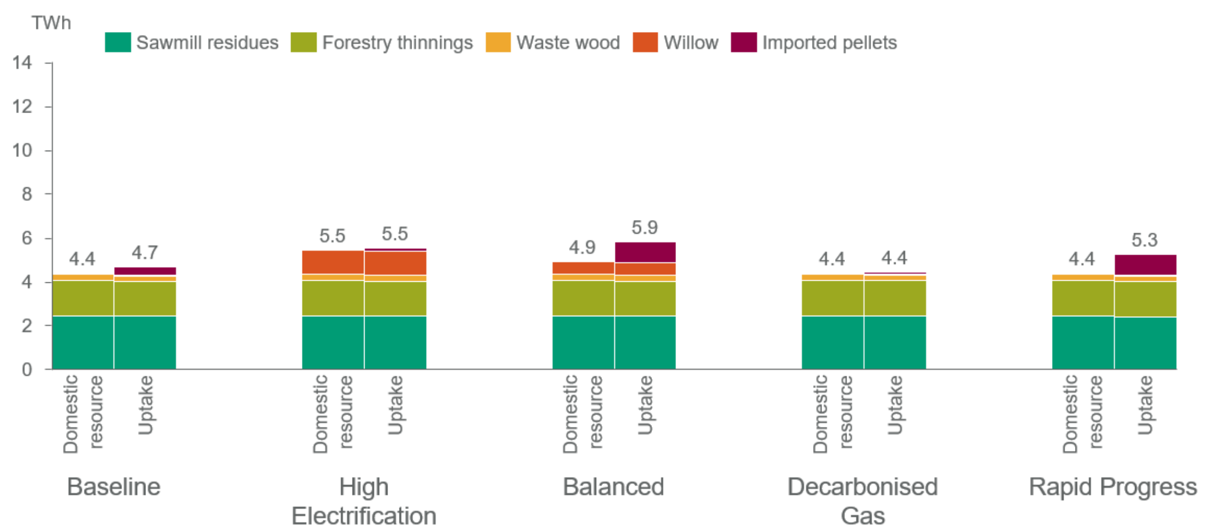
Domestic solid biomass resources currently available for bioenergy use are by-products and wastes from the forestry sector (forestry thinnings and sawmill residues), agriculture (straw), industry (tallow), and households and business (residual waste which cannot be recycled and waste wood). The quantities of these resources depend on activity in the sector generating them, and not by demand for bioenergy. For example, forestry thinnings arise when the forest is in its early years or when harvested at maturity to produce large diameter sawlogs that can be processed at sawmills to provide lumber. Driving activities such as these are not influenced by how the energy system changes. Therefore, the quantity of each of these bioresources is assumed to be the same under each of the scenarios modelled in the National Heat Study.

Significant increases in solid biomass resources could, however, be achieved by cultivating perennial energy crops such as SRC willow. This would require land currently used for farming to be made available. As for cultivation of grass silage for biomethane production, it is assumed that this can be achieved through reductions in the beef herd and improvements in grassland productivity. In the *High Electrification* scenario, it is assumed that all the newly available land is used for willow, substantially increasing the solid biomass resource. In the *Balanced* scenario, half the land is assumed to be used for willow, and in the other scenarios, available land is all assumed to be used grass silage for biomethane production rather than willow.

Figure 70 shows the domestic solid biomass resource and its uptake in the heat sector in 2030. As the supply chain for willow is immature, only relatively small quantities are available by 2030, but it is used. Similarly most of the forestry thinnings, sawmill residues and waste are used in each scenario. In addition to the resources shown in *Figure 70*, there is about 1 TWh of residual waste[42] that is used to generate power in dedicated EfW plant. In the *Balanced* scenario, industry is the main consumer, and its use in this sector in boilers and CHP plant is a key driver for the import of pellets.

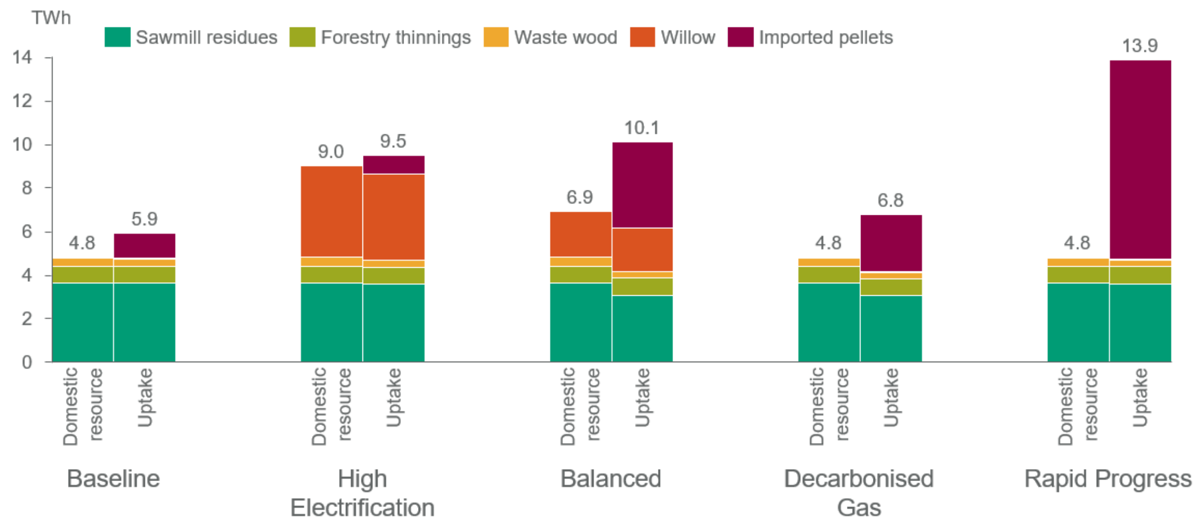
By 2050, the willow supply chain is mature. All land available for the cultivation of willow in the *High Electrification* and Balanced scenario can be used, leading to a significant increase in the potential willow resource (*Figure 71*). However, the forestry resource declines as the forest ages so less harvesting takes place. End users who have switched to wood chip or wood pellet boilers still require a fuel supply, so it is likely that increased imports of pellets will make up this decline (~ 0.8 TWh) in domestic forestry supply. Wood pellet imports also increase to supply industry sites which install CCUS; some are also used in gasification plant to produce biomethane or hydrogen.

Figure 70: Domestic and imported solid biomass resource and uptake in 2030, by scenario (TWh)



[41] See footnote 18.
[42] Accounting for the biogenic content e.g. paper and card of the residual waste only.

Figure 71: Domestic and imported solid biomass resource and uptake in 2050, by scenario (TWh)



9.5.2 Key actions for solid biomass

The modelling assumes that a developed mature market is in place for solid biomass and that there are no barriers to consumers' choice of bioenergy as a heating option. To deliver the modelled levels of uptake, a host of supporting policy actions and market development activity is required. In particular, delivering a substantial willow resource will require changes in land use and in farm management practices to increase the productivity of grass land sustainably, and so will need actions in both the energy and agricultural sector. In increasing the use of solid biomass, it is vital that robust sustainability guidance is in place, covering both domestic and imported resources, as well as all end uses.

10 Key actions

The study has highlighted several areas where policy can act to deliver on the heat decarbonisation opportunities. We explore three categories here – the study helps to identify:

- **Actions that can be taken now** to contribute to our decarbonisation targets.
- Some technology pathways require **decisions now** to provide market certainty and avoid delayed action.
- Actions that need to be **immediately investigated further** to support the next wave of policy effort.

In some cases, the findings reinforce measures already included in the 2021 Climate Action Plan. In others, they provide direction as to the prioritisation of effort and the need for extended measures through the lens of decarbonising heat as quickly as possible and ultimately reaching net-zero emissions from heat. In acting and making the necessary decisions, it will be essential to understand areas of interdependency where a choice in one sector or for one technology could affect future decisions or policy options.

Besides the urgency of implementation, longevity and continuity of policy are essential to achieve significant replacement of high-carbon heating technologies. Given the long lifetime of heating systems (15+ years), less than 8% of existing systems are replaced each year, so most homes and businesses will purchase new heating systems only twice before 2050. In addition, the supply chains for heating and energy efficiency are still developing, particularly in the residential and commercial sectors, and comprise many small businesses and some larger enterprises that deliver a broad range of services. For these reasons, stable policies with relatively long lifetimes are likely to be more effective at promoting renewable system adoption than policies that aim to achieve radical change within only a few years.

ACT NOW: Actions that can be taken now

Plan and prioritise district heating deployment – target the regulatory, planning and financing barriers to reduce the implementation cost and timelines for district heating projects.

District heating technologies are available now and have been deployed at scale in other countries. The modelling shows that heat network infrastructure can be built and supplied by various technologies and fuels at a cost that competes with fossil fuel options. Low-carbon heat sources, supplied via district heating networks, could meet up to 50% of building heat demand.

The primary barriers to uptake relate to planning, regulation and financial factors. Policy frameworks that put district heating infrastructure delivery on a similar footing to other energy infrastructure can alleviate many of these barriers. State-owned companies that deliver gas and electricity networks can access low-cost financing and have the specialised technical and centralised skills and tools to deliver these infrastructures at scale. Replicating these conditions for district heating infrastructure can drive significant deployment.

Policy, regulation and planning that supports heat extraction from newly-built power stations to supply heat networks can further improve the economics of district heating. Opportunities for heat extraction from power stations and waste heat recovery from industrial sites, geothermal sources and low-grade heat from data centres to feed into district heating schemes should also be encouraged.

Shift the emphasis of building decarbonisation policy to elimination of fossil fuel heating.

Current support schemes apply the fabric-first principle. Its application asks consumers to use available fabric technologies and budget to reduce heat demand before installing a heating system. Policy at an EU level supports this approach and captures the sentiment in the phrase 'energy efficiency first.'

However, this approach is not guaranteed to be consistent with the rapid decarbonisation needed to meet the goals of the Climate Action legislation. It is not financially viable for a large proportion of consumers in the analysis [38] and consumers do not favour it in the consumer choice modelling. Even in scenarios that model grant supports of 60-80% of the capital cost, consumers still do not install the more extensive fabric measures in large numbers. Model outcomes suggest consumers are likely to prefer to install the low-cost and low-hassle fabric options, such as draught proofing, roof insulation and cavity wall insulation, combined with a low-carbon heat supply technology, such as an electric heat pump. Heat pump technology is available now, and they are prominent in all scenarios, including in the *Rapid Progress* and the *Decarbonised Gas* scenarios. Customers much less frequently choose the more expensive and challenging fabric options, such as floor and solid wall insulation and high-efficiency glazing. Fabric is instead used to improve the payback on the heating system investment and to ensure the suitability of a building for low-temperature heat sources (heat pumps). This approach puts decarbonisation first, with fabric retrofit in a supporting role, leading to faster decarbonisation of heat.

These results suggest that realigning the fabric-first principle with legislative requirements for deep and rapid emissions cuts can deliver enhanced uptake of low-carbon technologies and fuels. They also suggest that retrofit activity targets can be more aligned with emissions reduction goals by focusing on the heat supply rather than on the final BER a building achieves. Scheme design that focuses on meeting the minimum levels of fabric performance to support a switch away from fossil fuel heating sources, or includes only fabric measures that offer a short payback period when combined with the low-carbon heating system, is likely to see more uptake, require less investment and see more emissions cuts. Consumers may then make additional fabric improvements in the future when higher fuel costs or lower fabric efficiency costs provide more attractive paybacks, and when consumers have access to further investment budgets.

Improvements in building thermal performance remain an important policy goal from the perspectives of health, wellbeing, fuel poverty and comfort. However, policies associated with building regulations and planning permission (triggered by building works) may achieve better thermal performance than with decarbonisation (triggered by heating system replacement).

Raise awareness of the competitive low-carbon heating options available for services sector buildings and industry; address the non-financial barriers preventing uptake.

The services sector has a strong uptake of renewable heating technologies (heat pumps, district heating and biomass fuels) in all scenarios, including the *Baseline* scenario. The results suggest that renewable and low-carbon options already make economic sense for many consumers. Heat pumps, district heating and biomass fuels all see strong uptake in the services sector. In the industry sector, several technologies are competitive, particularly for those industry sites using oil. However, this uptake is not yet happening to the same degree because of other non-financial uptake barriers facing organisations in the enterprise sectors, such as lack of awareness, split incentives between landlords and tenants, the low proportion of energy costs in total business operating costs and centralised corporate decision-making on energy investments.

Awareness-raising campaigns and other promotional activities can help bring the opportunities into view. Streamlined, trusted and accessible support and advice can help build demand and support the services sector consumers to navigate the early stage supply chains for some of these technologies. The leadership role of the public sector can help build the supply chain capacity in Ireland. The Climate Action Plan's commitment to stop the installation of fossil fuel heating systems from 2023 will help drive this.

As with the residential sector, fabric upgrades have an important role in supporting delivery of low-carbon heat supply technology in the commercial and public services sectors. Scheme design that focuses on meeting the minimum levels of fabric performance to support a shift away from fossil fuel heat supply is likely to be less complex, see more uptake, require less investment and deliver more (and faster) emissions cuts.

Implement nationally appropriate sustainability governance and market development activities to deliver the bioenergy potential aligned with economy-wide emission reduction goals.

Bioenergy meets 7-16% of heat demand in all scenarios in 2030 and 2050. Domestic resources and imported biomass fuels are primarily used in solid and gaseous forms, with some small amounts of bioliquids in some scenarios. The resource assessments for the biomass feedstocks consider upstream GHG emissions and other important sustainability aspects, such as biodiversity. Hence, the resource estimates are based on specific good practice approaches to their cultivation, harvesting, collection and use, which help to minimise overall climate impacts. For example, only energy crops that are grown on environmentally suitable land with a minimum of additional nutrient inputs are available for the model. Energy crops grown in ways that depart from these assumptions risk causing environmental damage and more GHG emissions in the land use and agricultural sectors.

Therefore, robust and nationally appropriate sustainability standards and governance are required. EU sustainability governance only applies to larger sites. Its direct transposition into Irish law means that governance rules would not apply to the large proportion of bioenergy use in Ireland below the minimum EU size threshold. The EU legislation allows countries to set size thresholds that are aligned with their individual circumstances. Such nationally appropriate sustainability governance measures and other market development supports can provide a foundation for biomass supply chains to contribute to their full potential while reducing the risk of emissions increases in the agricultural sector and from land-use change.

Develop policy frameworks that allow the costs and benefits of renewable and low-carbon gases to be shared across all gas customers. Enable off-grid heat users that currently use higher-cost and higher-carbon fossil fuels to access biomethane outside of the grid.

While the resource estimates for feedstocks that can produce biogas are lower than previous estimates, what is available is widely used to produce biomethane in the scenarios. The cost of off-grid biomethane is competitive with oil. Grid-injected biomethane is competitive with other options when it makes up a low proportion of total gas fuel in the grid and when all gas consumers share the costs and benefits.

The cost of grid-injected biomethane fuel is spread across all gas consumers, so each consumer sees a slight increase in price and a small decrease in emissions. Consumers pay for the costs of biofuels in transport and renewable power in this way. However, if biomethane costs and benefits are seen by an individual consumer, the fuel becomes significantly less competitive against gas and the other low-carbon options available. A similar loss of competitiveness occurs if the proportion of biomethane in the grid grows.

Biomethane is typically more competitive in off-gas grid applications where it is transported directly to an industry site to replace oil. The relative carbon savings are also higher when used at these sites. Policy frameworks that seek to support the development of biomethane should allow these routes to compete with grid injection options.

Deliver plans for renewable deployment on the electricity grid.

The analysis shows that electricity use for heating has a prominent and increasing role in all the scenarios examined, with particularly strong growth post-2035. Delivery of renewable capacity and supporting grid flexibility must stay ahead of demand growth to realise the benefits of emissions savings from this demand-side electrification of heat. The high-resolution electricity modelling shows power sector emissions reducing by about 50% by 2030 (relative to 2018), while demand increases by 61-69% in the same period – driven by data centres, electric vehicles and heat electrification. The power sector modelling sees 10-11 GW of installed wind capacity by 2030 to meet a renewable electricity percentage of at least 70%. The Climate Action Plan is targeting an 80% renewable electricity share by 2030, and its delivery will further enhance the heat sector emissions savings.

Include spatial planning in policy considerations.

The modelling shows that there are spatial variations in technology uptake. Rural oil-heated buildings favour heat pumps, district heating is deployed in cities and towns, and bioenergy uptake is prominent at sites located away from the gas grid. Spatial factors are also important for electricity infrastructure to ensure that the grid is ready for electrified heat demands. Policy approaches that account for these patterns can avoid sub-optimal outcomes that could arise due to the provision of competing incentives for alternative low-carbon technology options.

For example, public services heat demands are significant anchor demands that improve the economics of district heating networks. Should the public sector respond to competing policy signals and install other low-carbon technology options, the opportunity for district heating is likely to be diminished in all sectors.

Heat extraction from newly-built power stations is among the lowest-cost energy sources for heat networks. Policy signals that seek to co-optimise the location of power generators to meet the power system's needs and district heating demands can maximise these low-cost heating opportunities.

Provide long term and stable policy signals.

Technology changes in the heat sector happen gradually due to the turnover rate of energy technologies as they reach the end of their useful life. The retirement of existing technology is a critical decision point where homeowners and businesses can move to a low-carbon option. Clear policy signals on continuing support and implementation timelines for technology adoption can influence the uptake of low-carbon systems. Policies with long-term plans and committed lifetimes can have the most significant impact and provide certainty and stability to aid the development of robust supply chains.

DECIDE NOW: Decisions required now

The role of negative emissions in achieving economy-wide net-zero goals by 2050.

The anticipated decarbonisation actions and technological improvement may not be enough to achieve carbon neutrality given the challenge of eliminating emissions in 'hard-to-decarbonise' parts of industry and agriculture. In government-approved carbon budgets and sector emissions ceilings, this implies that some sectors will need to achieve negative annual emissions to meet the goal of economy-wide carbon neutrality. The routes to negative emissions in Ireland imply decisions about land use, fuel use, CCUS and the role of bioenergy and direct air capture. These decisions have onward implications for factors such as:

- **The amount of energy supply available from energy crop cultivation in Ireland**.

  For example, forestry planting that is significantly higher than the current 8,000 hectares per year target is likely to limit the potential for planting energy crops that produce biomethane and solid biomass fuels.

- **The amount of negative emissions that BECCS can deliver.**

  A transition to zero-emission fuels such as hydrogen and renewable electricity means there will be less CO_2 available for capture (where a bioenergy alternative might have been installed), and this may limit the opportunity to achieve economy-wide net zero by 2050. However, waiting for BECCS technology may result in higher peak annual and total cumulative emissions overall. Land-use options also affect how much bioenergy may need to be imported.

- **The demand for electricity and renewable electricity generation capacity**.

  Direct air capture technologies add to the demand for electricity, which requires additional renewable electricity production and competes with hydrogen production potentials.

A policy determination on the role of negative emissions to achieve economy-wide carbon neutrality by 2050 will help align onward policy decisions across land use, CCUS and renewable electricity generation requirements. Development risks for negative emissions technologies should be considered continuously as part of policy considerations.

Plot a path for carbon capture, utilisation and storage.

Carbon dioxide removal is a well-established technology in some industrial sectors, including hydrogen production, fossil gas processing and biomethane upgrading. However, carbon capture technologies on power and heat generation plants are expensive due to the high energy penalty associated with the CO_2 capture process and the low CO_2 content in the flue gas. As a result, despite few demonstrations worldwide, CO_2 capture processes on power and heat generation are still awaiting large-scale deployment globally. Technical work carried out as part of the National Heat Study outlines the progress made towards deploying the technology at scale. Should Ireland wish to have the option to deploy this technology long term, then advanced planning around the role of CCUS and BECCS in Ireland is needed. Decisions are required on where and how the clustering of sites and infrastructure might be achieved. In order to facilitate the deployment of CCUS in Ireland, policy must address regulatory aspects related to CO_2 storage (such as liability, monitoring requirements, ownership) and business models, as well as financing mechanisms. In addition, investigation of emerging applications for the utilisation of CO_2 (such as concrete curing, green cement, synthetic fuels) should be encouraged.

The role and source of biomass fuels, and in what quantities, are also important factors to consider. This can provide certainty to infrastructure developers about the scale of CO_2 volumes to be transported and aid the development of business models for long-term operation. Mechanisms to encourage awarding negative emissions from BECCS and other NETs in line with recent developments in other countries should also be explored.

Timetable for fossil fuel phase-out

To achieve a reduction to zero, heat consumers must only choose renewable and low-carbon options (such as electricity, bioenergy or green hydrogen-based heating sources) after a certain point in time. Technology life determines the latest date that this must happen. Fossil fuel technologies used for space and water heating have lifetimes of approximately 15 years. Hence, all consumers deciding how to heat their buildings from 2035 must choose a renewable or low-carbon option for an endpoint of net zero to be achieved by 2050.

In the industry sector, technology lifetimes are around 25 years. To reach zero by 2050, while getting the most out of their heating technologies, the industry sector would need to begin phasing out fossil fuels as early as 2025. However, this pathway likely presents competitiveness challenges for the industry sector and a large-scale phase-out of fossil fuels is unlikely in the near term. Pushing back the phase-out date would require early retirement of some systems to achieve the 2050 target.

If the emissions cuts from heat energy are to stay within the proposed carbon budget limits, then the move from fossil fuel will need to begin before 2025. If heat-using sectors are to carry a larger share of the decarbonisation target beyond a pro rata share, then fossil fuel phase-out must speed up even more.

For the industry sector, clear policy guidance on the future role of CCUS, the gas grid and the plans for the electricity grid and market can guide the investment decisions. For the buildings sector, decisions on the policy mix to drive decarbonisation are needed to accelerate investment in decarbonisation technologies and fuels.

The future role of the gas grid.

The National Heat Study has examined the role of green hydrogen in heating and included it as a decarbonising fuel for the power sector. However, its supply is likely to be limited until after 2030. The analysis shows that waiting for the deployment of green hydrogen leads to higher cumulative emissions overall across scenarios. Other technology options (heat pumps, district heating etc.) are available now to heat buildings, and many industry sites can also decarbonise by other means. Hence, in most of the decarbonisation scenarios studied, hydrogen has a lesser role.

Biomethane is available in moderate quantities and in the near term. However, it is not available in large enough quantities to bridge the emissions deficit to other scenarios until hydrogen becomes available in larger quantities. A larger role for biomethane is possible in the context of a policy decision that reduces the land requirement for the national herd. A lesser role is also possible if policy seeks to use available land for other energy crops or forestry and other sequestration options. Biomethane can also be deployed outside of the gas grid.

The gas distribution grid has a limited role in the decarbonisation scenarios. The deployment of district heating and heat pumps reduce the demand for gas. As gas use for space heating declines, it leaves fewer consumers to cover the fixed costs of the network, so they pay increasingly higher prices. This price effect further accelerates the move toward other technologies. Policy planning is required to limit the negative impacts of this transition for gas grid stakeholders.

The gas transmission grid sees reduced but significant demand from power and industry sectors. The scenarios examined include a role for a separate hydrogen grid to supply low-carbon fuel and a methane grid to supply sites that use CCUS to abate their emissions. A comprehensive government plan would need to be developed if this scenario was to be pursued and would need to address aspects such as:

- Alignment with the role envisaged for CCUS to achieve carbon neutrality by 2050.
- Advance development of hydrogen governance and regulation.
- Uncertainties on the additionality of green hydrogen and how renewable resources may be prioritised for hydrogen production or power generation. A transition plan from methane to hydrogen that avoids stranding biomethane assets and supply chains.

The role of secondary heating in the residential sector.

Solid fuels such as coal and peat used in stoves, ranges and open fires produce significant emissions (circa 1.6 $MtCO_2$ per annum). Many people living in rural Ireland use solid fuels to provide much of their heating demand. This can keep fuel bills low, increase comfort and reduce reliance on oil as a primary heating source. But it comes at the expense of reductions in air quality in homes, towns and cities. Reducing the use of fossil fuels burnt in the home for heat has both climate and health benefits.

However, removing secondary heating as a condition of wider decarbonisation action in a home may cause reductions in the uptake of the necessary measures. Phasing out this activity or replacing it with low-carbon options, such as sustainably sourced and certified firewood, can deliver CO_2 savings quickly. Policy can explore the role of secondary heating in enabling the uptake of heat pumps and other low-carbon options. In any event, policy must find a pathway to eliminate the in-home use of coal and peat for heating to reach net-zero emissions - and early wins will contribute significantly to reducing cumulative emissions.

INVESTIGATE NOW: Actions for immediate further investigation

How do the decarbonisation pathways perform in low probability / high impact events?

The modelling analysis carried out in the National Heat Study focuses on exploring the pathways to net-zero emissions for heat. While the assumptions around technology and infrastructure sizing consider extreme peaks in demand, the work has not explored how the scenarios perform in extreme weather events. For example, in a highly electrified scenario, prolonged periods of low temperatures could cause security of supply. Low temperatures can reduce heat pump efficiency when they are working hardest to maintain internal temperatures. Wind speeds are often below average during these freezing spells. More work is needed to understand how technology deployment can be configured to manage the danger of power cuts and deliver backup heating options if they occur.

How can new business models help the industry sector meet the competitiveness challenges of decarbonisation?

The unit costs of low carbon and renewable fuels for the industry sector are typically higher than the fossil fuel options they currently use. Industry sites not altering their energy use to avail of lower energy prices are fully exposed to the high average unit costs of low-carbon fuels. New business models that allow industry sites to interact more dynamically with energy markets can allow them to consume more renewable energy during lower price periods.

How can the delivery of green hydrogen be accelerated and its cost reduced?

The potential for green hydrogen is far greater than Ireland's energy demand. It can be used as a fuel for heat, power and transport and has many non-energy uses. The National Heat Study analysis examined the role of hydrogen in the heat sector and included it as a decarbonising fuel for electricity generation. However, green hydrogen is unlikely to be available at scale until the 2030s and likely to be more costly than other decarbonisation options. These factors limit the role of hydrogen in the heat sector.

Policy and research efforts that can hasten the deployment of green hydrogen and lower its cost can enable the fuel to play a larger decarbonising role. The ongoing research efforts are focusing on reducing electrolysis costs, enhancing how flexibly they can operate and improving the overall efficiency to help reduce the cost of production. The absence of suitable geological storage options increases the costs of hydrogen in Ireland. Further investigation into the availability of suitable geological storage in Ireland and into the development of liquid storage technologies could help lower the storage cost component of hydrogen fuel.

Within the 2020s, there may be a role for the initial development of green hydrogen with dedicated wind generation in parts of the country with limited electricity grid. 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 can transport hydrogen produced in these areas for use in transport or industry as pure hydrogen.

What are the preferred routes for achieving net zero in the electricity sector, and what role has demand-side flexibility?

The National Heat Study has modelled several routes to net zero in the power sector by 2050, including the deployment of green hydrogen fuel with hydrogen-ready gas turbines and BECCS. These fuels and technologies decarbonise the conventional generation required for the security of electricity supply when variable renewable electricity is less plentiful. Identifying the opportunities and challenges of decarbonising the conventional generation asset base is a pressing policy area given the scale of electricity demand growth expected over the coming years and decades.

The availability of BECCS and CCUS requires CCUS infrastructure to be deployed and sufficient availability of sustainable biomass fuels. Depending on the volumes required, Ireland may need to import this bioenergy. Suitable sites in Ireland also need to be identified. The need for CCUS technology depends on the policy decisions regarding the role of these technologies in achieving economy-wide carbon neutrality. Hydrogen-fuelled gas turbines is another route to decarbonisation. The deployment of green hydrogen relies on the availability of wind power capacity, both offshore and onshore. Further work is needed to understand how using wind for hydrogen production interacts with the electricity system's needs, and if the capacity can be deployed quick enough to meet the total requirements. Further work is also required to examine geological storage options and what impact ammonia storage may have on the emissions ceilings for these gases. Other low-carbon power generation options not examined as part of this work may also have a role.

Additional investigation is also required to understand the electricity system benefits that may accrue from large co-generation plants serving heat and power markets flexibly. Grid-connected electrolysers can produce hydrogen during high renewables and low-cost electricity. The fuel can be stored for long periods of time and can combust in gas turbines to generate energy during periods of low renewable availability. Industry sites could also benefit from this business model. For example, industry sites that electrify their heat demand, install thermal storage capacity and maintain their power generation capacity can both reduce their average electricity costs and receive revenue for the electricity market. These price arbitrage opportunities may be significant to a small, highly renewable electricity system. Large-scale district heating systems with heat storage can also interact with the power system in this way. Storage with combined heat and power generators and heat pumps can all act together to optimise heat and power production. Further work is required to understand the benefits and costs of the interactions at a site and system level. Further investigation is also needed to understand how current market and grid operation rules would need to change to facilitate such systems and market interactions, and the impacts on energy consumers.

How does the economy develop in deep decarbonisation scenarios?

The National Heat Study analysis uses some macro-economic inputs as part of the modelling. However, no further iteration has taken place to understand how the deep decarbonisation scenarios examined here might impact overall economic growth. The ongoing energy cost increases for industry, energy cost reductions for buildings and a large amount of capital investment in all sectors are likely to have a significant economic impact. Further work is needed to understand how deep decarbonisation pathways affect economic activity, exchequer funds and energy demand. Consideration should be given to how the counterfactual of remaining a high-carbon economy would affect foreign direct investment, the ability to attract finance, ongoing exchequer costs, and litigation that would result from non-compliance with international and national legislation.

Glossary

Term	Description
AD	Anaerobic digestion
Archetype	A simplified representation of a normally large number of real-world items, such as buildings.
ASHP	Air source heat pump
BER	Building energy rating
Capex	Capital expenditure
CBA	Cost benefit analysis
CCS	Carbon capture and storage
CCUS	Carbon capture, utilisation and storage
CHP	Combined heat and power
CF	Counterfactual
CSO	Central Statistics Office
DECC	Department of the Environment, Climate and Communications
DH	District heating
Direct-fired heating equipment	Industrial heating equipment where combustion gases come into direct contact with the product being heated, such as in furnaces or kilns.
EfW	Energy from waste
Energy-related emissions	Greenhouse gas emissions resulting from the combustion of fossil fuels for energy use, either from direct use of fossil fuels for energy, or indirectly from electricity use. It excludes emissions not from the combustion of fossil fuels, such as biogenic greenhouse gas emissions from agriculture or industrial process emissions.
ESRI	Economic and Social Research Institute
ETS	Emissions Trading Scheme (regarding the EU's emissions trading scheme)
Final energy	The actual amount of energy used to meet a demand (that is actual fuel used). These data are reported in aggregated form in the National Energy Balance. Corresponds to the energy consumption that normally appears on energy bills.
GDP	Gross domestic product
GHG	Greenhouse gas
GIS	Geographic information system (GIS) – a spatial system that creates, manages, analyses and maps all types of data.
GSHP	Ground source heat pump
GSI	Geological Survey Ireland

Term	Description
GVA	Gross value added
HHP	Hybrid heat pump
High-grade heat	Industrial heat of temperature >500 °C
High T	High temperature
HP	Heat pump
HS	Heating system
Indirect heating	Industrial heating equipment where heat is supplied through a medium such as steam/hot water.
kWh	Kilowatt hour; a unit of energy
Low-grade heat	Industrial heat of temperature <100 °C
LRVC	Long-run variable costs
MACC	Marginal abatement cost curve
Medium-grade heat	Industrial heat of temperature <150 °C and >500 °C
Medium/low-grade heat	Industrial heat of temperature <100 °C and >150 °C
NACE	Statistical Classification of Economic Activities in the European Community
NECP	National Energy and Climate Plan
NEMF	National Energy Modelling Framework
NET	Negative emission technologies
Non-ETS	This refers to industrial sites or other greenhouse gas emitters which are not part of the EU's emission trading scheme.
NOx	Nitrogen oxide pollutants; the x represents the number of oxygen atoms bonded to each nitrogen atom within the substance. These can be produced during combustion of fuels.
NPC	Net present cost
Opex	Operational expenditure
PM	Particulate matter emitted from combustion of fuels.
PSO	Public Service Obligation
PV	Photovoltaics, which are solar electricity panels.
SDR	Social discount rate
SEAI	Sustainable Energy Authority of Ireland
Small area (SA)	Smallest administrative land area in Ireland, over which Census data are published, typically containing 80 to 120 dwellings.

Term	Description
SOx	Sulphur oxide pollutants; the x represents the number of oxygen atoms bonded to each nitrogen atom within the substance. These can be produced during combustion of fuels.
SRC	Short rotation coppice
Stock	Represents either one building or one piece of equipment, depending on the building sector being discussed.
Technology efficiency	The conversion efficiency of a technology, which links useful and final energy.
TRL	Technology readiness level
Useful energy demand	The amount of energy required to fulfil a demand. Does not take any losses into account (for example, due to technology conversion efficiency).
VOC	Volatile organic compounds

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12 Appendix

12.1 Model overview

The National Energy Modelling Framework (NEMF) is a full national energy-economy model that assesses the impacts of packages of energy policies and measures on energy supply and demand. It combines several SEAI sectoral energy models and datasets to produce policy-rich outlooks for the whole energy system.

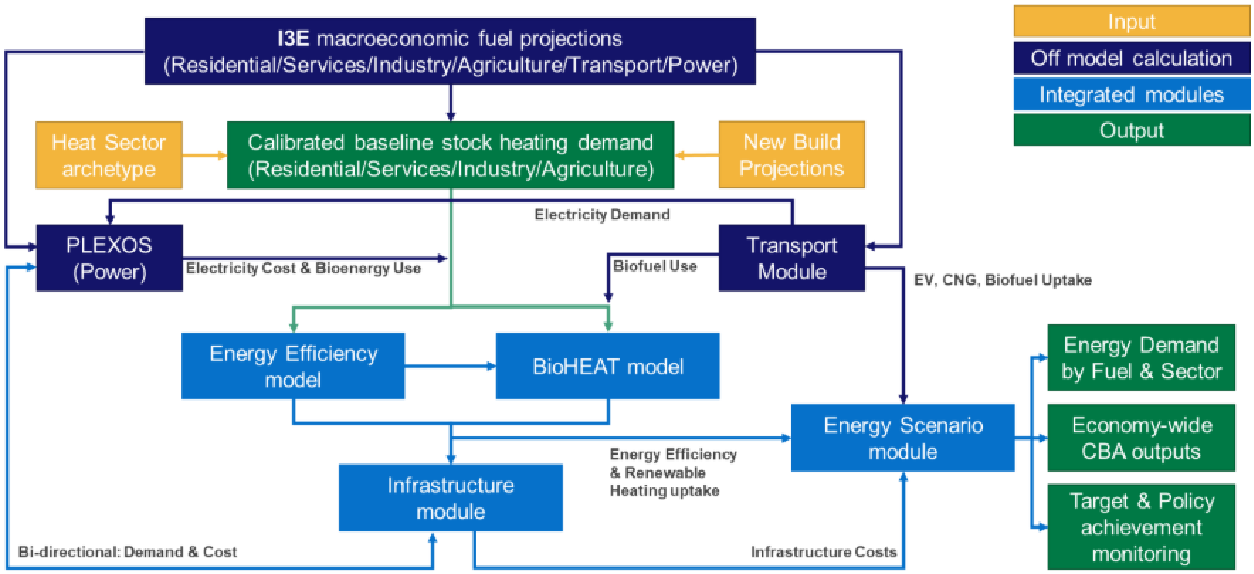
Main inputs:

- A 'Baseline' – macro-economic scenarios from ESRI's I3E model.
- Assumptions regarding packages of policies and measures across all sectors determined in collaboration with stakeholders.
- Data on technology performance, costs, consumer characteristics etc.

Main outputs:

- Energy supply and demand to 2050 by sector and fuel.
- Renewable energy target achievement and energy-related CO_2 emissions.
- Economy-wide cost benefit analysis (CBA) outputs.

Figure 72: High-level schematic of SEAI's NEMF



The uptake in the heat and transport sectors are used to adjust macro-economic fuel projections. The NEMF integrates uptake of technologies in the heat and transport sectors to calculate the adjusted annual fuel demand projections. Initial macro-economic fuel demands for the heat sector are used to calibrate baseline stock heating demand for residential, services, industry and agriculture sectors. This is used to calculate uptake of energy efficiency and renewable heating systems and the resulting impact on fossil, electric and bioenergy fuels. BioHEAT also tracks demand for bioenergy feedstocks for biofuels in transport and power sectors, based on off-model calculations of transport tool and an initial PLEXOS model run. The impact of resulting uptake on electricity demand and profile is then used to re-run PLEXOS to get an updated electricity cost and bioenergy use. The previous year, PLEXOS output calculated the in-year electricity cost annually. Finally, outputs from energy-efficiency uptake, BioHEAT, transport tool and PLEXOS are used, along with further manual adjustments defined by the user, to calculate the adjusted fuel demands across all sectors.

The H_2 module is used to calculate the cost of hydrogen production and supply for end use in heat, transport and power sector. This considers various technologies for hydrogen production (such as biomass gasification, on-grid electrolyser, renewable co-located electrolyser) as well as storage to calculate the least cost of hydrogen production. Additional cost of transmission and distribution network are included to determine the consumer cost for hydrogen.

The CBA module takes the cost-based outputs of the previous modelling to determine the NPC on a scenario or sectoral basis. The CBA has dual functionality in that it produces financial and economic CBA outputs based on the requirement. For this study, an economic CBA was performed from the perspective of a societal view. This type of CBA considers capex, variable and fixed opex, long-run variable energy costs, carbon costs and associated damage costs of non-GHG pollutants.

12.2 Marginal abatement cost curves (MACCs)

The findings presented in this report show various options to decarbonise the heat sector in Ireland at an archetype level. For some consumers, this decarbonisation comes alongside a net cost saving by moving to low-carbon heating systems, whereas for other consumers, this decarbonisation comes at a net cost. A useful approach to consider the costs or savings of decarbonisation is through the use of MACCs, which compare the cost and carbon savings of different methods of reducing emissions compared to the counterfactual (that is existing) systems in place. This method also provides a high-level breakdown of the relative cost effectiveness to abate different segments of heating demand within a sector.

This section shows three MACCs for the residential (*Figure 73*), services (commercial and public) (*Figure 74*) and industry (*Figure 75*) sectors. These account for the total lifetime costs/savings and abated emissions to deploy combined packages of energy efficiency and low-carbon heating systems.

The x-axis of these graphs shows the total annual abated emissions by the technology energy-efficiency end-state (2050) uptake in this scenario compared to the annual emissions in 2020. Note that the breakdown by technology type does not explicitly pull out energy-efficiency improvements, but graphs include the costs of energy-efficiency improvements installed in each archetype. The y-axis of these graphs represents the relative cost of abating these emissions, in €/tCO_2, calculated by dividing the net present value of the technology energy-efficiency package combination by the lifetime abated emissions relative to the counterfactual case. Each column (except for the district heating columns) represents the portion of stock (and their relevant 2020 emissions) in an archetype that takes up each technology type (such as heat pumps). The district heating columns instead represent small areas aggregated by similar cost-effectiveness (€/tCO_2) values. Negative €/tCO_2 values (that is bars which go below the x-axis) represent both a cost saving and a carbon saving; positive €/tCO_2 values (that is bars which go above the x-axis) represent a net cost, but a carbon saving. The order of the archetypes is from the most cost effective (in terms of €/tCO_2) on the left to least cost effective on the right.

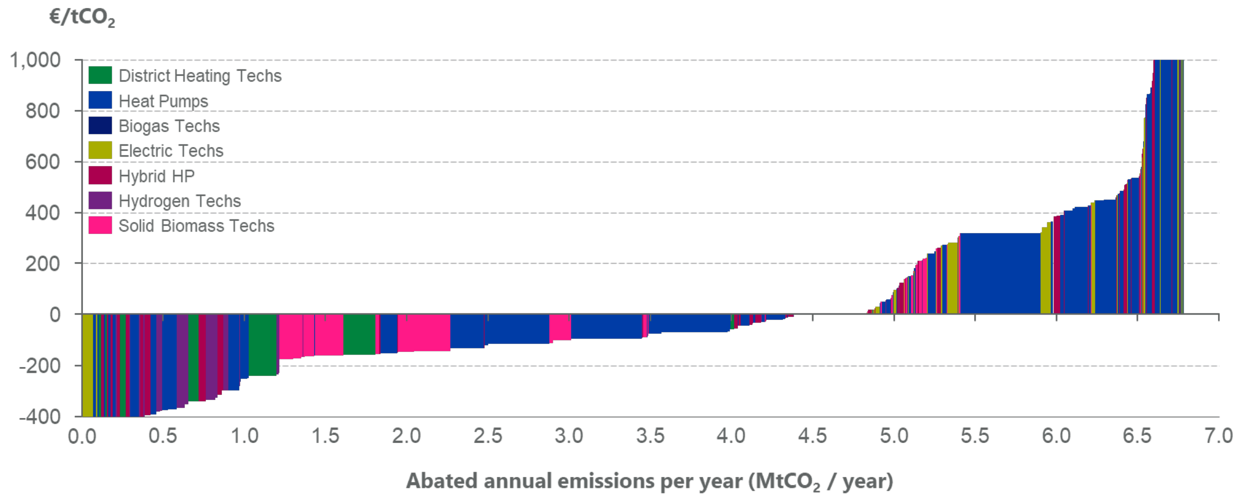
Due to this report's focus on the impact of decarbonisation on the customer, the fuel costs considered in the production of these graphs are inclusive of any environmental levies and other taxes applied to fuels, including the cost of carbon emissions associated with the use of each fuel. The report does not consider grants or other financial support to assist with the upfront cost of renewable heating systems or energy-efficiency improvements.

Throughout this section, 'cost effective' refers specifically to values of €/tCO_2, and does not refer to the consumer uptake decision-making and the previously stated cost effectiveness in terms of payback period. Although the uptake modelling is not determined by the relative cost of carbon abatement (in €/tCO_2), and is instead determined based on payback period or lowest lifetime cost of the heating system (as explained in Section 3.3.2), the graphs and commentary below provide details on which portions of the stock in each sector can decarbonise in a cost-effective manner and which archetypes will require more significant investment to decarbonise.

12.2.1 Residential sector MACC

Decarbonisation provides net savings for over 65% of abated emissions in the residential sector; however, 25% of the residential stock requires more than €200/tCO_2 to decarbonise their heating in the *Balanced* scenario. *Figure 73* is the MACC for the residential sector in the *Balanced* scenario, showing the final renewable heating technology mix in 2050 in this sector, and the cost of abatement of emissions relative to the counterfactual heating system.

Figure 73: MACC in the residential sector in the Balanced scenario, using 2050 technology and fuel costs



Both ends of the x-axis (very high negative or positive €/tCO_2 values) represent stock with existing direct electric heating technologies. The cost of abatement is calculated considering the emissions that the counterfactual heating systems would emit in 2050 when the electricity grid has a very low emissions factor, and so the carbon savings of any renewable technology are distinctly low when compared to this counterfactual. Therefore, the denominator (carbon savings) is very small for these archetypes, and thus any cost saving results in a very high negative €/tCO_2 value, while any net cost gives a very high positive €/tCO_2 value.

In terms of technologies, district heating is generally cost effective, with most uptake delivering low-carbon heat at an abated-emissions weighted average of -142 €/tCO_2. Solid biomass technologies also generally tend to represent cost-effective decarbonisation, with an average value of -100 €/tCO_2. Where hydrogen boilers are taken up, they are also very cost effective, with an average cost of -291 €/tCO_2. Ignoring edge cases (explained in the paragraph above), heat pumps on average offer an average cost effectiveness of decarbonisation of 30 €/tCO_2; however, there is a large proportion of stock in which heat pumps provide decarbonisation while also saving money over the lifetime of the heat pumps.

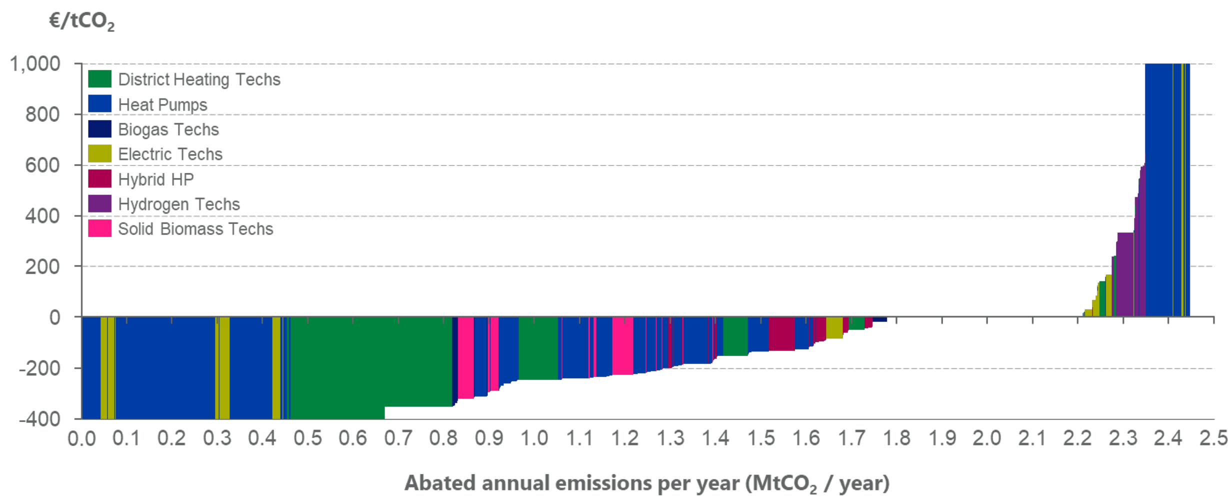
The stock to the left (representing the first ~1.2 $MtCO_2$ of abated emissions) represents buildings with poor initial insulation and existing gas and electric heating; these are the most expensive fuels per kWh of fuel used in 2050 in the *Balanced* scenario and so have the highest counterfactual fuel costs. These buildings uptake extensive energy-efficiency improvements, and a mix of renewable heating technologies. The next ~2.5 $MtCO_2$ of abated emissions, up to 4 $MtCO_2$ of cumulative abated emissions and where the columns have values between -200 €/tCO_2 and -50 €/tCO_2, represent mainly oil boilers, switching to a mix of heat pumps and solid biomass boilers. This entire portion of stock making up the 4 $MtCO_2$ of most cost-effective abatement (on the left side of the graph) represents mainly detached and semi-detached homes, which are more cost effective to decarbonise than terraced homes and apartments. However, this section is not strictly differentiated by property type (such as detached home); the counterfactual heating system (such as oil boiler) is a better indicator of decarbonisation cost effectiveness than property type.

The next portion of the stock, 4-6 $MtCO_2$ on the x-axis, represents buildings with existing solid boilers taking up a mix of heat pumps, solid biomass boilers and direct electric heating, with cost effectiveness ranging between -50 and 320 €/tCO_2. The final, rightmost portion of the graph represents homes where heat pumps are generally not cost effective, generally smaller properties with high heating demands; in this section, uptake is seen of direct electric heating, HHPs (burning hydrogen), and some heat pumps where all other technologies are less cost effective for decarbonisation.

12.2.2 Services (commercial and public) MACC

Most heating emissions savings in the commercial and public sectors are accompanied with cost savings, with 73% of annual emissions abated with negative €/tCO_2 values. Only a small proportion of emissions (7%, representing 20% of buildings across these two sectors with generally smaller heating demands) decarbonise with a cost higher than €200/tCO_2. *Figure 74* is the MACC for the services (commercial and public) sector in the *Balanced* scenario, showing the final renewable heating technology mix in 2050 in these sectors, and the cost of abatement of emissions compared to the counterfactual heating system.

Figure 74: MACC in the commercial and public sectors in the Balanced scenario, using 2050 technology and fuel costs



The stock at both ends of the x-axis again represents archetypes with existing direct electric heating technologies, with very low emissions savings due to the low emissions factor of electricity in 2050. Compared to the residential sector, a greater proportion of the abated emissions in these sectors comes from district heating, based on more commercial and public buildings situated in heat-dense areas.

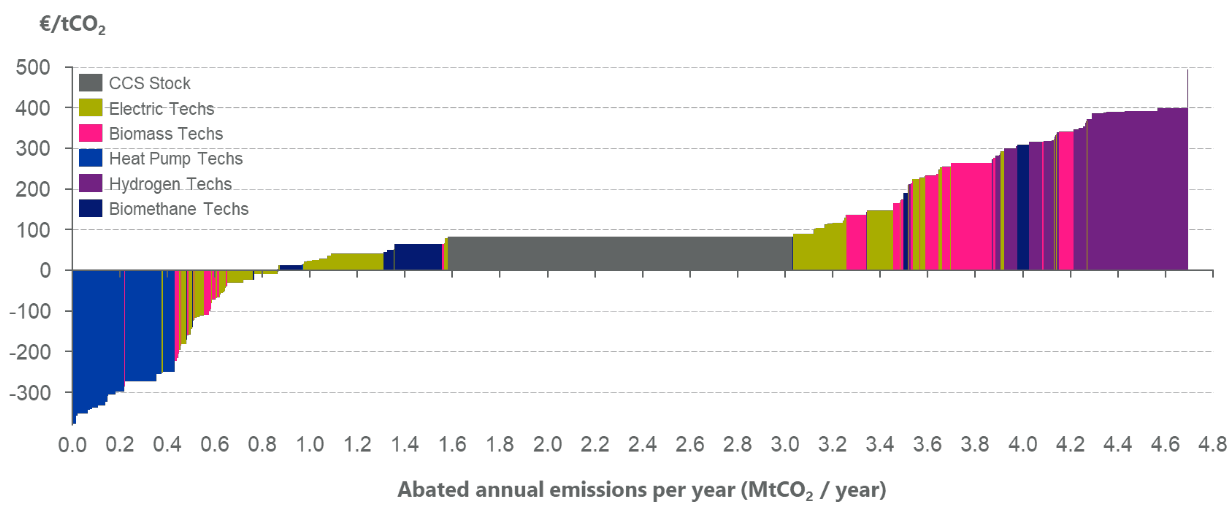
The columns between 0.8 and 1.8 $MtCO_2$ on the x-axis, with values between -320 and 0 €/tCO_2, represent all education buildings and most hotels, healthcare buildings and restaurants. These typically have existing oil and gas boilers with some direct electric heating, and switch to a mix of heat pumps, solid biomass boilers and HHPs.

The columns further right than 1.8 $MtCO_2$ on the x-axis represent hard-to-decarbonise retail, hotel and healthcare archetypes, generally with high heating demand per stock. These archetypes take up hydrogen boilers, direct electric heating and some heat pumps.

12.2.3 Industrial MACC

Relative to the residential, commercial and public sectors, the industry sector is much more expensive to decarbonise, with only 18% of annual emissions abatement in archetypes with net savings from heat decarbonisation. Over 25% of abated emissions in this sector are in stock with a cost of decarbonisation of over €200/tCO_2. *Figure 75* is the MACC for the industrial sector in the *Balanced* scenario, showing the final renewable heating technology mix in 2050 in these sectors, and the cost of abatement of emissions compared to the counterfactual heating system.

Figure 75: MACC in the industry sector in the Balanced scenario, using 2050 technology and fuel costs



The left-most portion of the graph shows the suitable industrial heat pumps replacing existing oil and gas boilers, across all industrial subsectors, saving both emissions and money over the lifetime of these systems. Most of the rest of the industrial stock has positive €/tCO_2, unlike the previous two graphs (residential MACC in Section 12.3.1 and the services MACC in Section 12.3.2) where the majority of uptake has net lifetime savings compared to the counterfactual systems. However, it should be noted that the scale of the y-axis is different in this industrial graph compared to the graphs for the other sectors; for the positive values of €/tCO_2, the industrial sector generally sees decarbonisation options up to a maximum of only 500 €/tCO_2, whereas the residential and services sectors both contain hard-to-decarbonise sub-segments where values exceed 500 €/tCO_2.

The next portion of stock (0.4-1.4 MtCO_2 on the x-axis), and with values ranging between -200 to 80 €/tCO_2, represents CHP systems, dryers and boilers switching to a mixture of direct electric, biogas and solid biomass fuel use. These are generally in the other minerals and wood products industrial subsectors.

The widest column represents the total CCUS stock in this scenario, with one average cost of abatement of 82 €/tCO_2 given, and 1.45 MtCO_2 of emissions abated annually by this stock.

Beyond the CCUS column, up to 3.9 MtCO_2 on the x-axis represents the uptake of direct electric and solid biomass fuels replacing fossil fuels in boilers, ovens and furnaces. These archetypes are generally in the chemicals, wood products, and food and drink sectors.

The far-right section is dominated by the uptake of hydrogen (and some biomethane and biomass), which has high €/tCO_2 values due to the high fuel cost of hydrogen. These archetypes are mainly in the metals sector (to the very right) and the chemicals, wood products, and food and drink sectors (to the left of this hydrogen-heavy section).

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