AtkinsRéalis

Industry of Future Programme

Summary Report

Department for Energy Security and Net Zero

May 2023

5212735-SNC-ZZ-ZZ-TREP-X-000002

NOTICE

This document and its contents have been prepared and are intended solely as information for the Department for Business, Energy, and Industrial Strategy and use in relation to the final report summarising the findings from the Industry of Future Programme.

AtkinsRéalis assumes no responsibility to any other party in respect of or arising out of or in connection with this document and/or its contents.

In Spring 2023 the Department for Business, Energy and Industrial Strategy (BEIS) was split to form three separate departments, the energy portfolio now falls under the Department for Energy Security and Net Zero (DESNZ). Throughout this report BEIS is retained.

Since the issue of this Summary Report to the Department for Energy Security and Net Zero SNC-Lavalin has rebranded. We reached an inflection point in our journey, and we're harmonizing our brands to establish one company, one strategy and one integrated offering. SNC-Lavalin, Atkins, and Faithful+Gould will now be known as AtkinsRéalis, a world-leading design, engineering and project management organization that connects people, data and technology to transform the world's infrastructure and energy systems.

This document has 145 pages including the cover.

DOCUMENT HISTORY

Document title: Summary Report

Document reference: 5212735-SNC-ZZ-ZZ-TREP-X-000002

Revision	Purpose description	Originated	Checked	Reviewed	Authorised	Date
C01	First Issue	RBH / MW	TWa / JG	RE	SL	27/05/2023

CONTENTS

TABLES

FIGURES

ACRONYMS AND ABBREVIATIONS

Acronym	Expansion
AD	Anaerobic Digestion
AMP	Asset Management Plan
ATC	Advanced Thermal Conversion
BAT	Best Available Techniques
BAU	Business As Usual
CapEx	Capital Expenditure
CCUS / CCS	Carbon Capture, Utilisation and Storage / Carbon Capture and Storage
CfD	Contract for Difference
CHP	Combined Heat and Power
CHPQA	Combined Heat and Power Quality Assurance
COMAH	Control of Major Accident Hazards
CPI	Confederation of Paper Industries
DNO	Distribution Network Operator
EB	Electric Boiler
ESC	Energy Systems Catapult
ETP	Energy Technology Perspectives
ETS	Emissions Trading Scheme
EMC	European Milling Centre
H2	Hydrogen
HVO	Hydrotreated Vegetable Oil
IDT	Industrial Decarbonisation Tool
IEA	International Energy Agency
IETF	Industrial Energy Transformation Fund
IFP	Industry of Future Programme
IFS.02	Industrial Fuel Switching Programme Phase 2

Acronym	Expansion
MBC	Manchester Bioresources Centre
MW	Megawatt
NDA	Non-disclosure Agreement
NG	Natural Gas
NIE	Northern Ireland Electricity Networks Limited
NOx	Nitrous Oxides
NZIP	Net Zero Innovation Portfolio
OFWAT	The Water Services Regulation Authority
OPAC	Opacilite
OpEx	Operational Expenditure
ORC	Organic Rankine Cycle
PCC	Post Combustion Capture
PFO	Processed Fuel Oil
PGD	Par Grade Dryer
PPA	Power Purchase Agreements
PV	Photovoltaic
REGO	Renewable Energy Guarantees of Origin
RGGO	Renewable Gas Guarantees of Origin
SSSI	Site of Special Scientific Interest
TERC	Translational Energy Research Centre
TIC	Total Installed Cost
TRL	Technology Readiness Level
VPPA	Virtual Power Purchase Agreement
VSD	Variable Speed Drive
WwTW	Wastewater Treatment Works

EXECUTIVE SUMMARY

The BEIS Industry of Future Programme (IFP) was a government initiative aimed at spearheading decarbonisation of UK industry by supporting the commercialisation of deep decarbonisation and energy efficiency technologies. The purpose of the Scoping Study phase of the BEIS IFP was to produce decarbonisation roadmaps for industrial sites. The BEIS IFP targets for these roadmaps were 20% CO_2 emissions reduction by 2025, 66% reduction by 2035 and 90% reduction by 2050. The UK-wide target is to reach Net Zero CO_2e emissions by 2050, this is discussed further in section 2.

The 15 industrial sites that participated in the programme were selected by BEIS via an open competition. The sites were split between seven sectors: chemicals, paper, minerals, food, water, transport, and pharmaceuticals. The BEIS IFP focused on sites with carbon emissions above 10 ktCO_2/y that were located outside of industrial clusters, known as dispersed sites.

In total 49 decarbonisation roadmaps were produced for 15 industrial sites. Roadmap development was dependent on multiple factors including carbon capture, utilisation and storage (CCUS) and hydrogen cluster access, electrical grid constraints, site location, planning constraints, impact on local communities and site preference.

Of the 49 roadmaps produced, 39 met the ultimate 2050 emissions target of 90% reduction in CO_2 emissions. A considerable number did not meet the interim targets, with 37 missing the 2025 target and 20 missing the 2035 target. Initial emissions targets were missed primarily due to low technology readiness levels (TRLs) of certain deep decarbonisation measures and constraints around external infrastructure, primarily for the electricity grid, hydrogen and captured CO_2.

The financial cases for the roadmaps are generally unfavourable within the current economic climate. Only 14 of the 49 roadmaps are expected to payback by 2050. Within the study a fixed cost was applied to each tonne of CO_2 produced by sites which fall under the current UK Emissions Trading Scheme (ETS), however no further financial incentives such as Contract for Difference (CfD) were applied. Economic modelling was developed to enable a like-for-like comparison between different technologies and roadmap options (e.g. converting a site to hydrogen versus electrifying a site). More detailed economic examination and modelling are recommended.

During the production of these decarbonisation roadmaps, several main challenges to their implementation were identified and are listed below:

- While many sites were enthused and engaged with the programme and the prospect of decarbonisation, this level of support was not unanimous across all stakeholders. Companies will need to reassess their culture from the top down if they wish to meet government targets in the transition to Net Zero.
- Some companies incentivised decarbonisation and energy efficiency projects through lowering internal financial barriers (such as targeted internal rate of return) or redefining how they considered success. Many sites within IFP were not found to have adopted this tactic.
- There is concern around risks and financial implications of decarbonising, particularly that costs associated with implementation of decarbonisation technologies would render products from dispersed sites uncompetitive internationally and relative to sites within industrial clusters. Without clear and committed strategy from government, sites are hesitant to invest in decarbonisation for fear of making the 'wrong' decision. Government support could help offset concerns of international competition while alleviating uncertainty around the decision making process.
- Obtaining connection for new renewable or electrical infrastructure is the primary barrier to electrification. While the technology exists to enable electrification of large swathes of industry supported by installation of renewable generation, the grid cannot currently support this.
- CCUS and hydrogen technologies are generally not as commercially advanced as electrical technologies. The infrastructure to support them currently does not exist and is not predicted to be available to many dispersed sites until, at best, the mid 2030s.
- There is a particular issue around energy infrastructure in Northern Ireland. There is a complete lack of large-scale CCUS, or hydrogen pipelines planned, and the distribution network operator (DNO) is known to oppose additional decentralised electricity generation.
- The forecast costs of low carbon fuels in the HM Treasury Green Book are high relative to fossil fuels.

While sites can be expected to lead on many of these barriers, guidance and investment from government will be necessary to overcome others.

Beyond the challenges outlined above, there have been several other important findings and subsequent recommendations identified throughout this study:

- The existing electricity grid is not currently considered fit for achieving net zero by 2050. While serious investment is planned (totalling tens of billions of pounds), it is not estimated to be sufficient, but further study is recommended to determine the full extent of the investment cost and work required to future-proof the system and enable the transition to Net Zero[1] . This should include consideration for investment and upgrade beyond what will be required by industry, including upgrades to accommodate changes such as in domestic heating, micro-grids, and electric vehicles.
- Dispersed sites face key challenges that sites within industrial clusters are more likely to be insulated against, primarily access to infrastructure. This study has considered sites on an individual basis, but there appears to be opportunity for the development of mini-clusters which might be key to enabling decarbonisation efforts.
- In the case of hydrogen versus electrification for dispersed sites, electrification was more consistently found to be the attractive option when considering cost and practicality of implementation. Generally, electrification technologies are better developed (higher TRLs), cheaper to run, easier to integrate on-site and present fewer safety concerns. Hydrogen could in many instances achieve a deeper level of decarbonisation, although these gains were often marginal and abatement costs were far greater. To offset the advantages of electrification, the future cost of hydrogen would have to be far more competitive than what is currently forecast.
- Most industrial sites were keen to engage with the process and reduce their carbon emissions. They understood the need to do so beyond government mandate or cultivating a good public image. Current consensus is they are most hampered by a lack of clear direction while future UK energy strategy is developed.
- Sites with carbon emissions or CO_2 equivalent emissions inherent to their process (e.g. wastewater, steel, cement/concrete) will require a different approach to achieve zero emissions than those sites which primarily require fuel or electricity for heat, calcining processes, operation of machinery and plant operations.

1 This could be undertaken by the Future System Operator proposed by BEIS and Ofgem.

As a result of external developments, BEIS have decided that the IFP will be discontinued and not proceed beyond this Scoping Study phase. Promoting clearer guidance on funding, incentives and support available to sites and decarbonisation policy would be useful in helping these sites and the wider industrial sector to decarbonise.

If the most ambitious decarbonisation roadmaps developed for this programme were actioned across each of the 15 sites, this would result in a net reduction of 972 $ktCO_2$ annually in 2050, equivalent to a 97% reduction in their total baseline emissions. The cost of this is estimated to be approximately £424 million[2]. Ten of the sites would primarily achieve decarbonisation through electrification while five of the sites would achieve decarbonisation through hydrogen.

Alternatively, a 966 $ktCO_2$ annual reduction in emissions could be achieved by 2050, equivalent to 96% of total baseline, at a cost of £320 million. 12 of the sites would achieve decarbonisation via electrification, one through hydrogen, one through CCUS and one with green gas.

With commitment from government to a coherent energy policy, coupled with investment and upgrade to the National Grid, decarbonisation of UK industry is possible. Sites and companies will have to take responsibility for nurturing an approach which supports this. With the right leadership, good planning and the appropriate national infrastructure, most industries should be able to decarbonise prior to 2040.

2 Neither this cost nor the later include consideration for connection to infrastructure (e.g. DNO grid upgrades).

1. INTRODUCTION

1.1. CONTEXT

Decarbonisation of industry is an essential step in the UK achieving Net Zero greenhouse gas emissions by 2050, as mandated by the 2008 Climate Change Act [1]. In 2018, 16% of total UK greenhouse gas emissions – equivalent to 72 $MtCO_2e$ – came from industry [2][3]. Fully decarbonising industry will require efficiency improvements to existing industrial processes, switching from high carbon fuels to low carbon fuels, and the deployment of carbon capture, utilisation, and storage (CCUS). While many of these solutions are not yet widely adopted, achieving Net Zero by 2050 requires industrial decarbonisation technologies to be ready for large-scale deployment from the 2030s. Through site engagement, it has become apparent that the success of the UK's Net Zero efforts does not hinge solely upon technological developments. It will be dependent on a wider political, financial, and societal shift, ensuring public buy-in and the development of a stable and favourable policy landscape.

1.2. PROGRAMME OVERVIEW

The BEIS Industry of Future Programme (IFP) aimed to provide UK industry with a greater understanding of how to decarbonise their operations, as well as support the commercialisation of deep decarbonisation and energy efficiency technologies at these sites [3].

The programme focused on dispersed sites outside of industrial clusters. Eligible sites were divided into three Lots based on annual scope 1 and scope 2 CO_2 emissions as defined in Table 1-1 [4]:

- Lot 1: sites with emissions over 100 $ktCO_2$/y.
- Lot 2: sites with emissions between 50 and 100 $ktCO_2$/y.
- Lot 3: sites with emissions between 10 and 50 $ktCO_2$/y.

Table 1-1 – Scope 1, 2 and 3 Definitions

Term	Definition
Scope 1 emissions	Direct emissions from owned or controlled sources: stationary combustion, mobile combustion, process emissions and fugitive emissions. Not all sources will be relevant to all industries.
Scope 2 emissions	Indirect emissions from the generation of purchased electricity, steam, heating, and cooling consumed. This is relevant to almost all businesses.
Scope 3 emissions	All other indirect emissions that occur in an organisation's value chain.

The first stage of the BEIS IFP was a Scoping Study aimed at developing decarbonisation roadmaps for each site. The BEIS IFP originally targeted 40 industrial sites. The 15 industrial sites that participated in the programme were selected by BEIS. These sites were within seven sectors: chemicals, paper, minerals, food, water, transport, and pharmaceuticals. Table 1-2 outlines the sites' scope 1 and 2 emissions and Figure 1-1 shows their locations.

Due to recent developments, the BEIS IFP will not continue beyond the Scoping Study phase which this report describes. The stages implemented may serve slightly different purposes to what was originally envisaged.

3 See note in section 1.1 on exclusion of CO_2 equivalents from scope of the BEIS IFP.

Table 1-2 – Overview of Sites Involved in the BEIS IFP.

Company	Sector	Location	Lot No.	Baseline Scope 1 Emissions ($ktCO_2/y$)	Baseline Scope 2 Emissions ($ktCO_2/y$)	Total Baseline Emissions ($ktCO_2/y$)	Reference Year
Dow Silicones UK	Chemicals	Barry, Wales	1	167.6	8.5	176.1	2020
Croda Europe		Rawcliffe Bridge, East Yorkshire	3	12.7	2.7	15.4	2018
Solenis		Bradford, West Yorkshire	2	57.0	1.4	58.4	2020
Palm Paper	Paper	King's Lynn, Norfolk	1	182.8	5.1	187.9	2021
Essity		Prudhoe Mill, Northumberland	2	52.2	29.9	82.1	2019
Kimberly-Clark Ltd[4]		Barrow Mill, Cumbria	2	37.4	13.8	51.2	2021
Churchill China UK	Minerals	Marlborough Works, Stoke-on-Trent	3	10.7	1.4	12.1	2021
Imerys Minerals[5]		Par Complex, Cornwall	3	27.3	0.9	28.3	2019
Midland Quarry Products[5]		Cliffe Hill, Leicestershire	3	13.1	2.2	15.2	2021
British Sugar	Food	Wissington Factory, King's Lynn	1	298.0	1.0	299.0	2017-2018
HJ Heinz Foods		Kitt Green Factory, Wigan	3	38.2	6.9	45.1	2021
United Utilities[6]	Water	Davyhulme Wastewater Treatment Works, Manchester	-	4.6	0.7	5.3	2022 Financial Year[7]
Almac	Northern Ireland – Pharmaceuticals	Craigavon, Northern Ireland	3	6.5	5.4	11.9	2020
Derry Refrigerated Transport[8]	Northern Ireland – Transport	Craigavon, Northern Ireland	-	N/A	0.4	0.4	2021
Food Processing Site	Northern Ireland – Food	Northern Ireland	3	9.8	4.9	14.7	2019

4 Kimberly-Clark's Barrow site applied to the BEIS IFP as a Lot 1 site using reference data from 2015. 2021 data was subsequently provided, reclassifying the site as Lot 2.
5 Total emissions do not exactly match the sum of scope 1 and 2 emissions due to rounding.
6 United Utilities applied to the BEIS IFP on the basis of emitting over 100 $ktCO_2e/y$. As noted in section 2.1, CO_2 equivalent emissions were out of scope of the programme. The roadmap produced considered only CO_2 emissions, which were considerably lower. Due to the low number of participating sites, BEIS retained the site in the programme.
7 2022 Financial Year from April 2021 – March 2022.
8 Derry Refrigerated Transport applied to the BEIS IFP as a Lot 3 site. Analysis of their energy use data identified that their baseline emissions were considerably lower than this due to most emissions being attributed to logistics and transportation fuel use off-site. Due to the low number of participating sites, BEIS retained the site in the programme.

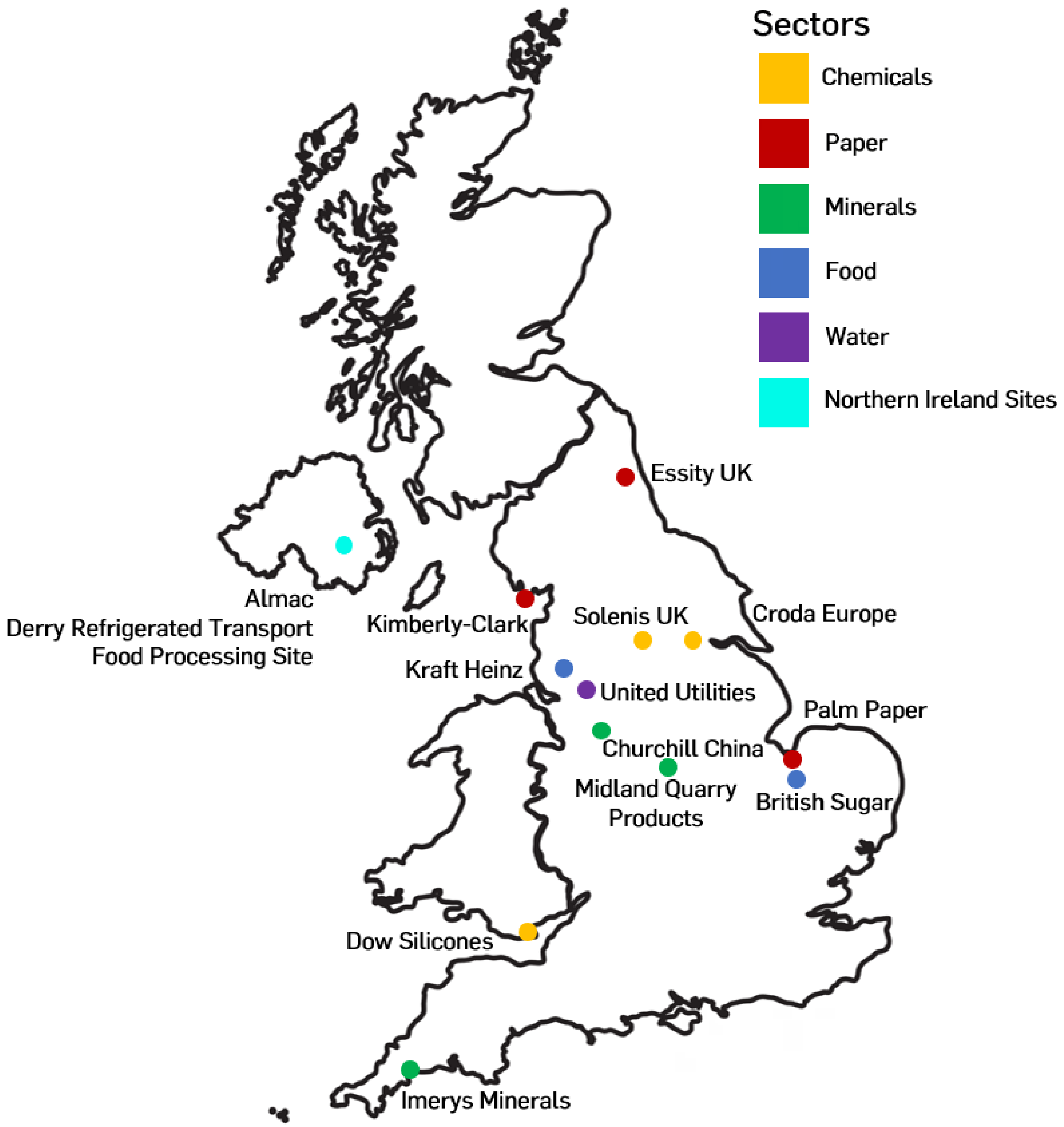


Figure 1-1 – Locations of Sites Involved in the BEIS IFP Scoping Study.

Figure 1-2 shows the total site emissions by Lot number and scope. Figure 1-3 shows the distribution of sites across sectors and Lot numbers. In Figure 1-3, the three Northern Ireland sites – in transport, pharmaceuticals, and food sectors – are grouped together.

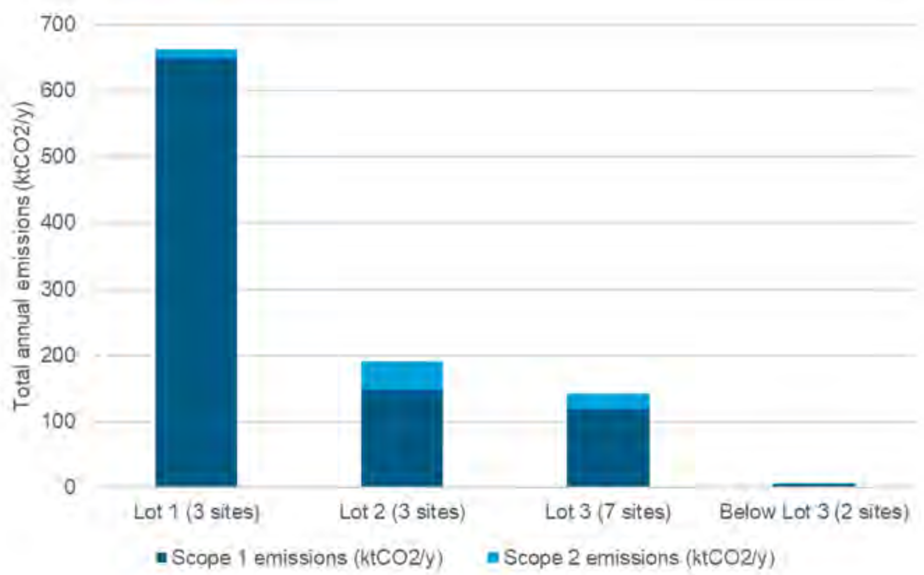


Figure 1-2 – Total Emissions from Sites by Lot Number and Emissions Scope.

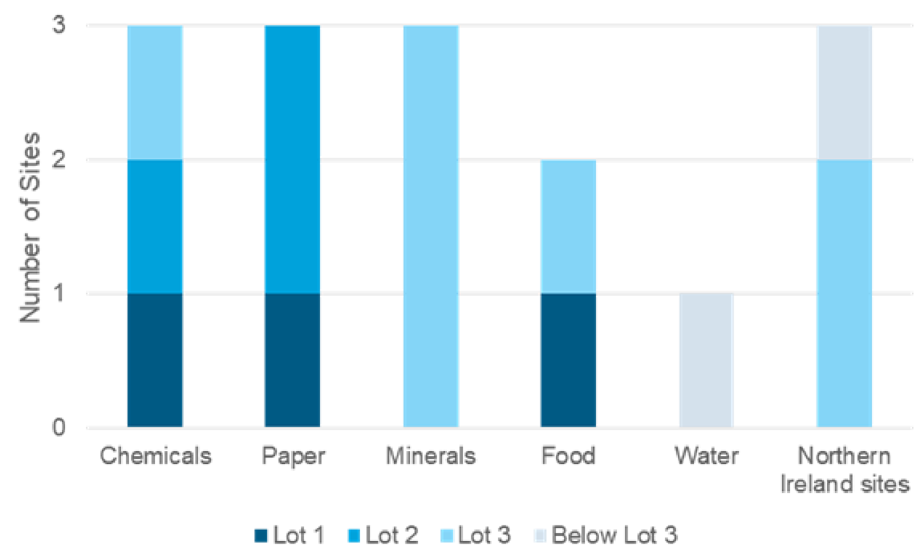


Figure 1-3 – Distribution of Sites by Industry Type and Lot Number.

1.3. PROGRAMME PURPOSE

The aims of the BEIS IFP were to:

- Support companies with high carbon emissions and energy use to transition to a low carbon future through increased energy efficiency and implementation of decarbonisation technologies.
- Allow companies to consider the next generation of industrial decarbonisation and energy efficiency technologies, and to help them to better navigate the complex technology landscape and transition to Net Zero more quickly and effectively.
- Increase government and market understanding of site and sectoral technology gaps and availability.

The goal of this study was to develop tailored, technology-neutral decarbonisation roadmaps for each industrial site, that target 90% reduction in CO_2 emissions by 2050. The reason the BEIS IFP 2050 target is not "Net Zero" CO_2e is outlined in section 2.

2. ASSUMPTIONS, EXCLUSIONS AND LIMITATIONS

This section outlines:

- The scope of the BEIS IFP and the inherent exclusions and limitations.
- Criteria used to down select decarbonisation technologies used in the AtkinsRéalis Industrial Decarbonisation Tool (IDT).
- Key assumptions associated with decarbonisation technologies, interpretation of site energy use data and roadmap development in the IDT.

The purpose of this is to add context to the methodology in section 3.

2.1. PROGRAMME SCOPE

The study scope was to assess the decarbonisation potential and challenges for dispersed industrial sites with emissions between 10 and 100 $ktCO_2/y$. Excluded from the programme were cluster-associated sites, and major oil, gas, and power producers. Several sectors were not covered by the programme as no applications were received from representative sites. These sectors include steel, cement, glass and textiles, notable as most are considered difficult to abate industries. Despite these exclusions, the total CO_2 emissions of sites involved in the programme (1.0 $MtCO_2$ see Table 1-2) correspond to approximately 3% of total emissions from dispersed industrial sites (33.6 $MtCO_2e/y$ [5]) or around 1.4% of total emissions across all industrial sites.

The programme assessed decarbonisation across a range of industries and considered an extensive selection of technologies, varying from technology readiness level (TRL) 3 through TRL 9. To fulfil programme requirements, AtkinsRéalis agreed the following assumptions and exclusions with BEIS to enable or simplify modelling.

The BEIS IFP targeted 90% CO_2 emissions reduction by 2050. This does not align with the UK-wide Net Zero CO_2e target. There are several reasons for this. Foremost is the last 10% of residual emissions are expected to be the most difficult to abate. At this level, fully sized or additional decarbonisation options begin to plateau, resulting in diminishing returns. In many instances this skews capital expenditure (CapEx) and operational expenditure (OpEx) and renders otherwise attractive decarbonisation pathways unviable. This issue is compounded by the 30 year future forecast over which the roadmaps are developed. Further technology advancements (e.g. improvements in efficiency of deep decarbonisation technologies, new emerging technologies) ahead of 2050 could disrupt the decarbonisation landscape. It is expected that these new technologies will be incorporated at suitable junctures to further reduce emissions and meet the Net Zero target.

In line with the BEIS IFP target, accounting was based solely on CO_2 emissions and does not consider CO_2 equivalents. This allowed application of the same technologies across the portfolio of industries, and fair comparison of decarbonisation effectiveness.

The decarbonisation solutions considered were bounded by the site. Scope 3 emissions (as defined in Table 1-1) were therefore excluded from the study.

- Every effort has been made to ensure the accuracy of the roadmaps by utilising data from a range of reputable sources. Several technology options shortlisted for inclusion within the roadmaps (which run up to 2050) are in their infancy, meaning their associated CapEx and fixed OpEx might change as the technology continues to develop. Additionally, the roadmaps utilise HM Treasury Green Book data, although sites were provided with the opportunity to utilise their own energy and carbon pricing forecast data to enable them to obtain a view based on assumptions that are consistent with values used within their business (there was limited uptake of this option).
- It is expected that CapEx of technologies will decrease ahead of 2050, particularly because of the technology maturation and establishment of the CO_2 and hydrogen markets. Given the wide umbrella of technologies considered, each subject to different maturity paths, external market forces and potential for political intervention, forecast of cost reductions was deemed overly complex for the scope of this study and risked introducing a substantial margin of error. Subsequently, this cost reduction is not reflected in model outputs.
- The production of roadmaps within developing technical markets as well as the evolution of national and international policy complicates forward planning. In recognition of this and the incomplete data provided by the sites, the overall accuracy for CapEx throughout the BEIS IFP has been targeted at +/- 50%, however it should be recognised that this margin might be greater for individual technologies. Due to the inherent volatility of energy cost forecasting, the accuracy of OpEx towards 2050 is likely to be subject to a higher margin of error, however the modelling still allows for relative comparison between competing technologies and the business as usual (BAU) forecast.
- No credit was given for companies currently using renewable energy guarantees of origin (REGO) certificates, renewable gas guarantees of origin (RGGO) certificates or other offsets. Similarly there was no consideration for Contracts for Difference (CfDs). This was to enable a baseline comparison between site emissions and technology costs, without unfairly skewing results (e.g. applying CfDs to hydrogen would offer it an advantage over electricity or CCUS, when the CfD could just as easily be applied to these technologies)

2.2. TECHNOLOGY RESEARCH

A key part of the Scoping Study methodology (detailed in section 3) was research of decarbonisation technologies. The initial list of candidate technologies was based on the International Energy Agency (IEA) Energy Technology Perspectives (ETP) Clean Energy Technology Guide [6], which contains over 500 technologies. Technologies were down selected based on the following factors:

- **Relevance to industry sectors and sites:** technologies not applicable to any of the sectors included in the programme were excluded.
- **Technology Readiness Level (TRL):** as per the requirements of the BEIS IFP, technologies below TRL 3 were excluded.
- **Technology function:** technologies used to produce a physical product were excluded, as they were not applicable to reducing emissions at the participating sites.
- **Technology type:** derivative technologies, variants of a technology with relatively small differences, were excluded.
- **BEIS input:** some technologies were excluded following discussions with BEIS to arrive at a final manageable list of technologies.
- **Tool and background calculation development:** some technologies were removed as IDT development progressed and it became clear they were not appropriate for inclusion due to their relevance to the specific sites covered under this study.

Examples of excluded technologies include renewables other than solar photovoltaic (PV) and wind, for example geothermal or tidal, which would have low applicability/relevance across the portfolio of sites. Some biomass technologies were excluded due to the relative complexity of the technology compared to existing site processes and limitations in the availability of feedstock – for example, biomass gasification. Hydrogen production was also excluded (see section 2.3).

In addition to the exclusions made in arriving at a final list of technologies, the research process was subject to several assumptions. These are categorised into assumptions applicable across multiple technologies (listed below) and assumptions applicable to specific technology categories (listed in section 2.3):

- Low TRL technologies are assumed to develop to higher TRL and become widely available for use at sites by 2050. Whilst subsequent BEIS programmes may help achieve this, some technologies may not develop sufficiently for widespread commercial deployment.
- Data for low TRL technologies, particularly costs, are naturally subject to high uncertainty or are unavailable as they have not reached full system pilot/demonstration scale.
- CapEx may decrease significantly once technologies reach higher TRL and are manufactured at scale. Future cost decreases due to increased technological maturity were not considered.
- Separate research into typical external infrastructure upgrade costs and practicality was carried out. Cost estimates were made in each roadmap, separately to the on-site costs. Early engagement with relevant parties – e.g., distribution network operators (DNOs) or vendors – was recommended where appropriate as a mitigation for the uncertainty in external infrastructure costs.
- Cost estimates for technologies assume a typical total installed cost (TIC), although this will be highly variable between sites. Where the vendors were able to provide reliable TIC, these were used. Where any TIC was unavailable, a percentage of CapEx was used. As a mitigation for site-specific variation in TIC, early engagement with vendors was recommended where appropriate.
- Efficiency data for various technologies were based on values provided by vendors or other data sources and are indicative only. When deployed, efficiencies may vary significantly depending on application-specific utilisation profiles, operating conditions, and other site factors.

2.3. TECHNOLOGY-SPECIFIC ASSUMPTIONS

2.3.1. Hydrogen Technologies

- Except where noted due to existing site plans, hydrogen was not assumed to be produced at the industrial sites, as:
  - On-site blue hydrogen production would almost certainly be unfeasible for the scale of demand of a single site[9].
  - On-site electrolysis would be challenging to deploy given it is approximately 60-70% efficient as a process and unlikely to be coupled with substantial on-site renewable energy generation at the sites selected for this project. Therefore, it would almost always be cheaper and more efficient to use electricity directly for power or heat than to convert it to hydrogen first.
  - Electrolysis using grid electricity would not produce low carbon hydrogen until the electricity grid decarbonises. Due to the low overall system efficiency, this process would also be cost prohibitive.
  - Existing pipe infrastructure would be used to accommodate hydrogen blends up to 20%. Fuel blend compositions above this would require upgrades to site pipework to accommodate hydrogen.
- All utilised hydrogen was assumed to be 100% blue hydrogen in the short-medium term. In the longer-term, green hydrogen fuel switches were considered for sites expected to have appropriate cluster access. This did not influence the research output but affected the assumed cost of hydrogen in the IDT and the resultant scope 2 emissions, therefore impacting the viability of hydrogen technologies.
- Hydrogen carrier substances such as ammonia, methanol and liquid organic hydrogen carriers were excluded. These intermediates are generally not expected to be used to produce heat in industrial processes.

2.3.2. Biomass Technologies

- Fuel cost for biomass technologies was assumed to be equal to the cost of wood chips, based on the wood chip fuel supply.
- Footprint of on-site storage was not estimated as it is dependent on the technology selected and duty cycle.

2.4. TECHNOLOGY-SPECIFIC EXCLUSIONS

- Transport of captured carbon via trucks was excluded. Only relatively small scales can practically be transported using road vehicles and this would present additional logistical challenges to sites.

2.5. INDUSTRIAL SITE ENGAGEMENT

Due to the unique nature of each participating industrial site, both in terms of processes and data availability, assumptions were necessary at a site-level to enable use of the IDT. This list gives an overview of common assumptions:

- Energy consumption datasets from sites were received in various formats, with the most granular providing minute data, and the least granular providing only monthly data, or quarterly in one case. The IDT required input data in an hourly format, necessitating conversion of all datasets that were not hourly. When converting less granular data, uniform hourly consumption was assumed.
- Discrepancies between various sources of data were relatively common, for example total gas consumption data being inconsistent with the sum of the gas consumption of all gasburning equipment. In most cases, assumptions were made to reconcile the data, and these were checked with the sites to confirm validity.
- Efficiencies of on-site equipment were not always provided. In such cases, indicative efficiencies were used.

9 See section 4.5.1.1 for definitions of different types of hydrogen.

FOR PUBLICATION

- Some sites were not able to provide a full year of representative energy use data, usually due to changes in site operations. In such cases, the available datasets were used to generate a yearly profile. For example, for a site providing only 10-months of data, a yearly profile was generated by assuming energy use in the missing months was equal to the average of the provided data.
- Many sites did not provide comprehensive steam usage data, primarily due to a lack of suitable metering. In such cases, steam usage was estimated based on the available data.
- Some sites did not have comprehensive metering for all processes and equipment. Energy usage profiles were estimated in such cases, via assumptions tailored to each site, for instance using energy balances.
- Data for smaller, infrequently run equipment such as backup boilers or generators was not always provided. Due to the relatively small contribution of such assets to total energy use at a site, they were excluded from analysis where data was not available.

2.6. INDUSTRIAL DECARBONISATION TOOL

The following assumptions were made in relation to the IDT:

- All technology inputs were static (no changes over time in costs or efficiencies were modelled). For example, wind turbines installed in 2025 were assumed to have the same cost and efficiency as wind turbines installed in 2045.
- The cost of carbon abated was calculated based on the cost of implementation of interventions without consideration of available government support mechanisms. This allowed cost of carbon abated to be compared on a like-for-like basis. Qualitative recommendations on relevant government support schemes were provided to all sites.
- Carbon prices, electricity and fuel carbon factors, electricity and fuel import costs, and discount rates were all taken from HM Treasury Green Book. The associated energy/fuel pricing assumptions were adopted for the study, where available.
- BEIS 2022 Greenhouse Gas Reporting Conversion Factors were adopted [6]. This includes bioenergy, which includes CO_2 equivalents. This is inconsistent with the scope of the programme being limited to CO_2. The emission factors for these fuels were considered small enough to not adversely affect the accuracy of the roadmaps.
- Year of first availability of green and blue hydrogen varied between sites, depending primarily on distance from hydrogen clusters.
- Where appropriate, green, and blue hydrogen fuel switches were incorporated into roadmaps. The associated costs were based on the BEIS Hydrogen Production Costs 2021 report [7] and emissions factors were taken from the BEIS Low Carbon Hydrogen Standard [8]. A 20% markup was added to account for cost to end user and transmission/distribution costs (i.e. on top of the production cost). Green hydrogen cost was based on cost of hydrogen generated from dedicated offshore wind (there are large variations in green hydrogen cost depending on how it is produced).
- The IDT imported key technical parameters for each technology from the research parameter database (the output metrics from the research phase), for example CapEx and efficiencies for technologies such as gas turbines and boilers, in addition to assumptions regarding efficiency degradation over time.
- Baseline data inputs from sites were assumed to represent a 'typical' operating year. Where changes to baseline operation are planned by sites, these were incorporated into the BAU forecast.
- Fuel sourcing, generation and selling of fuels were excluded (other than export of electricity generated on-site to the grid).
- No consideration was given to carbon credit allocations sites might be receiving.
- No account was taken for renewable energy guarantees of origin (REGO) certificates, renewable gas guarantees of origin (RGGO) certificates or other offsets when generating the BAU forecast.
- Emissions reductions were calculated as a reduction on the baseline year, rather than a reduction relative to the BAU forecast.

3. METHODOLOGY

This section summarises programme execution and AtkinsRéalis' engagement with sites, to provide context to the roadmap summaries in section 5.

3.1. PROGRAMME TIMELINE

The programme timeline was divided into four distinct phases, as illustrated in Figure 3-1:

- Programme start-up.
- Data gathering, technology research and IDT development.
- Development of industry roadmaps using the IDT.
- Final reporting.

The start-up phase involved initiating contact with each site to familiarise them with the aims of the programme and arrange site visits. This phase was delayed due to several factors, mostly owing to the different approaches to non-disclosure agreement (NDA) requirements by individual entities and finalisation of the agreements.

With NDAs in place, the data gathering required to produce decarbonisation roadmaps began. Alongside this, research was undertaken to support the expansion and development of the IDT. The data provided by sites was used to understand their operations and energy use and allowed development of BAU profiles.

Once data gathering was complete, a review of the site operations was undertaken, and a longlist of decarbonisation technologies was presented to the site teams in Workshop 1. AtkinsRéalis and the site teams worked to select the technologies which best fit with each site.

AtkinsRéalis then began development of the decarbonisation roadmaps. Preliminary sizing and cost calculations were carried out, driven by the proposed decarbonisation goals of the BEIS IFP. The findings of this exercise were presented to the site teams in Workshop 2. This enabled some further input from sites, following which the detailed roadmaps were developed by AtkinsRéalis using the IDT.

With roadmaps finalised, supporting roadmap reports were produced for each site along with this overview report summarising the programme findings.

A more detailed project timeline is shown in Figure 3-1.

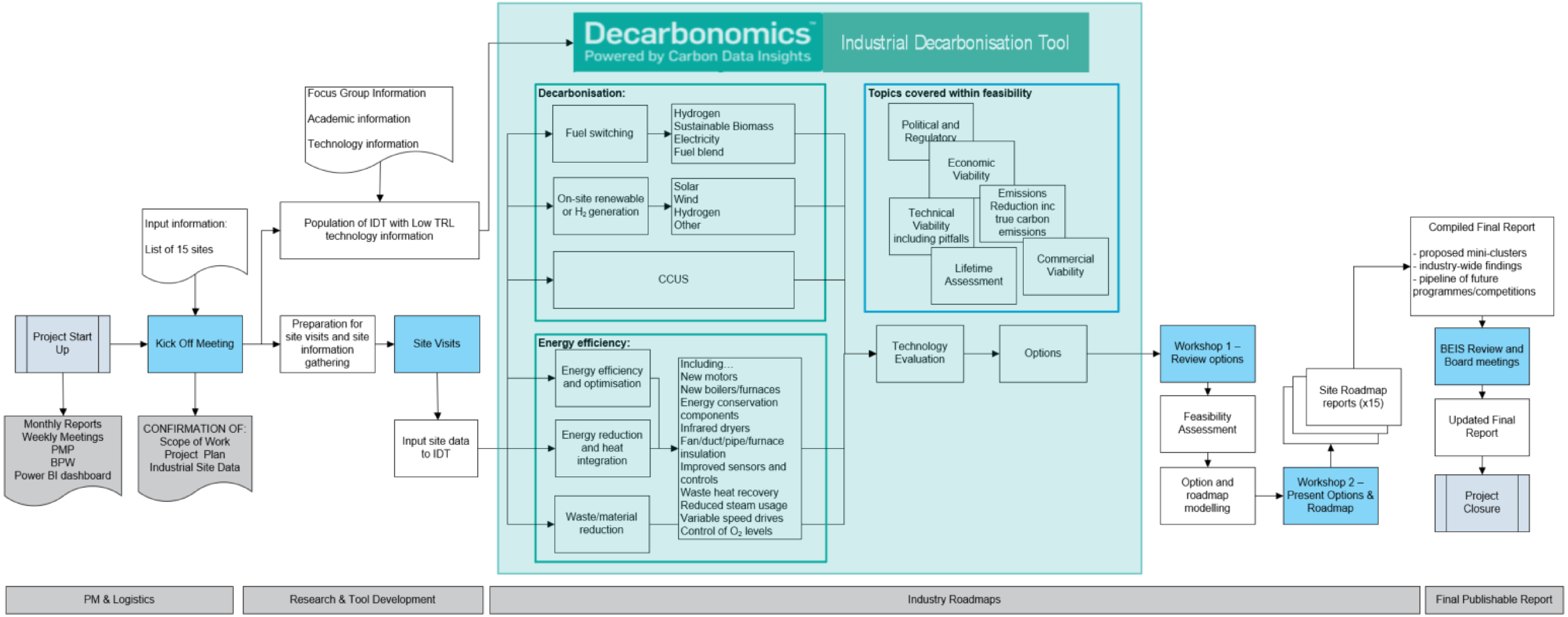


Figure 3-1 – BEIS IFP Scoping Study Activities.

3.2. TECHNOLOGY RESEARCH

A workflow detailing how the research was undertaken for low carbon technologies considered within this programme is shown in Figure 3-2. The key task to note is the three-stage process of data collection to build up the data bank that was utilised in the IDT. This investigation passed through internal data collection (based on AtkinsRéalis internal library of information), then information available in the public domain before finally reaching out to technology suppliers to gather vendor-specific data. For a non-exhaustive list of sources AtkinsRéalis utilised to develop the data bank, see Appendix A. AtkinsRéalis have ensured that data captured have the appropriate data usage conditions/permissions and prioritised the most up-to-date information where possible.

The number of technologies considered was reduced based on various criteria (see section 2.2). To maximise the relevance for the sites, AtkinsRéalis also reviewed technologies previously considered by the sites and where possible incorporated these within the technologies list. For a full list of the technologies that were considered within this programme, see Appendix B.

Translational Energy Research Centre (TERC) were consulted at the start of the programme. Their input was very high level due to the lack of visibility and knowledge of the sites in the early stages of the programme. Energy Systems Catapult (ESC) provided ongoing support, engagement, and external reviewing capability with particular focus on the Northern Ireland sites.

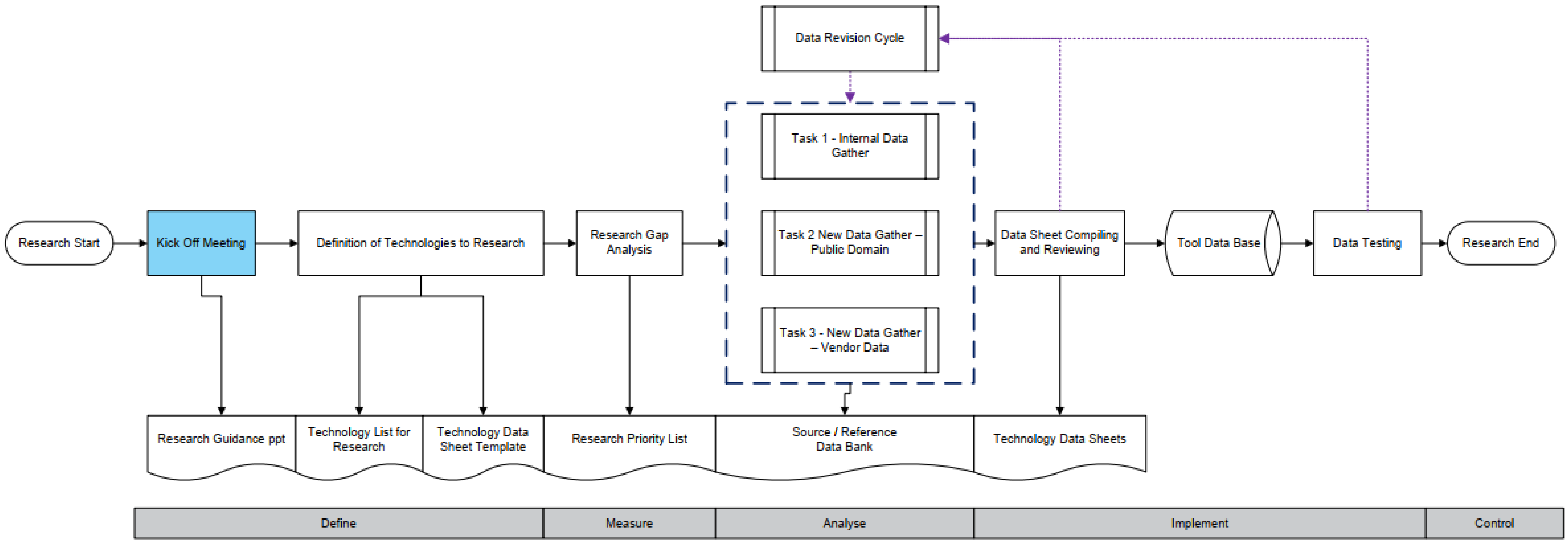


Figure 3-2 – Technology Research Workflow.

3.3. INDUSTRIAL DECARBONISATION TOOL DEVELOPMENT

The IDT has been developed by AtkinsRéalis as part of the Decarbonomics service line and provides insight into various decarbonisation options, to identify the most suitable net zero roadmaps for a site, optimised depending on site requirements.

By understanding current and future operations, the user is able to use the Tool to view different interventions and assess the impact they have on reducing emissions. This 'what if' analysis provides confidence to the site that the most appropriate route to net zero can be identified, and this is supplemented with insights into carbon, OpEx and CapEx estimates for the roadmap duration. In essence, the IDT enables technology evaluation and scenario assessment to determine net zero progress, carbon and cost implications.

Once the technology information was refined through research, key metrics from the site questionnaire document and site metering data were extracted by the Tool. These were used to establish a comprehensive overview of site operations along with a projection of what BAU would look like, generating a forecast from the baseline year to 2050. This accounts for any planned changes such as new build developments, equipment replacements or a change to production that will have an impact on the energy usage on the site. This BAU forecast is then modified by including energy efficiency and deep decarbonisation technology interventions, enabling the user to understand the impact of each technology across the site and enabling the industrial partners to meet their net zero targets. Within the IDT, decarbonisation interventions were selected for inclusion in the resulting roadmap options, under the following categories:

- Energy efficiency:
  - Energy efficiency and optimisation
  - Energy reduction and heat integration
- Deep decarbonisation:
  - Fuel switching
  - On-site renewables
  - CCUS
  - Energy storage

Once the site team have evaluated the opportunities and constraints across the site, appropriate interventions are selected and combined in a scenario. Multiple scenarios can be generated per site, with each scenario demonstrating a potential net zero roadmap. The IDT performs the required calculations, to determine the impact to the fuel and / or electricity supply required by the site following installation of the selected technologies. Each scenario is compared against the BAU forecast to understand impacts on carbon emissions and operational performance. Financial calculations which are completed for each of the scenarios are based on cost and performance data from the research database. The results of the calculations are viewed in a dashboard and are discussed in appropriate sections within this report.

The IDT shares a common benchmark database with the AtkinsRéalis Decarbonomics tool and Intellectual Property is retained by AtkinsRéalis.

3.4. APPLICATION OF THE DECARBONISATION HIERARCHY

When selecting decarbonisation interventions for inclusion in the IDT, the project-wide decarbonisation hierarchy was followed.

Energy efficiency, process optimisation and sub-metering improvement measures are typically some of the easiest interventions to implement, both from a cost and complexity standpoint. Enactment of these measures in turn reduces/informs the required size of subsequent deep decarbonisation interventions. These measures were therefore incorporated into roadmap options in the IDT prior to more complex and costly options such as electricity generation, fuel switching or CCUS.

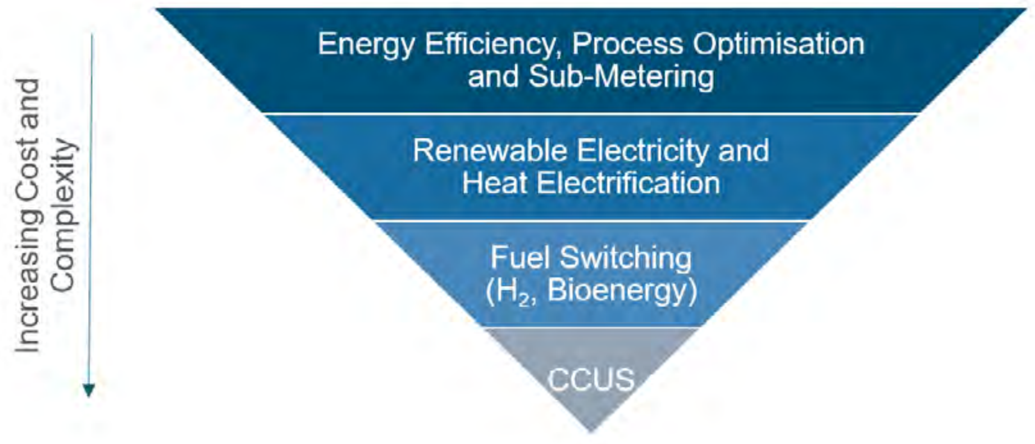


Figure 3-3 – Decarbonisation Hierarchy.

3.5. INDUSTRIAL SITE ENGAGEMENT

Throughout the programme the AtkinsRéalis team had several key engagement points with the participating industrial sites.

Data Gathering: sites completed a questionnaire document outlining key energy use on-site. Many sites also supplied additional metering data. Data analysis was performed to identify any gaps or inconsistencies in the data. Alongside this data analysis, the AtkinsRéalis team undertook a systematic survey of each site following each process end-to-end to ensure full understanding of the energy assets, distribution networks, energy use and end user (process, operational, product) requirements. Throughout the walkover surveys, AtkinsRéalis' site teams also reviewed the condition of the existing energy assets and noted where opportunities for potential energy efficiency measures existed. These exercises provided a complete overview of energy inputs, uses and losses – this marked completion of the 'input data received' milestone.

Sub-metering: this phase was originally included in the initial tender but was excluded from the BEIS IFP during delivery as it was determined that all the industrial partners were able to provide sufficient data for the purpose of roadmap development without the need for additional investigation. Installation of sub-metering would have also incurred considerable programme delays. Therefore, no sub-metering was required for this programme. Where relevant, specific recommendations on improvements to sub-metering were made to sites to support feasibility review and sizing of interventions.

Data Analysis: as discussed in section 3, Workshop 1 summarised the data for review with the stakeholders present to ensure a representative baseline had been built up for the option and roadmap development stage.

Roadmap Development: the AtkinsRéalis site teams updated the IDT and produced detailed roadmap options, which were presented to each site at Workshop 2.

Issue Roadmap Report: any final comments gathered during Workshop 2 were incorporated into each of the 15 roadmap reports prior to issue and a full quality assurance process was carried out.

Issue Summary Reports: two summary reports were prepared providing an overview of the programme methodology and findings. One report was intended for use solely by BEIS and the other (this report) was intended for publication by BEIS to inform wider stakeholders of the programme.

4. OVERVIEW OF TECHNOLOGIES RESEARCHED

This section provides an overview of the technologies researched during the programme, with respect to:

- A brief introduction to the technologies.
- The potential for technologies to support decarbonisation.
- Practical considerations on the implementation of technologies.

It offers context on the interventions discussed in the roadmap summaries in section 5.

4.1. ENERGY EFFICIENCY

Energy efficiency involves measures that reduce the amount of energy (and therefore emissions) required to manufacture a product or provide a service. A project-wide energy efficiency checklist was produced to capture the generic principles of energy efficiency, outlined in Figure 4-1. This checklist was used in the development of all roadmap options.

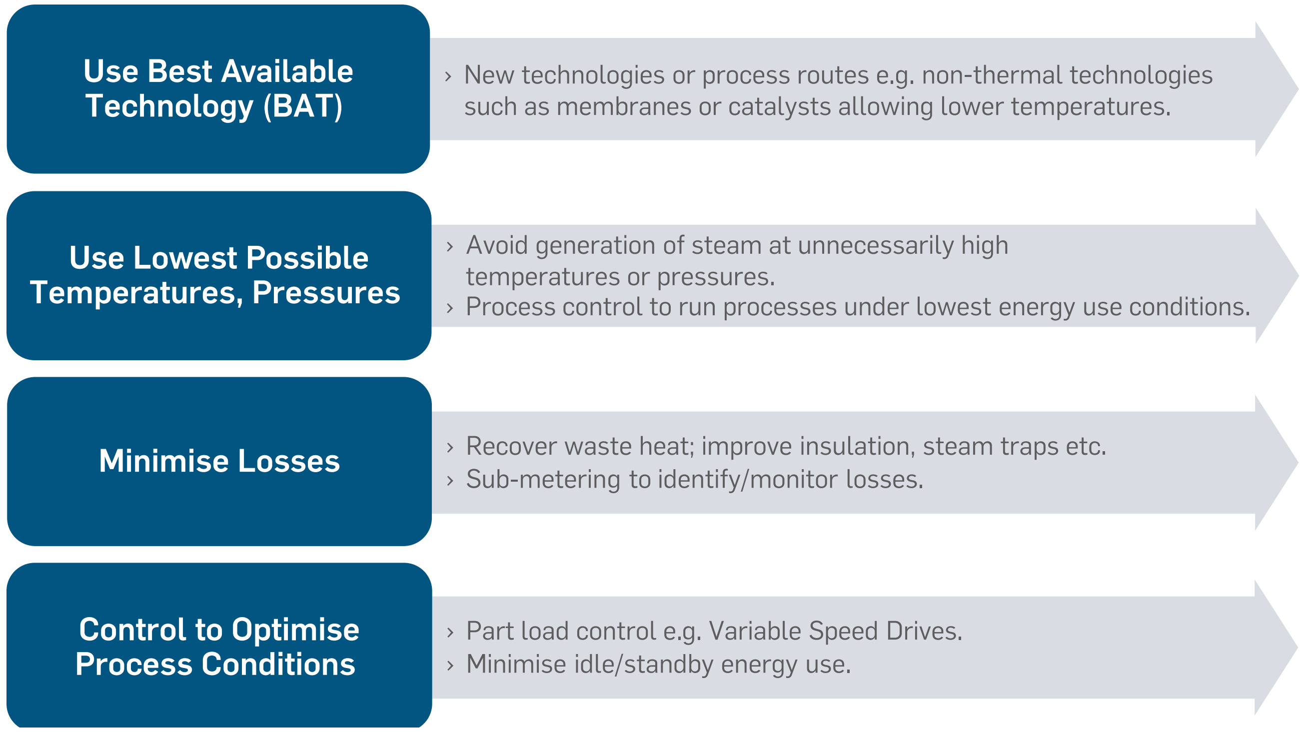


Figure 4-1 – General Principles of Energy Efficiency.

FOR PUBLICATION

4.2. RENEWABLE ELECTRICITY

Renewable electricity is generated from a source that is not depleted when used, such as wind, solar or geothermal power. Four sources of renewable electricity were considered:

- UK-wide greening of the electricity grid.
- Purchase of renewable energy guarantees of origin (REGO) certificates.
- Power Purchase Agreements (PPAs).
- Installation of on-site renewables.

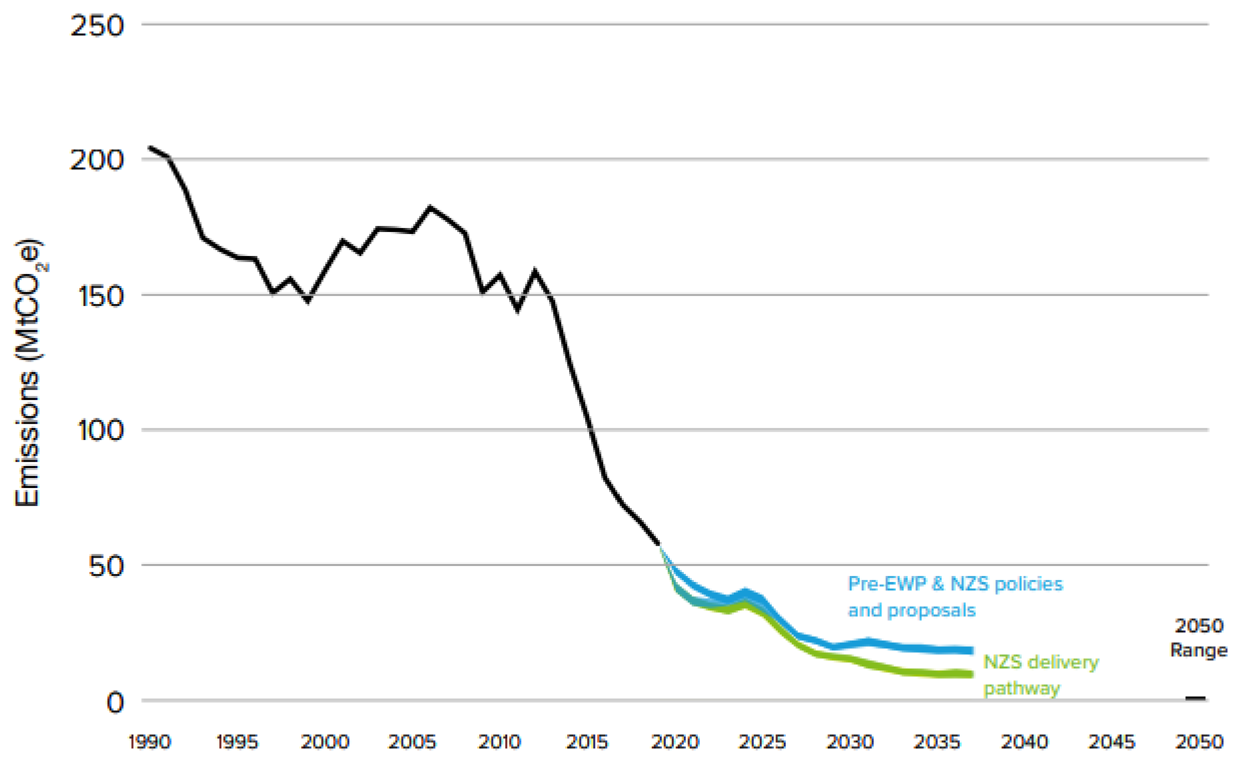


Figure 4-2 – Indicative Power Emissions Pathway to 2037[10]

4.2.1. Greening of the Electricity Grid

The 2021 UK Net Zero Strategy committed to "fully decarbonise our power system by 2035". The UK's grid electricity is expected to rapidly decarbonise year-on-year through connection of increased capacity of renewables. Across all sites scope 2 emissions are forecast to reduce according to Figure 4-2, irrespective of site action [9]. Cost of grid electricity is however volatile, for example prices are currently inflated due to the ongoing energy crisis.

10 Acronyms included in Figure 4-2 refer to the 2020 Energy White Paper (EWP) [23] and 2021 Net Zero Strategy (NZS) [9].

4.2.2. Purchase of Renewable Energy Guarantees of Origin Certificates

Purchase of REGOs guarantees that an equivalent amount of low carbon electricity has been generated compared with that used on-site. Through purchasing REGOs for the entirety of a site's electricity supply, sites could report that they are utilising zero carbon power. Increased demand for REGOs would increase their cost over time. Purchase of quality REGOs is necessary to ensure equivalent additional electricity generation capacity is installed as a direct result of certificate purchase and "greenwashing" is avoided[11].

4.2.3. Power Purchase Agreements

In PPAs a third party finances the installation of a renewable generation technology and agrees to sell the energy to the site at a fixed price. There are three common types of PPAs [10]:

- Direct wire PPAs, also called private wire PPAs, require a direct physical connection between the generator and the consumer.
- Indirect wire PPAs, also called grid connected PPAs, entail a contractual agreement where a buyer purchases a specified amount of electricity from a specified asset belonging to a generator.
- Virtual PPAs (VPPAs), also called synthetic/financial PPAs, entail a contractual agreement where the generator and consumer are not directly connected, instead both parties are connected to the national electricity grid.

4.2.4. Installation of On-Site Renewable Generation

The primary renewable generation technologies considered during the programme were solar PV and wind turbines. Feasibility considered land available, proximity to buildings and planning policy. Outlay of CapEx is required for both installation and upgrade of grid connection. Grid upgrade and connection was not included in the total CapEx, it was considered as a separate infrastructure cost. OpEx is minimal (primarily due to maintenance costs) and excess generation may be exported.

A primary challenge with renewable energy is intermittency. Often, renewables must be installed at scale to achieve appreciable decarbonisation. The low utilisation factors of solar and wind power (e.g. compared to gas turbines) can be mitigated to a certain extent through energy storage technologies (see section 4.6).

4.3. COMBINED HEAT AND POWER

Combined heat and power (CHP) is the simultaneous generation of heat and power in a single process.

Previously CHP presented a compelling decarbonisation case owing to the efficiency gains from local and simultaneous heat/power generation and an electricity grid that was not as 'green' as it is today. Many UK sites adopted CHP plants due to gas being cheaper than electricity per unit of energy and government initiatives such as the Combined Heat and Power Quality Assurance (CHPQA). The CHPQA provides a practical, determinate method for assessing all types and sizes of CHP schemes throughout the UK. The CHPQA aims to monitor, assess, and improve the quality of UK CHP schemes.

Key considerations for decommissioning of CHP assets to support decarbonisation are:

- Decommissioning before end of life would likely be OpEx negative and result in the sites being unable to earn export revenue.
- Availability of grid capacity to support the additional electricity demand that was previously provided by the CHP, or if low carbon generation could replace the CHP to maintain low-cost electricity.
- The economic case for gas-fired CHP will likely fall away in the next 10-20 years due to the increasing carbon price from the UK Emissions Trading Scheme (ETS), withdrawal of CHPQA incentives and increasingly competitive renewable generation options.
- As the electricity grid decarbonises, gas-fired CHPs now result in higher net emissions when compared with traditional usage of the electricity grid. This disparity will increase significantly once the electricity grid achieves zero carbon status, as shown in Figure 4.3.

11 Greenwashing is defined as the act of providing the public or investors with misleading or false information about the environmental impact of a company's operations.

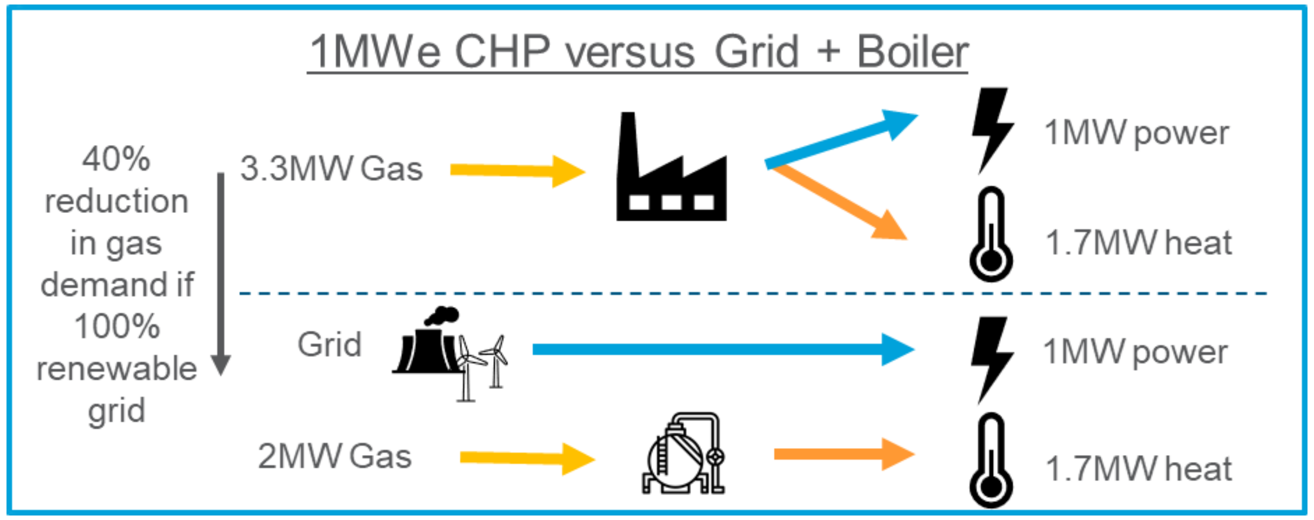


Figure 4-3 – 1 MWe CHP Compared to a Traditional Electricity Grid and Boiler Setup.

CHP plants can still find use as an energy efficiency option to reduce use of an expensive fuel or limit the volume of CO_2 produced where a fossil fuel is being burned. Hydrogen-fired CHPs are also an option but face fundamental challenges:

- Overall energy efficiency from point source electricity production and conversion losses is very low when compared against using the electricity directly. This issue is particularly glaring in the case of green hydrogen.
- Blue hydrogen cost is not significantly lower than grid electricity cost.
- Timescales for hydrogen infrastructure and fuel supply to dispersed sites are uncertain.

Biogas-fired CHP assets fitted with CCUS have the potential to allow sites with biogenic fuel sources to become carbon negative.

4.4. ELECTRIFICATION

Electrification involves the use of electricity to power a process instead of fossil fuels. Electrification technologies considered during roadmap development include:

- Heat pumps.
- Electric steam boilers.
- Electrode steam boilers.
- Mechanical vapour recompression.
- Electric process heaters.
- Organic Rankine cycles (ORC).

4.4.1. Heat Pumps

Conventional heat pumps are widely available today. They use a refrigeration cycle (see Figure 4.4, [11]) that takes heat from a source and uprates it to a higher temperature. This uprated heat can be used in space heating, hot water supply and process heating. Heat pumps can utilise low or high grade waste heat. They can also utilise heat from air, water, or the ground. The grade, source and required heat output determine the type of heat pump required and its performance.

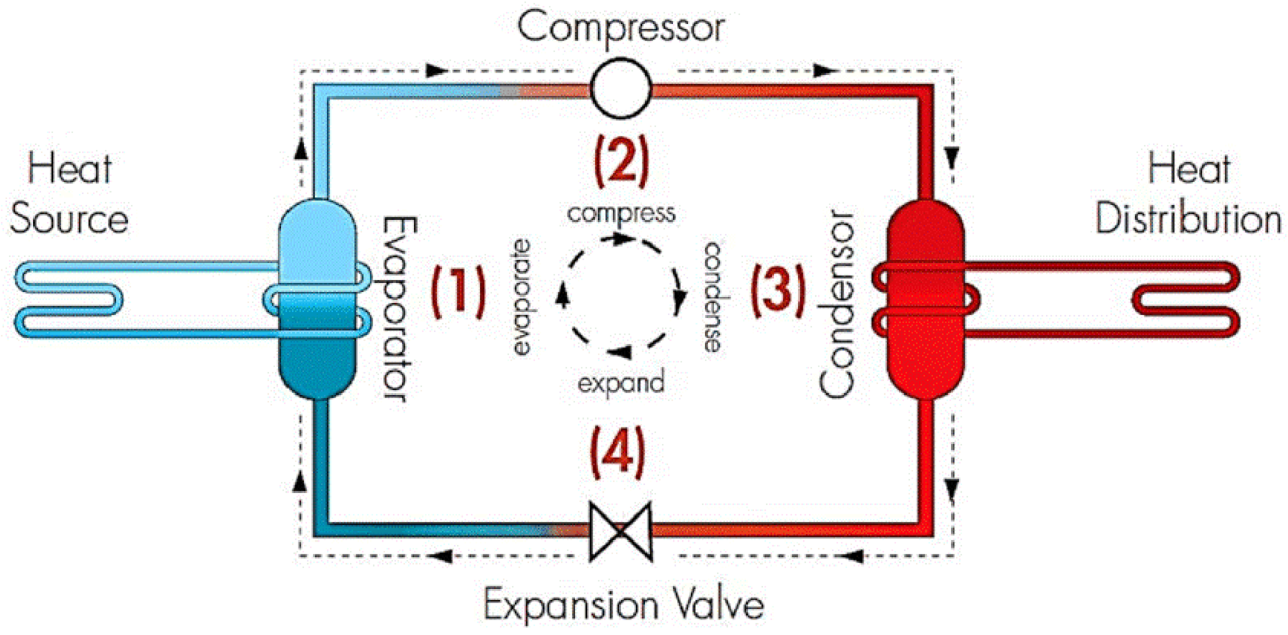


Figure 4-4 – Typical Heat Pump Refrigeration Cycle Schematic.

Certain working fluids used in heat pumps (e.g. hydrofluorocarbons) have high global warming potential, as well as health or safety implications (for example due to leakage). Careful consideration was given when selecting heat pumps to avoid negating the potential decarbonisation benefits of the technology.

4.4.2. Other Heat Electrification Technologies

Electric steam boilers use electricity and a resistive element to produce steam with ~99% efficiency. Electrode steam boilers use electrodes immersed in water to produce steam. Electrode boilers produce a higher throughput of steam than resistance-type electric steam boilers.

Mechanical vapour recompression takes waste vapour from evaporation/distillation processes, compresses it using electricity to raise the temperature and then uses this as a new heating medium to displace steam use.

Electric process heaters such as resistance heaters use electricity and a resistive element to heat a process medium (liquid or gas).

These interventions can be used in place of existing fossil fuel assets such as boilers and burners. However, given the existing energy mix of the electricity grid, using grid electricity to power these technologies does not present a promising decarbonisation proposal. This will improve as the grid decarbonises (or if renewable electricity is used). The financial case is also currently weak due to the ongoing energy crisis inflating the cost of grid electricity.

ORC converts low temperature waste heat (as low as 70-100°C) into electricity by passing a heating medium through a turbine. However, it would be more efficient to re-use the waste heat if possible.

4.5. FUEL SWITCHING

Fuel switching is the substitution of one energy source for another. Switching to fuels with lower carbon intensities was considered in roadmap development, mainly hydrogen or biofuels.

4.5.1. Hydrogen

4.5.1.1. Production Methods

There are various forms of hydrogen production in the UK, with the key ones defined as follows:

- Grey hydrogen – currently the most common form of hydrogen production, where natural gas is processed via steam/autothermal reformation (where natural gas and heated steam are reacted) to generate hydrogen (and CO_2 as a by-product).
- Blue hydrogen – hydrogen is produced in the same way as for grey hydrogen, but CCUS is incorporated to capture the undesired CO_2 by-product.
- Green hydrogen – renewable energy, such as solar or wind, are used to power electrolysis units which split water into its components of hydrogen and oxygen. This results in a zero carbon emission process. This is currently the least used of the three types as the technology has not reached the maturity, scale and deployment required to achieve adequate volume of supply. The consequence is it is the most expensive approach to hydrogen production. Green hydrogen is expected to become more widespread as its cost decreases.

The UK's Hydrogen Strategy [12] affirms that low-carbon hydrogen is the focus for hydrogen roll-out within the UK, with blue hydrogen to be the production method best placed to be deployed at scale within industrial clusters in the near-term, while green hydrogen is scaled up to drive costs down. BEIS has forecast that large-scale blue hydrogen can be expected from the mid-2020s, with small green hydrogen production projects ready to build in the early 2020s. Figure 4-5 provides a graphical indication of how the share of hydrogen production by technology type has been proposed to change in the coming decades [13].

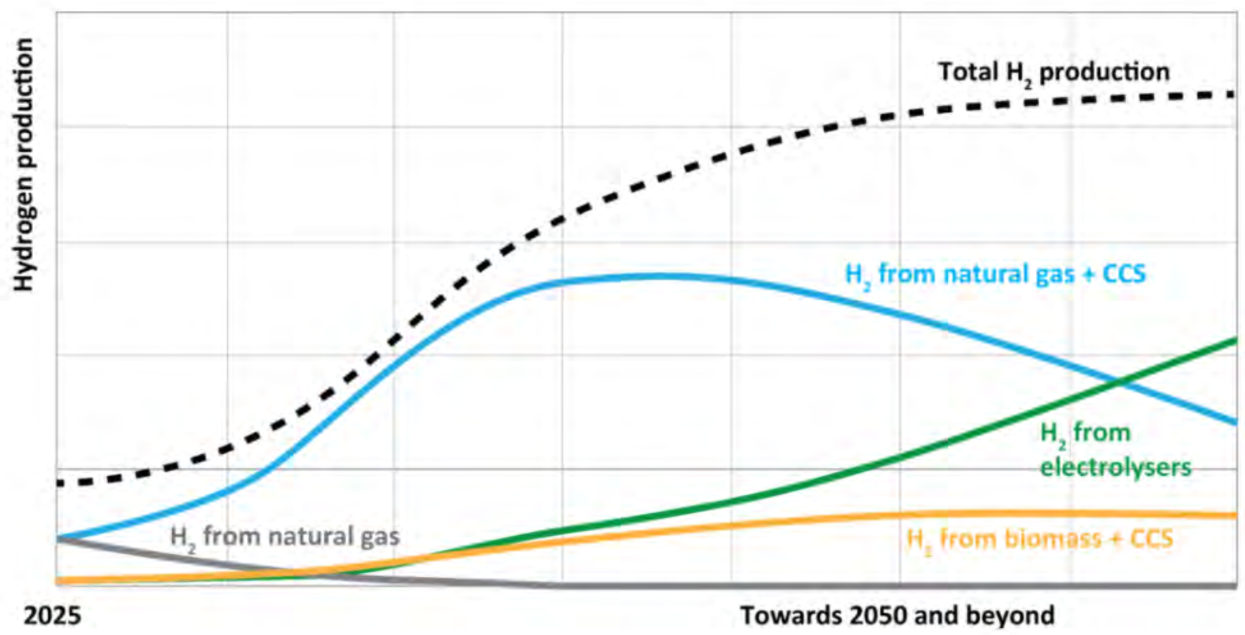


Figure 4-5 – Illustrative Projection of Future Hydrogen Production Methods.

4.5.1.2. Hydrogen Use

Hydrogen can be used in combustion processes, in a similar way to natural gas. The principal product from this is water vapour. As with natural gas combustion, burning hydrogen in air produces nitrous oxide (NOx) as a by-product. Production of NOx is greater for combustion of hydrogen but can be managed by emission control systems. Hydrogen 'use' technologies are at a wide range of technological maturities.

4.5.2. Bioenergy

Bioenergy is an energy vector derived from biomass. Biomass is naturally derived from organic materials, which can be used directly or converted by bio-chemical, thermo-chemical, and physio-chemical processes to create a usable bioenergy vector. These products can be in solid (e.g. wood, charcoal), liquid (e.g. biodiesel, bioethanol) and gaseous form (e.g. biogas, syngas).

Bioenergy can either be used directly on-site or purchased through renewable gas guarantees of origin (RGGO) certificates. Purchase of RGGOs guarantees an equal amount of biomethane has been injected into the gas grid compared with the amount of natural gas used on-site. As with REGOs, purchase of quality RGGOs is necessary to ensure equivalent additional biomethane capacity is installed as a direct result of certificate purchase and "greenwashing" is avoided.

Many different bioenergy sources currently enable the claim of 'Net Zero' emissions when used as a fuel. The overall 'Net Zero' emissions of such fuels are being increasingly debated globally.

This is due to lifecycle emissions associated with land-use change, soil erosion, chemical fertiliser use, and transportation. The supply of bioenergy is limited in the UK by process and feedstock availability. This can prove a challenge to security of supply for larger gas consumers, such as industry.

Bioenergy was considered during roadmap development where:

- Biomass/organic residues are available locally or on-site.
- Incorporation of its use with CCUS to become a carbon negative process.
- Few decarbonisation alternatives exist

4.6. ENERGY STORAGE

Renewable energy generation is often intermittent, particularly solar PV's diurnal generation pattern. Energy storage is critical in converting intermittent generation assets into baseload-compatible supply for achieving decarbonisation.

Technologies such as batteries, thermal energy storage, compressed air/liquid energy storage, pumped hydro, and hydrogen/gas storage all present solutions for various applications, such as:

- Heat recovery at sites with batch processes.
- Storage of surplus renewable electricity.
- Catering for peak loads to minimise boiler/heat pump size or peak electrical demand on the grid.

Figure 4-6 illustrates the potential of discharge rate versus capacity of the various energy storage technologies listed above [14].

FOR PUBLICATION

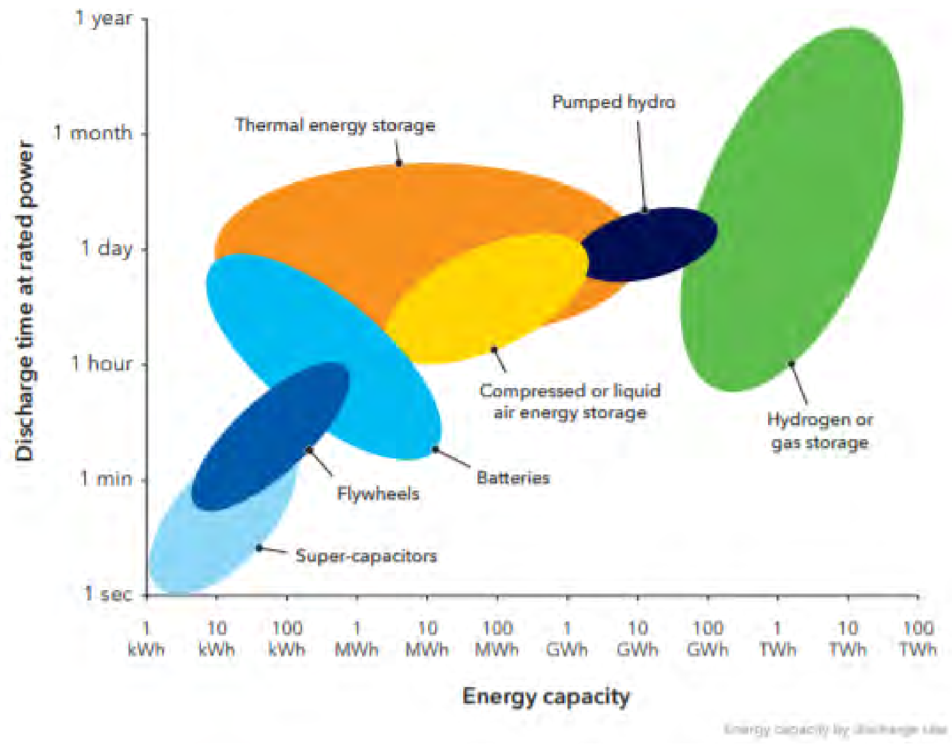


Figure 4-6 – Discharge Time Against Capacity for Energy Storage Technologies.

Currently, individual sites can rely on electricity or gas grids to ensure continuity of supply. Energy storage has not been included as part of the decarbonisation roadmap options for most sites. By 2050 there may be greater uptake of on-site energy storage for various reasons such as grid balancing, on-site generation uptake, efficiency/process integration or cost reduction. Given the rapid development and change in these fields, it is difficult to forecast what this might look like.

4.7. CARBON CAPTURE, UTILISATION AND STORAGE

Most carbon capture processes consider the capture of CO_2 emissions post combustion. The typical technologies used for carbon capture are:

- Solvents, such as amines.
- Aqueous potassium carbonates.
- Solid sorbents.
- Membranes.

CCUS technologies are both CapEx and OpEx intensive (owing to the thermal or electrical energy requirements, dependent on technology). The use of solvents is expected to be the lowest cost in the short-medium term. Demonstration plants are now being investigated at sites of similar scale to those involved in the BEIS IFP using this technology (amine). Other capture technologies are at a lower development level. Sites considering CCUS need to determine how the captured CO_2 will be used or stored. Unless a site opts for utilisation of the carbon, longevity of the carbon storage must be considered to determine if it can achieve decarbonisation.

The following points outline key scenarios where CCUS would be a suitable technology to consider:

- Direct emissions from a process that cannot be abated by electrification or fuel switching.
- Larger single points of emission for economies of scale (modular applications generally start at ~35 $ktCO_2$/year).
- On-site or nearby application for captured CO_2 or proximity to storage infrastructure.

5. SITE DECARBONISATION PROGRESS AND KEY FINDINGS

If sites continue to operate in a BAU manner, none are expected to achieve the BEIS IFP decarbonisation targets of 20% emissions reduction by 2025, 66% by 2035 and 90% by 2050.

No single roadmap option is recommended preferentially, with the BEIS IFP providing an indication of potential decarbonisation pathways between year of study and 2050. The outputs should be used by the sites to guide further investigation of optimal pathways, utilising key technologies presented.

Costs of roadmap options are presented in terms of CapEx, abatement cost and payback. A negative abatement cost means that a cost saving is delivered per tonne of carbon abated. A positive abatement cost means that it costs the site to abate each tonne of carbon.

Payback period refers to the time taken for the CapEx to be compensated for by OpEx savings relative to the BAU forecast. Payback is calculated up to 2050. Should OpEx be higher than the BAU forecast following full implementation of a roadmap, payback is not expected to be achieved. Only those interventions with a positive payback term have an associated payback stated in the financial tables. If an intervention does not payback, this is shown by a dash in each of the tables.

Abatement costs and payback do not account for additional infrastructure costs (e.g. such as cost for electricity grid connection upgrades, on-site piping to hydrogen connection point).

Table 5-18 at the end of this section provides key metrics for all 49 roadmap options produced during the programme, including an indication of additional infrastructure costs.

5.1. CHEMICALS – DOW SILICONES

The following section summarises the findings by AtkinsRéalis when considering routes to decarbonisation for Dow Silicones and their Barry site. The financial figures included do not represent investment decisions being taken by Dow Silicones. The assumptions listed in section 2 should also be considered. All figures are advisory based on analysis undertaken at the time, various factors will affect the figures presented and further analysis is required before any investment decisions are taken.

5.1.1. Dow Silicones Summary of Roadmaps

The Dow Silicones Barry site is a high complexity chemical site with continuous multi-unit operations, manufacturing a range of siloxane and silane products. The total baseline emissions for Dow Silicones in the baseline year (2020) were 176,100 tCO_2/y, of which 167,600 tCO_2/y were scope 1 emissions resulting from the use of natural gas fired assets, primarily the CHP, standby boilers, and hot oil units. The remaining 8,500 tCO_2/y of scope 2 emissions resulted from various electrical consumers. Dow Silicones has decarbonised the scope 2 emissions by purchasing REGOs. For the BEIS IFP, the scope 2 emissions have been reported under a local-reporting method which means scope 2 emissions have been included for each industrial partner's site.

Three decarbonisation pathways were produced for the site. The options focus on CCUS installation on the CHP plant (**Roadmap Option 1**), blue hydrogen fuel switching of natural gas assets (**Roadmap Option 2**), and site electrification (**Roadmap Option 3**). Roadmap Option 3 presents the strongest tangible decarbonisation benefits.

Roadmap Option 1 would fail to achieve the 2050 target due to the availability and capture efficiency of the selected CCUS technology. In 2035, hot oil units are replaced with electrified units with the expectation of the grid becoming increasingly decarbonised, thereby minimising scope 2 emissions. The CCUS facility is installed to process exhausted CO_2 from the CHP plant in 2040. Whilst the CCUS plant achieves a net reduction in scope 1 emissions, there are scope 1 and scope 2 emissions associated with the plant operation. Roadmap Option 1 would reduce carbon emissions to 24,600 tCO_2/y (86% reduction from the baseline) and the total CapEx is expected to be £115.3M. Compared to the BAU forecast, Roadmap Option 1 would result in a considerable annual OpEx saving following implementation of all interventions. The overall abatement cost is expected to be -£51/tCO_2 and payback would be achieved in approximately 8 years.

Roadmap Option 2 involves fuel switches to blue hydrogen which has associated scope 2 emissions as the hydrogen is derived from fossil fuels. In 2030 an initial 20% blue hydrogen fuel switch is implemented. In 2040 the CHP plant is replaced with a 100% hydrogen CHP. Roadmap Option 2 would reduce carbon emissions to 29,300 tCO_2/y (83% reduction from the baseline) and the total CapEx is expected to be £88.5M. Compared to the BAU forecast, Roadmap Option 2 would result in a minor OpEx saving, with an abatement cost of -£32/tCO_2. Payback is not expected to be achieved by 2050.

Roadmap Option 3 would result in two of the three BEIS emissions targets being comfortably met, with emissions reduced to 6,400 t/CO_2 by 2050 (a 96% reduction from the baseline). Energy efficiency measures on the main reactor and a very energy intensive unit operation are applied between 2020 and 2030. A waste heat recovery pump is implemented in 2030 to reduce net energy demand of the site. Solar PV is also implemented within the site boundary in 2025 and outside of the site boundary in 2030, providing additional electrical generation to support an increased demand from site. The final phase electrifies hot oil systems in 2030 and replaces the CHP plant with electrode boilers for steam production in 2040. Implementing Roadmap Option 3 would have a CapEx of £54.2M (excluding grid connection upgrade cost estimated at £51M) and the highest OpEx of the three options, which is above the BAU forecast. The overall cost of abatement would therefore be -£6/tCO_2, and payback is not expected to be achieved by 2050.

Several key considerations were noted in the development of the roadmap options for Dow Silicones Barry:

- Considerable changes to electricity demand and generation on-site are expected to necessitate a new grid connection, which is expected to contribute significant additional CapEx for the electrification option.
- 15% of CO_2 would be reduced by modifying technology within a very energy intensive unit operation at an estimated CapEx of £20M.
- South Wales Industrial Cluster implemented by 2030 for 20% fuel hydrogen blend.
- South Wales Industrial Cluster external infrastructure in place by 2040 to supply blue or green hydrogen to the site and transport captured carbon from site.

5.1.2. Dow Silicones Key Findings: Policy Considerations

5.1.2.1. UK ETS

See section 6.6.3 for an overview of the UK ETS. If the UK ETS carbon price becomes higher than modelled, this will make decarbonisation measures more competitive compared to the BAU case. Changes to the taxing of electricity versus gas may cause the price ratio to narrow more than modelled.

5.1.2.2. Hydrogen versus Electrification

Dow Silicones' decarbonisation efforts are heavily dependent on national policy, as development of hydrogen and electric technologies in the UK is dependent on both private and government investment. Government is looking to formalise hydrogen subsidies through a CfD framework (although this is yet to be confirmed), however similar funding to alleviate the charges on grid electricity or other energy vectors have not been made. Despite this, the lack of certainty regarding hydrogen infrastructure in the UK means that Dow Silicones are not clear on the direction that the Barry site will take and will continue to struggle to make informed forecasts or investment decisions. Any such decisions are likely to be postponed until government policy is formalised.

5.1.3. Dow Silicones Key Findings: Cluster Access

Dow Silicones are part of the South Wales Industrial Cluster located in Barry, Wales, very close to the port and closely located with other CO_2 emitters, although these are relatively small. Proximity of CO_2 stores is one of the biggest challenges for South Wales. Any capture and storage of CO_2 by emitters in South Wales will either require CO_2 shipping or a significant government funded national infrastructure project.

There are several proposed hydrogen projects in South Wales with the closest proposed productions sites in Bridgend (green hydrogen) and Port Talbot (blue hydrogen). Wales and West Utilities have also proposed hydrogen networks across South Wales to serve several sectors.

5.1.4. Dow Silicones Key Findings: Sub-metering

Dow Silicones has extensive sub-metering across the site. This has previously allowed the site to implement no regret efficiency measures and enable identification of future optimisations.

Hourly metering data has been provided as part of the BEIS IFP for the major consumers of gas, steam, and electricity. Energy efficiency and deep decarbonisation options were identified by the analysis of the sub-metering data provided. The site is recommended to undertake a detailed study to identify further areas of heat sinks which could utilise low temperature heat available from the site processes.

5.1.5. Dow Silicones Key Findings: Permitting Requirements

Dow Silicones Barry is a Control of Major Accident Hazards (COMAH) registered site with its own CHP plant and a lease of a third-party steam methane reforming plant for hydrogen generation. The applicability of additional permitting requirements summarised in section 6.5 must be considered, particularly with respect to both hydrogen (Roadmap Option 2) and carbon capture technologies (Roadmap Option 1). Roadmap Option 3 is expected to involve no/minimal additional permitting requirements compared to current site operations. Renewable installations must comply with local permitting and planning requirements.

5.1.6. Dow Silicones Key Findings: Key Roadblocks

5.1.6.1. DNO Issues

The local DNO is National Grid Electricity Transmission, and they are responsible for granting permission for connection of new generation sources to the grid and grid upgrades. Based on publicly available information, available headroom for the Barry site could not be identified.

Roadmap Option 3 would result in considerable changes to the site electricity demand and generation. It is expected that a new connection to the grid would be required to accommodate these changes. Peak electricity demand is expected to be 166 MW (based on removing the CHP and installing five 21 MW electrode boilers, three electric hot oil systems with combined capacity of 10 MW, and a 6 MW heat pump). Peak electricity export requirement for the solar array is expected to be 18 MW. The new two-way connection would need to be sized to accommodate the increased peak electricity demand.

New connection costs are estimated to cost in the region of £300-450/kW. For a connection cost of £375/kW, an additional infrastructure cost of £51M would be required to upgrade the import capacity by 136 MW, discounting the current 30 MW of import capacity. Grid connection costs can vary significantly depending on several factors, mostly dictated by the state of the grid in the local area. Early engagement with the DNO is advisable.

5.1.6.2. Carbon and Hydrogen Transport Availability

Dow Silicones is part of the South Wales Industrial Cluster, which is a cluster of businesses aimed at achieving Net Zero. Roadmap Options 1 and 2 are dependent on the availability of transport and storage technologies off-site for concentrated CO_2 and blue or green hydrogen. Should this not be possible, this will pose a major roadblock to decarbonisation in Roadmap Options 1 and 2, provided these options are selected for implementation.

5.1.6.3. Fuel Costs

Roadmap Option 3 would result in OpEx increases compared to BAU, due to the higher cost of hydrogen and electricity relative to natural gas. This means that the interventions do not have payback. This could be improved if government shift tax from electricity to gas or subsidise electricity or hydrogen. Uncertainties around this will likely delay any investment decision from Dow Silicones.

5.1.7. Dow Silicones Feasibility of Roadmaps

Three roadmap options were produced for Dow Silicones Barry. Each roadmap option has significant uncertainties in timescales for connection and gas transportation infrastructure upgrades. All options presented feature combinations of on-site and off-site renewable electricity generating assets to reduce both existing and increased electrical import requirements introduced through interventions. Energy efficiency measures, particularly on the very energy intensive unit operations and a high temperature heat pump are also present in all the roadmaps reducing carbon emissions by up to 43% relative to the baseline year.

None of the options modelled would meet the 2025 net carbon emission reduction target of 20%. Only Roadmap Option 3 would meet the 2050 target of a 90% net carbon emissions reduction. The performance of the three roadmap options presented are shown in Figure 5-1.

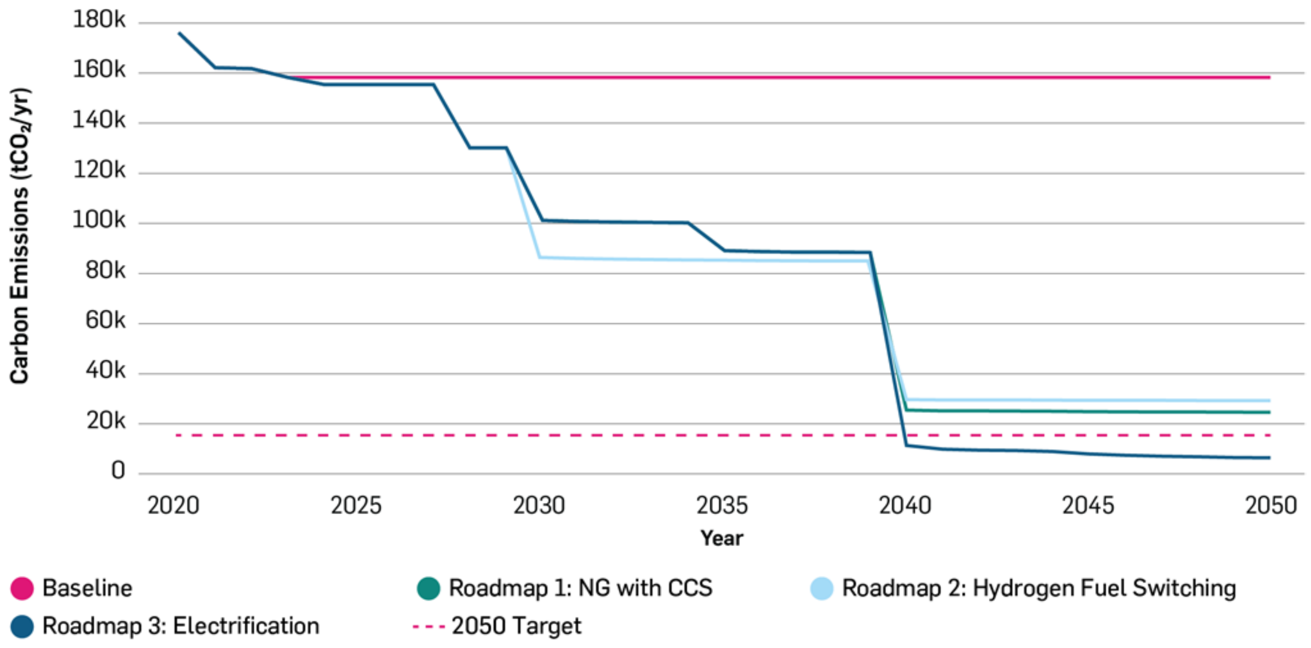


Figure 5-1 – Dow Silicones Carbon Emissions: Comparison of Roadmap Options.

All roadmap options are deemed to be technically feasible at proposed year of install with respect to TRL.

Dow Silicones Barry has a high electrical demand compared to the available land identified suitable for renewable energy. Utilising the land available on-site for renewable energy would result in a less than 1% impact on emissions reduction. Still, on-site solar might be implemented with no significant challenge and is likely to constitute a no regret measure. Off-site renewables may be accessed by PPAs, or through a more traditional build-own-operate model.

Waste heat recovery heat pumps considered in the roadmaps are TRL 6-9 and available largely within demonstration projects at waste heat temperatures greater than 90°C and commercially deployed for temperatures less than 90°C. The waste heat source is considered at a temperature range of 55-90°C. It was considered technically feasible to install a heat pump which uses the waste heat as input to provide heat in the form of steam to the main steam distribution system which operates at 10bar(g). Full deployment of the high temperature heat pump is expected in 2030.

Both electric and electrode boilers have a TRL of 9, with commercially deployed large scale units in operation globally. Hydrogen boilers are currently at a TRL of 7-8 with full deployment in the UK provisionally expected from 2032. Hydrogen and electrode boiler interventions are however aligned with the end of Dow Silicones CHP asset life in 2040 and are therefore assumed to be at a sufficient level of deployment for use on-site

For carbon capture technology assessed within this study, a TRL of 7-9 is currently estimated, as relatively few projects have been implemented at industrial sites globally. It should be noted that installation and operation of a carbon capture plant is expected to require risk assessment and operator training, with the greatest impact on the site operating state. Detailed engineering design with vendor support is strongly advised to assess scale, performance, suitable capture media, downstream processing and risks due to higher relative process complexity.

For all intervention technologies, intervention dates applied within this study are provisionally aligned considering both equipment TRL and supporting infrastructure.

The CapEx for Roadmap Option 3 is expected to be considerably lower than Options 1 and 2 (see Table 5-1 and Figure 5-2). A key reason for the CapEx difference between the roadmap options is the grid connection cost which has not been factored into the IDT modelling due to uncertainty in the costing. The additional grid connection cost for Roadmap Option 3 is estimated to be £51M, increasing the total CapEx from £54 to £105M.

Roadmap Options 1 and 2 have infrastructure costs modelled within the IDT which includes connection and transportation costs for hydrogen and CCUS. These connection costs will ultimately have a considerable impact on the commercial viability of Dow Silicones decarbonisation roadmap.

The abatement costs are expected to be negative for all roadmap options, meaning they would deliver cost savings compared to the BAU forecast for each tonne of carbon abated.

Table 5-1 – Dow Silicones Key Metrics for Roadmap Options 1-3.

	CO_2 Emissions in 2050 ($ktCO_2$/y) (% change)	CapEx (£M)	Abatement Cost (£/tCO_2)	Payback Period (years)
Roadmap Option 1	**24.6 (-86%)**	115.3	-51	7.9
Roadmap Option 2	**29.3 (-83%)**	88.5	-32	56.3
Roadmap Option 3	**6.4 (-96%)**	54.2*	-6*	-

*Exclusive of grid connection at an estimated cost of £51M.

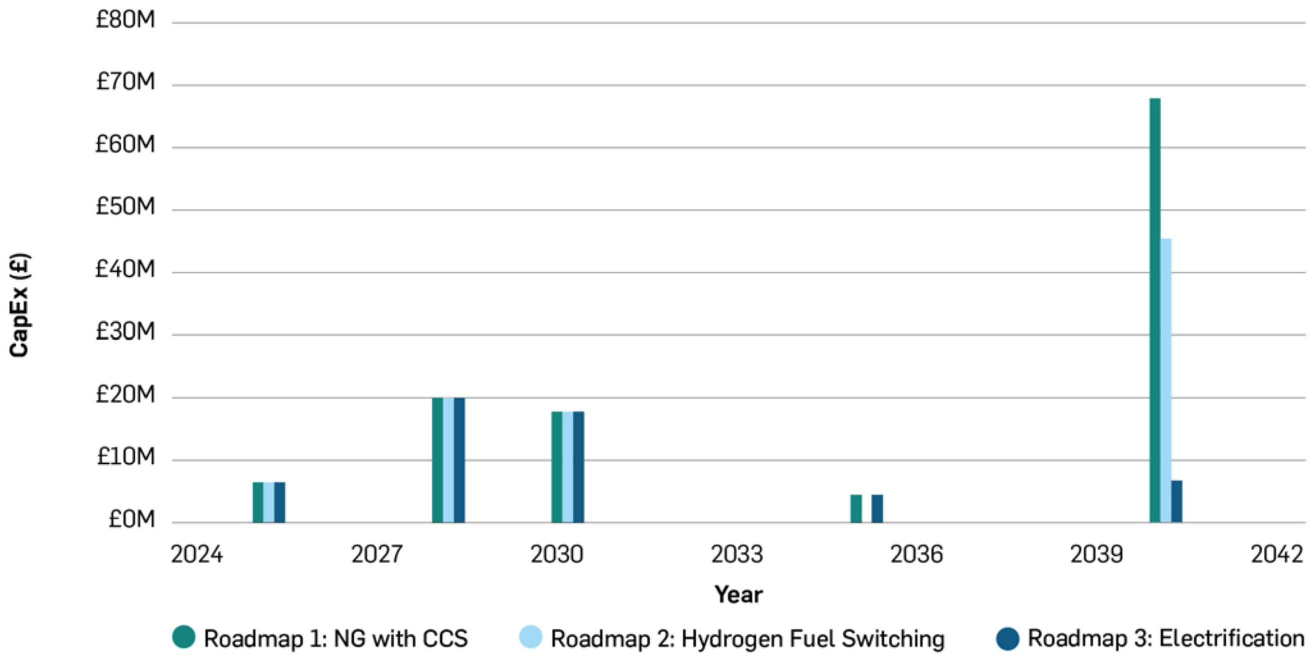


Figure 5-2 – Dow Silicones CapEx Distribution: Comparison of Roadmap Options.

Roadmap Options 1 and 2 are projected to lead to a cost saving relative to the BAU forecast OpEx, whereas Roadmap Option 3 would likely lead to additional cost if grid connection costs are factored into to the total cost. Roadmap Option 1 is projected to have the lowest OpEx in 2050, 30% lower compared to the BAU forecast. Roadmap Option 3 would have the greatest OpEx cost in 2050, 15% higher compared to the BAU forecast.

5.2. CHEMICALS – CRODA

The following section summarises the findings by AtkinsRéalis when considering routes to decarbonisation for Croda Europe and their Rawcliffe Bridge site. The financial figures included do not represent investment decisions being taken by Croda. The assumptions listed in section 2 should also be considered. All figures are advisory based on analysis undertaken at the time, various factors will affect the figures presented and further analysis is required before any investment decisions are taken.

5.2.1. Croda Summary of Roadmaps

Croda Europe's Rawcliffe Bridge site in East Yorkshire produces over fifty distinct products for global customers within the personal care, crop care and healthcare markets. The total baseline emissions for the site in the baseline year (2018) were 15,400 tCO_2/y of which 12,700 tCO_2/y were scope 1 emissions resulting from natural gas burning in two boilers, spray dryer and hot oil reactor units. The remaining 2,700 tCO_2/y were scope 2 emissions resulting from electricity use for process units. Croda decarbonised the scope 2 emissions in 2019 by purchasing REGOs. For the BEIS IFP, the scope 2 emissions were reported under a local-reporting method; therefore scope 2 emissions were included for each industrial partner's site.

The roadmap options presented to Croda consider ways to decarbonise the site's projected energy requirements assuming BAU operation and incorporating growth projects being implemented between 2023-2027.

Croda's Process Innovation Teams are continually sourcing and developing alternative technologies to enable their sites to manufacture existing products with lower energy requirements. Croda's Research and Development Teams are developing new "low carbon products" and looking at new technology platforms such as biotechnology in order to reduce overall energy requirements through product portfolio transformation. The work carried out by these teams falls outside the scope of these roadmap options but will ultimately contribute to reducing the Rawcliffe Bridge site's overall energy requirements and facilitate the Net Zero transition.

Three decarbonisation pathways were produced for the site: **Roadmap Option 1** focusses on site electrification and **Roadmap Options 2 and 3** focus on fuel switching to blue and green hydrogen respectively. Each roadmap assumed that 80% of the site's steam requirement could be provided by a local government scheme. An 80% reduction in on-site steam generation would result in a fuel saving of 61,600 MWh/y in 2027 and total scope emissions reduction of 11,300 tCO_2/y, equivalent to a 73% reduction in carbon emissions from the baseline. Availability of steam from an off-site local source will go some way to helping decarbonisation of the site, however, natural gas boilers would continue to supply the remaining steam required on-site. The second phase in each roadmap would be the electrification of the hot oil reactors and spray dryer units from 2030 until 2050.

Additional interventions in **Roadmap Option 1** are the electrification of the boilers in 2040. Roadmap Option 1 would reduce carbon emissions to 570 tCO_2/y in 2050 (96% reduction from the baseline), with £3.1M CapEx required. Electrical infrastructure upgrades to increase the import connection from 4 MWe to 15 MWe are estimated to cost an additional £4.1M. The total abatement cost of this option is expected to be £62/tCO_2. This is the lowest abatement cost of the three roadmap options but would still not result in payback being achieved by 2050.

Roadmap Option 2 is a hydrogen fuel switching roadmap. In 2030 a 20% blue hydrogen fuel switch is identified to introduce the use of hydrogen on-site prior to 2040. In 2040 the natural gas boilers are replaced with 100% hydrogen ready boilers. Roadmap Option 2 would reduce carbon emissions to 3,900 tCO_2/y (75% reduction from the baseline). The total CapEx is £6.4M and the cost of abatement is expected to be £96/tCO_2.

Roadmap Option 3 would see the highest reduction in carbon emissions, with 200 tCO_2/y remaining in 2050 (99% reduction) using green hydrogen. The use of green hydrogen instead of blue hydrogen in Roadmap Option 2, would result in the greatest reduction in scope 2 emissions. The total CapEx is £6.4M and the cost of abatement is expected to be £119/tCO_2 (the highest of the three options due to the price of green hydrogen).

Croda currently have an application under the 2022 Hydrogen Business Model and Net Zero Hydrogen Fund Electrolytic Allocation round. The application is for an on-site electrolyser to produce green hydrogen from 2025-2035. If approval is granted, the Rawcliffe Bridge site will follow a CfD mechanism. Roadmap Option 3 was identified as the preferential route for the Rawcliffe Bridge site. This assumed either the successful application for an on-site electrolyser (producing green hydrogen on-site from 2025) or provision of green hydrogen to the site by the East Coast Cluster in 2040.

Several key considerations were noted in the development of each roadmap option:

- An off-site local steam source will be available by 2027. 80% of the site steam can be provided by this source until 2039. The steam is imported at 90% of the current natural gas costs and £1M CapEx assumed for the infrastructure changes needed to receive the steam on-site.
- Two electric hot oil heaters have an approximate TIC of £86,200.
- Direct electric process heating for the spray dryer has an approximate TIC of £300,000.
- Rawcliffe Bridge is 8 km from Drax Power Station that lies on the East Coast Cluster, therefore it is possible for hydrogen options to be considered viable for the site.
- Improved sub-metering is highly recommended for the site to optimise their implementation of the chosen roadmap. Focus should be around process waste heat and condensate recovery around the steam systems.

5.2.2. Croda Key Findings: Policy Considerations

5.2.2.1. Economic Feasibility

All three roadmaps are heavily reliant on government support and infrastructure upgrades. For the Rawcliffe Bridge site to reduce on-site emissions, low carbon fuel will need to be available. The high fuel cost for electricity and hydrogen results in an uneconomical outcome for each roadmap. Without governmental support to incentivise fuel switching to low carbon fuels, industrial sites will have no positive economic reason to switch fuels as the OpEx remain higher than those for natural gas. The expansion of the UK ETS would mean sites such as Rawcliffe Bridge will start to pay for scope 1 emissions (see section 5.2.2.2 for discussion of the current exclusion of Croda's Rawcliffe Bridge site from the UK ETS). Decarbonisation would become more economically attractive through reducing the amount paid for the site scope 1 emissions.

The roadmap options for the Rawcliffe Bridge site consider full site fuel switching. The reliable procurement of hydrogen and electricity to the site until 2050 is an area of concern. Croda are keen to understand whether the national grid will be able to meet the predicted requirements following fuel switching. A government policy outlining a robust plan surrounding grid investment and upgrades should be shared with industry for an informed decision when selecting a roadmap option to follow.

5.2.2.2. UK Emissions Trading Scheme

See section 6.6.3 for an overview of the UK ETS. There is a clause in the UK ETS which excludes individual units <3 MW from the aggregation. Croda's Rawcliffe Bridge site, alongside other smaller industrial sites are currently not included. It is possible that the site will be included in the next expansion of the scheme, resulting in higher OpEx carbon costs. If the Rawcliffe Bridge site were to be included, much greater carbon costs would be seen due to the predicted increase in costs associated with scope 1 emissions. This would mean OpEx associated with decarbonisation would become more economically feasible when compared against the BAU forecast plus expanded UK ETS carbon tax.

5.2.3. Croda Key Findings: Cluster Access

The Rawcliffe Bridge site is approximately 8 km from Drax which is situated directly on the East Coast Cluster line for hydrogen. It is possible that hydrogen will be accessible to the site.

5.2.4. Croda Key Findings: Sub-metering

Sub-metering is somewhat poor across the site and requires a complete overhaul. Improvements could be made to provide better understanding of the processes, key examples being:

- Monitoring steam utilisation will aid strategic steam process improvements, targeted lagging, and steam trap management.
- Greater accuracy in the amount of steam used across site to correlate to the natural gas fuel requirement.
- Monitoring of the condensate being lost on-site to allow targeted efficiency improvements to harvest and re-utilise the waste condensate.
- Allow site to undertake a heat source and sink study for strategic heat recovery improvements to operations.

5.2.5. Croda Key Findings: Permitting Requirements

Croda is currently a COMAH registered site. As a part of Roadmap Options 2 and 3, hydrogen would be brought onto site, stored, and burned to produce steam.

The additional permitting requirements associated with hydrogen technologies summarised in section 6.5 must be considered. Croda do not have existing plans to bring hydrogen onto site and would not do so without consultation with local stakeholders. Roadmap Option 1 is expected to involve no/minimal additional permitting requirements compared to current site operations. Renewable installations must comply with local permitting and planning requirements.

5.2.6. Croda Key Findings: Key Roadblocks

5.2.6.1. DNO Issues

The local DNO is Northern Power Grid. Full site electrification would require an 11 MW import upgrade for the electrical supply. The DNO must be contacted to provide details of the upgrade requirements for the site. Roadmap Option 1 would result in four-fold increase in the site import capacity required as the site moves from natural gas burning to electrification. The new connection cost is expected to be £300-450/kW. The cost of the required new import connection is therefore expected to be between £3.3M and £5M. The timescales associated with this upgrade is the major roadblock for Roadmap Option 1. Early consultation with the DNO is advisable.

5.2.6.2. Hydrogen Availability

The Rawcliffe Bridge site is approximately 8 km from Drax which is situated directly on the East Coast Cluster line for hydrogen. It is possible that hydrogen will be accessible to the site. Assuming a pipeline can be installed between Drax and Rawcliffe Bridge, or the electrolyser funding is approved, hydrogen could be utilised on-site as an alternative fuel.

Roadmap Option 3 would reduce Croda's carbon emissions by the greatest margin (99% from 2018 baseline emissions), with availability of green hydrogen critical to this scenario. It was assumed that the East Coast Cluster would supply blue hydrogen, therefore an alternative method for green hydrogen production and supply to sites would be necessary. Funding streams that support the CapEx and OpEx of a green hydrogen production unit (e.g., an electrolyser) would encourage industrial partners to produce green hydrogen on-site for site/local area usage.

5.2.7. Croda Feasibility of Roadmaps

Roadmap Option 3 is an ambitious option with a high CapEx and OpEx requirement, however it has the greatest decarbonisation potential (see Figure 5-3) and is preferable for the Rawcliffe Bridge site specifically, assuming funding is obtained for an on-site electrolyser. Roadmap Option 1 is a more realistic recommendation and meets the BEIS IFP 2050 target. With a smaller CapEx and OpEx (inclusive of the estimated electrical connection upgrades), Roadmap Option 1 would provide a significant amount of decarbonisation by 2050.

The opportunity to decarbonise through electrification heavily relies on a secure supply of electricity from the grid. It is noted that specific to the Rawcliffe Bridge site, Roadmap Option 3 could be preferential due to the application for an on-site electrolyser. This report has not accounted for the advantages of an electrolyser and the ability to produce green hydrogen on-site in 2025. A consideration should be made that the method to produce green hydrogen is less efficient (approximate efficiency of electrolysis might be 60-70% [15] and efficiency of fuel combustion in boiler in the region of 85%) than using electricity directly for heating (approximately 99% efficient).

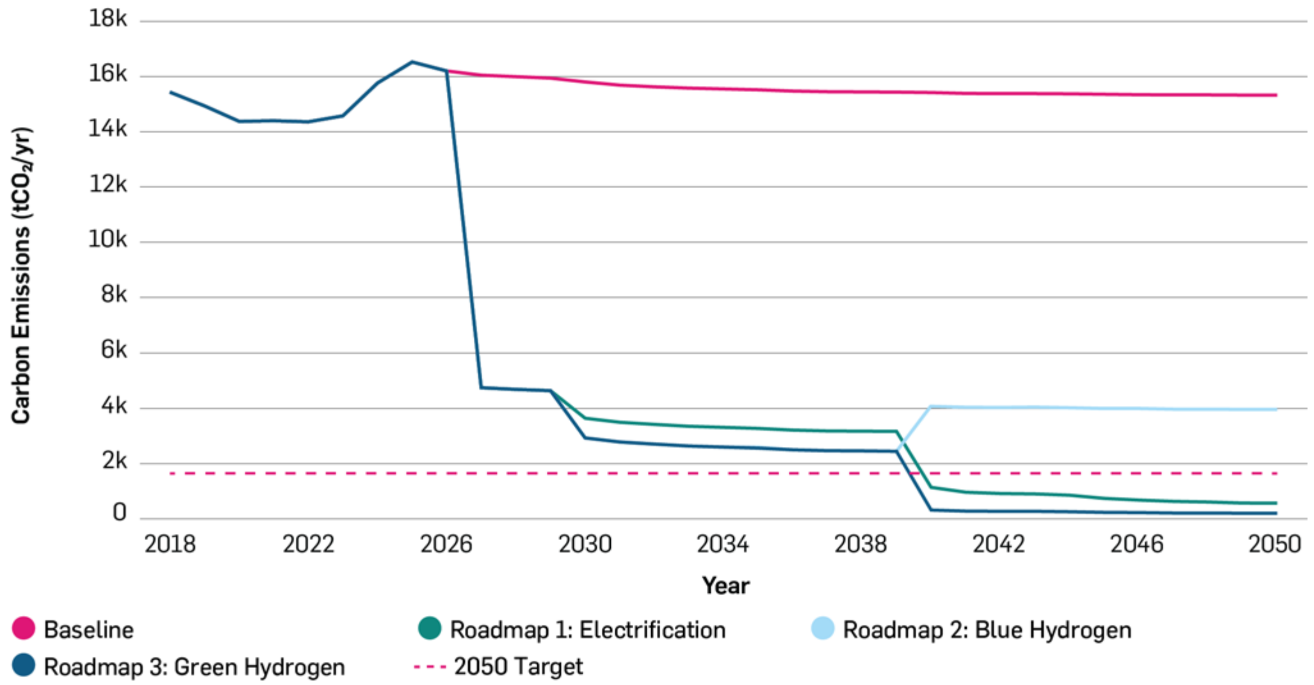


Figure 5-3 – Croda Carbon Emissions: Comparison of Roadmap Options.

The CapEx for Roadmap Option 2 and 3 is expected to be approximately double the CapEx for Roadmap Option 1 (see Table 5-2 and Figure 5-4). The CapEx difference is due to the TIC for a hydrogen boiler being three times greater than the cost for an electric boiler of the same asset size, quantity, and redundancy. This is due to the account being taken for hydrogen grid connection upgrade costs.

The electricity grid connection upgrade cost (£3.3M – £5M range) was not included as a CapEx in the IDT but would be an additional cost that would have an impact on the commercial viability of site decarbonisation. It is important to note that the site would need a connection upgrade if they were to produce green hydrogen on-site.

Table 5-2 – Croda Key Metrics for Roadmap Options 1-3.

	CO_2 Emissions in 2050 ($ktCO_2$/y) (% change)	CapEx (£M)	Abatement Cost (£/tCO_2)	Payback Period (years)
Roadmap Option 1	0.6 (-96%)	3.1*	62*	-
Roadmap Option 2	3.9 (-75%)	6.4	96	-
Roadmap Option 3	0.2 (-99%)	6.4	119	-

*Excludes £3.3M – 5M electric grid connection upgrade cost.

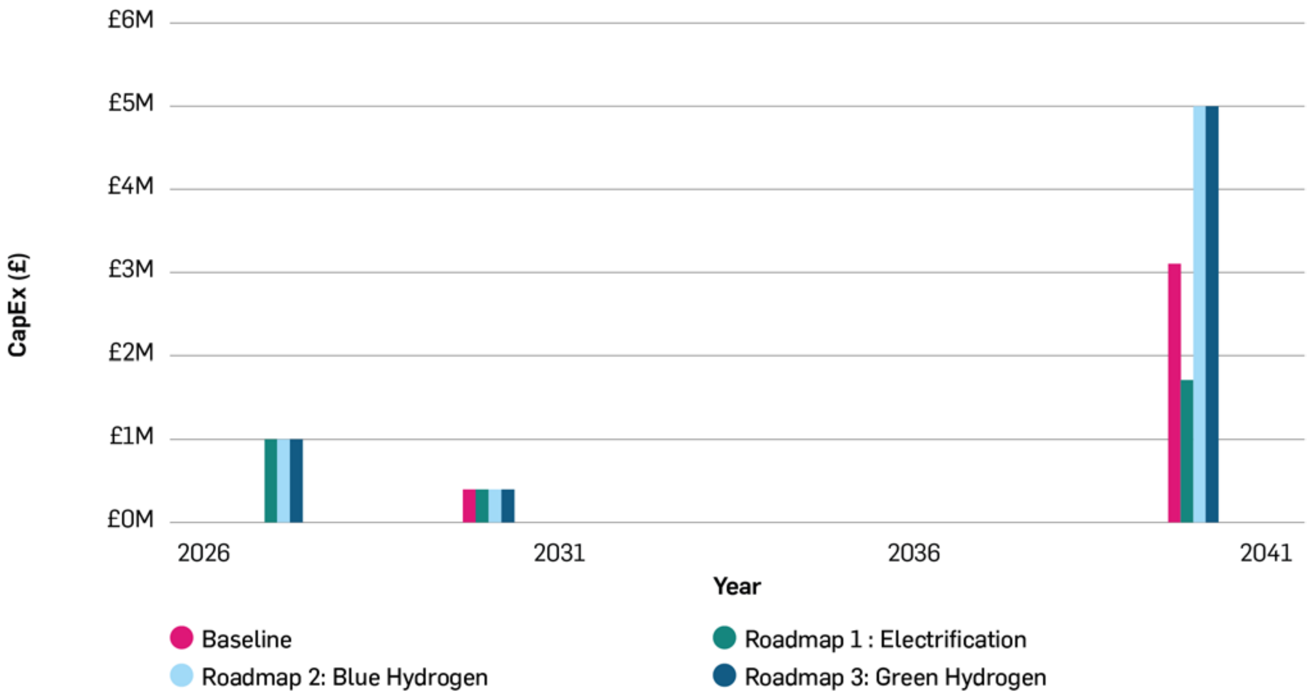


Figure 5-4 – Croda CapEx Distribution: Comparison of Roadmap Options.

Relative to the predicted BAU forecast, OpEx in 2050 for Roadmap Option 1 is expected to be just under double. Conversely, OpEx is expected to be more than double for Option 2 and 3, with Option 3 being the highest. The much greater OpEx for green hydrogen is due to the current governmental pricing forecasts. At this current time, electricity and green hydrogen are considerably expensive relative to gas and would result in each roadmap option presented being uneconomical for the site.

The interventions included in phase 2 of the roadmaps are already technically feasible. A 100% fuel switch to either hydrogen fuels or electricity is dependent on the fuel being available on-site at the required quantities. As outlined in Section 5.2.4, improvements in sub-metering will determine the ultimate feasibility of heat integration across site. Early engagement with electric equipment manufacturers, and schemes to support on-site hydrogen development and usage would mitigate the risk of fuel supply.

5.3. CHEMICALS – SOLENIS

The following section summarises the findings by AtkinsRéalis when considering routes to decarbonisation for Solenis UK Industries and their site in Bradford. The financial figures included do not represent investment decisions being taken by Solenis. The assumptions listed in section 2 should also be considered. All figures are advisory based on analysis undertaken at the time, various factors will affect the figures presented and further analysis is required before any investment decisions are taken.

5.3.1. Solenis Summary of Roadmaps

Solenis UK Industries is a leading global manufacturer of specialty chemicals, delivering sustainable solutions for water-intensive industries. The company produces a range of water treatment chemistries, process aids and functional additives, as well as monitoring and control systems. The total baseline emissions for the Solenis site in Bradford in the baseline year (2020) were 58,600 tCO_2/y. Scope 1 emissions resulting directly from burning natural gas and methanol on-site account for 98% of the site's total emissions. Much of this fuel is burnt in the CHP plant. Scope 2 emissions resulting indirectly from electricity purchased from the grid account for the remaining 2% of the site's total emissions. The BAU forecast has accounted for idling of the chelates process in 2022 and implementation of a new CHP scheme in 2025.

Three decarbonisation pathways were produced for the Solenis Bradford site. These options primarily focus around CCUS (**Roadmap Option 1**), fuel switching of CHP fuel supply to green hydrogen (**Roadmap Option 2**), and site electrification (**Roadmap Option 3**).

None of the options modelled would meet the BEIS IFP 2025 net carbon emission reduction target of 20%. Roadmap Options 2 and 3 would comfortably meet the BEIS IFP 2050 target of a 90% net carbon emissions reduction.

Roadmap Option 1 is not expected to meet the 2050 target due to the availability and capture efficiency of the selected CCUS technology. Roadmap Option 1 would reduce carbon emissions to 11,700 tCO_2/y (80% reduction from the baseline). Whilst the CCUS plant would achieve a net reduction in scope 1 emissions, there would be scope 1 and scope 2 emissions associated with the plant operation. The total CapEx is expected to be £58.1M. Compared to the BAU forecast, Roadmap Option 1 would result in an annual OpEx saving. The overall abatement cost is expected to be £11/tCO_2 meaning that payback would be achieved in approximately 34 years.

Roadmap Option 2 involves fuel switching from natural gas to green hydrogen in 2040. A 20% fuel switch to blue hydrogen is implemented in the interim from 2030 to 2040. Green hydrogen fuel switching is required to meet the BEIS IFP 2050 target since fuel switching to blue hydrogen has associated scope 2 emissions. Roadmap Option 2 would reduce carbon emissions to 590 CO_2/y (99% reduction from the baseline). The total CapEx is expected to be £22.1M and when compared to the BAU forecast, Roadmap Option 2 would result in a considerably higher annual OpEx following fuel switching to green hydrogen. The overall abatement cost is expected to be £83/tCO_2 meaning that payback is not expected to be achieved within project timeframes.

Roadmap Option 3 involves site electrification, removing the CHP and implementing electrode boilers for steam production in 2040. Roadmap Option 3 would reduce carbon emissions to 3,500 CO_2/y (94% reduction from the baseline). The total CapEx is expected to be £8.6M (excluding £19M additional CapEx associated with electrical infrastructure). Compared to the BAU forecast, Roadmap Option 3 would result in a considerably higher annual OpEx following site electrification. The overall abatement cost is expected to be £13/tCO_2 meaning that payback is not expected to be achieved within project timeframes.

Further investigation is recommended to identify potential pathways to early decarbonisation, such as bridging technologies, engagement with potential technology incentives or early adoption of alternative fuel sources.

Several key considerations were noted in the development of the roadmap options for the Solenis Bradford site:

- East Coast Cluster implemented by 2030 enabling 20% blue hydrogen fuel blend in Roadmap Option 2.
- East Coast Cluster external infrastructure in place by 2040 to supply green hydrogen to the site and/or transport captured carbon from site for Roadmap Option 1 and 2.
- Considerable changes to the electrical infrastructure are expected to necessitate a new grid connection for site electrification, requiring significant additional CapEx for Roadmap Option 3.

5.3.2. Solenis Key Findings: Policy Considerations

5.3.2.1. UK ETS

See section 6.6.3 for an overview of the UK ETS. If the UK ETS carbon price becomes higher than modelled, this will make decarbonisation measures more competitive compared to the BAU case. Changes to the taxing of electricity versus gas may cause the price ratio to narrow more than modelled.

5.3.2.2. Hydrogen versus Electrification

Solenis' decarbonisation efforts are heavily dependent on national policy, as development of hydrogen and electric technologies in the UK is dependent on both private and government investment. Government is looking to formalise hydrogen subsidies through a CfD framework (although this is yet to be confirmed), however similar funding to alleviate the charges on grid electricity or other energy vectors have not been made. Despite this, the lack of certainty regarding hydrogen infrastructure in the UK means that Solenis are not clear on the direction that the Bradford site will take and will continue to struggle to make informed forecasts or investment decisions. Any such decisions are likely to be postponed until government policy is formalised.

5.3.3. Solenis Key Findings: Cluster Access

The closest cluster to the Solenis Bradford site is the East Coast Cluster which aims to be operational by 2026, which aligns with Phase 1 for all roadmaps. Hydrogen fuel switching and carbon capture interventions relying on this cluster have been assumed feasible post 2030.

5.3.4. Solenis Key Findings: Sub-metering

The Solenis Bradford site has a lack of local sub-metering across site, in the 4 bar(g) steam distribution and some electricity users. It is recommended that Solenis Bradford site invest in the installation of local sub-metering for the 4 bar(g) steam distribution network to improve visibility on steam usage. This visibility has the potential to deliver significant energy and cost savings on-site. Improvements could be made to provide better understanding of the processes, key examples being:

- Monitoring steam utilisation will aid strategic steam process improvements, targeted lagging, and steam trap management.
- Greater accuracy in the amount of steam used across site to correlate to the natural gas fuel requirement.
- Monitoring of the condensate being lost on-site to allow targeted efficiency improvements to harvest and re-utilise the waste condensate.
- Allow site to undertake a heat source and sink study for strategic heat recovery improvements to operations.

5.3.5. Solenis Key Findings: Permitting Requirements

Solenis Bradford is a COMAH registered site. The additional permitting requirements summarised in section 6.5 must be considered, particularly with respect to both hydrogen (Roadmap Option 2) and carbon capture (Roadmap Option 1) technologies. Roadmap Option 3 is expected to involve no/minimal additional permitting requirements compared to current site operations. Renewable installations must comply with local permitting and planning requirements.

FOR PUBLICATION

5.3.6. Solenis Key Findings: Key Roadblocks

5.3.6.1. DNO Issues

The local DNO is Northern Power Grid, and they are responsible for granting permission for connection of new generation sources to the grid and grid upgrades. Based on publicly available information, any available headroom for the Solenis Bradford site could not be identified.

Roadmap Option 3 would result in considerable changes to the site demand and generation, and therefore new connections to the grid would be required to accommodate these changes. Peak electricity demand is expected to be 62 MW (based on peak process electricity demand, installing electrode boilers and heat pumps). A new connection cost is expected to be £300-450/kW.

A connection cost of £375/kW would imply an additional infrastructure cost of £19M to upgrade the import capacity by 52 MWe, discounting the existing 10 MW of import capacity the site is permitted to use. It should be noted that grid connection costs are highly-site specific and subject to discussion with the DNO. Early engagement with the DNO is advisable.

5.3.6.2. Hydrogen and Carbon External Infrastructure

Roadmap Options 1 and 2 are dependent on the availability of gas transport facilities off-site for concentrated CO_2 and blue or green hydrogen. Should this not be possible, this will pose a major roadblock to decarbonisation in Roadmap Options 1 and 2.

5.3.6.3. Fuel Costs

Roadmap Options 2 and 3 would result in OpEx increases compared to BAU, due to the higher cost of green hydrogen and electricity relative to natural gas. This means that the interventions do not have payback within the project timelines. This could be improved if government shift tax from electricity to gas or subsidise electricity or hydrogen. Uncertainties around this will likely delay any investment decision from Solenis.

5.3.7. Solenis Feasibility of Roadmaps

Three roadmap options were produced for the Solenis Bradford site. Each roadmap option has significant uncertainties in timescales for connection and gas transportation infrastructure upgrades. All options presented include a very small quantity of renewable electricity generation in the form of rooftop solar panels due to limited space available on or near the site. Energy efficiency measures are also present in all the roadmaps, however only the implementation of heat pumps on the fluidised bed dryers will have any significant impact on reducing carbon emissions (by circa 6% relative to the baseline year).

None of the options modelled are expected to meet the 2025 net carbon emission reduction target of 20%. All options excluding Roadmap Option 1 would meet the 2050 target of 90% net carbon emissions reduction. The performance of the three roadmap options presented is shown in Figure 5-5.

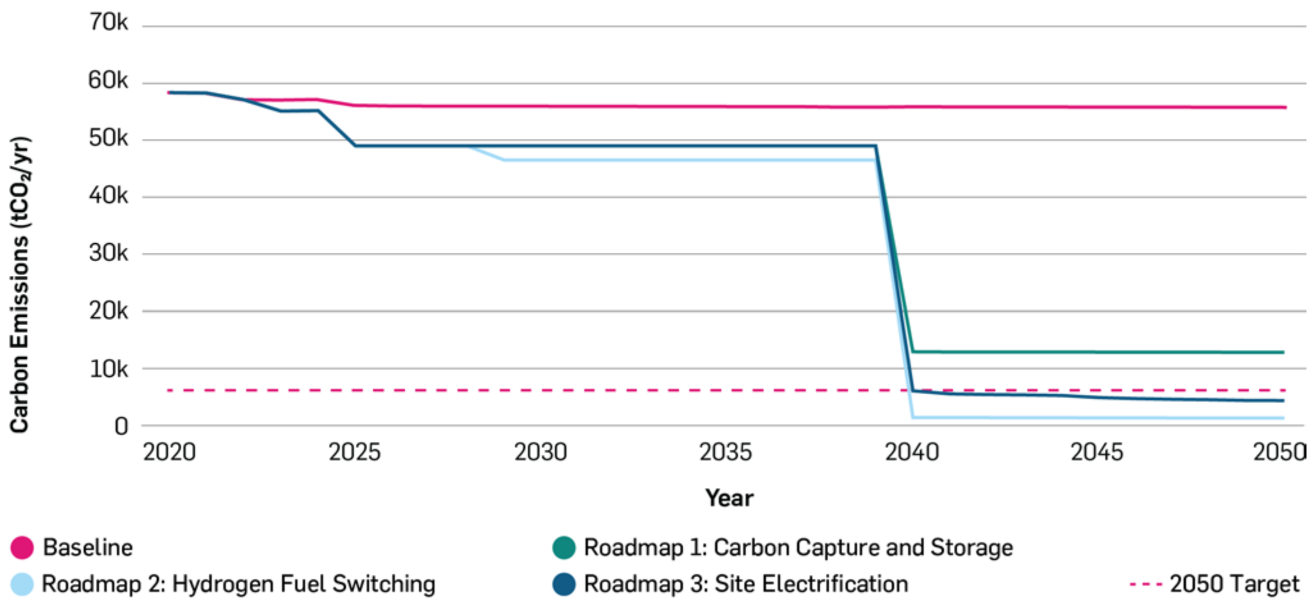


Figure 5-5 – Solenis Carbon Emissions: Comparison of Roadmap Options

All roadmap options are deemed technically feasible at proposed year of installation with respect to TRL.

Solenis Bradford has a high electrical demand on-site compared to the limited available rooftop space identified as suitable for renewable energy. However, solar PV as a means of renewable electricity generation is a well-established technology within the UK and should be considered to offset a portion of the site grid import demands. This is likely to constitute a no-regret measure. Off-site solar PV appears to present no significant challenges. Off-site renewables may be accessed by PPAs, or through a more traditional build-own-operate model.

Waste heat recovery heat pumps considered in the roadmaps are TRL 6-9, available largely within demonstration projects at waste heat temperatures greater than 90°C and commercially deployed for temperatures less than 90°C. The fluidised bed dryers exhaust waste heat at a temperature range of 40-60°C. It was considered technically feasible to apply a heat pump on the exhaust waste heat from stage 1 of each fluidised bed dryer to provide heat in the form of steam. Full deployment of the high temperature heat pump is expected in 2030.

Both electric and electrode boilers have a TRL of 9, with commercially deployed large scale units in operation globally, particularly where electricity costs are competitive. Hydrogen boilers are currently at a TRL of 7-8 with full deployment provisionally expected from 2032. For carbon capture technology implemented within this study, a TRL of 7-9 is currently estimated, as relatively few projects have implemented at industrial sites globally. It should be noted however that installation and operation of a carbon capture plant is expected to require risk assessment and operator training, with the greatest impact on current site operating state. Detailed engineering design with vendor support is strongly advised to assess scale, performance, suitable capture media, downstream processing and risks due to higher relative process complexity. The site cannot be fully decarbonised through CCUS due to the carbon capture plant availability and efficiency, resulting in residual scope 1 emissions.

For all intervention technologies, intervention dates applied within this study are provisionally aligned considering both equipment TRL and supporting infrastructure.

FOR PUBLICATION

The CapEx for Roadmap Options 2 and 3 is expected to be considerably lower than Roadmap Option 1 (see Table 5-3 and Figure 5-6). A key reason for the CapEx differences between the roadmap options are the grid connection costs which have not been factored into the IDT modelling due to uncertainty in the costing. The additional grid connection cost for Roadmap Option 3 is estimated to be £19M, increasing the total CapEx to £28M. Roadmap Options 1 and 2 had infrastructure costs modelled within the IDT which includes connection and transportation costs for hydrogen and CCUS. These connection costs will ultimately have a considerable impact on the commercial viability of the Solenis Bradford site's decarbonisation. The CapEx for Roadmap Option 1 is expected to be very high due to installation of carbon capture plant plus external infrastructure requirements.

The abatement costs are expected to be positive for all roadmap options, meaning they would deliver an increase in cost compared to the BAU forecast for each tonne of carbon abated. Roadmap Option 1 has the lowest abatement cost, meaning that it would deliver a more cost effective solution per tonne of carbon abated, however would not meet the BEIS 2050 target of 90% reduction in carbon emissions. Roadmap Option 2 has a significantly higher abatement cost, meaning that whilst it would deliver the target reduction in emissions, it would be significantly more expensive for the site per tonne of carbon abated. Roadmap Option 3 has a similar abatement cost to Roadmap Option 1 however this does not take grid connection upgrade costs into account.

Table 5-3 – Solenis Key Metrics for Roadmap Options 1-3.

	CO_2 Emissions in 2050 ($ktCO_2$/y) (% change)	CapEx (£M)	Abatement Cost (£/tCO_2)	Payback Period (years)
Roadmap Option 1	**11.7 (-80%)**	58.1	11	33.5
Roadmap Option 2	**0.6 (-99%)**	22.1	83	-
Roadmap Option 3	**3.5 (-94%)**	8.6*	13*	-

*Exclusive of electricity grid connection at an estimated cost of £19M.

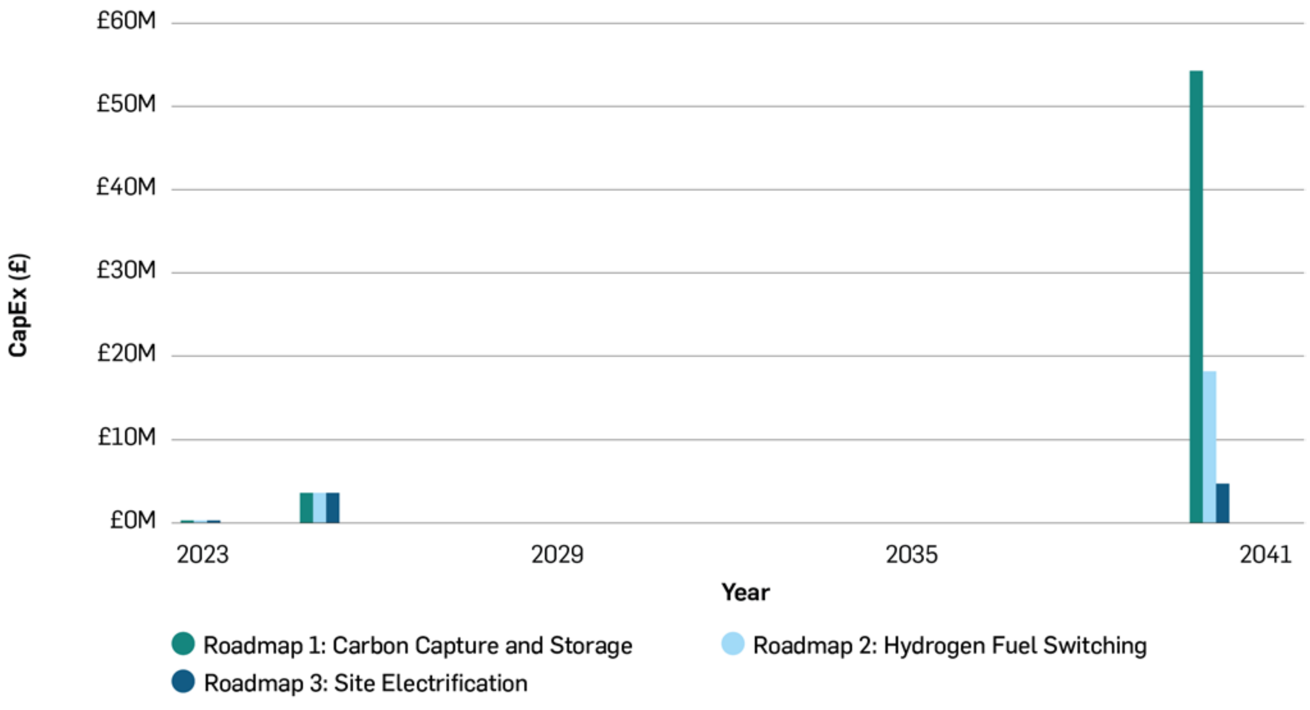


Figure 5-6 – Solenis CapEx Distribution: Comparison of Roadmap Options.

Relative to the predicted BAU forecast OpEx in 2050, only Roadmap Option 1 would remain below the predicted BAU forecast OpEx. Both roadmap Options 2 and 3 show an increase in OpEx relative to the BAU forecast, with Roadmap Option 2 having the highest OpEx. This is due to the high predicted cost of green hydrogen and electricity in the future.

5.4. PAPER – PALM PAPER

The following section summarises the findings by AtkinsRéalis when considering routes to decarbonisation for Palm Paper and their King's Lynn site. The financial figures included do not represent investment decisions being taken by Palm Paper. The assumptions listed in section 2 should also be considered. All figures are advisory based on analysis undertaken at the time, various factors will affect the figures presented and further analysis is required before any investment decisions are taken.

5.4.1. Palm Paper Summary of Roadmaps

The King's Lynn Palm Paper site in Norfolk produces a variety of different grades of paper with varying gloss, colour and whiteness in a highly automated, continuous facility utilising recycled fibres as the raw process material. The total baseline emissions for Palm Paper in 2021 were 187,900 tCO_2/y, of which 182,800 tCO_2/y were scope 1 emissions resulting from the use of natural gas fired assets, primarily the CHP and standby boilers, with the remaining 5,100 tCO_2/y of scope 2 emissions resulting from various process consumers.

Six decarbonisation pathways were produced for the King's Lynn Palm Paper site, primarily centring around electrification (**Roadmap Options 1, 2 and 5**), fuel switching of key natural gas assets to hydrogen (**Roadmap Option 3**) and CCUS (**Roadmap Options 4 and 6**). All options presented feature varying levels and combinations of both on-site and off-site renewable electricity generating assets to offset both existing and elevated electrical import requirements introduced through interventions. Recovery of waste heat currently lost through CHP stack heat exchangers is also proposed at high-level.

Roadmap Option 1 would meet only the ultimate 2050 emissions target of 90%, with a net carbon emissions reduction of 95%. The roadmap option features the phased ownership of off-site solar PV and electrification of natural gas fired assets. Roadmap Option 1 would require a comparatively low CapEx of £38.1M. The total abatement cost of this option is expected to be £116/tCO_2. While none of the options produced for Palm Paper are expected to reach payback by 2050, this option is expected to have the highest abatement cost due to the high electricity costs.

Roadmap Option 2 would meet only the ultimate 2050 emissions target of 90%, with a net carbon emissions reduction of 95%. The roadmap option features phased on-site solar PV installation, electrification of natural gas fired assets and additional renewable generation capacity through the acquisition of off-site wind assets. Roadmap Option 2 would require an estimated CapEx of £55.3M and result in a total abatement cost of £110/tCO_2.

Roadmap Option 3 would result in no carbon emissions targets being met, with an ultimate net carbon emissions reduction of 85% by 2050. The roadmap option features phased on-site solar PV installation, fuel switching of the natural gas fired CHP to blue hydrogen and electrification of standby boilers. Roadmap Option 3 would require an estimated CapEx of £69.3M and result in a total abatement cost of £38/tCO_2. The abatement cost is expected to be far lower than Roadmap Options 1 and 2 due to the lower forecast cost of blue hydrogen compared to electricity.

Roadmap Option 4 would result in only the ultimate 2050 emissions target of 90% being met, with a net carbon emissions reduction of 92%. The roadmap option features phased on-site solar PV ownership, replacement of the CHP with a dedicated natural gas fired boiler, post-combustion carbon capture and electrification of standby boilers. Roadmap Option 4 would require an estimated CapEx of £125.1M and result in a total abatement cost of £35/tCO_2. This is the lowest overall abatement cost of the options presented to Palm Paper due to the low relative cost of natural gas versus electricity or alternative fuels.

Roadmap Option 5 would result in only the ultimate 2050 emissions target of 90% being met, with a net carbon emissions reduction of 95%. This mirrors Roadmap Option 1 with the change that supplementary firing of the boiler is electrified early, and a combination of on-site and off-site solar PV is utilised. Roadmap Option 5 would require an estimated CapEx of £39.5M and result in a total abatement cost of £89/tCO_2.

Roadmap Option 6 would result in only the ultimate 2050 emissions target of 90% being met, with a net carbon emissions reduction of 93%. The roadmap option features phased on-site solar PV installation, electrification of standby boilers and retention of the CHP with post-combustion carbon capture fitted. Roadmap Option 6 would require an estimated CapEx of £115.1M and result in a total abatement cost of £38/tCO_2.

Roadmap Options 1, 2 and 5 present favourably high levels of decarbonisation at low relative CapEx, requiring minimal comparative on-site infrastructure upgrade and low equipment complexity. However, these roadmap options would considerably increase OpEx relative to the BAU forecast following full implementation based on programme fuel and carbon price tracks and require higher off-site electrical infrastructure requirements. Roadmap Options 3, 4 and 6 would result in more favourable OpEx at the expense of higher equipment CapEx, equipment complexity and potential additional costs to enable hydrogen/CCUS infrastructure.

Several key considerations were noted in the development of the roadmap options for Palm Paper:

› Electrical infrastructure must be sufficiently developed to allow for increased site electrical demand, particularly to allow continued operation during periods of planned or unplanned shutdown. Infrastructure requirements should be planned for ultimate electric import/generation requirements of site to minimise design and construction re-work and subsequent cost. Additional infrastructure costs are not included in the total CapEx.

› Standby means of electrical generation are not expected to be feasible due to the scale of electrical demand. Financial risk analysis is therefore recommended to assess financial risk of steam loss to process versus cost of additional redundancy measures:

  – Assessment of independence that can be applied to systems to mitigate unplanned downtime.

  – Consider resilience by retaining natural gas burning or alternative fuel standby asset(s).

› Additional renewable electricity generation or significant grid import must be considered to bridge the energy gap imposed by the decommissioning of the CHP and replacement electrode boiler. A further increase in renewable capacity may be assessed later by site to determine an optimum renewables-grid balance. Private wire enabled renewables projects may offer improved financials for electrical import/export, however, this has not been considered within the scope of the programme.

› Hydrogen and CCUS infrastructure must be sufficiently developed to facilitate hydrogen import/carbon export from site, with full consideration of additional engineering design and costs.

› Additional costs, process risk and complexity must be fully considered and addressed for the implementation of hydrogen fired or carbon capture systems.

5.4.2. Palm Paper Key Findings: Policy Considerations

See section 6.6.3 for an overview of the UK ETS. If the UK ETS carbon price becomes higher than modelled, this will make decarbonisation measures more competitive compared to the BAU case. Changes to the taxing of electricity versus gas may cause the price ratio to narrow more than modelled.

5.4.3. Palm Paper Key Findings: Cluster Access

To enable hydrogen transport to site, the East Coast Cluster offers a potential phase 3 (2028-2037) connection point at Leicester approximately 75 miles from site. However, aligning the proposed CHP fuel switching with end of asset life (~25 years) may be more viable. A hydrogen connection may be more readily available through phase 4 of the East Coast Cluster project with its proposed expansion into Bacton (~50 miles from site) and surrounding areas. This would allow either grid connection or establish additional generation and storage facilities closer to site. Hydrogen supply to site may therefore be enabled through direct pipeline transmission as grid connections are developed. Road transport was not considered feasible due to volume of hydrogen required.

The East Coast Cluster, located in the Teesside and Humber regions, will allow for the transport and offshore storage of captured CO_2. Transport of captured CO_2 at the King's Lynn Palm Paper site will therefore likely be dependent on the Humber terminal requirements. Transported CO_2 is provisionally expected to be as pressurised or liquefied gas via direct pipeline transmission or road/marine transport solutions. Potential common transmission piping may be explored with adjacent industrial partners to minimise additional cost, with an alternate potential common transport route using the River Great Ouse for barge transport.

5.4.4. Palm Paper Key Findings: Sub-metering

Sub-metering is extensive across site, providing the required granularity to conduct this study. Additional monitoring could be provided to facilitate energy efficiency projects on-site.

› Monitoring of electricity use by different motors on-site will aid with strategic installation of variable speed drives (VSDs) or rationalisation projects.

› Monitoring of targeted waste heat recovery streams to facilitate waste heat recovery projects on-site.

5.4.5. Palm Paper Key Findings: Permitting Requirements

The additional permitting requirements summarised in section 6.5 must be considered, particularly with respect to both hydrogen (Roadmap Option 3) and carbon capture (Roadmap Options 4 and 6) technologies. The electrification roadmap options are expected to involve no/minimal additional permitting requirements compared to current site operations. Renewable installations must comply with local permitting and planning requirements.

5.4.6. Palm Paper Key Findings: Key Roadblocks

5.4.6.1. DNO Issues

The local DNO, UK Power Networks, is responsible for granting permission for connection of new generation sources to the grid and grid upgrades. It was found that electricity substations local to King's Lynn have limited available headroom, meaning it is likely that there will be limits on new renewable installations until grid upgrades can take place. The cost of grid upgrades ahead of the DNO's schedule is expected to be prohibitive. As such, Palm Paper may have limited autonomy over installation of solar PV or wind both on-site and off-site for all roadmap options. The 2022 study conducted by the Confederation of Paper Industries (CPI) and Fichtner [16] indicated a connection cost of £119-181M to install a new 132kV national grid connection from the Walpole substation. This does not consider private wire renewable opportunities local to site, for which electrical infrastructure costs may differ.

Additionally, the current export limit imposed by the DNO of 30 MW peak export currently limits renewables installation, curtailing generated power. This was considered within the constraints of this study but may be explored further for future renewable generation projects.

All roadmap options would result in considerable changes to the site demand and generation. It is expected that new connections to the grid would be required to accommodate these changes. A new connection cost may be higher than that of the CPI report, at £300-450/kW. It should be noted that all grid connection costs are subject to discussion with the DNO. Export connection costs are less certain than import connection costs because incorrect connection sizing would have impacts on the grid. Connection costs present a key roadblock to deployment of either roadmap, particularly the more ambitious electrification options.

No allowance was made for the upgrades to internal site electrical infrastructure following uprating of equipment. Costs might range from £2000-3000 per meter of new trenched cabling from on-site renewables to assets dependent on its capacity. No consideration was given to upgrades or development around other supporting infrastructure such as cabinets, motor control centres, junction boxes or substations. Some of these works might be considered non-contestable and require upgrade by the DNO.

5.4.6.2. Carbon and Hydrogen Transport Availability

Palm Paper is located close to the Bacton Industrial Cluster, which is a cluster of businesses aimed at achieving Net Zero. Roadmap Options 3, 4 and 6 are dependent on the availability of transport and storage technologies off-site for concentrated CO_2 and blue or green hydrogen. Should this not be possible, this will pose a major roadblock to decarbonisation in Roadmap Options 3, 4 and 6, provided these options are selected for implementation.

5.4.6.3. Fuel Costs

All roadmap options except for Roadmap Option 4 would result in OpEx increases compared to BAU, due to the higher cost of hydrogen and electricity relative to natural gas. This means that the interventions are not expected to reach payback by 2050. This could be improved if government shift tax from electricity to gas or subsidise electricity or hydrogen.

5.4.7. Palm Paper Feasibility of Roadmaps

Six decarbonisation pathways were produced for the Palm Paper site. No options modelled meet the 2025 net carbon emission reduction target of 20%, with all options excluding Roadmap Option 3 meeting the 2050 target of a 90% net carbon emissions reduction. The performance of the six roadmap options presented is shown in Figure 5-7, highlighting performance against target.

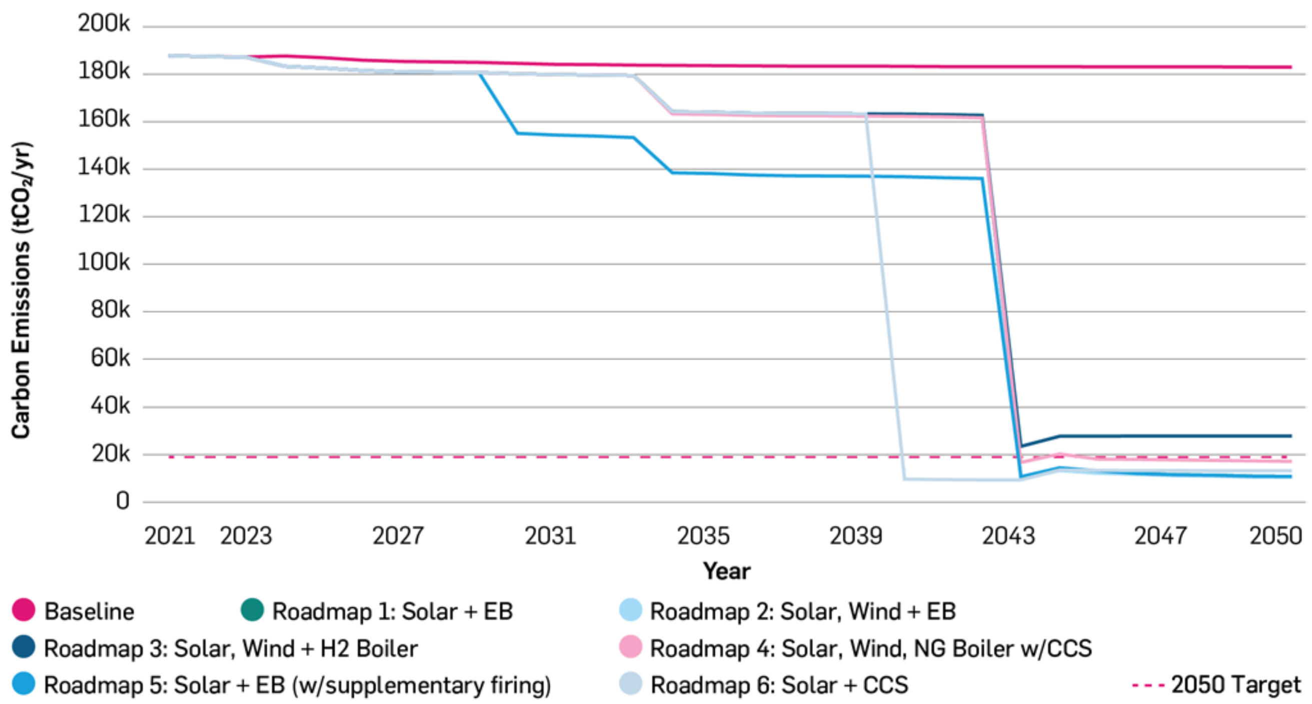


Figure 5-7 – Palm Paper Carbon Emissions: Comparison of Roadmap Options.

All roadmap options are deemed technically feasible at proposed year of installation with respect to TRL. Both solar and wind as means of renewable electricity generation are well-established technologies within the UK, being deployed at both small and large scale capacities. On-site solar presents no significant challenges, however, engineering design with vendor engagement is recommended to fully identify siting and access constraints, electrical requirements and insurance and maintenance costs. Off-site wind or solar challenges lie with the party responsible for installation, operation, and decommissioning. If this is to be executed by Palm Paper, suitable engineering design and operation should be carried out, including key considerations of land use agreements and management. Off-site renewables may additionally be accessed by PPA. These were considered within the modelling scope of the study however they present potentially attractive means of increasing renewable import capacity for site.

Both electric and electrode boilers are considered at a TRL of 9, with commercially deployed large scale units in operation globally, particularly where electricity costs are competitive.

Hydrogen boilers are currently at a TRL of 7-8 with full deployment provisionally expected from 2032. Hydrogen interventions are however aligned with end of CHP asset life in 2043 and are therefore assumed to be at a sufficient level of deployment for use on-site.

For carbon capture technology implemented within this study, a TRL of 7-9 is currently estimated, as relatively few projects have been implemented at industrial sites globally. It should be noted however that installation and operation of a carbon capture plant is expected to require risk assessment and operator training, with the greatest impact on current site operating state compared to the other roadmap options presented. Detailed engineering design with vendor support is strongly advised to assess scale, performance, suitable capture media, downstream processing and risks due to higher relative process complexity.

For all intervention technologies, intervention dates applied within this study are provisionally aligned considering both equipment TRL and supporting infrastructure.

Table 5-4 presents a summary of key CapEx figures against decarbonisation targets for all options modelled, shown in Figure 5-8.

Table 5-4 – Palm Paper Key Metrics for Roadmap Options 1-6.

	CO_2 Emissions in 2050 ($ktCO_2$/y) (% change)	CapEx (£M)	Abatement Cost (£/tCO_2)	Payback Period (years)
Roadmap Option 1	10.3 (-95%)	38.1	116	-
Roadmap Option 2	10.0 (-95%)	55.3	110	-
Roadmap Option 3	17.4 (-85%)	69.3	38	-
Roadmap Option 4	15.6 (-92%)	125.1	35	-
Roadmap Option 5	10.3 (-95%)	39.5	89	-
Roadmap Option 6	12.2 (-93%)	115.1	38	-

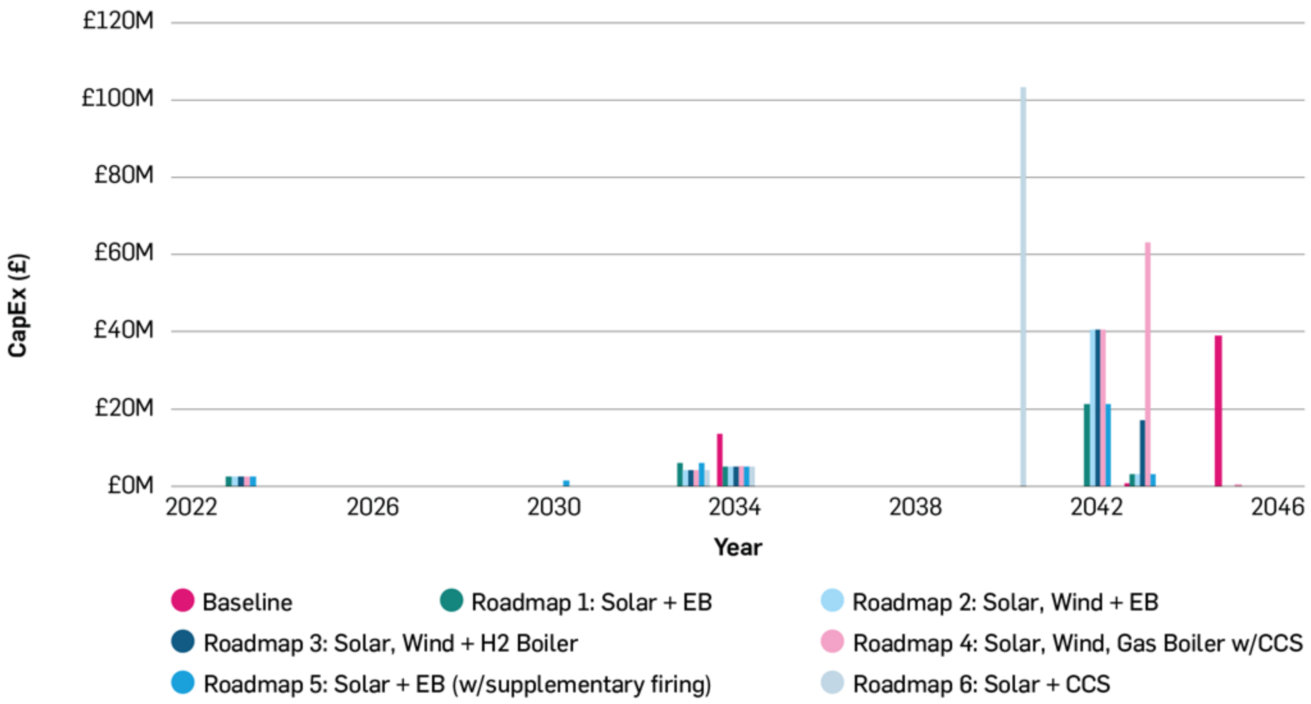


Figure 5-8 – Palm Paper CapEx Distribution: Comparison of Roadmap Options.

Deep electrification (Roadmap Options 1, 2 and 5) is expected to have a lower CapEx but significantly higher OpEx, whereas both hydrogen fuel switching (Roadmap Option 3) and carbon capture (Roadmap Options 4 and 6) have higher CapEx but lower OpEx.

A transient site financial assessment, considering policy, changes to price track and supporting infrastructure should be conducted prior to implementation of any intervention to ensure financial feasibility.

5.5. PAPER – ESSITY

The following section summarises the findings by AtkinsRéalis when considering routes to decarbonisation for Essity and their Prudhoe Mill site. The financial figures included do not represent investment decisions being taken by Essity. The assumptions listed in section 2 should also be considered. All figures are advisory based on analysis undertaken at the time, various factors will affect the figures presented and further analysis is required before any investment decisions are taken.

5.5.1. Essity Summary of Roadmaps

Essity's Prudhoe Mill in the Northeast of England operates two paper machines with an annual capacity of 95,000 tonnes and seven converting lines producing rolled and folded tissue products in varying sizes, weights, thicknesses, and whiteness.

The total emissions in the baseline year of 2019 for the Prudhoe site were 82,100 tCO_2/y, of which 52,200 tCO_2/y were scope 1 emissions resulting from natural gas use. The main energy assets on-site are two natural gas fired boilers and direct fired air burners on the two paper machines. The remaining 29,900 tCO_2/y were scope 2 emissions resulting from the import of electricity on-site.

Three decarbonisation roadmaps were produced for the Prudhoe Mill site, primarily focusing on the utilisation of renewables and electrification (Roadmap Options 1 and 2), and fuel switching of key natural gas assets to hydrogen (Roadmap Option 3). All options presented feature on-site renewable electricity generating assets to offset both existing and elevated electrical import requirements introduced through interventions.

In Roadmap Option 1, an off-site solar PPA and electrification of natural gas assets is proposed which would result in all emissions targets being met. By 2050, 96% reduction in emissions would be expected. This option also has a comparatively lower CapEx of £25.7M due to the proposed PPA with a third party. The cost of abatement would be £116/tCO_2, which is the highest of the three options, and payback would not be achieved before 2050. An alternative scenario where Essity fund the solar array themselves has also been costed, and this has an overall CapEx of £49.2M with the solar array itself costing £23.5M. It should be noted that the graphs and figures included correspond to the first option, whereby a PPA is included in the roadmap option.

In Roadmap Option 2, off-site wind and electrification, would also result in all emissions targets being met. By 2050 a 96% reduction in emissions would be expected. However, because of the ownership of the off-site wind farm, Essity would ultimately be responsible for all associated financial costs for this intervention. This entails a high CapEx of £63.8M. In 2050, Essity's OpEx would be lower than the BAU forecast due to the power generation from the wind farm. The cost of abatement would be £45/tCO_2, which is the lowest of the three options. Payback would not be achieved before 2050.

In Roadmap Option 3, blue hydrogen fuel switching and a solar PV PPA would result in none of the emissions targets being met. By 2050 an 82% reduction in emissions would be expected. However, the option has a comparatively low CapEx of £12.6M. Due to the cost of hydrogen far exceeding that of natural gas, the OpEx following the full fuel switch and solar PV installation would be higher than the BAU forecast. The cost of abatement would be £87/tCO_2, and payback would not be achieved before 2050.

All options assume that the required infrastructure to enable interventions is either already established or upgrades to enable it are possible. This is indicative and is dependent on wider work out of site scope and should therefore be investigated further between the year of study and intervention date. At present, Roadmap Option 1 may be the more favourable option for Essity because of the PPA and the financial benefits this brings, particularly as Roadmap Option 3 is very reliant on sufficient hydrogen supply to the site.

Several key considerations were noted in the development of the roadmap options Essity Prudhoe Mill:

- Considerable changes to electricity demand and generation on-site are expected to necessitate a new grid connection, which is expected to contribute significant additional CapEx for the electrification option.

- Large areas of land will be required to accommodate off-site solar or wind. A PPA could be considered to ease the installation and planning process for each of the roadmap options.
- East Coast cluster infrastructure would need to be extended to supply blue or green hydrogen to Prudhoe Mill by 2033.

5.5.2. Essity Key Findings: Policy Considerations

5.5.2.1. UK ETS

See section 6.6.3 for an overview of the UK ETS. If the UK ETS carbon price becomes higher than modelled, this will make decarbonisation measures more competitive compared to the BAU case. Changes to the taxing of electricity versus gas may cause the price ratio to narrow more than modelled.

5.5.2.2. Hydrogen versus Electrification

Essity's decarbonisation efforts are heavily dependent on national policy, as development of hydrogen and electric boilers in the UK is dependent on both private and government investment. Government is looking to formalise hydrogen subsidies through a CfD framework (although this is yet to be confirmed), however similar funding to alleviate the charges on grid electricity or other energy vectors have not been made. Despite this, the lack of certainty regarding hydrogen infrastructure in the UK means that Essity are not clear on the direction that hydrogen availability will take and will continue to struggle to make informed forecasts or investment decisions. Any such decisions are likely to be postponed until government policy is formalised.

5.5.3. Essity Key Findings: Cluster Access

Essity's Prudhoe Mill site is not located near a hydrogen cluster, however there is potential for clusters to expand networks and come closer to the site in the future. The site is located approximately 50 miles from the nearest connection point to a hydrogen cluster (East Coast Cluster). East Coast Cluster are proposing expansion of hydrogen infrastructure in the area in the early 2030s.

5.5.4. Essity Key Findings: Sub-Metering

The sub-metering on-site is somewhat limited and there have been inconsistencies in the data, However, the daily data provided by Essity was sufficient to perform the BAU analysis. Additional monitoring could be provided to facilitate energy efficiency projects on-site.

5.5.5. Essity Key Findings: Permitting Requirements

The additional permitting requirements summarised in section 6.5 must be considered for Roadmap Option 3 due to the use of hydrogen on-site. Roadmap Options 1 and 2 which focus on electrification are expected to involve no/minimal additional permitting requirements compared to current site operations. Renewable installations must comply with local permitting and planning requirements.

5.5.6. Essity Key Findings: Key Roadblocks

5.5.6.1. DNO Issues

The local DNO is Northern Powergrid, and they are responsible for granting permission for connection of new generation sources to the grid and grid upgrades. The current export limit imposed by the DNO currently limits renewable installations, curtailing generated power. When considering the sizing of wind and solar generation, the export limit should be discussed with the DNO. This has been considered within the constraints of this study but may be explored further for future renewable generation projects.

All roadmap options would result in considerable changes to the site electricity demand and generation. It is expected that new connections to the grid would be required to accommodate these changes. New connection costs are estimated to cost in the region of £300-450/kW. It should be noted that all grid connection costs are subject to discussion with the DNO.

Export connection costs are less certain than import connection costs because incorrect connection sizing would have impacts on the grid. Connection costs present a key roadblock to deployment of either roadmap, particularly the more ambitious electrification options. Grid connection costs can vary significantly depending on several factors, mostly dictated by the state of the grid in the local area. Early engagement with the DNO is advisable.

5.5.6.2. Hydrogen Transport Availability

Essity's Prudhoe Mill is not currently located near a hydrogen cluster. The nearest cluster is the East Coast Cluster, which is 50 miles away, however Phase 2 of the project is expansion into other areas which would make this more feasible. Roadmap Option 3 is dependent upon the availability of blue or green hydrogen which can be supplied to the site. Should this not be possible, this will pose a major roadblock to decarbonisation in Roadmap Options 3, provided this option is selected for implementation.

5.5.6.3. Fuel Costs

Roadmap Options 1 and 3 would result in OpEx increases compared to BAU, due to the higher cost of hydrogen and electricity relative to natural gas. The only intervention in both cases which has a payback is the on-site solar array. The financials of both roadmap options could be improved if government shift tax from electricity to gas or subsidise electricity or hydrogen.

5.5.7. Essity Feasibility of Roadmaps

Three decarbonisation pathways were produced for Essity's Prudhoe Mill. Each roadmap option has significant uncertainties in timescales for connection and hydrogen transportation infrastructure upgrades. All options presented feature combinations of on-site and off-site renewable electricity generating assets to reduce both existing and increased electrical import requirements introduced through interventions. Waste heat recovery from Paper Machine 2 is included in every roadmap option as a key energy efficiency measure.

Roadmap Options 1 and 2 would meet the 2025 net carbon emission reduction target of 20%, however Roadmap Option 3 would only achieve a 17% reduction in emissions by 2025. The same trend is noted for the 2050 target of a 90% net carbon emissions reduction, with both Roadmap Options 1 and 2 expected to surpass the target and Roadmap 3 only expected to achieve an 82% emissions reduction. The performance of the three roadmap options presented is shown in Figure 5-9.

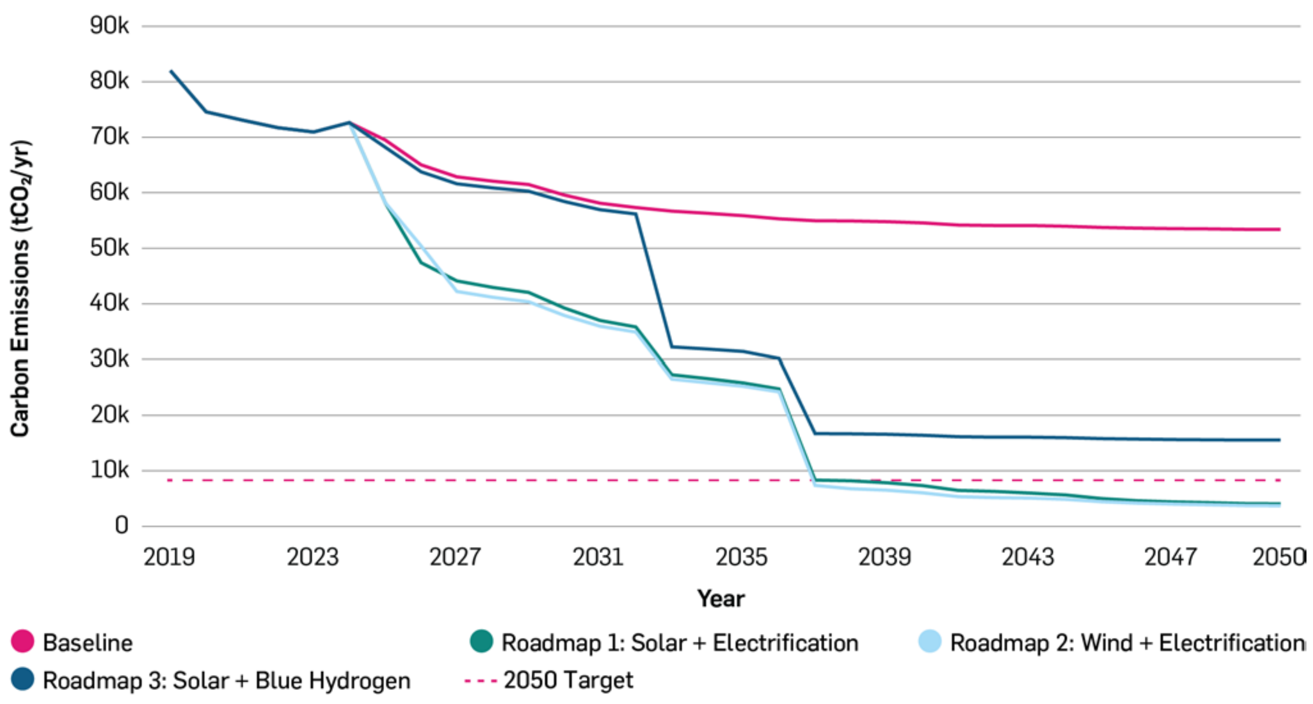


Figure 5-9 – Essity Carbon Emissions: Comparison of Roadmap Options.

FOR PUBLICATION

All roadmap options are deemed technically feasible at proposed year of install with respect to TRL.

Essity has a high site electrical demand compared to the available land identified suitable for renewable energy. Utilising the land available on-site for renewable energy would result in minimal impact on emissions reduction. Still, on-site solar might be implemented with no significant challenge and is likely to constitute a no-regret measure. This has been considered in the form of rooftop solar. Off-site renewables may be accessed by PPAs or through a more traditional build-own-operate model. Solar has been considered in Roadmap Options 1 and 3 in the form of a PPA, while wind has been considered in Roadmap Option 2.

Both electric and electrode boilers have a TRL of 9, with commercially deployed large scale units in operation globally, particularly where electricity costs are competitive. Hydrogen boilers are currently at a TRL of 7-8 with full deployment in the UK provisionally expected from 2032. Hydrogen and electrode boiler interventions are however aligned with the end of asset life of Essity boilers in 2037 and are therefore assumed to be at a sufficient level of deployment for use on site.

This also applies to electric and hydrogen burners which have earliest installation dates of 2025 and 2033 respectively. Electric burners have a TRL of 9 and are readily available. Hydrogen burners which can run on 100% hydrogen are currently available however they have a TRL of 7-8 as they are still in their commercial development phase. It is expected these will be available and commercially deployed before installation in 2033.

For all intervention technologies, intervention dates applied within this study are provisionally aligned considering both equipment TRL and supporting infrastructure.

The CapEx for Roadmap Option 1 is expected to be considerably lower than that of Roadmap Option 2 (see Table 5-5 and Figure 5-10). A key reason for the CapEx difference is that Roadmap Option 1 considers electricity supplied to site from renewables through a virtual PPA. Roadmap Option 2 on the other hand considers the costs necessary for Essity to construct and operate their own off-site wind generation. In neither instance has allowance been made for the upgrades to internal site electrical infrastructure following uprating of equipment. Costs might range from £2000-3000 per meter of new trenched cabling dependent on capacity required.

The positive abatement costs shown in the table below indicate that Essity will need to invest compared to their BAU operation if they are to decarbonise and meet 90% reduction in emissions by 2050. None of the scenarios explored have a payback period before 2050.

Table 5-5 – Essity Key Metrics for Roadmap Options 1-3.

	CO_2 Emissions in 2050 ($ktCO_2$/y) (% change)	CapEx (£M)	Abatement Cost (£/tCO_2)	Payback Period (years)
Roadmap Option 1	**3.4 (-96%)**	25.7	116	-
Roadmap Option 2	**3.0 (-96%)**	63.8	45	-
Roadmap Option 3	**15.0 (-82%)**	12.6	87	-

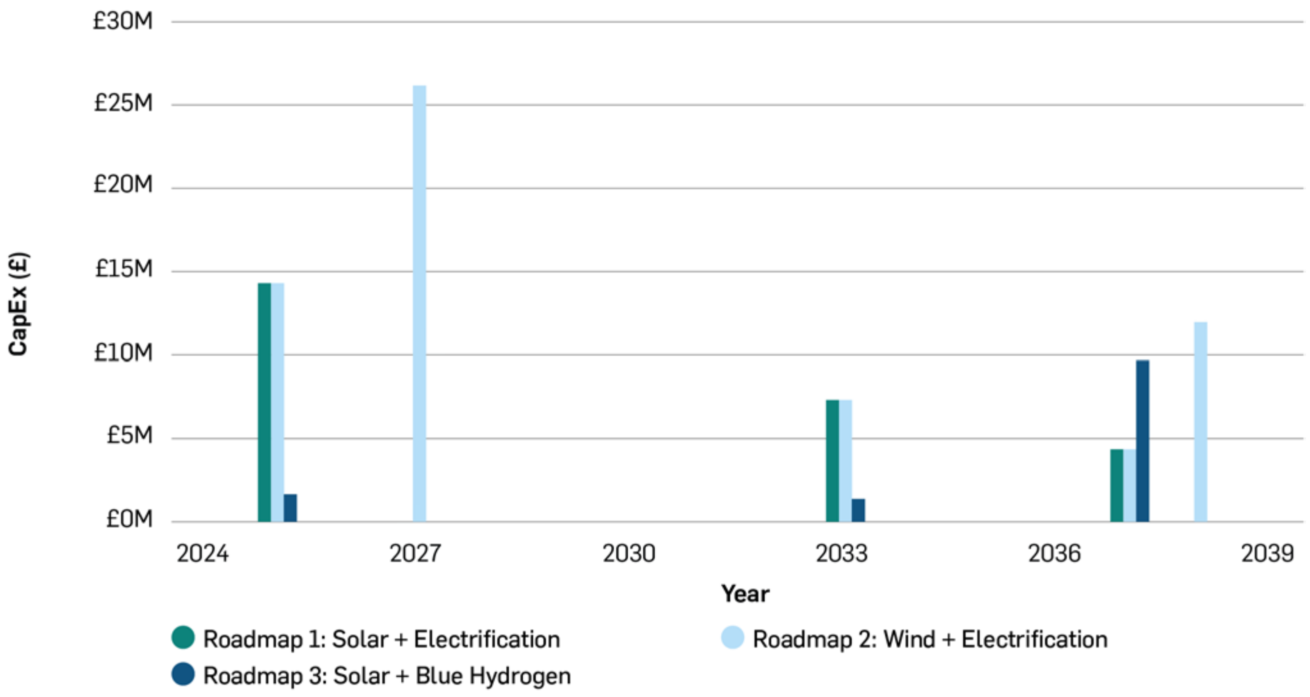


Figure 5-10 – Essity CapEx Distribution: Comparison of Roadmap Options.

In terms of OpEx, Roadmap Option 1 is expected to be the most expensive option, followed by Roadmap Option 3 and Roadmap Option 2 coming in below the BAU forecast.

At this current time, the prices of electricity and green hydrogen are considerably higher than natural gas, affecting the economic feasibility of each roadmap option.

FOR PUBLICATION

5.6. PAPER - KIMBERLY-CLARK

The following section summarises the findings by AtkinsRéalis when considering routes to decarbonisation for Kimberly-Clark and their Barrow Mill site. The financial figures included do not represent investment decisions being taken by Kimberly-Clark. The assumptions listed in section 2 should also be considered. All figures are advisory based on analysis undertaken at the time, various factors will affect the figures presented and further analysis is required before any investment decisions are taken.

5.6.1. Kimberly-Clark Summary of Roadmaps

Kimberly-Clark's Barrow Mill is in Barrow-In-Furness and adjacent to the proposed Carlton Power Green Hydrogen Project, which is intended to feed the mill and other local industry with green hydrogen from 2025. The Barrow Mill site produces approximately 110,000 tonnes of paper per year using a continuous highly automated production process. Kimberly-Clark produce a variety of tissue paper products from paper pulp delivered to the site.

The total emissions in the baseline year (2021) for the Barrow site were 51,200 tCO_2/y, of which 37,400 tCO_2/y were scope 1 emissions resulting from natural gas use. The main energy assets on the site are the natural gas boilers, and burners for the paper machines. The remaining 13,800 tCO_2/y were scope 2 emissions resulting from the import of electricity on-site.

Five decarbonisation roadmaps were produced for the Kimberly-Clark site, primarily focusing on electrification **(Roadmap Options 2, 3 and 4)**, fuel switching of key natural gas assets to hydrogen **(Roadmap Options 1, 3, 4 and 5)** and capturing carbon emissions for off-site utilisation or storage **(Roadmap Option 5)**. All options presented feature both on-site and off-site renewable electricity generating assets to offset both existing and elevated electrical import requirements introduced through interventions.

All options modelled are expected to meet both the 2025 net carbon emission reduction target of 20%, and the 2050 target of a 90% net carbon emissions reduction. None of the options are expected to achieve payback before 2050.

Roadmap Option 1 would provide the greatest level of decarbonisation (95% by 2050) where the process heating assets are switched to hydrogen by 2026, requiring the installation of hydrogen-ready boilers and hood burners. This would however result in a significant increase in site OpEx. The total CapEx of this option is estimated at £13.6M excluding on-site infrastructure upgrades, and the total abatement cost would be £234/tCO_2. The high level of decarbonisation is reliant on the supply of green hydrogen being approximately three times larger than what can be supplied from the Carlton Power Ltd electrolyser.

Roadmap Option 2 would provide a comparable level of decarbonisation (93% by 2050) where the process heating assets are electrified by 2026. The decarbonisation level achieved is lower than Roadmap Option 1 as there is an increase in scope 2 emissions due to relying on grid electricity for the increased demand, however if renewable electricity were sourced, the level achieved would be identical. This option would result in a significant increase in site OpEx. The total CapEx is estimated at £17.7M excluding on-site infrastructure upgrades or additional connections to the grid which would require discussions with DNO, Electricity North-West. The total abatement cost is estimated to be £130/tCO_2.

Roadmap Options 3 and 4 are a splice of Roadmap Options 1 and 2 to present an alternative to either full fuel switching or full electrification of the heating assets. Roadmap Option 3 considers the fuel switching of the hood burners and electrification of the boilers by 2026 while Roadmap Option 4 considers the inverse. Both options would present a similar level of decarbonisation with Roadmap Options 3 and 4 both achieving a 94% reduction by 2050. Roadmap Option 3 would require the lowest CapEx of the five roadmaps at an estimated £6.8M excluding on-site infrastructure upgrades or additional connections to the grid.

Roadmap Option 4 would require the highest CapEx of the fuel switching and electrification options with an estimated cost of £24.4M. Both options would result in a significant increase in site OpEx by 2050. The overall abatement costs are expected to be £173/tCO_2 and £197/tCO_2 for Roadmap Options 3 and 4 respectively.

Roadmap Option 5 would provide the lowest level of decarbonisation (90% by 2050) and the highest estimated CapEx of £26.6M excluding on-site infrastructure upgrades or additional connections to the grid. This option features a carbon capture plant installed in 2025 to scrub the flue gas from the boiler's flue stack, and hydrogen fuel switching of the hood burners. The option results in a significant increase in site OpEx and an overall abatement cost of £148/tCO_2.

Several key considerations were noted in the development of the roadmap options for Kimberly-Clark:

- All options assume that the required infrastructure to enable interventions is either already established or upgrades to enable it are possible. This is indicative and is dependent on wider work out of site scope. This should be investigated further between the year of study and intervention date. Costs associated with infrastructure upgrades are not included in total CapEx.
- The proposed PPA will supply 80% of the current electricity demand for the Barrow Mill.
- The off-take agreement with Carlton Power Ltd for green hydrogen from their proposed electrolyser is currently non-binding. It is noted that this off-take agreement for green hydrogen does not cover the site's current natural gas use, with the output of the electrolyser estimated at 15.7 MWth (400 kg/h). An estimated 43 MWth equivalent of green hydrogen would be required to meet the site's current natural gas usage, which in theory would require two additional 35 MWe electrolysers.
- The roadmap options have been compared with one another excluding any available subsidies which may be applicable. This will affect the OpEx comparison as the fuel costs could be impacted significantly depending upon available government subsidies.
- Kimberly-Clark have expressed their intention to install hydrogen ready equipment in line with the Carlton Power Ltd electrolyser coming online in 2025.

5.6.2. Kimberly-Clark Key Findings: Policy Considerations

5.6.2.1. UK ETS

See section 6.6.3 for an overview of the UK ETS. If the UK ETS carbon price becomes higher than modelled, this will make decarbonisation measures more competitive compared to the BAU case. Changes to the taxing of electricity versus gas may cause the price ratio to narrow more than modelled.

5.6.2.2. Hydrogen versus Electrification

Kimberly-Clark's decarbonisation efforts are heavily dependent on national policy, as electrolysis for large scale hydrogen production and the electrification of heat both domestically and industrially present significant challenges to an already constrained national grid. Policy is expected to develop around increasing demands, including peak demand and export which may impact Kimberly-Clark, particularly for options where deep electrification is suggested. This is not fully defined at the current time but should be monitored in-line with identified decarbonisation pathways to assess feasibility.

Kimberly-Clark have indicated that their off-take agreement strike price is reliant on the cost of natural gas and subsidies from the government to offset the levelized cost of electricity. Therefore, the development of policy applicable to the pricing of hydrogen plays a significant role in the feasibility of the scenarios utilising hydrogen.

5.6.3. Kimberly-Clark Key Findings: Cluster Access

There is no planned hydrogen or CCUS cluster in proximity, the nearest planned cluster is HyNet which is to be constructed approximately 120 miles from site. Outside of planned clusters, the nearby Morecambe Gas Hub is investigating a transition into a CO_2 storage facility.

5.6.4. Kimberly-Clark Key Findings: Sub-metering

The sub-metering on-site is somewhat limited and there were inconsistencies in the data. There were discussions over which dataset to use to form the basis of the report, and assumptions were required to generate time series data used in the calculations of the energy profiles on-site. Additional monitoring could be provided to facilitate energy efficiency projects on-site and improve data accuracy.

5.6.5. Kimberly-Clark Key Findings: Permitting Requirements

The permitting requirements summarised in section 6.5 must be considered, particularly with respect to both hydrogen (Roadmap Options 1, 3, 4 and 5) and carbon capture (Roadmap Option 5) technologies. Permitting requirements associated with Roadmap Option 2 are expected to be minimal compared to current site operations. Renewable installations must comply with local permitting and planning requirements.

5.6.6. Kimberly-Clark Key Findings: Key Roadblocks

5.6.6.1. DNO Issues

The local DNO is Electricity North-West, who are responsible for granting permission for connection of new generation sources to the grid and grid upgrades. The current export limit imposed by the DNO of 30 MW peak export limits renewables installation, curtailing generated power. This has been considered within the constraints of this study but may be explored further for future renewable generation projects.

All roadmap options result in considerable changes to the site demand and generation. It is expected that new connections to the grid would be required to accommodate these changes. A new connection cost is expected to be £300-450/kW. It should be noted that all grid connection costs are subject to discussion with the DNO. The cost of grid upgrades ahead of the DNO's schedule is expected to be prohibitive. Export connection costs are less certain than import connection costs because incorrect connection sizing could have impacts on the grid. Connection costs present a key roadblock to deployment of all roadmaps, particularly the more ambitious electrification options.

It should be noted that grid connection costs are highly-site specific and subject to discussion with the DNO. Early engagement with the DNO is advisable.

5.6.6.2. Carbon and Hydrogen Transport Availability

Kimberly-Clark's Barrow Mill is not near an industrial cluster. Roadmap Option 5 relies on the transportation and storage of CO_2. It has been assumed a pipeline connected between the site and the nearby Morecambe Bay Gas hub, which is due to transition in the late 2020s to a storage project, may be used. As the site is not situated near a planned CCUS cluster it would require further area to accommodate storage and tanker facilities.

All roadmap options assume availability of green hydrogen through the non-binding agreement between Carlton Power and Kimberly-Clark.

5.6.6.3. Fuel Costs

All roadmap options result in OpEx increases compared to the BAU forecast, due to the higher cost of hydrogen and electricity relative to natural gas. This means that the roadmap options do not have payback. This could be improved if government shift tax from electricity to gas or subsidise electricity or hydrogen.

5.6.7. Kimberly-Clark Feasibility of Roadmaps

All scenarios would meet the BEIS target of 90% reduction of CO_2 emissions by 2050, as shown in Figure 5-11. As all scenarios have adopted the very aggressive timeline put forward by Kimberly-Clark most achieve the 90% goal by 2035. Both Roadmap Options 2 and 5 could also achieve the 90% goal by 2035 if the subscription under the PPA was increased.

As shown in Figure 5-11, all roadmap options have comparable gradients until 2025 where the different mix of the hydrogen fuelled boilers and burners, or the electrification of the heating assets is implemented.

Roadmap Option 1 sees the sharpest decrease in emissions due to the use of green hydrogen for both the boilers and the burners, as there are no associated scope 2 emissions. Roadmap Options 2, 3, and 4 all increase the electricity demand of the site and therefore the emissions reductions achieved taper off in 2026 before gradually decreasing in line with Roadmap Option 1 due to the 'greening' of the grid. Roadmap Option 5 almost completely flattens as the only decrease in emissions from 2026 is from the 'greening' of the electricity demand, and as it does not have any electrification of heating assets this effect is less pronounced than the other scenarios.

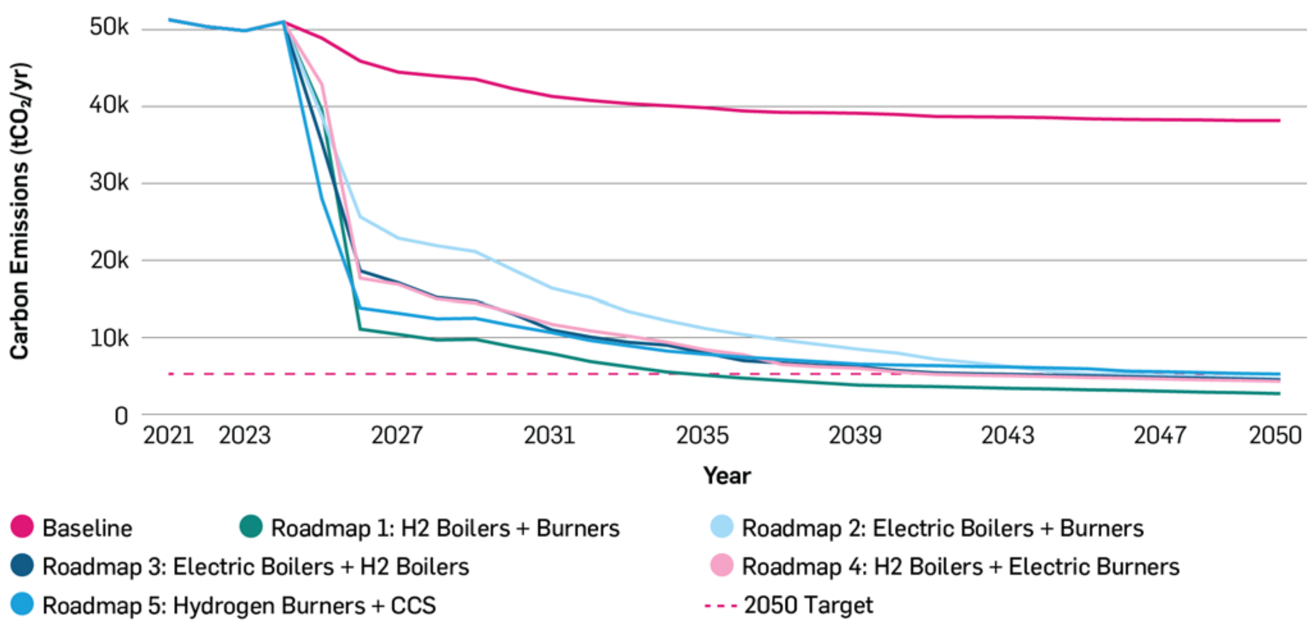


Figure 5-11 – Kimberly-Clark Carbon Emissions: Comparison of Roadmap Options.

All roadmap options are deemed technically feasible at proposed year of install with respect to TRL.

Off-site wind is considered in all options. Approximately 80% of the site's current electricity yearly demand is estimated to be imported from an off-site wind farm under the PPA. This is estimated to cover approximately 75.5 GWh/y of the site's electricity demands. The area availability is not a concern with the current intention of Kimberly-Clark entering into the PPA, as the site has already been built and commissioned.

The agreement is intended to operate as a 'behind the meter' agreement so there is no representative area. Hydrogen ready boilers have a TRL of 7-8 and can directly replace the mothballed boilers which could fit within the currently occupied floor space. They are sized to replace the current natural gas fired boilers, and duty standby arrangement has been costed for a 1:1 installation. It is expected that the hydrogen boilers will be capable of sustainable operation using 100% hydrogen fuel when installation is assumed to begin on-site in 2025.

Hydrogen ready burners are sized on the current thermal capacity of the existing burners and aligned with burner replacement in 2025. Hydrogen burners which can run on 100% hydrogen are currently available however they have a TRL of 7-8 as they are still in their commercial development phase. It is assumed that these will be available for installation in 2025.

For both hydrogen interventions, there may be additional requirements regarding the pipe and cable routing, or separation distances required to be consistent with Dangerous Substances and Explosive Atmospheres Regulations stipulation.

Electrode boilers and electric hood heaters both have a TRL of 9. They are commercially deployed large scale units in operation globally and installation dates are assumed to be the same as those for the hydrogen interventions. They have been sized to replace current gas fired boilers and burners.

For carbon capture technology implemented within this study, a TRL of 7-9 is currently estimated, as relatively few projects have been implemented at industrial sites globally. It should be noted that installation and operation of a carbon capture plant is expected to require risk assessment and operator training, with the greatest impact on the site operating state. Detailed engineering design with vendor support is strongly advised to assess scale, performance, suitable capture media, downstream processing and risks due to higher relative process complexity.

For all intervention technologies, intervention dates applied within this study are provisionally aligned considering both equipment TRL and supporting infrastructure.

The positive abatement costs shown in the table below indicate that Kimberly-Clark will need to invest compared to their BAU operation if they want to decarbonise and meet 90% reduction in emissions by 2050. None of the scenarios explored have a payback period before 2050.

It was found that the full electrification of the heating assets would provide the lowest abatement cost as shown in Roadmap Option 2. A combination of electrode boilers and hydrogen hood burners would give the lowest CapEx as shown in Roadmap Option 3. Roadmap Option 5 which considered installation of CCS would have the largest CapEx and the smallest impact on the carbon emissions. Its implementation is also subject to higher uncertainty given availability of land area.

Table 5-6 – Kimberly-Clark Key Metrics for Roadmap Options 1-5.

	CO_2 Emissions in 2050 ($ktCO_2$/y) (% change)	CapEx (£M)	Abatement Cost (£/tCO_2)	Payback Period (years)
Roadmap Option 1	**2.5 (-95%)**	13.6	234	-
Roadmap Option 2	**3.6 (-93%)**	17.7	130	-
Roadmap Option 3	**3.1 (-94%)**	6.8	173	-
Roadmap Option 4	**3.1 (-94%)**	24.4	197	-
Roadmap Option 5	**5.0 (-90%)**	26.6	148	-

All options are front loaded around 2025 and 2026 due to Kimberly-Clark's intended aggressive decarbonisation timeline.

Roadmap Option 1 has the largest increase of OpEx due to the high price of green hydrogen.

All roadmap options feature the installation of rooftop solar in 2023 hence the equal CapEx shown in this year in Figure 5-12. The installation year of the electrode and hydrogen ready boilers and the electric air heaters and hydrogen ready hood burners have been kept consistent throughout each of the options to allow direct comparison.

Due to how the interventions were modelled, the CapEx of the hydrogen ready burners and boilers are shown in 2026 rather than the proposed installation year of 2025 as shown in Figure 5-12. Across all scenarios the CapEx is incurred mostly in 2025 and 2026 to follow the aggressive timeline to decarbonise.

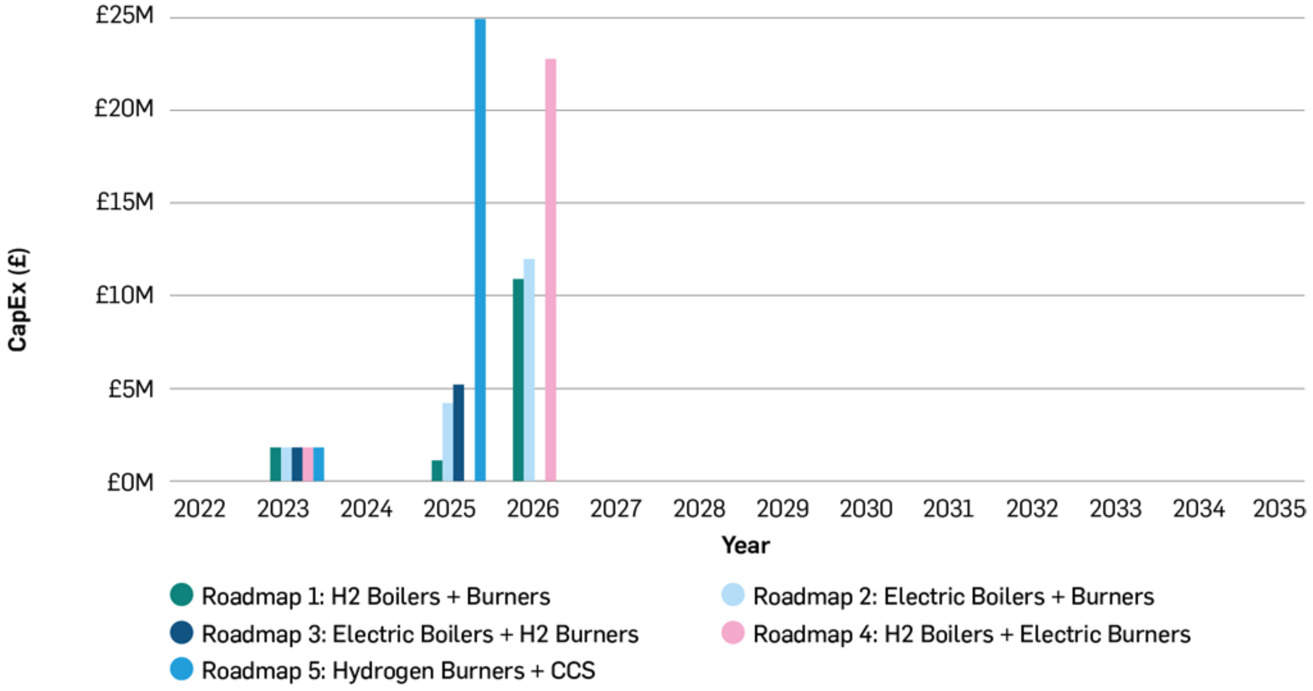


Figure 5-12 – Kimberly-Clark CapEx Distribution: Comparison of Roadmap Options.

5.7. MINERALS – CHURCHILL CHINA

The following section summarises the findings by AtkinsRéalis when considering routes to decarbonisation for Churchill China and their Marlborough Works site. The financial figures included do not represent investment decisions being taken by Churchill China. The assumptions listed in section 2 should also be considered. All figures are advisory based on analysis undertaken at the time, various factors will affect the figures presented and further analysis is required before any investment decisions are taken.

5.7.1. Churchill China Summary of Roadmaps

Churchill China's Marlborough Works site near Stoke-on-Trent manufactures ceramic tableware from raw "slip" clay. The total baseline emissions for the site were 12,100 tCO_2/y, of which 10,700 tCO_2/y were scope 1 emissions resulting from natural gas use, primarily in kilns, heaters, and dryers. The remaining 1,400 tCO_2/y were scope 2 emissions resulting from various electricity uses.

Three decarbonisation roadmap options were produced for Churchill China. No energy efficiency measures were included in the roadmap options due to the extensive work completed by Churchill China in this field to date.

Roadmap Option 1 centres around a phased fuel switch to blue hydrogen in all kilns, heaters, and dryers between 2035 and 2042, coupled with installation of on-site solar PV in 2030. The roadmap would result in none of the emissions targets being met. By 2050 a 73% reduction in emissions would be expected. This option would require a comparatively low CapEx of £9.1M (excluding the cost of a new electricity grid connection, estimated at £0.8M). Due to the cost of hydrogen far exceeding the cost of natural gas, the abatement cost of Roadmap Option 1 is expected to be £217/tCO_2, and payback would not be reached by 2050.

Roadmap Option 2 involves the phased electrification all kilns, heaters, and dryers between 2035 and 2042, again coupled with solar PV in 2030. This option would result in the final emissions target being met (92% emissions reduction by 2050). This option presents a higher CapEx of £16.4M (excluding the cost of a new electricity grid connection, estimated at £3.7M). Similarly, the higher cost of electricity than natural gas and the relatively small solar array means the abatement cost of Roadmap Option 2 is expected to be £229/tCO_2, the highest of the three options. Payback is not expected to be achieved by 2050.

Roadmap Option 3 considers an immediate total fuel switch to biomethane through purchase of RGGOs. This presents a useful bridging option (until hydrogen or electric kilns are available) that meets all emissions reduction targets (95% emissions reduction by 2050). This option has zero associated CapEx but with higher OpEx than the BAU forecast from 2022. The abatement cost of Roadmap Option 3 is expected to be £140/tCO_2. Payback is not applicable in this case, as no CapEx would be required.

A key reason for the high OpEx for all three roadmap options is that Churchill China does not currently qualify for inclusion in the UK ETS (as individual burners are rated at less than 3 MW capacity), meaning there is no cost saving associated with carbon reduction. This means higher fuel costs are not mitigated by carbon cost savings.

Hydrogen fuel switching has a lower CapEx than electrification but a lower decarbonisation potential due to the scope 2 emissions associated with blue hydrogen production. Using green hydrogen in the longer term to reduce emissions further would be an inefficient use of renewable electricity compared with direct electrification of heat. Therefore, based on currently available information, phased electrification of heat between 2035 and 2042 with biomethane bridging would most effectively decarbonise the site. Ultimately, Churchill China will need to continue engaging with trials for hydrogen and electric kilns to ensure that their decision-making is underpinned with robust technical evidence.

Several key considerations were noted in the development of the roadmap options for Churchill China:

- Hydrogen and electricity costs present major barriers to the decarbonisation of Marlborough Works.
- Churchill China's current exclusion from UK ETS means there is a no financial incentive for decarbonisation of the site, meaning all options are considerably more expensive than the BAU forecast.
- It is anticipated that installation of on-site renewable electricity generation will not be possible until the local electricity grid has been upgraded, likely by 2030 based on Churchill China's previous engagement with their DNO.
- Considerable changes to electricity demand and/or generation on-site are expected to necessitate a new grid connection, which is expected to contribute considerable additional CapEx and may present a roadblock for site electrification or installation of renewables.
- ORC electricity generation and VPPAs were qualitatively discussed as potential ways to further reduce scope 2 emissions. To determine the feasibility of ORC for Churchill China, improvements in stack monitoring are necessary in consultation with an ORC supplier.
- A biomethane fuel switch is not suitable for widespread UK industrial decarbonisation but presents a promising bridging option until a hydrogen fuel switch or site electrification are possible.

5.7.2. Churchill China Key Findings: Policy Considerations

5.7.2.1. UK ETS

See section 6.6.3 for an overview of the UK ETS. There is a clause which excludes individual units <3 MW from the aggregation. Therefore, many smaller industrial sites (such as Churchill China) are currently not included. However, the UK government have committed to expanding the scope of the scheme in future to hit national emissions reductions targets. The government are currently consulting on what this expansion could look like. Lowering of the 20 MW threshold and scrapping/amendment of the <3 MW aggregation clause are both being considered. As such, it is likely that over the period 2025-2030 that such qualifying criteria will be lowered, meaning Churchill China among other sites not currently in the scheme may be exposed to carbon taxation. This would mean the sites start paying for their scope 1 emissions at the UK ETS market rate, whereas they currently pay nothing. This will provide a significant additional financial incentive to decarbonise. However, defining the exact revised qualifying criteria and date from which it applies is currently speculation and will become clearer over the next year when the government release further details.

5.7.2.2. Hydrogen versus Electrification

Churchill China's decarbonisation efforts are heavily dependent on national policy, as development of hydrogen and electric kilns in the UK is dependent on both private and government investment. Government is looking to formalise hydrogen subsidies through a CfD framework (although this is yet to be confirmed), however similar funding to alleviate the charges on grid electricity or other energy vectors have not been made. Despite this, the lack of certainty regarding hydrogen infrastructure in the UK means that Churchill China are not clear on the direction that kiln technology will take and will continue to struggle to make informed forecasts or investment decisions. Any such decisions are likely to be postponed until government policy is formalised.

5.7.2.3. Availability of RGGOs

The availability of RGGOs is likely to be constrained in the UK as more industrial sites decarbonise, precluding their suitability for widespread use in industrial decarbonisation. Further, it is uncertain whether UK policy around RGGOs will change in future. Currently there are challenges around their additionality, overall 'net' emissions when transportation and processing are considered, fugitive greenhouse gas emissions, and concerns around direct competition between food and fuel. Clarity on whether RGGOs are expected to continue to be available as present or whether policy is likely to change, would provide certainty and confidence for decarbonisation ahead of electric or hydrogen technologies becoming available. Within the BEIS IFP, RGGOs have only been considered as a bridging technology, where alternatives have proved unsuitable.

5.7.3. Churchill China Key Findings: Cluster Access

Marlborough Works is approximately 50 miles away from the nearest hydrogen and CCUS cluster (Hynet North-West). As such, availability of a hydrogen or CO_2 pipeline on-site could be expected in the medium term and could therefore contribute to Churchill China's decarbonisation efforts ahead of 2050. It was considered that CCUS would likely not be suitable for the site due to its small scale, integration issues with existing plant stacks and the current lack of monitoring of flue gas CO_2 concentration. Hydrogen is regarded as a potential kiln decarbonisation option. Progress of Hynet North-West and expansion beyond the existing planned network will be important to Churchill China's future options.

5.7.4. Churchill China Key Findings: Sub-metering

Roadmap Options 1 and 2 involve installation of ORC units. Stack flowrates and temperatures were not available, meaning electricity generation could not be meaningfully calculated. Identification of suitable kilns for installation of ORC units and monitoring of stack discharges in consultation with suppliers is recommended to determine the ultimate feasibility of installation of ORC.

5.7.5. Churchill China Key Findings: Permitting Requirements

The additional permitting requirements summarised in section 6.5 must be considered for import, potential storage, and combustion of hydrogen in Roadmap Option 1. The permitting requirements associated with Roadmap Options 2 and 3 are expected to be minimal compared to current site operations. Renewable installations must comply with local permitting and planning requirements.

5.7.6. Churchill China Key Findings: Key Roadblocks

5.7.6.1. DNO Issues

The local DNO is National Grid Electricity Transmission, and they are responsible for granting permission for connection of new generation sources to the grid and grid upgrades. Churchill China have previously attempted to install considerable solar PV capacity on-site. However, the installation capacity was capped due to the constrained local grid. As of October 2022, 2 MW had been installed on-site. The local DNO is expected to carry out grid upgrades in 2028, meaning it is not expected that considerable renewable generation would be able to be installed until 2030.

Considerable changes to electricity generation and/or demand are likely to necessitate a new or upgraded electric grid connection. Grid connection upgrade costs are expected to be £300-450/kW. The upper bound is used as the local electricity grid is known to be constrained. The cost of this is expected to be considerable, estimated at £788,000 and £3.7M for Roadmap Options 1 and 2 respectively. Evidently, these additional costs present a barrier to site decarbonisation. It should be noted that grid connection costs are highly-site specific and subject to discussion with the DNO. Early engagement with the DNO is advisable.

5.7.6.2. Hydrogen Transport Availability

Marlborough Works is approximately 50 miles away from the nearest hydrogen and CCUS cluster (Hynet North-West), and is reliant on its future expansion or scope for pipeline connection availability. Roadmap Option 1 is dependent on the availability of transport and storage technologies for blue or green hydrogen. Should this not be possible, this will pose a major roadblock to roadmap implementation.

5.7.6.3. Fuel Costs

All roadmap options result in OpEx increases compared to BAU, due to the higher cost of hydrogen and electricity (and RGGOs) relative to natural gas. This means that the interventions do not have payback by 2050. This could be improved if government shift tax from electricity to gas or subsidise electricity or hydrogen. Inclusion of the site in the UK ETS could also help mitigate increased OpEx for Churchill China. Uncertainties around this will likely delay any investment decision from Churchill China.

5.7.6.4. Availability of RGGOs

There may be constraints on the supply of RGGOs in the UK if increasing numbers of sites buy them as decarbonisation interventions. It was assumed that adequate supply will be able to be procured. Should purchase of sufficient RGGOs not be possible, this will pose a major roadblock to decarbonisation of Marlborough Works until electric or hydrogen kiln technology is available.

5.7.7. Churchill China Feasibility of Roadmaps

Three decarbonisation pathways were produced for Churchill China. Roadmap Option 3 would be the least technologically ambitious option but has the greatest decarbonisation potential, meeting all the BEIS IFP emissions reductions targets. Roadmap Options 1 and 2 are both constrained by technology development, with phased decarbonisation of heat from 2035 meaning the initial two decarbonisation targets are missed. Roadmap Option 2 would be more effective in decarbonising heat than Roadmap Option 1, which is expected to fail to meet all emissions targets due to scope 2 emissions from blue hydrogen production (imperfect capture and storage of CO_2 emissions from steam methane reforming plant).

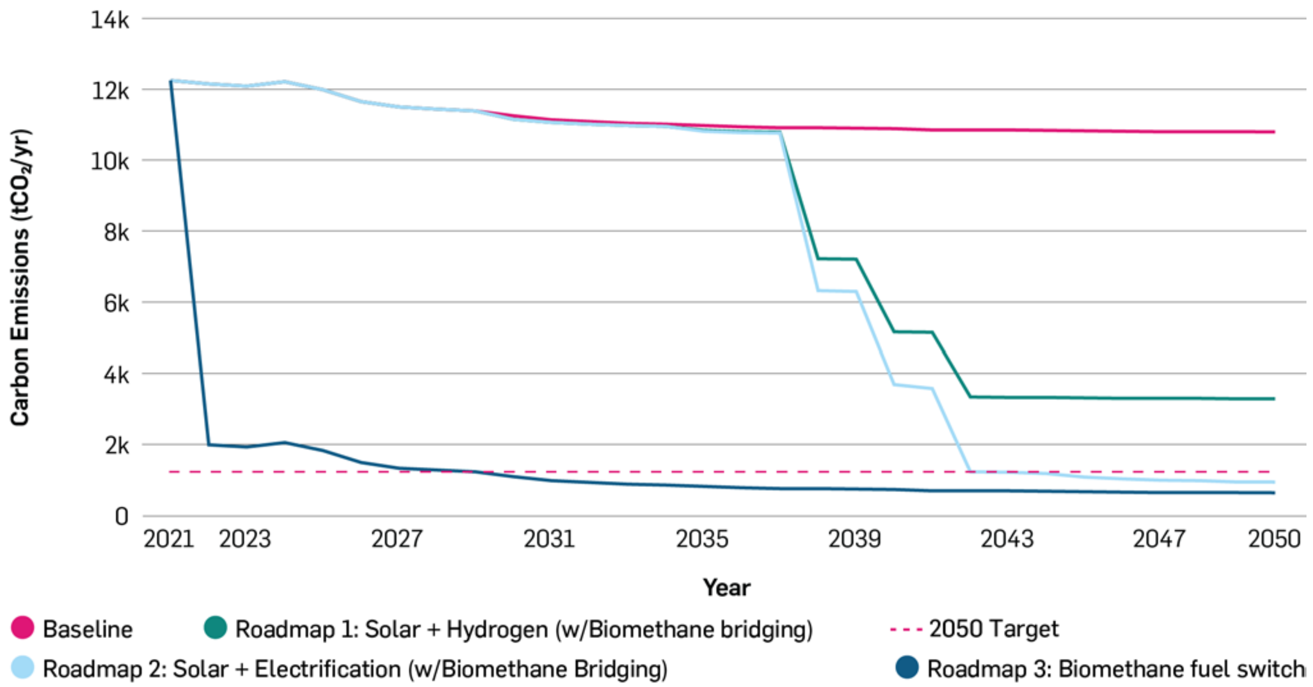


Figure 5-13 – Churchill China Carbon Emissions: Comparison of Roadmap Options.

A key issue with both Roadmap Options 1 and 2 is the low TRL of suitable electric and hydrogen-fired kilns. Churchill China's ongoing participation in trials will ultimately determine the technical feasibility and costs of either option for Marlborough Works. Further to this, the generation of hydrogen at the necessary scale is not expected to be possible in the short term. Given the site's distance from the nearest hydrogen cluster, hydrogen supply is likely to be sparse. Delays to the development of hydrogen infrastructure in the area would have knock-on effects on the timescales for decarbonisation of Roadmap Option 1.

Whilst replacement of kilns, heaters and dryers is phased to minimise impact on operations, the replacement of each asset will affect production if the new asset cannot be installed alongside the old, particularly tunnel kilns. If new assets could be installed alongside the old assets, conversion of the old asset from operation to stand-by would provide considerable resilience should electricity or hydrogen supply be unstable.

The feasibility of ORC for the site could not be determined due to the lack of stack monitoring data available. Should Churchill China wish to pursue this further, implementation of monitoring in consultation with suppliers would be necessary.

While solar PV is technically feasible, installation on-site is not expected to be possible until at least 2030. It was assumed that 48,000 m^2 of land surrounding Marlborough Works would be suitable for solar PV installation. Should this assumption prove incorrect, and considerably less land is available for solar PV installation, both Roadmap Options 1 and 2 would be affected. The peak export requirement for 3 MW of solar PV is 1.75 MWp. Without the site export limit, the feasibility of these arrays cannot be ascertained. An alternative solution that could be explored is a VPPA, where there would be more flexibility on land meaning wind power could be installed to further decrease scope 2 emissions. However, the cost saving of a VPPA is marginal compared to grid electricity.

The CapEx for Roadmap Option 2 would be the highest by a considerable margin due to the higher assumed cost of kiln electrification compared to hydrogen fuel switching. The Roadmap Option 2 CapEx does not include cabling for the solar PV, purchase/lease of land or a potential new grid connection cost which would need to be sufficient for the 8,200 kW increase in demand. The Roadmap Option 1 CapEx does not include the cabling, land purchase/lease or a potential new electricity grid connection required for the solar PV or the new hydrogen pipework from the grid connection.

The CapEx for Roadmap Option 3 would be zero and the OpEx associated with purchase of sufficient RGGOs for full decarbonisation would be lower than OpEx for both Roadmap Options 1 and 2, meaning although more expensive than the BAU forecast it would be by far the least expensive option overall. The availability of RGGOs in future is not clear, meaning it is potentially only a feasible option in the short-medium term.

All three roadmaps are expected to result in a positive cost of abatement, and payback is not reached for any roadmap by 2050. Of the three, Roadmap Option 3 is expected to have the lowest cost of abatement, although it may only be feasible in the short-medium term. The abatement costs for Roadmap Options 1 and 2 are similar, with Roadmap Option 2 being marginally lower. This is due to the lower expected kiln costs and lower forecast hydrogen costs compared to electricity.

The OpEx for Roadmap Option 1 would be lower than Roadmap Option 2 when all interventions have been implemented, due to the lower forecast price of blue hydrogen compared to electricity. This higher OpEx and CapEx therefore means that electrification is by far the most expensive option.

Table 5-7 – Churchill China Key Metrics for Roadmap Options 1-3.

	CO_2 Emissions in 2050 ($ktCO_2$/y) (% change)	CapEx (£M)	Abatement Cost (£/tCO_2)	Payback Period (years)
Roadmap Option 1	3.3 (-73%)	9.1*	217*	-
Roadmap Option 2	0.9 (-92%)	16.4**	229**	-
Roadmap Option 3	0.6 (-95%)	0	140	0

*Exclusive of CapEx associated with a new electricity grid connection, estimated at £0.8M.
**Exclusive of CapEx associated with a new electricity grid connection, estimated at £3.7M.

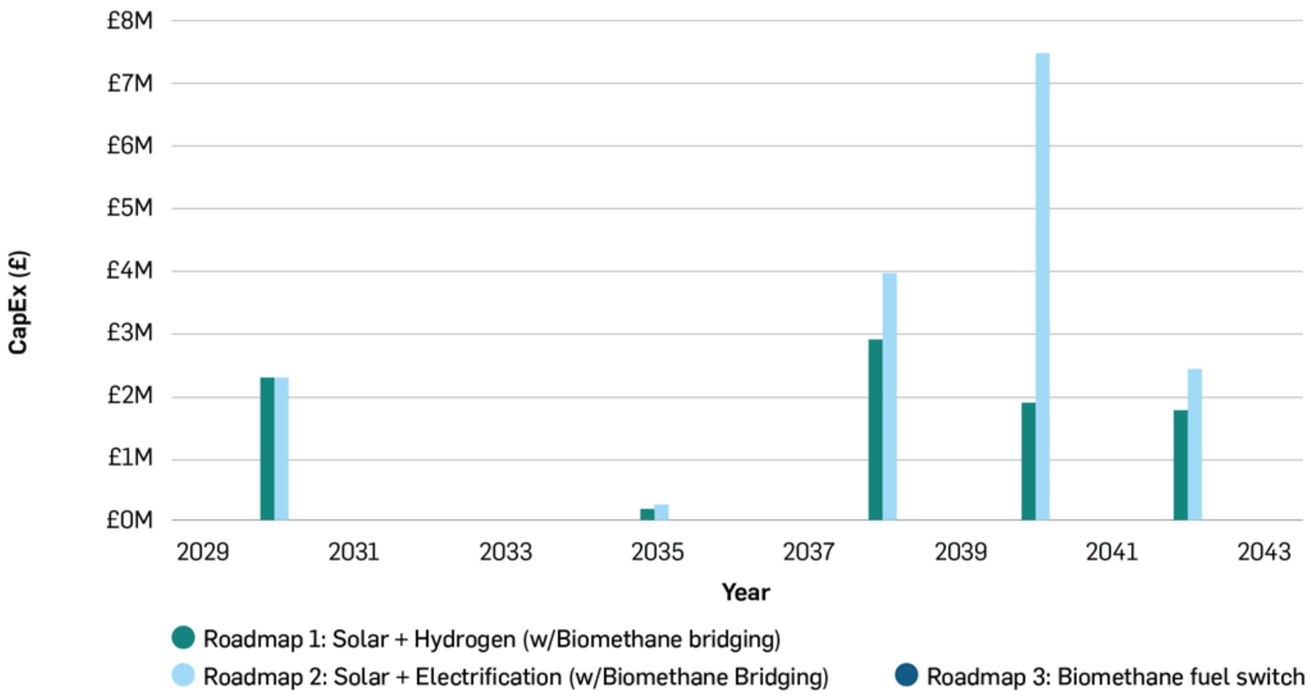


Figure 5-14 – Churchill China CapEx Distribution: Comparison of Roadmap Options.

5.8. MINERALS – IMERYS MINERALS

The following section summarises the findings by AtkinsRéalis when considering routes to decarbonisation for Imerys Minerals and their site in Par. The financial figures included do not represent investment decisions being taken by Imerys Minerals. The assumptions listed in section 2 should also be considered. All figures are advisory based on analysis undertaken at the time, various factors will affect the figures presented and further analysis is required before any investment decisions are taken.

5.8.1. Imerys Minerals Summary of Roadmaps

The Imerys Minerals site in Par, Cornwall, produces a variety of clay products from base material for further processing and export off-site. Primary processing occurs within three business units throughout the site, Par Grade Dryer (PGD), European Milling Centre (EMC) and Opacilite (OPAC).

The total baseline emissions for Imerys Minerals in this year were 28,300 tCO_2/y, of which 27,300 tCO_2/y were scope 1 emissions resulting from the use of natural gas fired assets, primarily the CHP and standby boilers. The remaining 900 tCO_2/y scope 2 emissions resulted from various process consumers such as pumps and centrifuges[12].

Three decarbonisation pathways were produced for the Imerys Minerals site, primarily centring around electrification, identified as the most favourable fuel switching option. All options presented feature varying levels and combinations of both PPA (identified by the Imerys Minerals site team) and off-site wind to offset both existing and elevated electrical import requirements introduced through interventions. There was a lack of granularity of OPAC gas consumption meaning natural gas use in the calciner was not known. Electrification of the calciner was not expected to be feasible. In the absence of data the decarbonisation potential for Roadmap Option 1 was capped at 90% by 2050 to indicate the extent of decarbonisation required.

No options are expected to meet the 2025 net carbon emission reduction target of 20% but all would meet the 2050 target of a 90% net carbon emissions reduction.

Further investigation is recommended to identify potential pathways to early decarbonisation, such as bridging technologies, engagement with potential technology incentives or early adoption of alternative fuel sources.

Roadmap Option 1 would result in only the ultimate 2050 emissions target being met, with a net carbon emissions reduction of 90% by 2050. This roadmap option features a wind generation PPA, CHP decommissioning and electrification of natural gas fired assets. Roadmap Option 1 would require an estimated CapEx of £2.7M. Despite elevated electrical import requirements, the OpEx following full electrification is forecast to be lower than the BAU forecast. As such, the total abatement cost is expected to be -£26/tCO_2 meaning payback would be achieved in approximately 3 years.

Roadmap Option 2 would also result in only the ultimate 2050 emissions target being met, with a net carbon emissions reduction of 91% by 2050. This roadmap option features a wind generation PPA, CHP decommissioning, electrification of natural gas fired assets and additional off-site wind generation capability. Roadmap Option 2 would require an estimated CapEx of £26.8M. Elevated electrical import requirements are partially offset by the increased electrical generation capacity. The OpEx following full electrification with additional wind generation capacity is expected to be lower than the BAU forecast. As such, the total abatement cost is expected to be -£63/tCO_2 meaning payback would be achieved in approximately 5 years.

Roadmap Option 3 would again result in only the ultimate 2050 emissions target being met with a net carbon emissions reduction of 91% by 2050. This roadmap option features a wind generation PPA, CHP decommissioning, electrification of natural gas fired assets and additional off-site solar generation capability. Roadmap Option 3 would require an estimated CapEx of £17.3M. Elevated electrical import requirements are again partially offset by the increased electrical generation capacity. The OpEx following full electrification with additional wind generation capacity is forecast to be lower than the BAU forecast. As such, the total abatement cost is expected to be -£40/tCO_2 meaning payback would be achieved in approximately 6 years.

12 Note total emissions quoted do not equal the sum of scope 1 and 2 emissions due to rounding.

Roadmap Option 1 is presented as the baseline electrification case with Roadmap Options 2 and 3 investigating the potential for increased renewable generation capacity through the acquisition of wind or solar generating assets. Roadmap Option 1 presents the extent of decarbonisation required to meet a 90% reduction in carbon emissions, with comparatively low CapEx whilst still presenting a favourable OpEx forecast. It should be noted that the cost of electrical import through the 4.2 MW PPA has not been modelled across all three options as this is currently provisional with no indicative cost data available. Roadmap Options 2 and 3 give increasing net OpEx reductions from year of installation at the expense of increased CapEx.

Several key considerations were noted in the development of the roadmap options for Imerys Minerals:

- Electrical infrastructure must be sufficiently developed to allow for increased site electrical demand, particularly to allow continued operation during periods of peak demand. Infrastructure requirements should be planned for ultimate electric import/generation requirements of site to minimise design and construction re-work and subsequent cost. Costs associated with required infrastructure upgrades are not included in the total CapEx.
- The PPA-specific electrical import cost has not been modelled due to lack of price track data. The reported OpEx figures should be refined once this data is available to assess intervention impact more accurately on site financials.
- Due to limited metering data, the alignment of wind and solar generation loading profiles against site demand should more fully be assessed. A flat demand profile has been used, despite the nature of batch-wise processing at Imerys Minerals. Generation from wind assets during non-operational periods would be expected to be exported if storage capability is not in place. DNO-imposed export limits, infrastructure and price agreements should be factored into future assessment to determine potential improvements more accurately for wind.
- Electrification of process critical drying assets introduces potential risk for a common failure mode across drying equipment and the site being driven to shut down, incurring financial losses.
- Standby means of electrical generation are not expected to be feasible due to the scale of electrical demand. Financial risk analysis is therefore recommended to assess financial risk of steam loss to process versus cost of additional redundancy measures:
  - Assessment of independence that can be applied to system to mitigate unplanned downtime.
  - Consider resilience by retaining natural gas burning or alternative fuel standby asset(s).
- Additional renewable electricity generation or significant grid import must be considered to bridge the energy gap imposed by the decommissioning of the CHP and deeper electrification interventions. A further increase in renewable capacity may be assessed later by site to determine an optimum renewables-grid balance. Private wire enabled renewables projects may offer improved financials for electrical import/export, however, this has not been considered within the scope of the programme.
- Additional costs, process risk and complexity must be fully considered and addressed for the implementation of electric drying interventions.

5.8.2. Imerys Minerals Key Findings: Policy Considerations

See section 6.6.3 for an overview of the UK ETS. If the UK ETS carbon price becomes higher than modelled, this will make decarbonisation measures more competitive compared to the BAU case. Changes to the taxing of electricity versus gas may cause the price ratio to narrow more than modelled.

5.8.3. Imerys Minerals Key Findings: Cluster Access

The nearest proposed hydrogen and CCUS cluster is the Southampton hydrogen hub, as one of six major industrial clusters identified by UK government. A feasibility study has been conducted with hydrogen generation capability from 2030 proposed, dependent on technical feasibility. Utilisation of this potential future hydrogen/CCUS hub if developed would require significant expansion into the south-west of England, with the Imerys Minerals site located approximately 180 miles from Southampton.

Additionally, the hydrogen source requires consideration, with multiple off-site generation methods available. Currently, blue hydrogen is most commercially available out of low carbon hydrogen types, however, it has residual carbon emissions as the process utilises natural gas as a feedstock for typical hydrogen generating process routes such as steam methane reformation. As hydrogen technology and infrastructure develop, green hydrogen through routes such as electrolysis may be more readily available and should be explored if hydrogen firing is desired by site.

Due to the status of the Southampton hub, site proximity and technology readiness, hydrogen has been excluded with electrification preferentially explored within the scope of the Imerys Minerals roadmap.

5.8.4. Imerys Minerals Key Findings: Sub-metering

Sub-metering is extensive across site, providing the required granularity required to conduct this study. However, greater depth and rationalisation of some disparity in reported figures is recommended to allow greater precision when assessing future project work.

- Greater granularity of monitoring for each business unit. Currently meter data are only available for PGD, EMC and OPAC, limiting the ability to fully assess decarbonisation potential on-site.
- Disparity between hourly and monthly metered data.

5.8.5. Imerys Minerals Key Findings: Permitting Requirements

All roadmap options are expected to have no/minimal additional permitting requirements compared to current site operations, particularly when compared to hydrogen or CCUS interventions. Wind and solar installations must comply with local permitting and planning requirements.

5.8.6. Imerys Minerals Key Findings: Key Roadblocks

The local DNO is responsible for granting permission for connection of new generation sources to the grid and grid upgrades. Based on high level assessment, it was found that the nearest available substation to site would be Par Harbour. Based on open source national grid maps, this substation was found to have available demand headroom (>20%), allowing electrification and subsequent increased electrical import to site. However, this station is already constrained in export capacity (<10%). The Imerys Minerals Par site, however, has an existing private wire connection to surrounding renewables networks. It is therefore suggested that further renewables generation again utilise high voltage private wire connections for import, potentially requiring upgrade to accommodate increased demand. This limited export capacity again highlights the potential risk of exporting high amounts of renewable electricity through proposed wind and/or solar installations, particularly during times when the site is not operational. This should be assessed against current CHP generation export capacity and cost of external infrastructure improvements.

The DNO-imposed export limit for Imerys Minerals was not provided, however, this should be factored into all future work, particularly where renewables such as wind are proposed, giving generation profiles that may at times exceed site demand. It should be noted that no DNO limit was used within the scope of this study due to lack of visibility.

All roadmap options result in considerable changes to the site demand and generation. It is expected that new connections to the grid would be required to accommodate these changes. A new connection cost is expected to be £300-450/kW. It should be noted that all grid connection costs are subject to discussion with the DNO. Export connection costs are less certain than import connection costs because incorrect connection sizing would have impacts on the grid. Connection costs present a key roadblock to deployment of all roadmaps.

5.8.7. Imerys Minerals Feasibility of Roadmaps

Three decarbonisation pathways were produced for the Imerys Minerals site, primarily centring around electrification. No options modelled would meet the 2025 net carbon emission reduction target of 20%, with all options meeting the 2050 target of a 90% net carbon emissions reduction.

There was a lack of granularity of OPAC gas consumption meaning natural gas use in the calciner was not known. Electrification of the calciner was not expected to be feasible. In the absence of data, the decarbonisation potential for Roadmap Option 1 was capped at 90% by 2050 to indicate the extent of decarbonisation required. The performance of the three roadmap options presented is shown in Figure 5-15 and Table 5-8, highlighting performance against target.

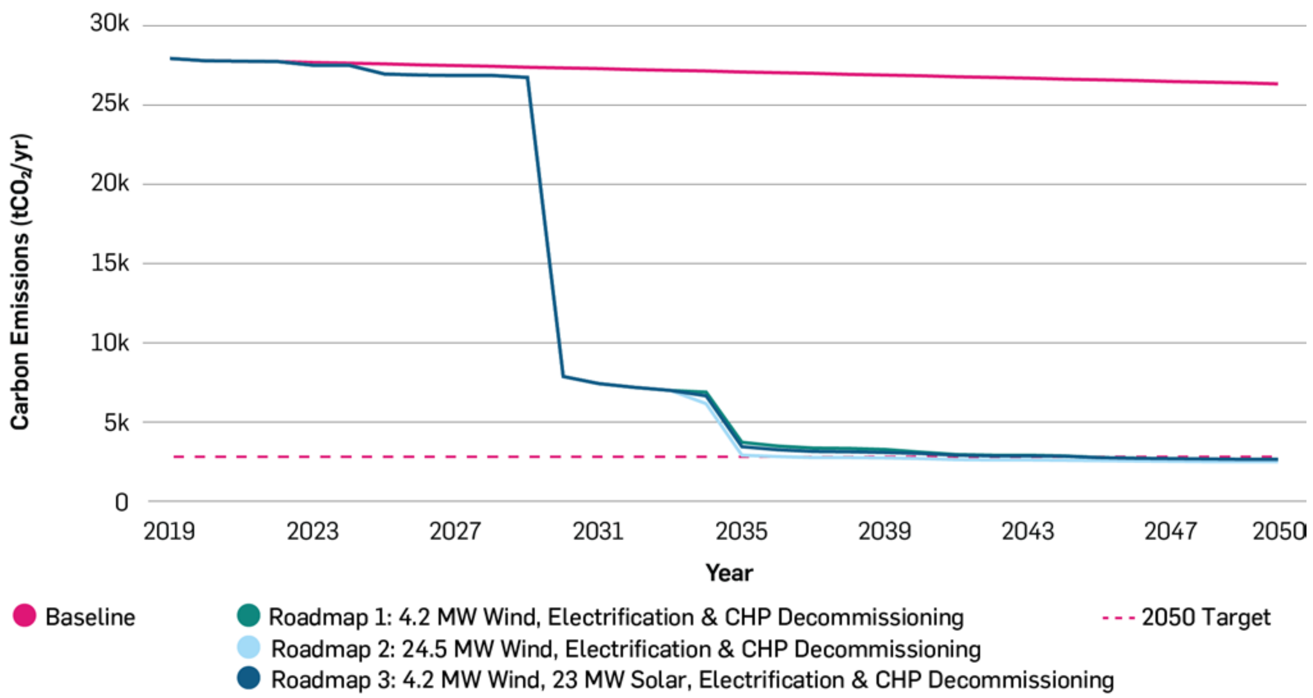


Figure 5-15 – Imerys Minerals Carbon Emissions: Comparison of Roadmap Options.

All roadmap options are deemed technically feasible at proposed year of installation with respect to TRL. Both solar and wind as means of renewable electricity generation are well-established technologies within the UK, being deployed at both small and large scale capacities. Off-site wind or solar challenges lie with the party responsible for installation, operation, and decommissioning. If this is to be executed by Imerys Minerals , suitable engineering design and operation should be carried out, including key considerations of land use agreements and management.

Electric heaters are considered at a TRL of 9, with commercially deployed small to large scale units in operation globally, particularly where electricity costs are competitive.

For all intervention technologies, intervention dates applied within this study are provisionally aligned considering both equipment TRL and supporting infrastructure.

Table 5-8 presents a summary of key CapEx figures against decarbonisation targets for all options modelled, shown in Figure 5-16.

Table 5-8 – Imerys Minerals Key Metrics for Roadmap Options 1-3.

	CO_2 Emissions in 2050 ($ktCO_2$/y) (% change)	CAPEX (£M)	Abatement Cost (£/tCO_2)	Payback Period (years)
Roadmap Option 1	**2.8 (-90%)**	2.7	-26	2.7
Roadmap Option 2	**2.5 (-91%)**	26.8	-63	5.4
Roadmap Option 3	**2.7 (-91%)**	17.3	-40	6.0

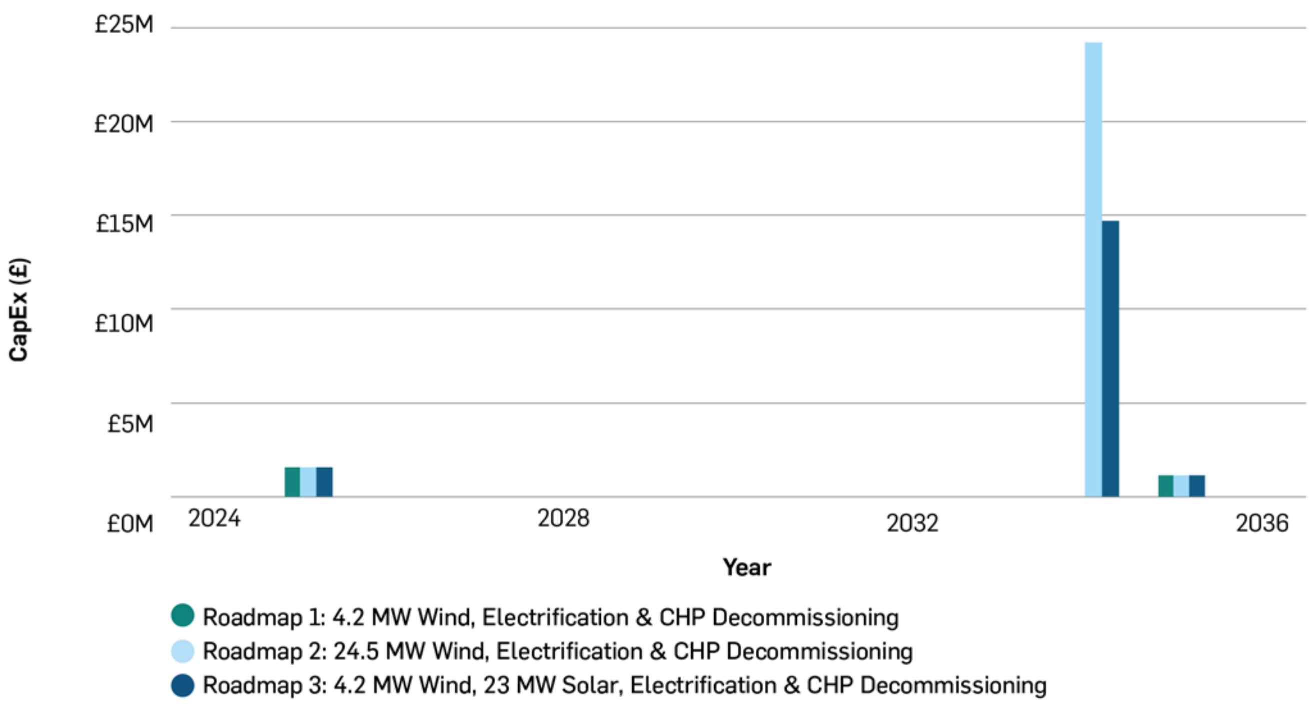


Figure 5-16 – Imerys Minerals CapEx Distribution: Comparison of Roadmap Options.

The increased use of renewables in Roadmap Options 2 and 3 presents favourable OpEx reductions at the cost of higher CapEx. A time-dependent site financial assessment, considering policy, changes to price track and supporting infrastructure should be conducted prior to implementation of any intervention to ensure financial feasibility.

5.9. MINERALS – MIDLAND QUARRY PRODUCTS

The following section summarises the findings by AtkinsRéalis when considering routes to decarbonisation for Midland Quarry Products and their Cliffe Hill site. The financial figures included do not represent investment decisions being taken by Midland Quarry Products. The assumptions listed in section 2 should also be considered. All figures are advisory based on analysis undertaken at the time, various factors will affect the figures presented and further analysis is required before any investment decisions are taken.

5.9.1. Midland Quarry Products Summary of Roadmaps

Midland Quarry Products' Cliffe Hill site in Leicestershire is made up of two adjacent quarries, Old Cliffe Hill being an active quarry, while New Cliffe Hill contains an asphalt plant. The total baseline emissions for Cliffe Hill in 2021 were 15,200 tCO_2/y, of which 13,100 tCO_2/y were scope 1 emissions resulting from diesel use in vehicles and processed fuel oil (PFO) use by a burner used to heat aggregate. The remaining 2,200 tCO_2/y were scope 2 emissions resulting from electricity use by conveyors, crushers, and heated bitumen tanks[13]. The site set a target of 90% emissions reduction by 2042, this was used in place of the BEIS IFP 2050 target.

Two decarbonisation roadmap options were produced for the Cliffe Hill site, one focussed on the electrification of plant and process, and one which considers switches to fuels with lower carbon intensities. Of the two roadmap options, the electrification roadmap presents the strongest tangible decarbonisation benefits

Roadmap Option 1 involves energy demand reduction through automation of temperature control of the PFO burner, installation of VSDs on primary motors, re-rating of suitable motors and optimisation of water pumping requirements. Further decarbonisation is provided through installation of solar PV on-site, installation of seven 240 kW electric vehicle chargers and phased replacement of the on-site industrial vehicles with electric alternatives.

Roadmap Option 1 would result in two of the three emissions targets being comfortably met, with a 97% emissions reduction by 2042.

The initial emissions target would not be met due to the low TRL of some of the key technologies. The CapEx associated with this roadmap option is expected to be £17M, which is higher than Roadmap Option 2 (this excludes CapEx associated with upgrade of the electricity grid connection, estimated to be £5.9M). OpEx savings relative to the BAU forecast are expected following full roadmap implementation. The overall cost of abatement of this option is expected to be -£80/tCO_2 and payback would be achieved in approximately 7 years.

Roadmap Option 2 involves the same energy efficiency measures as the electrification option, a fuel switch in vehicles to biodiesel, installation of a multi-fuel burner that is compatible with natural gas use and installation of a smaller solar PV array. Roadmap Option 2 would only meet the first emissions reductions target, ultimately resulting in a 61% emissions reduction by 2042. It is considered a more practical option in the short-term but would have a lower decarbonisation potential due to continued reliance on fossil fuels. Notably, the CapEx would be comparatively lower (£11.6M, excluding CapEx associated with upgrade of the electricity grid connection, estimated to be £5.9M), but OpEx savings are also expected to be lower. The overall cost of abatement is expected to be -£102/tCO_2, i.e. lower than the electrification option. Payback is therefore expected to be achieved in less than 6 years.

Several key considerations were noted in the development of the roadmap options for Midland Quarry Products:

- The on-site vehicles are excluded from the UK Emissions Trading Scheme, meaning there is no financial incentive to decarbonise them.
- It is anticipated that installation of on-site renewable electricity generation will not be possible until the local electricity grid has been upgraded, likely by 2030 (based on discussions of another site with the same DNO).
- Considerable changes to electricity demand and/or generation on-site are expected to necessitate a new grid connection, which is expected to contribute significant additional CapEx for both roadmap options.
- To determine the ultimate feasibility of the interventions in the recommended roadmap and optimise their implementation it is recommended that sub-metering on-site is improved. Specifically, electricity uses by key motors, diesel use attributed to each vehicle type and water pumping operations.
- Interventions such as biodiesel fuel switch in vehicles may be implemented as bridging interventions until electrification of site is possible.

5.9.2. Midland Quarry Products Key Findings: Policy Considerations

5.9.2.1. UK ETS

See section 6.6.3 for an overview of the UK ETS. The scheme currently applies to sites with 20 MW or more of stationary combustion plant on-site once all individual units are aggregated together. This means that the Cliffe Hill on-site vehicle fleet are excluded from the scheme and there is currently no financial incentive to decarbonise them.

5.9.3. Midland Quarry Products Key Findings: Cluster Access

The Cliffe Hill site is located approximately 100 miles away from the nearest hydrogen and CCUS cluster (HyNet North-West). Availability of a hydrogen or CO_2 pipeline on-site is unlikely to be compatible with site targets in 2042, meaning it was excluded as an option for vehicle or burner decarbonisation. CCUS is not suitable for the site regardless of cluster access.

5.9.4. Midland Quarry Products Key Findings: Sub-metering

Sub-metering is somewhat poor across site. Improvements could be made to provide better granularity of the processes, key examples being:

- Monitoring of electricity use by different motors on-site will aid with strategic installation of VSDs and re-rating of motors.
- Greater accuracy in the volumes of fuel used by each vehicle, as well as the contract length/ownership of each vehicle would allow for more strategic vehicle replacement or retrofit.
- Monitoring the volumes of water pumped around the site versus the volumes used would allow for pumping operations to be more strategic.

5.9.5. Midland Quarry Products Key Findings: Permitting Requirements

Both roadmap options are expected to have no/minimal additional permitting requirements compared to current site operations, particularly when compared to hydrogen or CCUS interventions. There is best practise guidance on charging of electric batteries and installation of chargers (relevant to vehicles in Roadmap Option 1) from the Institution of Engineering and Technology [17] and Control of Substances Hazardous to Health [18]. Renewable installations must comply with local permitting and planning requirements.

5.9.6. Midland Quarry Products Key Findings: Key Roadblocks

5.9.6.1. DNO Issues

The local DNO is National Grid Electricity Transmission, and they are responsible for granting permission for connection of new generation sources to the grid and grid upgrades. Midland Quarry Products were not able to specify available headroom for Cliffe Hill. Based on publicly available information it was found that electricity substations local to Cliffe Hill have limited available headroom. The site is therefore considered to be in a constrained area [19].

13 Note total emissions quoted do not equal the sum of scope 1 and 2 emissions due to rounding.

The costs associated with installing new electricity connections are substantial. Grid connection upgrade costs are estimated to be in the region of £300-450/kW. The upper bound is used as the local electricity grid is known to be constrained. For Roadmap Option 1, they are expected to be £5.9M and for Roadmap Option 2 they are expected to be £5.1M. These connection costs present a key roadblock to deployment of either roadmap, particularly the more ambitious electrification option. Grid connection costs can vary significantly depending on several factors, mostly dictated by the state of the grid in the local area. Early engagement with the DNO is advisable.

5.9.6.2. Fuel Costs

Roadmap options presented would result in OpEx reductions compared to BAU, despite the higher cost of electricity relative to PFO. The significant increase in electrical demand is partially met by the proposed solar installation, helping to offset high resultant OpEx. This could be further improved if government shift tax from electricity to gas/fuel oils or subsidise electricity.

5.9.6.3. Biofuel Availability

There is a limited supply of biofuels in the UK meaning they are not suitable for widespread use in industrial decarbonisation. It has been assumed that adequate supply could be procured at a price 1.5 times that of red diesel. Should this not be possible, this will pose a major roadblock to decarbonisation of Cliffe Hill if this intervention is selected for implementation.

5.9.7. Midland Quarry Products Feasibility of Roadmaps

Roadmap Option 1 is the more ambitious option with the greatest decarbonisation potential, meeting the final two of the three IFP emissions reductions targets. While Roadmap Option 2 is considered more realistic, it has a lower decarbonisation potential (see Figure 5-17). Roadmap Option 2 does however present a useful bridging opportunity to initially decarbonise the site ahead of the availability of electric heaters and vehicles.

Roadmap Option 1 would meet both the 2035 and 2042 targets of 66% and 90% net carbon emissions reduction, however, would fail to meet the 2025 target of 20%. Roadmap Option 2 would meet only the 2025 target.

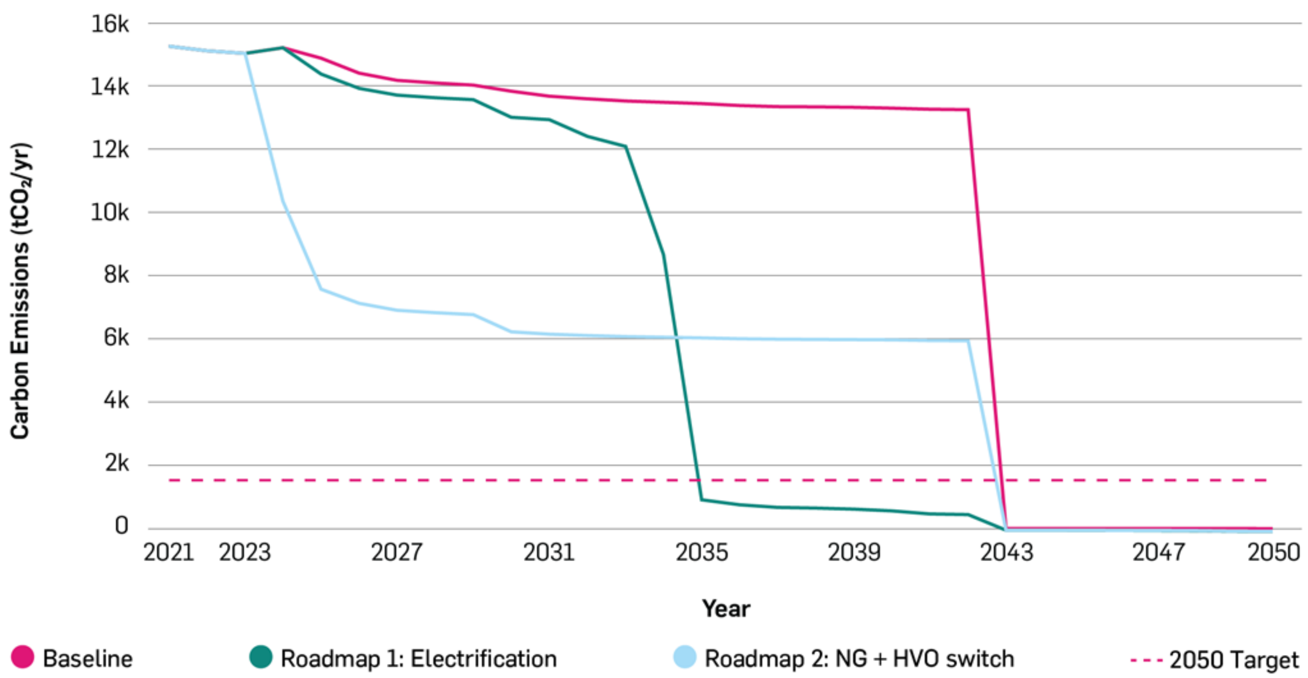


Figure 5-17 – Midland Quarry Products Carbon Emissions: Comparison of Roadmap Options.

The key interventions relating to the burner and on-site vehicle decarbonisation could be implemented much earlier for Roadmap Option 2 compared to Roadmap Option 1. This means that although ultimately total annual OpEx savings relative to the BAU forecast would be lower than those for Roadmap Option 1, these savings would be sustained for a much longer period. I.e. OpEx savings would be at their greatest from 2030 in Roadmap Option 2 but would not peak until 2035 for Roadmap Option 1.

Overall, Roadmap Option 2 is expected to have the lower cost of abatement. The vehicles in Roadmap Option 2 are expected to have a positive cost of abatement (£92/tCO_2), whereas vehicles in Roadmap Option 1 are expected to have a negative cost of abatement (-£55/tCO_2 on average, acknowledging the cost of chargers is not accounted for in this value). It is however the PFO burner replacement that results in Roadmap Option 2 being less expensive overall. In Roadmap Option 1 the abatement cost of the electric burner is expected to be slightly positive (£1.8/tCO_2) whereas in Roadmap Option 2 it is expected to be much lower (-£453/tCO_2). Given the large proportion of overall site emissions these interventions would abate, they have a large overall impact on the cost of each roadmap option.

Most of the interventions included in the roadmaps are already technically feasible (key exceptions being dryer drum burner and on-site vehicle electrification). Improvements in sub-metering will determine the ultimate feasibility of several of these interventions at the Cliffe Hill site.

A potential mitigation for delayed commercial readiness of the electrification interventions could be using hydrogenated vegetable oil as a bridging option. Furthermore, early engagement with electric equipment manufacturers may help to further mitigate these risks.

While solar PV is technically feasible, installation on-site is not expected to be possible until at least 2030. It has been assumed that 220,000 m^2 of land on the periphery of the Cliffe Hill site is suitable for solar PV installation. Should this assumption prove incorrect, and considerably less land be available for solar PV installation, Roadmap Option 1 would be most impacted as it requires a greater land area and emissions savings from solar installation are greater. The peak export requirements for Roadmap Options 1 and 2 are expected to be 13,210 kW and 11,280 kW respectively. Without knowing the site export limit, the feasibility of these arrays cannot be ascertained.

The CapEx for Roadmap Option 2 is lower than Roadmap Option 1 (see Table 5-9 and Figure 5-18). The key reasons for the CapEx difference between the roadmap options are the scale of solar installed and the cost of PFO burner replacement, £1.9M and £600,000 for electrification and multi-fuel respectively. Further to the CapEx in Table 5-9 and Figure 5-18, additional CapEx associated with electricity grid connections have been estimated to be £5.9M and £5.1M for Roadmap Options 1 and 2 respectively. These connection costs will ultimately have a considerable impact on the commercial viability of Cliffe Hill's decarbonisation.

Table 5-9 - Midland Quarry Products Key Metrics for Roadmap Options 1 and 2.

	CO_2 Emissions in 2042 ($ktCO_2$/y) (% change)	CapEx (£M)	Abatement Cost (£/tCO_2)	Payback Period (years)
Roadmap Option 1	0.4 (-97%)	17.0*	-80*	7.2
Roadmap Option 2	5.9 (-61%)	11.6**	-102**	5.7

*Exclusive of CapEx associated with a new electricity grid connection, estimated at £5.9M.

**Exclusive of CapEx associated with a new electricity grid connection, estimated at £5.1M.

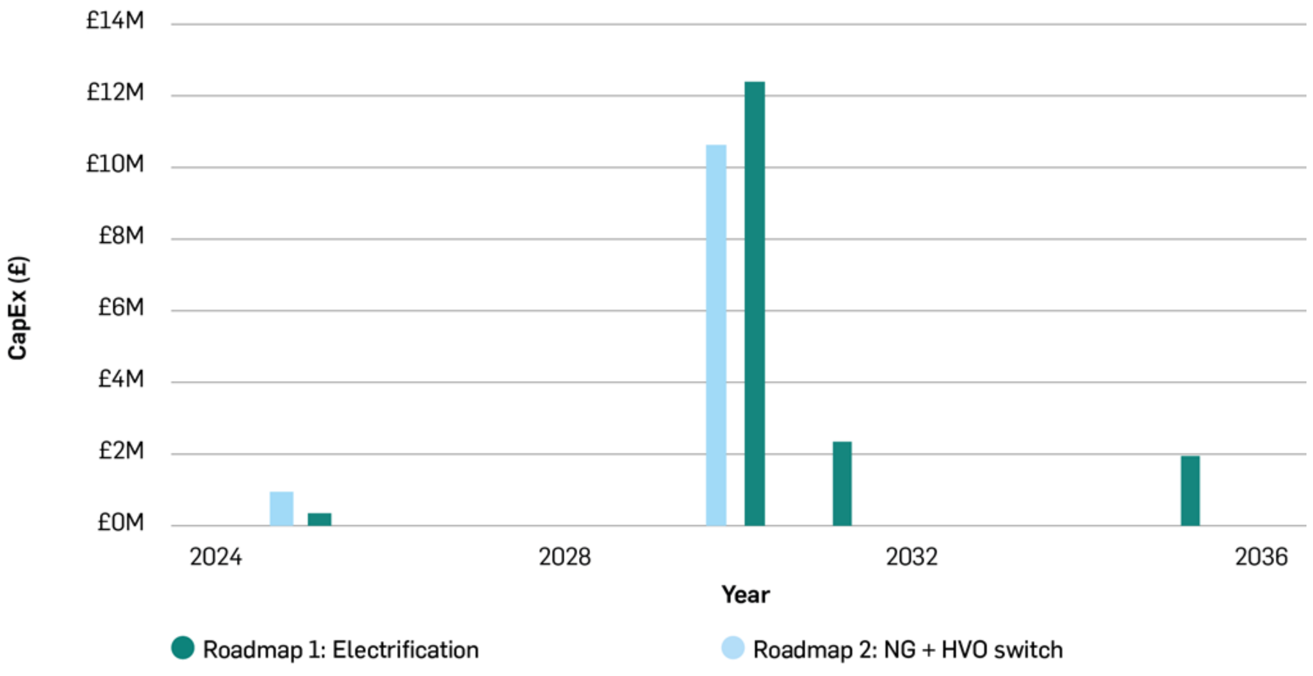


Figure 5-18 – Midland Quarry Products CapEx Distribution: Comparison of Roadmap Options.

Roadmap Options 1 and 2 are projected to lead to a cost saving relative to the BAU forecast OpEx. Roadmap Option 1 has the lowest OpEx in 2050, 39% lower compared to the BAU forecast.

Roadmap Option 2 has a slightly greater OpEx cost in 2050 relative to option 1, 32% lower compared to the BAU forecast.

5.10. FOOD – BRITISH SUGAR

The following section summarises the findings by AtkinsRéalis when considering routes to decarbonisation for British Sugar and their Wissington site. The financial figures included do not represent investment decisions being taken by British Sugar. The assumptions listed in section 2 should also be considered. All figures are advisory based on analysis undertaken at the time, various factors will affect the figures presented and further analysis is required before any investment decisions are taken.

5.10.1. British Sugar Summary of Roadmaps

British Sugar's Wissington site supplies customers throughout the UK with white sugar as a bagged or bulk crystal product, or in the form of a liquid sugar, along with producing several products/coproducts. The total baseline emissions for British Sugar, Wissington, using a baseline year of September 2017 through to August 2018, were 299,000 tCO_2/y, of which 298,000 tCO_2/y were scope 1 emissions resulting largely from the use of natural gas on-site in the CHP and directly for processes. As the site's CHP generates much of the electricity demand, only a small amount of electricity is imported to site, resulting in the remaining 1,000 tCO_2/y scope 2 emissions.

Two potential decarbonisation roadmap options are presented for the British Sugar, Wissington site, primarily based around the decommissioning of the site's CHP, installation of either electrode or hydrogen boilers and the use of renewable electricity generation. Both roadmap options modelled would meet the 2025 net carbon emission reduction target of 20% and the 2050 target of a 90% net carbon emission reduction.

Roadmap Option 1 (featuring electrification, a switch to natural gas in the lime kiln, installation of wind turbines and a process modification for the drying of sugar beet pulp) would achieve a similar, albeit slightly lower level of decarbonisation (94% by 2050) than Roadmap Option 2. However, this roadmap provides decarbonisation earlier and therefore provides a more significant reduction in total CO_2 emissions in the study period.

For this option, an increase in OpEx would be seen but is lower than the hydrogen roadmap. CapEx is estimated to be £154.5M (excluding grid connection and infrastructure upgrades). The overall cost of abatement is expected to be £94/tCO_2, and payback would not be achieved by 2050.

Roadmap Option 2 presents the greatest level of decarbonisation (99% by 2050), where key natural gas assets undergo a fuel switch to hydrogen, requiring the decommissioning of the site's CHP and installation of hydrogen-ready boilers, and land owned by British Sugar is utilised for wind generation. This roadmap also utilises on-site modular AD, and biogas produced is then used in a fuel switch for the lime kiln. This however gives a significant increase in site OpEx with total CapEx estimated at £90.5M (excluding grid connection and infrastructure upgrades). The overall cost of abatement is expected to be £21/tCO_2, and payback is not expected to be achieved by 2050.

Several key considerations were noted in the development of the roadmap options for British Sugar:

- Considerable changes to electricity demand and/or generation on-site are expected to necessitate a new grid connection, which is expected to contribute considerable additional CapEx and may present a roadblock for site electrification or installation of renewables. This is particularly true for Roadmap Option 1, which is more ambitious in its required infrastructure upgrades.
- The site is not located near any of the Track 1 industrial clusters and 50 miles from the nearest site (Bacton) identified in the East Coast Cluster feasibility study[14]. This will impact on the feasibility of Roadmap Option 2, which requires a supply of hydrogen to the site.
- The high level of decarbonisation achieved by Roadmap Option 2 also relies upon a fuel switch from blue hydrogen to green hydrogen being possible, as blue hydrogen does not have enough decarbonisation potential alone, due to associated residual scope 2 carbon emissions.
- There are further considerations for Roadmap Option 2 that are not accounted for within the outputs of the IDT, involving the loss of revenue from the sugar beet pulp, and the electricity generated by AD.

14 Track 1 clusters refer to those planned to be completed by the mid-2020s [21], see section 6.3 for further information.

5.10.2. British Sugar Key Findings: Policy Considerations

5.10.2.1. UK ETS

If the UK ETS carbon price becomes higher than modelled, this will make decarbonisation measures more competitive. Changes to the taxing of electricity versus gas may cause the price ratio to narrow more than modelled, making electrification more competitive. In addition, increasing renewable generation on the grid could start to drive down the price of grid electricity. Any government subsidies would also impact the choice of direction if either electricity or hydrogen were to be cost subsidised.

5.10.2.2. Hydrogen versus Electrification

British Sugar's decarbonisation efforts are heavily dependent on national policy. The government are looking to formalise hydrogen subsidies through a CfD framework (although this is yet to be confirmed), however similar funding to alleviate the charges on grid electricity has not been announced. This means that payback associated with electrification is often longer than for hydrogen alternatives. However, the lack of certainty regarding hydrogen infrastructure in the UK and the site's remoteness from Track 1 hydrogen clusters means that the ultimate feasibility of this option at the timescales suggested in this report is not clear.

5.10.3. British Sugar Key Findings: Cluster Access

The nearest connection point for hydrogen in the East Coast Cluster project is provisionally identified as Bacton (approximately 50 miles from site).

Evidently, the dates for which the site may be connected to a hydrogen pipeline are very uncertain and therefore British Sugar's ability to forward-plan if Roadmap Option 2 is selected may be limited.

5.10.4. British Sugar Key Findings: Sub-Metering

British Sugar's Wissington site is generally already well-metred across site, however steam production metering data were not available for this study meaning steam production from the CHP had to be estimated by summing all process steam data. It may therefore be helpful for any future studies if the site were to meter steam at the point of production.

5.10.5. British Sugar Key Findings: Permitting Requirements

The additional permitting requirements summarised in section 6.5 must be considered for Roadmap Option 2 due to the use of hydrogen. Roadmap Option 1 is expected to have no/minimal additional permitting requirements compared to current site operations. Renewable installations must comply with local permitting and planning requirements.

5.10.6. British Sugar Key Findings: Key Roadblocks

5.10.6.1. DNO Issues

The local DNO is UK Power Networks, and they are responsible for granting permission for connection of new generation sources to the grid and grid upgrades. Both roadmap options result in considerable changes to the site demand and/or generation. It is expected that new connections to the grid would be required to accommodate these changes at least in Roadmap Option 1.

For Roadmap Option 1, an extra 90 MW capacity of electrical supply to site would be necessary to facilitate electrification. Therefore, based on an estimated new connection cost of £300-450/kW, the resultant costs are estimated to be £27M - £40.5M. Government support with covering these costs would help facilitate the decarbonisation of site.

At this stage, for Roadmap Option 2, it has been assumed that the peak export requirement of 42 MW from wind could be accommodated for within the site's existing export limits. However further study of the roadmap (to consider the effects of the anaerobic digestion, AD, plant on export requirements) is necessary.

Grid connection costs can vary significantly depending on several factors, mostly dictated by the state of the grid in the local area. Early engagement with the DNO is advisable.

5.10.6.2. Hydrogen Transport Availability

British Sugar is located approximately 50 miles from the nearest provisional connection point in the East Coast Cluster project. Roadmap Option 2 is dependent on the availability of transport and storage technologies off-site for blue or green hydrogen. Should this not be possible, this will pose a major roadblock to decarbonisation in Roadmap Option 2, provided these options are selected for implementation.

5.10.6.3. Fuel Costs

Both roadmap options result in OpEx increases compared to BAU, due to the higher cost of hydrogen and electricity relative to natural gas. This means that the interventions do not have payback. This could be improved if government shift tax from electricity to gas or subsidise electricity or hydrogen. Uncertainties around this will likely delay any investment decision from British Sugar.

5.10.7. British Sugar Feasibility of Roadmaps

Two decarbonisation pathways were produced for British Sugar, Wissington. Both roadmaps have significant uncertainties in their timescales, primarily concerning grid infrastructure upgrades for Roadmap Option 1 and hydrogen transportation infrastructure upgrades for Roadmap Option 2. Both options presented feature the decommissioning of the sites CHP and the installation of on-site renewable electricity generating assets to reduce increased electricity import requirements introduced through interventions.

Roadmap Option 2 ultimately has a slightly greater decarbonisation potential by 2050 compared to Roadmap Option 1. However, Roadmap Option 1 has the overall greater decarbonisation potential in the years up to 2050, as it achieves significant reductions earlier. Both roadmap options would comfortably meet the 2050 target of a 90% reduction in emissions. Through the energy efficiency projects planned by British Sugar for 2023, both roadmaps also meet the 20% emissions reduction target in 2025. Figure 5-19 presents a comparison of the carbon emissions forecasted for the BAU operation of site and Roadmap Options 1 and 2.

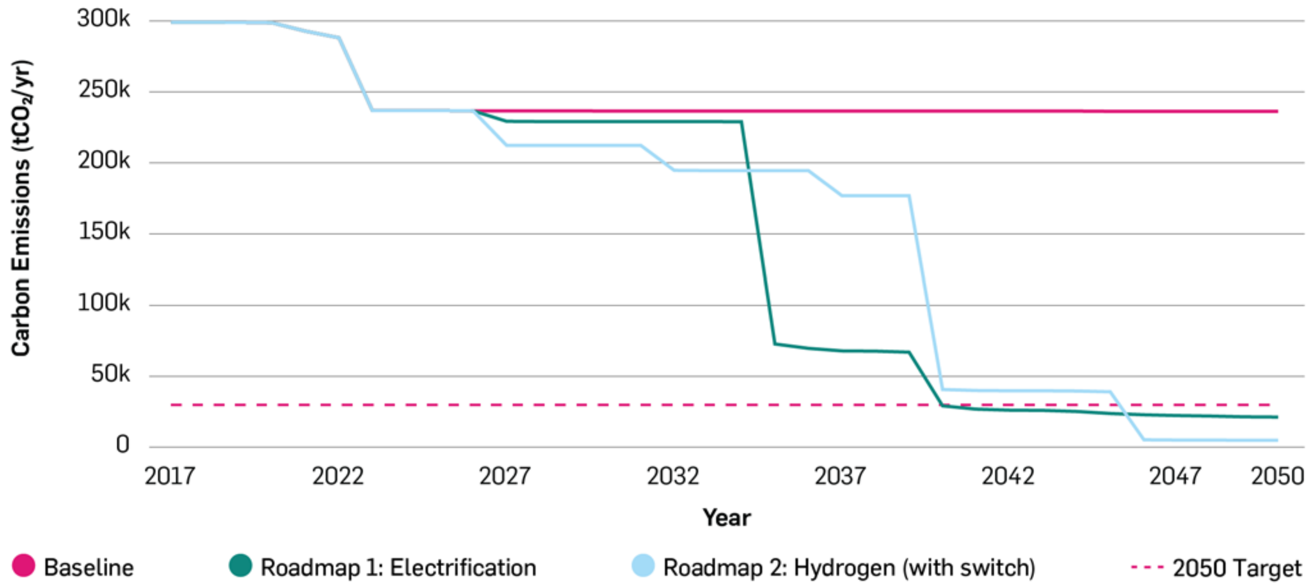


Figure 5-19 – British Sugar Carbon Emissions: Comparison of Roadmap Options.

All roadmap options are deemed technically feasible at proposed year of install with respect to TRL.

British Sugar has a large amount of land available for the siting of on-site renewable energy, however the sizes of interventions considered have high associated CapEx. Whilst direct purchase and installation of wind turbines was assumed, direct wire PPA options would also be a possible consideration for British Sugar.

Both electric and electrode boilers have a TRL of 9, with commercially deployed large scale units in operation globally, particularly where electricity costs are competitive. Hydrogen boilers are currently at a TRL of 7-8 with full deployment in the UK provisionally expected from 2032. Hydrogen and electrode boiler interventions are however planned for 2035 and 2040 respectively and are therefore assumed to be at a sufficient level of deployment for use on-site.

Throughout the IFP, biogas was not considered as a viable industry-wide alternative to natural gas or processed fuel oil in the UK. However, British Sugar has readily available sugar beet pulp which can be used as a feedstock for AD plants. British Sugar also have experience operating such plants at their Bury St Edmunds site.

For all intervention technologies, intervention dates applied within this study are provisionally aligned considering both equipment TRL and supporting infrastructure.

Based on costs included within the IDT only, Roadmap Option 2 has lower CapEx compared to Roadmap Option 1. However, as can be seen in Table 5-10, when including those interventions which are not costed within the IDT itself and required infrastructure upgrades, the estimated CapEx for both roadmaps are of similar magnitude.

Table 5-10 – British Sugar Key Metrics for Roadmap Options 1 and 2.

	CO_2 Emissions in 2050 ($ktCO_2$/y) (% change)	CapEx (£M)*	Estimated Total CapEx** (£M)	Abatement Cost (£/tCO_2)*	Payback Period (years)*
Roadmap Option 1	**16.8 (-94%)**	154.5	181.8 – 195.5	94	-
Roadmap Option 2	**4.3 (-99%)**	90.5	190.7 – 190.9	21	-

* Costed within IDT.

** CapEx including grid connection and infrastructure upgrades. Does not include CapEx for lime kiln modifications that may be required to enable a fuel switch in either roadmap.

When considering OpEx however, Roadmap Option 1 appears more attractive than Roadmap Option 2. In 2050, OpEx for both roadmap options is expected to be higher than the BAU forecast, with Roadmap Option 2 being the highest.

Furthermore, due to the distance of the British Sugar, Wissington site from Track 1 industrial clusters and the associated uncertainty of when a supply of hydrogen would be available to site, Roadmap Option 1 may be preferable to the site even though there is a forecast OpEx increase.

5.11. FOOD – HEINZ

The following section summarises the findings by AtkinsRéalis when considering routes to decarbonisation for Heinz and their Kitt Green site. The financial figures included do not represent investment decisions being taken by Heinz. The assumptions listed in section 2 should also be considered. All figures are estimated and advisory based on analysis undertaken at the time, various factors will affect the figures presented and further analysis is required before any investment decisions are taken. Heinz recognises the value of the Roadmap exercise with BEIS and will continue to develop the decarbonisation pathway as more technology and opportunities become available.

A late review of scope 1 and 2 emissions by Heinz identified errors in those used throughout process modelling for this exercise. The data provided by Heinz in 2022 at the start of the programme did not come from the validated authorised system. The difference in scope 1 emissions is relatively marginal (additional 2,000 tCO_2 per annum). The difference in scope 2 emissions was 10,000 tCO_2 lower. Despite the larger difference in scope 2 emissions, the impact is relatively minimal, given the predicted greening of the electrical grid through to 2035. Unfortunately, the difference was not identified in time to accommodate the correction in the roadmap modelling, however, the modelling outputs remain accurate to the basis provided herein.

5.11.1. Heinz Summary of Roadmaps

The Heinz Kitt Green site in Wigan manufactures canned soups, baked beans, pasta and snap pots for the UK and European market; the Kitt Green site is the largest food manufacturing facility in Europe.

The total baseline emissions for Heinz, using 2021 as the baseline year, were 45,100 tCO_2/y, of which 38,200 tCO_2/y were scope 1 emissions resulting from the use of natural gas fired boilers, with the remaining 6,900 tCO_2/y scope 2 emissions resulting from the import of electricity to site.

Due to the lack of energy use data provided, two high-level decarbonisation roadmaps were produced for the Heinz Kitt Green site, based mainly on fuel switching by replacement of the existing natural gas assets, with either hydrogen or electric alternatives. Both options presented also feature a small amount of on-site renewable electricity generation. No options modelled would meet the 2025 net carbon emission reduction target of 20%, with both meeting the 2050 target of a 90% net carbon emissions reduction.

Roadmap Option 1 features full electrification and achieves a similar, albeit slightly lower, level of decarbonisation than Roadmap Option 2 (97% by 2050), noting that this could achieve a 100% reduction if a potential solar VPPA was entered into. For this option, at end of programme scope in 2050, the OpEx increase would be comparatively lower. CapEx for electrode boilers is lower than for hydrogen-ready boilers, and not accounting for any infrastructure upgrades, Roadmap Option 1 has an associated CapEx of £5.7M. The total cost of abatement is estimated to be £121/tCO_2, and payback is not expected to be achieved. However, electrification requires significant infrastructure upgrades to support interventions on-site. This may impact dates provisionally identified and will require significant additional CapEx to facilitate. This means the total CapEx for Roadmap Option 1 may be considerably higher than the CapEx associated with Roadmap Option 2.

Roadmap Option 2 presents the greatest level of decarbonisation (99% by 2050), where key natural gas assets are switched to hydrogen, requiring the installation of hydrogen-ready boilers, and on-site space is utilised for solar generation. This however gives a significant increase in site OpEx with total CapEx (excluding on-site infrastructure upgrades) estimated at £20.0M. The total cost of abatement is estimated to be £153/tCO_2, and payback is not expected to be achieved. The high level of decarbonisation achieved by Roadmap Option 2 depends upon a switch from blue hydrogen to green hydrogen, as blue hydrogen does not have the decarbonisation potential alone, due to associated residual scope 2 carbon emissions.

5.11.2. Heinz Key Findings: Policy Considerations

5.11.2.1. UK ETS

If the UK ETS carbon price becomes higher than modelled, this will make decarbonisation measures more competitive with the BAU case. Changes to the taxing of electricity versus gas may cause the price ratio to narrow more than modelled, making electrification more competitive.

5.11.2.2. Hydrogen versus Electrification

Heinz, Kitt Green is already in formal agreement to work with HyNet North-West to potentially supply hydrogen to site whereas upgrades to the grid supply to site needed to facilitate electrification of site may not be achievable in the medium term. The government are looking to formalise hydrogen subsidies through a CfD framework (although this is yet to be confirmed), however similar funding to alleviate the charges on grid electricity has not been announced. This means that payback associated with electrification is often longer than for hydrogen alternatives. However, increasing renewable generation on the grid could start to drive down the price of grid electricity.

5.11.3. Heinz Key Findings: Cluster Access

The Heinz, Kitt Green site has already formally agreed to work with the nearest low carbon cluster (Hynet North-West). As such, availability of a hydrogen or CO_2 pipeline on-site is a likely possibility within the timeframe of the roadmaps. CCUS was deemed less suitable for the site regardless of cluster access as CCUS should only be considered if implementation of other options higher in the decarbonisation hierarchy is not possible. However, availability of hydrogen on-site is key to the viability of Roadmap Option 2, which involves replacement of existing natural gas boilers on-site with hydrogen-ready boilers.

5.11.4. Heinz Key Findings: Sub-metering

Sub-metering could be improved across the site, as the required granularity required to conduct this study was missing in areas, hence only high-level roadmaps have been produced. Additional monitoring could also help facilitate energy efficiency projects on-site:

- Monitoring of electricity use by motors on-site would aid strategic installation of VSDs.

5.11.5. Heinz Key Findings: Permitting Requirements

The additional permitting requirements summarised in section 6.5 must be considered for Roadmap Option 2 due to the use of hydrogen. Roadmap Option 1 is expected to have no/minimal additional permitting requirements compared to current site operations. Renewable installations must comply with local permitting and planning requirements.

5.11.6. Heinz Key Findings: Key Roadblocks

5.11.6.1. DNO Issues

The local DNO is Electricity North-West and they are responsible for granting permission for connection of new generation sources to the grid and grid upgrades.

Both roadmap options would result in considerable changes to the site demand and generation. It is expected that new connections to the grid would be required to accommodate these changes, with Roadmap Option 1 being the more ambitions.

For Roadmap Option 1, an extra 37 MW capacity of electrical supply to site is necessary to facilitate electrification. Therefore, based on an expected cost for a new connection of £300-450/kW, the resultant costs are estimated to be £11.9M-£17.8M. This would pose a significant roadblock to the electrification of site. Upgrades to internal infrastructure are also likely to be necessary.

Grid connection costs can vary significantly depending on several factors, mostly dictated but the state of the grid in the local area. Early engagement with the DNO is advisable.

5.11.6.2. Hydrogen Transport Availability

Heinz is part of the Hynet North-West low carbon cluster. Roadmap Option 2 is dependent on the availability of transport and storage technologies off-site for concentrated blue or green hydrogen. Should this not be possible, this will pose a major roadblock to decarbonisation in Roadmap Option 2, provided this option is selected for implementation.

5.11.6.3. Fuel Costs

Both roadmap options would result in OpEx increases compared to BAU, due to the higher cost of hydrogen and electricity relative to natural gas. This means that the interventions do not have payback. This could be improved if government shift tax from electricity to gas or subsidise electricity or hydrogen. Uncertainties around this will likely delay any investment decision from Heinz.

5.11.7. Heinz Feasibility of Roadmaps

Two decarbonisation pathways were produced for Heinz, Kitt Green. Both roadmap options incorporate on-site solar installations and employ a fuel switch to replace the existing natural gas assets. For Roadmap Option 1, this fuel switch is via the full electrification of site whereas Roadmap Option 2 employs a fuel switch to hydrogen.

Both roadmap options would exceed the 2050 target of a 90% reduction in emissions, whilst missing the 20% emissions reduction target in 2025. Figure 5-20 presents a comparison of the carbon emissions forecasted for the BAU operation of site and Roadmap Options 1 and 2. The comparison also shows the forecasted carbon emissions for Roadmap Option 2 if just blue hydrogen was used, with no switch to green before 2050.

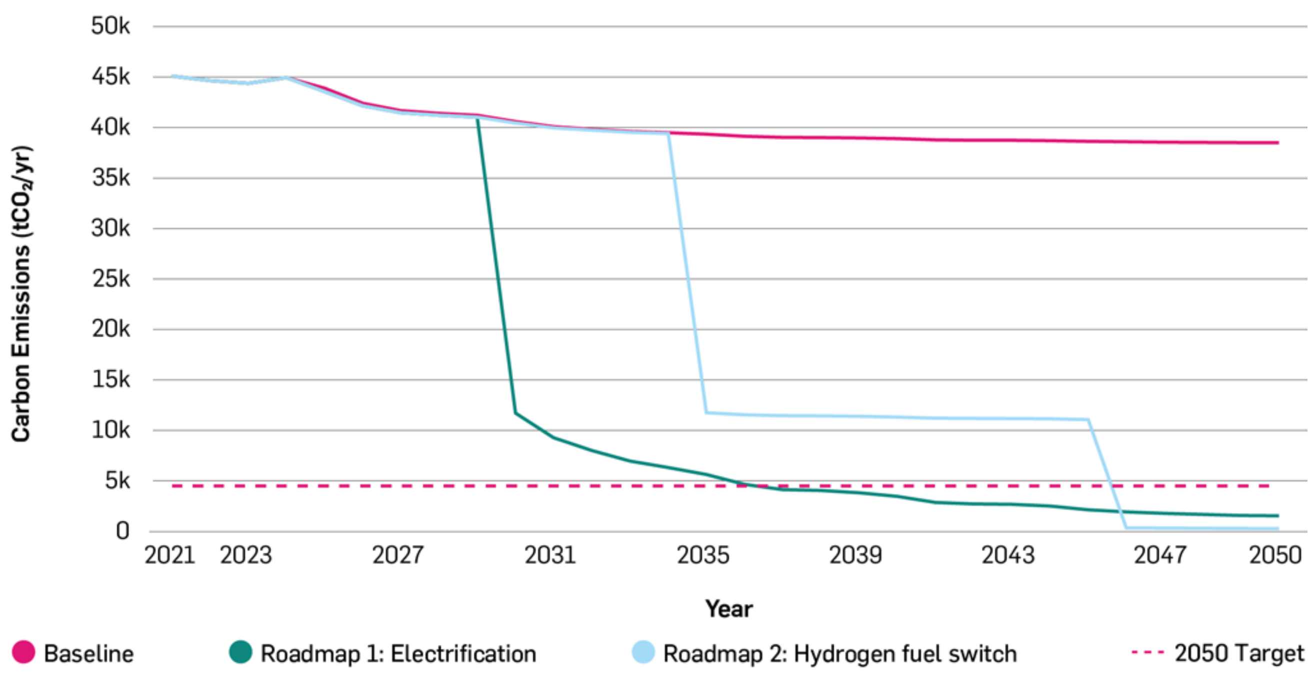


Figure 5-20 – Heinz Carbon Emissions: Comparison of Roadmap Options.

Both roadmap options are deemed technically feasible at proposed year of install with respect to TRL.

Heinz, Kitt Green has a high electrical demand compared to the available land identified suitable for renewable energy. Utilising the land available on-site for renewable energy would result in displacing less than 6% of the site's current annual electrical demand. Off-site renewables may be accessed by a potential VPPA, of which Heinz have indicated their intention to partake in, and should the replacement of any on-site buildings occur, the potential for roof-mounted solar array could be considered to increase capacity of on-site renewable generation.

Both electric and electrode boilers have a TRL of 9, with commercially deployed large scale units in operation globally, particularly where electricity costs are competitive. Hydrogen boilers are currently at a TRL of 7-8 with full deployment in the UK provisionally expected from 2032. The electrode boiler intervention is planned for 2030, and the hydrogen boiler for 2035 and it is therefore assumed that technology will be at a sufficient level of deployment for use on-site.

For all intervention technologies, intervention dates applied within this study are provisionally aligned considering both equipment TRL and supporting infrastructure.

Roadmap Option 2 would achieve the greatest level of decarbonisation due to green hydrogen having zero scope 2 emissions as it is modelled to be generated from 100% renewable electricity whilst grid electricity in Roadmap Option 1 still has minimal scope 2 emissions.

However, Roadmap Option 1 is modelled to deliver carbon savings significantly sooner and would result in the lowest total cumulative emissions up to 2050.

The roadmaps do not take account of potential energy efficiency projects planned for the Kitt Green site before 2025, or the VPPA which Heinz plans on entering before this date. Considering both, the emissions reduction by 2025 would be higher and the 20% emissions reduction target in 2025 may well be met by both roadmap options with Roadmap Option 1 also achieving full decarbonisation by 2030.

Whilst Roadmap Option 2 has the greatest decarbonisation potential, it also has the greatest cost, both in terms of CapEx and OpEx. The required infrastructure upgrades to enable the increased on-site electricity demand for Roadmap Option 1 are significant, however they represent lower costs overall versus CapEx and OpEx of Roadmap Option 2. When considering the infrastructure upgrades required, Roadmap Option 2 may be more feasible, as Heinz, Kitt Green is already in formal agreement to work with HyNet North-West to supply hydrogen to site.

Table 5-11 summarises the key parameters for comparing the feasibility of the roadmap options. The CapEx amounts stated here include estimates of the infrastructure upgrade costs (to present a fairer comparison between the two roadmap options).

Table 5-11 – Heinz Key Metrics for Roadmap Options 1 and 2.

	CO_2 Emissions in 2050 ($ktCO_2$/y) (% change)	CapEx (£M)*	CapEx including Additional Infrastructure Upgrades (£M)	Abatement Cost (£/tCO_2)*	Payback Period (years)*
Roadmap Option 1	**1.5 (-97%)**	5.7	17.6 – 23.5	121	-
Roadmap Option 2	**0.3 (-99%)**	20.0	20.2 – 20.3	153	-

*Costed in IDT.

5.12. WATER – UNITED UTILITIES

The following section summarises the findings by when considering routes to decarbonisation for United Utilities and their Davyhulme site. The financial figures included do not represent investment decisions being taken by United Utilities. The assumptions listed in section 2 should also be considered. All figures are advisory based on analysis undertaken at the time, various factors will affect the figures presented and further analysis is required before any investment decisions are taken.

Within the Industry of Future Programme, the Davyhulme Wastewater Treatment Works site is in the unique position of being a current producer of biogas. The modelling of Roadmap Option 2 for the Davyhulme site has assumed this biogas is available to the site at zero cost, resulting in a substantial decrease to site operating costs compared to using imported fuels, e.g. natural gas. No consideration has been given to the existing financial value being realised from the biogas being used in CHP generation. Therefore, the actual cost benefit of moving to biogas use in boilers will result in a loss of financial benefit as CHP engine output will be reduced. Therefore, the savings against operating cost and abatement cost would not be as substantial as presented here and could represent an overall increase in costs.

5.12.1. United Utilities Summary of Roadmaps

United Utilities' Davyhulme site processes raw sewage from the whole of the western side of Manchester, from Chadderton in the north to Bramhall in the south, as well as the Trafford Park industrial area, with a total population equivalent of 1.2 million. United Utilities' Davyhulme site is divided into two facilities, the Wastewater Treatment Works (WwTW) and the Manchester Bioresources Centre (MBC).

The 2022 Financial Year has been taken as the scope 1 and 2 emissions baseline year for this study. The site emits considerable biogenic emissions that are out of scope of the BEIS IFP (see section 2).

The total baseline CO_2 emissions for the site are 5,800 tCO_2/y, of which 4,600 tCO_2/y are scope 1 emissions resulting from on-site process and 1,200 tCO_2/y are scope 2 emissions, with the remaining emissions from biogenic processes on-site which were estimated.

Three decarbonisation roadmap options were produced for United Utilities. The first centred around installing new blue hydrogen CHP engines and boilers in 2040, coupled with installation of CCUS in 2030. The second involves fuel switching from natural gas to biogas for the site's boilers in 2025. The third considers the use of off-site renewables through a PPA in 2030 and the electrification of the boilers in 2035. No energy efficiency measures were included in the roadmap options due to the extensive work completed by United Utilities in this field to date.

Roadmap Option 1, CCUS and new blue hydrogen boilers and CHPs, would not result in the 2050 emissions target being met. By 2050 a 28% increase in emissions would be expected due to the scope 2 emissions associated with blue hydrogen. The option requires comparatively high CapEx of £40.8M. Due to the predicted cost of hydrogen far exceeding the cost of natural gas, the OpEx would increase from the BAU. A very high abatement cost is expected (£35,580/tCO_2) and payback would not be achieved.

Only **Roadmap Option 2**, fuel switching the natural gas boilers to biogas, meets the 2050 BEIS IFP target, with a total reduction of 98% by 2050. The relatively low CapEx associated with this option is £0.3M for ancillary equipment required to enable the fuel switching process. The OpEx following the implementation of the fuel switching would be significantly lower than the BAU forecast therefore the overall cost of abatement is expected to be -£101/tCO_2 and payback would be achieved in less than one year.

Roadmap Option 3, boiler electrification and solar PPA, presents an option which only meets the final 2050 emissions reduction target with a total of 94% emissions mitigated. The CapEx associated with his option is £4M which is relatively low due to the use of PPA. OpEx increase from the BAU baseline is seen from the implementation of this option. A high abatement cost is expected 1,868/tCO_2 and payback would not be achieved.

The biogenic source of United Utilities' biogas fuel allows the site to discount most the fuel's carbon emissions. The CapEx and OpEx from biogas fuel switching are significantly lower than the BAU as well as the other two options presented. Therefore, based on currently available information from United Utilities, biogas fuel switching would most effectively decarbonise United Utilities Davyhulme and MBC. Ultimately, United Utilities will need to continue engaging with trials to ensure that their decision-making is underpinned with robust technical evidence.

Several key considerations were noted in the development of the roadmap options for United Utilities:

- United Utilities Davyhulme and MBC emit a significant number of out-of-scope emissions due to the biogenic sources and emissions out of scope of the remit of this programme.
- Carbon emissions emitted from the combustion of biogas are significantly underestimated.
- The United Utilities site has land availability issues due to its location situated within the boundaries of local housing and the Manchester water way.
- Considerable changes to electricity demand and/or generation on-site are not expected to necessitate a new grid connection due to sites requirement for redundancy for the CHP engines as United Utilities Davyhulme is a 24 hours a day operating plant.
- A biogas fuel switch is not suitable for widespread UK industrial decarbonisation but presents a promising bridging option as the OpEx costs associated with biogas are not considered due to the site producing their own fuel.
- HyNet Clusters accessible to United Utilities supply blue hydrogen, whereas green hydrogen would be the optimal choice of fuel in the future.

5.12.2. United Utilities Key Findings: Policy Considerations

5.12.2.1. UK Emissions Trading Scheme

See section 6.6.3 for an overview of the UK ETS. The scheme currently applies to sites with 20 MW or more of stationary combustion plant on-site once all individual units are aggregated together.

United Utilities and other water industry sites are not currently part of the UK ETS. The UK government have committed to expanding the scope of the scheme in future and are currently consulting on what this expansion could look like. Lowering of the 20 MW threshold and removal/amendment of the <3 MW aggregation clause are both being considered. If this expansion occurs, United Utilities' Davyhulme site, among other sites not currently in the scheme, may be exposed to carbon taxation. This will provide a significant additional financial incentive to decarbonise.

5.12.2.2. OFWAT Regulation

The water industry is a regulated sector, governed by the Water Services Regulation Authority (OFWAT). There is also a responsibility to the environment, and the Environment Agency detail any new consents required to protect local watercourses, bathing waters, and other receiving waters following any new legislation. Changes in regulation could result in changes to carbon and greenhouse gas emissions through the need for new process stages to be implemented to ensure tightened consents are met. Currently carbon emissions from biogenic sources are out of scope and unaccounted for in terms of decarbonisation in the water industry, despite accounting for a significant proportion of site emissions. The capture of these emissions could generate a negative carbon source for the area as United Utilities will not be able to account for their capture. A change in policy would be required for this to be addressed across the water industry in their reported emissions.

5.12.2.3. Water Industry Context

United Utilities alongside the other water and sewage companies in England and Wales work within 5-year Asset Management Plan (AMP) periods under OFWAT regulations. The next AMP period is AMP8 2025 – 2030 and there are anticipated changes which will see tighter constraints placed on discharge of phosphorus and other substances. Moreover, this will potentially result in the need for expansion of existing processes or new asset installations. This may impact the site's already limited land availability for new decarbonisation processes as indicated in the roadmap for this study.

The Davyhulme MBC site is not a typical example of a biosolids treatment plant as there are limited sites with both ADs, a thermal hydrolysis process, and multiple dewatering processes. Additionally, the Davyhulme site's direct scope 1 and 2 emissions are significantly lower than many other plants of this size, due to substantial efficiency and decarbonisation upgrades which have already been completed and the use of biogenically produced fuels used in their CHP engines.

In terms of future opportunities of note, a few the existing CHP engines will be coming to the end of their asset life during the upcoming AMP and will either require a direct replacement or an alternative technology to replace the current units, which will be considered as part of the following roadmaps.

5.12.2.4. Hydrogen versus Electrification or CCUS

As mentioned above, United Utilities' decarbonisation efforts are heavily dependent on national policy and industry specific technology developments supporting the circular economy. Despite this, the lack of certainty regarding hydrogen infrastructure in the UK means that United Utilities are not clear on the direction that new technology will take and will continue to struggle to make informed forecasts or investment decisions. Any such decisions are likely to be postponed until government policy is formalised. As a byproduct of wastewater treatment is biogas production, electrification of the site replacing current biogas CHP generation units would require an alternative outlet to be available for the biogas created. As CCUS options become more viable and able to address nutrient recovery and net zero requirements in other areas of the sector, decarbonisation through electrification would begin to look more attractive.

5.12.3. United Utilities Findings: Cluster Access

United Utilities are in the Northwest of England. The Davyhulme and MBC site is approximately 8 km from the proposed HyNet for blue hydrogen. The nearest cluster for carbon storage is still 28 km away from the site. There are significant routing roadblocks resulting from housing and built-up areas around the vicinity.

There is an opportunity to negotiate support from the government's CCUS programme for sites capable of deploying CCUS technology by 2030. There is currently also some level of negative public perception to overcome regarding the capture and reuse of CO_2 from wastewater and biosolids sources.

5.12.4. United Utilities Key Findings: Sub-metering

United Utilities already has extensive sub-metering across the Davyhulme site. This has previously allowed the operational staff to target efficiency and asset optimisation resulting in significant power savings. Even though considerable monitoring exists, there is a significant amount of metering missing on the heat usage and requirements, which would add value to the site and allow further efficiency optimisations in future.

5.12.5. United Utilities Key Findings: Permitting Requirements

Davyhulme is classed as a COMAH lower tier site due to the quantities and nature of substances stored such as chemicals and biogas. The additional permitting requirements summarised in section 6.5 must be considered for hydrogen (Roadmap Option 1) and CCUS (Roadmap Option 2). Roadmap Option 3 is expected to have no/minimal additional permitting requirements compared to current site operations. Renewable installations must comply with local permitting and planning requirements.

5.12.6. United Utilities Key Findings: Key Roadblocks

5.12.6.1. DNO Issues

The local DNO, Electricity North-West, is responsible for granting permission for connection of new generation sources to the grid and grid upgrades. Roadmap Option 1 and 3 would result in considerable changes to the site electricity demand and generation. It is not, however, expected that a new connection to the grid would be required to accommodate these changes.

5.12.6.2. Carbon and Hydrogen Transport and Availability

United Utilities is located less than 8 km from the proposed HyNet infrastructure and 28 km from the nearest carbon storage cluster. Roadmap Options 1 and 2 are dependent on the availability of transport and storage technologies off-site for blue or green hydrogen. Should this not be possible, this will pose a major roadblock to decarbonisation in Roadmap Options 1 and 3, provided these options are selected for implementation. Longer term CCUS interventions are reliant on finding a potential outlet for the separated biogas constituents, of methane and CO_2.

5.12.6.3. Fuel Costs

Roadmap Options 1 and 3 would result in OpEx increases compared to BAU, due to the higher cost of hydrogen and electricity relative to biogas and biogas generated electricity. This means that the interventions do not payback. This could be improved if government shift tax from electricity to gas or subsidise electricity or hydrogen.

5.12.7. United Utilities Feasibility of Roadmaps

Three decarbonisation pathways were produced for United Utilities at Davyhulme and MBC. Each roadmap option has significant uncertainties in timescales for connection and gas transportation infrastructure upgrades. All options presented feature combinations of on-site and off-site renewable electricity generating assets to reduce both existing and increased electrical import requirements introduced through interventions. Roadmap Option 2 has the greatest decarbonisation and carbon abatement potential.

Energy efficiency measures have been very effective in reducing site electricity consumption as demonstrated in the last 10 years and similar efficiencies should be considered for application in the wider water industry elsewhere.

Only Roadmap Option 2 would meet the 2025 net carbon emission reduction target of 20% with an 88% reduction increasing to a 99% reduction by 2050. The performance of the three roadmap options are shown in Figure 5-21. The carbon abatement from Roadmap Option 2 is the most effective. This, however, underestimates the overall carbon on-site and more specifically the emissions produced by combustion.

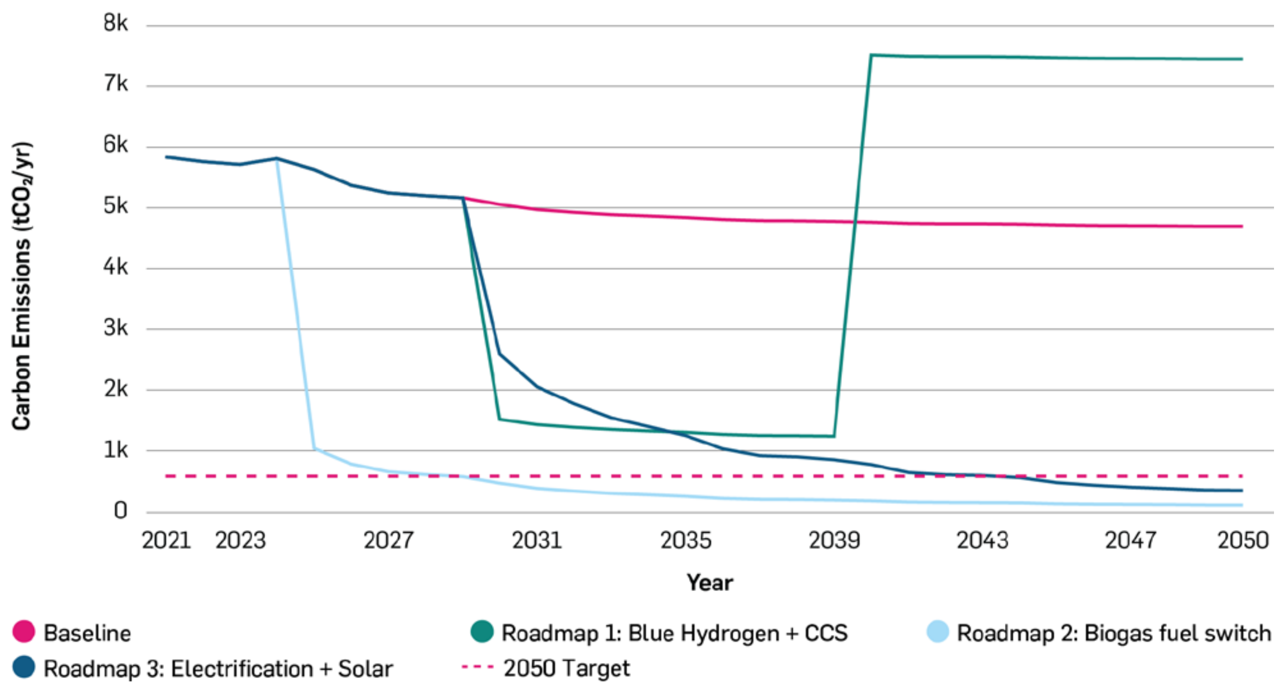


Figure 5-21 – United Utilities Carbon Emissions: Comparison of Roadmap Options.

All roadmap options are deemed technically feasible at proposed year of install with respect to TRL.

United Utilities' Davyhulme and MBC site has a high electrical demand compared to the available land identified suitable for renewable energy. Utilising the land available on-site is not an option as this may be required for future expansion of site processes to meet new regulations and permit requirements. For the purposes of Roadmap Option 3, it has been assumed that off-site renewables may be accessed by PPAs.

Electric boilers have a TRL of 9, with commercially deployed large scale units in operation globally, particularly where electricity costs are competitive. Hydrogen boilers are currently at a TRL of 7-8 with full deployment in the UK provisionally expected from 2032. Hydrogen boiler interventions are not necessarily aligned with the end of United Utilities' CHP fleet asset life, as assets will start to require replacement from 2027 onwards. The TRL is assumed to be at a sufficient level of deployment for use on-site.

For carbon capture technology implemented within this study, a TRL of 7-9 is currently estimated, as relatively few projects have been implemented at industrial sites globally. Installation and operation of a carbon capture plant is expected to require risk assessment and operator training, with the greatest impact on the site operating state. Detailed engineering design with vendor support is strongly advised to assess scale, performance, suitable capture media, downstream processing and risks due to higher relative process complexity. Alternative water industry focused CCUS technology may be more appropriate with a TRL of 9 but no large-scale deployments are currently in operation in the UK. It is anticipated this will change during the next few years.

For all intervention technologies, intervention dates applied within this study are provisionally aligned considering both equipment TRL and supporting infrastructure. The CapEx for Roadmap Option 2 is expected to be considerably lower than Options 1 and 3 (see Table 5-12 and Figure 5-22).

Table 5-12 – United Utilities Key Metrics for Roadmap Options 1-3.

	CO_2 Emissions in 2050 ($ktCO_2$/y) (% change)	CapEx (£M)	Abatement Cost (£/tCO_2)	Payback Period (years)
Roadmap Option 1	7.4 (28%)	40.8	35,580	-
Roadmap Option 2	0.1 (-98%)	0.3M	-101	1
Roadmap Option 3	0.4 (-94%)	4	1,868	-

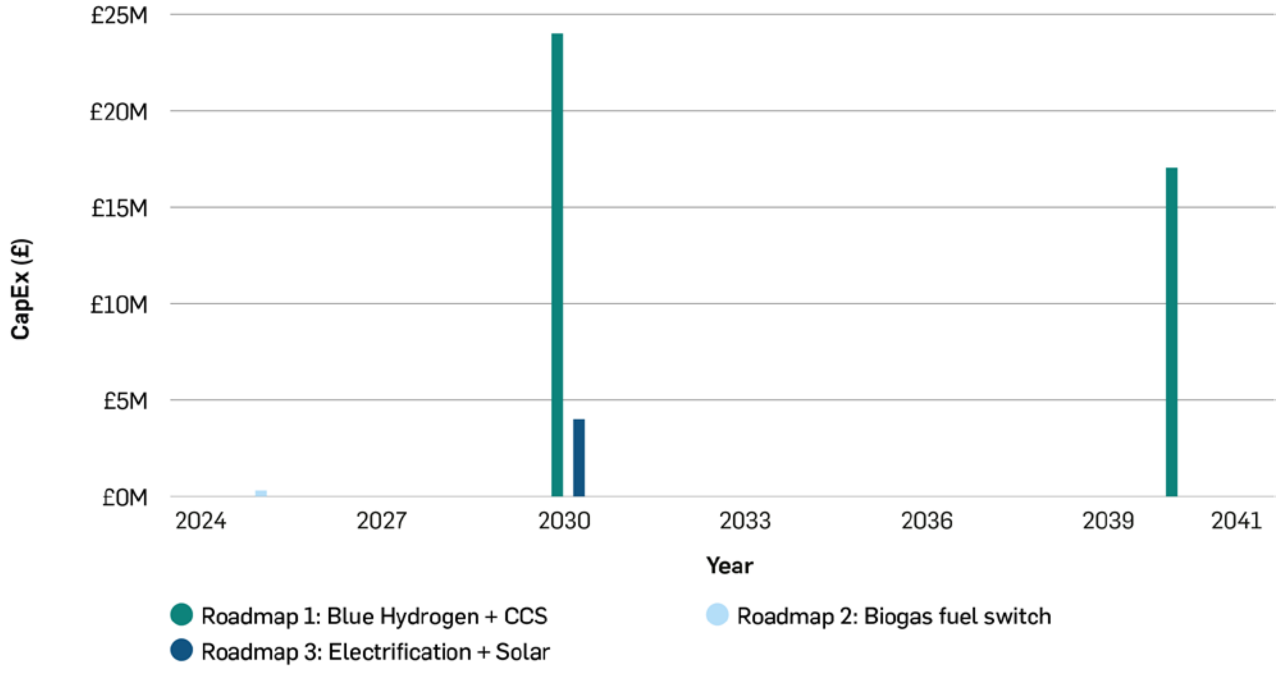


Figure 5-22 – United Utilities CapEx Distribution: Comparison of Roadmap Options.

5.13. NORTHERN IRELAND – ALMAC

The following section summarises the findings by AtkinsRéalis when considering routes to decarbonisation for Almac and their site in Craigavon. The financial figures included do not represent investment decisions being taken by Almac. The assumptions listed in section 2 should also be considered. All figures are advisory based on analysis undertaken at the time, various factors will affect the figures presented and further analysis is required before any investment decisions are taken.

5.13.1. Almac Summary of Roadmaps

Almac Group is a global leader in providing a range of expert services and support across the drug development lifecycle to pharmaceutical and biotech companies and is headquartered in Craigavon, Northern Ireland. The site makes use of dual-fuel boilers across several buildings on-site to provide heating services. Electricity is also used on-site for lighting of buildings and outside areas.

The total baseline emissions for Almac Craigavon, using 2020 as the baseline year, were 11,900 tCO_2/y, of which 6,500 tCO_2/y were scope 1 emissions from the use of dual-fuel boilers across several buildings on-site to provide heating services. These boilers use natural gas as the main heating asset, with 35-second oil as a back-up fuel source. The other 5,400 tCO_2/y were scope 2 emissions, from electricity import used on-site for lighting of buildings and outside areas. CO_2¬ emissions are expected to rise to 14,700 tCO_2/y in 2024, following completion of a new building on site.

Four decarbonisation roadmap options were presented to the Almac Group. The options are focused on renewable installation and site electrification, and include:

- **Roadmap Option 1:** installation of solar PV and complete electrification of the site via heat pumps and electric boilers.
- **Roadmap Option 2:** installation of solar PV and replacement of primary fuel usage with heat pumps, retaining oil boilers as back-up.
- **Roadmap Option 3:** installation of off-site wind and replacement of primary fuel usage with heat pumps, retaining oil boilers as back-up.
- **Roadmap Option 4:** installation of solar PV and replacement of primary fuel usage with heat pumps utilising heat recovery from chillers on-site.

Roadmap Option 1 would achieve a 97% reduction in CO_2 emissions, exceeding the BEIS 90% decarbonisation target. Solar PV cells are installed in 2026, in-line with the completion of the new building, whilst the dual-fuel boilers are replaced with heat pumps and electric boilers as required, based on their expected end-of-life. Once all installation is complete, it is expected Roadmap 1 would result in emissions being reduced to 389 t/CO_2 in 2050. Roadmap Option 1 would require the lowest CapEx of all roadmap options presented to Almac, at £10.4M. OpEx is expected to increase above the BAU forecast by 2050. The overall abatement cost is expected to be £53/tCO_2 and payback is not expected to be achieved by 2050.

Roadmap Option 2 would result in a marginally lower level of decarbonisation due to the retainment of oil boilers as back-up heating assets, resulting in 646 tCO_2 emissions in 2050 (95% reduction compared to the baseline). Roadmap Option 2 also requires a higher CapEx of £12.8M due to oil boilers having a higher CapEx per MW than electric boilers. OpEx is expected to increase above the BAU forecast by 2050. The overall abatement cost is expected to be £66/tCO_2, again not resulting in payback.

FOR PUBLICATION

Roadmap Option 3 would produce a similar level of decarbonisation to Roadmap Option 1 through the utilisation of two wind installations in 2034 and 2050, resulting in 382 tCO_2 in 2050 (97% reduction). This wind installation matches the predicted increased electrical demand of the site following replacement of dual-fuel boilers with electric heat pumps. However, this is for a much-increased CapEx of £44.1M. A significant OpEx saving is produced with this option, following the installation of both wind renewables interventions. However, the overall cost of abatement is still expected to be positive at £13/tCO_2, not resulting in payback.

Roadmap Option 4 would produce a similar level of decarbonisation to Roadmap Option 2 reaching 95% decarbonisation by 2050 (emissions would be 637 tCO_2 in 2050). This demonstrates that recovery of waste heat would offer minimal decarbonisation benefit. CapEx would be higher compared to Roadmap Option 2, at £14.4M, due to the use of waste heat pumps instead of air-source heat pumps. OpEx savings relative to the BAU forecast are expected by 2050. Again, the overall cost of abatement is still expected to be positive at £65/tCO_2, not resulting in a payback.

Several key considerations were noted in the development of the roadmap options for Almac:

- The Almac Group's current exclusion from UK ETS (due to site size, see section 6.6.2) means there is currently no financial incentive for decarbonisation of the site. However, the site may qualify for inclusion following governmental review.
- It is anticipated that installation of renewable electricity generation will not be possible until the local electricity grid has been upgraded, this is reliant on the local DNO Northern Ireland Electricity (NIE). See section 6.6.1 for further detail.
- Considerable changes to electricity demand and/or generation on-site are expected to necessitate a new grid connection, which is expected to contribute considerable additional CapEx and may present a roadblock for site electrification and installation of renewables.
- It is not currently possible to export additional generation from renewables back to the Northern Ireland grid, meaning all generation not used on-site must be curtailed. This limits the feasibility of large renewable installations, without additional measures being introduced such as obtaining a VPPA or forming a joint cluster with companies in the area.
- Planning permission for installation of renewables can be difficult to obtain in Northern Ireland, which may delay the installation of interventions.

5.13.2. Almac Key Findings: Policy Considerations

See section 6.6.3 for an overview of the UK ETS. The scheme currently applies to sites with 20 MW or more of stationary combustion plant on-site once all individual units are aggregated together. Many smaller industrial sites (such as Almac) are currently not included. The UK government have committed to expanding the scope of the scheme in future and are currently consulting on what this expansion could look like. Lowering of the 20 MW threshold and removal/amendment of the <3 MW aggregation clause are both being considered. If this expansion occurs, Almac among other sites not currently in the scheme may be exposed to carbon taxation. This will provide a significant additional financial incentive to decarbonise, however, due consideration must be given to the revisions and ensure small businesses finances are not stretched, as they are unlikely to possess the economic resilience of larger competitors.

5.13.3. Almac Key Findings: Cluster Access

There are currently no hydrogen or CCUS clusters located in Northern Ireland, and there are no plans for development and installation of these networks. Neither hydrogen nor CCUS were suitable for the site regardless of cluster access.

5.13.4. Almac Key Findings: Sub-metering

Almac has sub-metering across the site, allowing for the identification of future optimisation opportunities.

5.13.5. Almac Key Findings: Permitting Requirements

None of the roadmap options are expected to have additional permitting requirements compared to current site operations. Renewable installations must comply with local permitting and planning requirements.

5.13.6. Almac Key Findings: Key Roadblocks

5.13.6.1. DNO Issues

The local DNO, NIE, is responsible for granting permissions for connection of new generation sources to the grid and grid updates. NIE have stated that, due to the uptake in renewables in the area, new applicants must be aware of the current fee to connect to the grid, as well as the timescale of the grid connection [20]. This may be prohibitive to all potential roadmaps. As such, Almac may have limited autonomy over installation of renewables for all roadmap options.

Alongside issues with grid connection, it is not currently possible to export additional generation in Northern Ireland due to grid constraints, therefore requiring all generation not used on-site to be curtailed. This limits the feasibility of large renewable installations due to the significant CapEx incurred for a lower carbon benefit than expected. Planning permission for installation of both ground-mounted and solar carports can also be difficult to obtain in Northern Ireland, delaying the installation of interventions, and jeopardising the feasibility of installation on-site.

Almac have previously raised that they foresee problems sourcing expertise in the installation and maintenance of heat pumps for industrial sites, with only a few individuals in Northern Ireland able to properly implement this technology. This lack of suitable proficiency means sites including Almac are less confident in installing heat pumps as their primary heating asset, in case of any incident occurring which would require heat pump maintenance.

5.13.6.2. Grid Connection Costs

Considerable changes to electricity generation and/or demand are likely to necessitate a new or upgraded electric grid connection. Grid connection upgrade costs are expected to be £300-450/kW. The upper bound was used as the local electricity grid is known to be constrained. The cost of this is expected to be considerable, estimated at £8.8M for Roadmap Options 1 and 2, £18.5M for Roadmap Option 3 and £9.7M for Roadmap Option 4. Evidently, these additional costs present a barrier to site decarbonisation. It should be noted that grid connection costs are highly-site specific and subject to discussion with the DNO. Early engagement with the DNO is advisable.

5.13.7. Almac Feasibility of Roadmaps

5.13.7.1. Scenario Comparison

Four decarbonisation roadmaps were produced for Almac. Each roadmap options has significant uncertainties in timescales for grid connection. All options present renewable electricity generating assets to reduce both existing and increased electrical import requirements introduced through new buildings. All options also utilise electrified assets to replace fuel-based alternatives.

None of the options modelled would meet the net carbon emissions reduction target of 20% by 2025. However, all roadmaps are expected to meet the 90% decarbonisation target of 2050. The performance of the four roadmap options presented are shown in Figure 5-23.

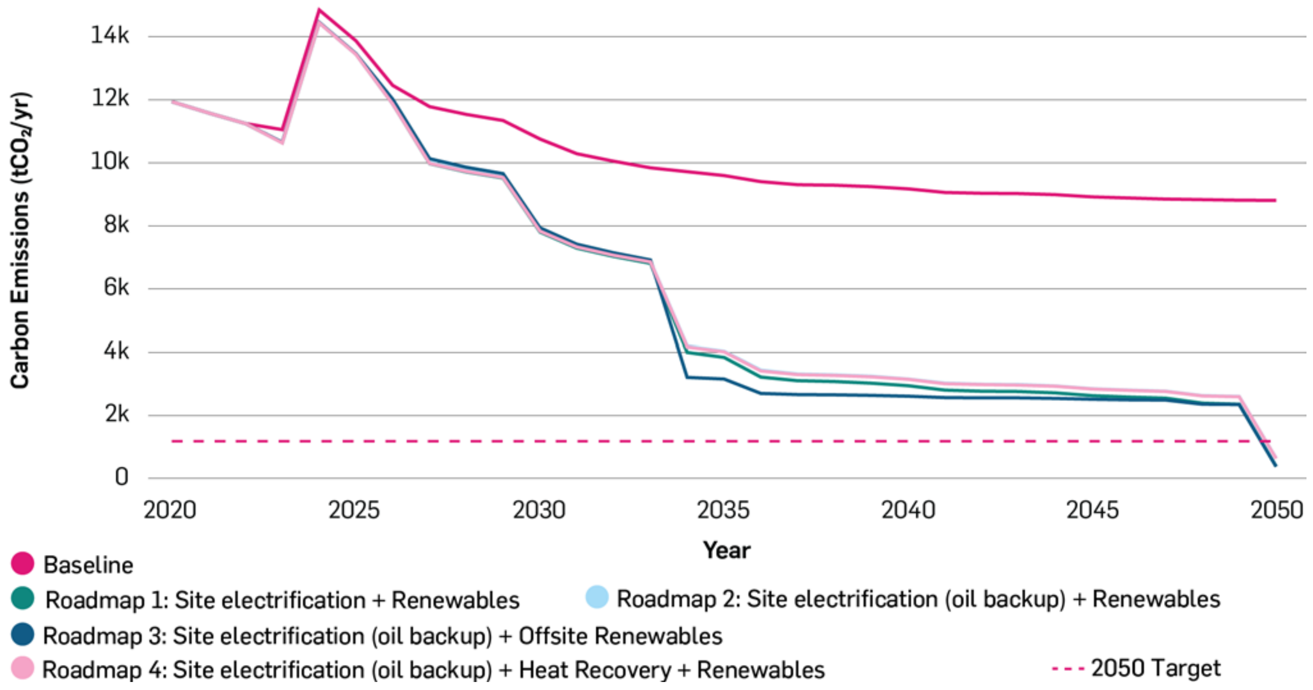


Figure 5-23 – Almac Carbon Emissions: Comparison of Roadmap Options.

All options are deemed technically feasible at proposed year of install with respect to TRL.

Almac has a higher electrical demand compared to the land identified suitable for renewable energy. Utilising the land available on-site would not result in matching site demand. However, implementation of on-site solar would result in a sizeable reduction in emissions, as demonstrated in Roadmap Option 1. Off-site renewables may be accessed through obtaining a VPPA or forming a joint cluster with other companies on the industrial park.

Air source heat pumps are TRL 9 and are often used commercially, for either 60°C or 80°C systems (the 60°C technology has been selected for the Almac roadmaps, based on the current boiler system). These have been selected to replace the dual-fuel boilers as primary heating assets, removing the natural gas heating requirement for the site. This technology is highly efficient compared to boiler technology, and therefore is considered technically feasible for the site.

Electric boilers have a TRL of 9, with commercially deployed large scale units in operation globally, particularly where electricity costs are competitive. These will be used as back-up heating assets, in Roadmap Option 1, to replace the dual-fuel boilers, removing the 35-second oil heating requirement for the site. This technology also has a greater efficiency when compared to the equivalent natural gas boiler and is considered feasible for deployment following end of life of the current boilers.

Waste heat recovery heat pumps considered in the roadmaps are TRL 6-9 and available largely within demonstration projects at waste heat temperatures greater than 90°C and commercially deployed for temperatures less than 90°C. It was considered technically feasible to install heat pumps which use waste heat from the chillers on-site as input to provide heat in the form of steam.

All presented roadmaps are expected to reach 90% decarbonisation by 2050, saving between 11,300 and 11,600 tCO_2 in 2050 when compared to the baseline, dependent on the roadmap option. As all sites use heat pumps, and the final installation date for the new build heat pump is assumed to be 2050, none of the roadmaps reach minimum carbon emissions until this replacement has taken place. Key metrics are displayed in Table 5-13.

Table 5-13 - Almac Key Metrics for Roadmap Options 1-4.

	CO_2 Emissions in 2050 ($ktCO_2$/y) (% change)	CapEx (£M)	Abatement Cost (£/tCO_2)	Payback Period (years)
Roadmap Option 1	**0.4 (-97%)**	10.4	53	-
Roadmap Option 2	**0.6 (-95%)**	12.8	66	-
Roadmap Option 3	**0.4 (-97%)**	44.1	13	-
Roadmap Option 4	**0.6 (-95%)**	14.4	65	-

All roadmaps are expected to fall short of the 2025 BEIS 20% decarbonisation target due to the new building coming online in 2024 assumed to be using the same dual-fuel (natural gas/35 sec oil) boilers. However, all roadmaps are expected to succeed in meeting the 2050 BEIS target, exceeding 90% reduction in carbon emissions by 2050.

All roadmap options would have a positive abatement cost, which means investment in decarbonisation would not have a finite payback time via reduced OpEx. CapEx for all roadmaps is presented in Figure 5-24.

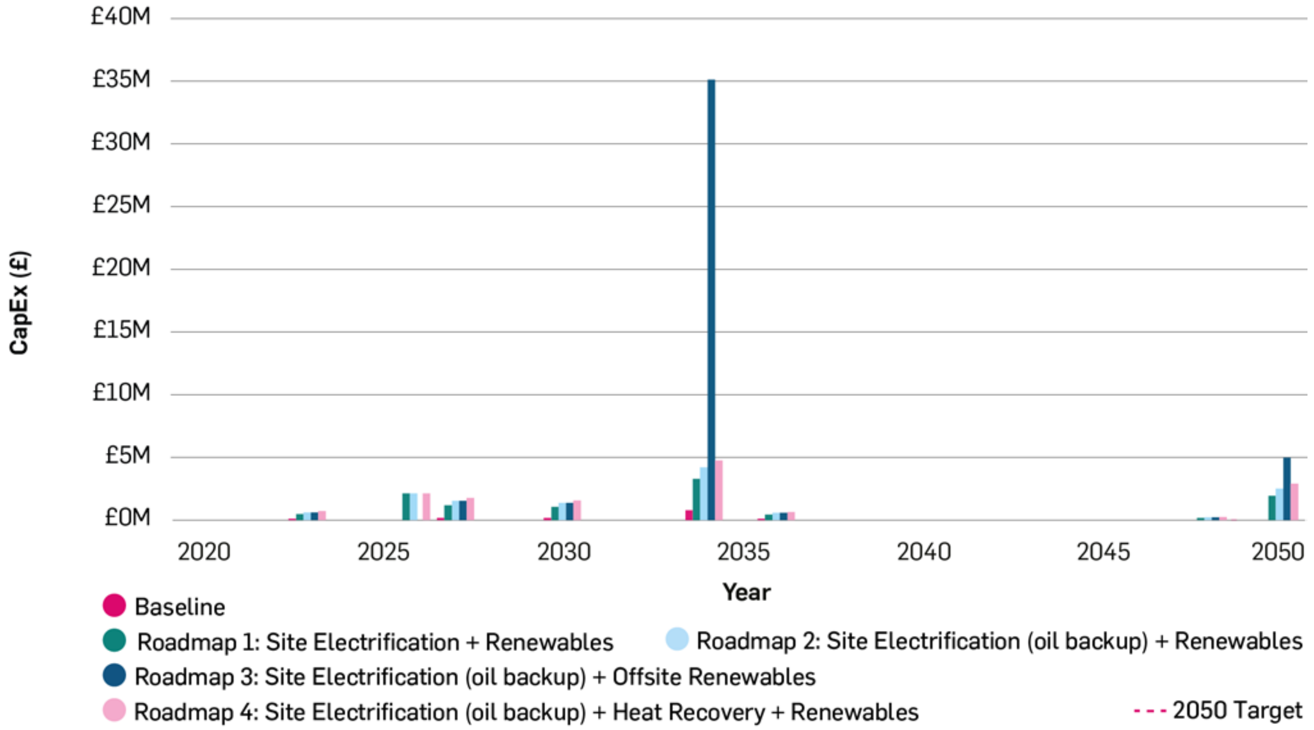


Figure 5-24 – Almac CapEx Distribution: Comparison of Roadmap Options.

Figure 5-24 demonstrates the major cost variation between the solar and wind installations, with the wind spike in CapEx in 2034 massively exceeding the CapEx of any other intervention. Roadmap Option 1 would have the lowest upfront cost at £10.4M, due to the relatively low-cost of electric boilers when compared to oil boilers. Roadmap Option 3 has the highest upfront cost at £44.1M due to the two-phase wind installation. The slight increase in waste heat pump CapEx compared to air source heat pumps CapEx is also demonstrated in Figure 5-24, displayed by the slightly increased upfront cost of Roadmap Option 4 compared to Roadmap Option 2.

All roadmaps would majorly exceed the baseline CapEx, that would be seen through like-for-like replacements of the dual-fuel boilers on-site. Based on these metrics, it is suggested that Almac should investigate further funding streams, to help their chosen decarbonisation route become more financially viable in the long-term.

Roadmap Options 1 and 2 would require marginally higher OpEx than the baseline, resulting in the site paying more in OpEx for new installations compared to BAU. Both roadmaps aim for partial to full electrification of the site, increasing site electricity demand and requiring increased import from the grid, where electricity pricing currently exceeds natural gas pricing per MWh. However, it is worth noting that there may be major shifts in electricity pricing, due to the increasing number of lower cost renewables on the grid, and potential changes to taxation of natural gas, making electrification of heat more economical.

Roadmap Option 4 would require slightly lower OpEx than the baseline, due to the reduction in electricity import because of implementing waste heat recovery. Roadmap Option 3 is the major outlier of those presented, with OpEx costs dramatically decreasing in 2034 following the installation of the first wind intervention. As grid electricity import is majorly reduced, alongside site electrification, OpEx remains low until 2050, after which they drop further following the second wind installation.

5.13.7.2. Plot Areas Available

Installation of wind or solar off-site is essential to reduce the electricity import requirement of the site and make the otherwise costly heat electrification more affordable. As such there needs to be suitable space off-site that can sufficiently house the wind turbines or solar panels. Based on modelling, installing sufficient turbines to meet the site demand would require approximately 585,000 m² of space accounting for both the 2037 and 2050 installations. For solar, approximately 23,200 m² would be required. As shown in Figure 5-25, there is space available a short distance of 280 m away from the site. Field A has an area of approximately 145,000 m², making it well suited to provide generation for the site using solar PV. This does not sufficiently meet the area required for the wind installation, however, there are numerous other fields located close-by, adding up to a total space of 1,160,000 m² which is sufficient to house the renewables. However, due to their further distance away and location on the other side of the river, these will incur a larger cabling and infrastructure cost. It is worth noting that this feasibility study has not investigated the CapEx and possibility of purchasing this land from the owners. There is also a site of special scientific interest (SSSI) in the vicinity which would need to be considered in any further feasibility studies.

Figure 5-25 – Almac Site Map Showing the Potential Off-site Location of Wind Turbines.

Obtaining the land shown in Figure 5-25 may prove unfeasible for the site, either due to a high CapEx required to obtain it or due to owners being unwilling to sell. As such there are alternative methods that the site could proceed with, such as obtaining a VPPA or forming a joint cluster to share a set of renewables with other companies on the industrial park. This avoids special constraints for the renewables and so would allow Almac to reduce its scope 2 emissions without using land space near site and having to invest capital.

Forming a cluster with other companies on the industrial park would allow the joint companies to split the initial CapEx of the development between them and likewise split the electrical generation between the companies. This would save on curtailed generation as there would always be electrical demand. This is particularly effective for Northern Ireland where no export capacity is available.

5.13.7.3. Sensitivity Analysis

At the request of the Almac, a sensitivity analysis was performed.

The IDT used electricity costs based on the current HM Treasury Green book values to calculate financial metrics.

However, due to recent events, these values have been called into question, being significantly lower than costs currently experienced by industry. Therefore, a sensitivity analysis of the payback times for each intervention has been completed, using an estimated electricity price of £0.30/kWh, as used at other sites in the area for predictive uses. This is displayed in Table 5-14.

Table 5-14 – Almac Sensitivity Analysis: Simple Payback Time.

Roadmap	Simple Payback Time (years)	
Pricing	Green Book Electricity Price	2022 Electricity Price (£0.30/kWh)
Solar Carport (North)	18	6
Solar Carport (East)	15	5
Solar Carport (South)	15	5
New Build roof	10	3

5.13.7.4. External Infrastructure Electrification

Prior to installation of interventions as seen in the roadmaps presented to Almac, the capacity of external grid connections must be increased for additional generation.

It was estimated that this could incur a cost of between £300-450/kW of extra capacity required. This was calculated based on a High-Intermediate-Low costing scale for both wind and solar interventions. The results can be seen in Table 5-15.

Table 5-15 – Almac External Infrastructure Electrification: Additional Capacity Cost.

Intervention	Additional Capacity Required (kW)	Low (£300/kW)	Intermediate (£375/kW)	High (£450/kW)
Roadmap Options 1 and 2	19,600	5.88M	7.35M	8.82M
Roadmap Option 3	41,100	12.3M	15.4M	18.5M
Roadmap Option 4	21,500	6.45M	8.06M	9.68M

5.14. NORTHERN IRELAND – DERRY REFRIGERATED TRANSPORT

The following section summarises the findings by AtkinsRéalis when considering routes to decarbonisation for Derry Refrigerated Transport and their site in Craigavon. The financial figures included do not represent investment decisions being taken by Derry Refrigerated Transport. The assumptions listed in section 2 should also be considered. All figures are advisory based on analysis undertaken at the time, various factors will affect the figures presented and further analysis is required before any investment decisions are taken.

5.14.1. Derry Refrigerated Transport Summary of Roadmaps

Derry Refrigerated Transport distributes chilled and frozen food products, operating from its offices and cold store warehouse, located in Craigavon, County Armagh, Northern Ireland.

The total baseline emissions for Derry Refrigerated Transport, using 2021 as the baseline year, were 360 tCO_2/y, predicted to increase to 362 tCO_2/y in 2025 following an extension to the Carn Cold Store facility. As the logistics/transportation of goods fell outside the programme scope, the modelling focuses on the decarbonisation of the offices, staffrooms, canteen, and Carn Cold Store facility, of which the only energy asset use is electricity for lighting, heating, and refrigeration purposes. Due to this, the site produces no scope 1 emissions, with the entirety of their scope 2 emissions resulting from the use of grid electricity. Derry Refrigerated Transport aims to reduce its CO_2 emissions by 90% by 2050, in-line with BEIS targets.

Four decarbonisation roadmap options were produced for Derry Refrigerated Transport. **Roadmap Option 1** centred around the use of an on-site solar installation. **Roadmap Option 2** focussed on the use of off-site wind installation. **Roadmap Options 3 and 4** both used the respective installations in combination with lithium-ion battery technology to allow storage of peak generation outputs and avoid curtailment.

For **Roadmap Option 1**, the BEIS 90% decarbonisation target would be exceeded, with a 95% reduction in CO¬2 emissions due to a combination of on-site electricity generation and grid decarbonisation, with the site producing 17 tCO_2 in 2050. Roadmap Option 1 would also require the lowest CapEx of all roadmap options, at £0.5M but an OpEx saving is expected relative to the BAU case, due to the reduction in grid electrical import. As a result, the overall cost of abatement is expected to be -£805/tCO_2 and payback would be achieved in approximately 10 years.

Roadmap Option 2 would result in a higher level of decarbonisation, with a 98% reduction in emissions by 2050 (6.41 tCO_2 in 2050) due to the installation of off-site wind turbines in 2027 meeting site electricity demand. Higher CapEx of £1.7M would be required, however, a greater OpEx saving would be made due to the reduction in grid electrical import. As a result, the overall cost of abatement is expected to be the lowest of all for roadmap options, at -£796/tCO_2, meaning payback would be achieved in approximately 10 years.

Roadmap Option 3, installation of on-site solar PV and lithium-ion battery storage in 2025 and 2027 respectively, would produce a similar decarbonisation effect to Roadmap Option 1, achieving 95% decarbonisation by 2050 (17 tCO_2 in 2050). As only 1% of solar generation would be expected to be curtailed on-site, there is minimal generation for the battery to store, meaning the battery has negligible effect on the site electricity demand. CapEx is expected to be £0.5M and a similar OpEx saving is expected compared to Roadmap Option 1. As a result, the overall abatement cost is expected to be -£744/tCO_2 and payback would be achieved in approximately 11 years.

Roadmap Option 4, installation of off-site wind and battery storage in 2027, would produce a slightly improved decarbonisation effect to Roadmap Option 2, achieving 99% decarbonisation by 2050 (5.3 tCO_2 in 2050). CapEx required would be higher than Roadmap Option 2, at £2.6M, but a greater OpEx saving would be made due to the battery installation limiting grid electrical import further. The overall abatement cost of this option is expected to be the highest of the four options (-£348/tCO_2) but would still achieve payback in approximately 14 years.

Several key considerations were noted in the development of the roadmap options for Derry Refrigerated Transport:

- It is anticipated that installation of renewable electricity generation will not be possible until the local electricity grid has been upgraded. This is reliant on the local DNO. For Derry Refrigerated Transport, this is NIE (see section 6.6.1).
- Considerable changes to electricity demand and/or generation on-site are expected to necessitate a new grid connection, which is expected to contribute considerable additional CapEx and may present a roadblock for installation of renewables.
- It is not currently possible to export additional generation from renewables back to the Northern Ireland grid, meaning all generation not used on-site is to be curtailed. This limits the feasibility of large renewable installations, without additional measures being introduced such as obtaining a VPPA or forming a joint cluster with other companies in the area.
- Planning permission for installation of renewables can be difficult to obtain in Northern Ireland, which may delay the installation of interventions.

5.14.2. Derry Refrigerated Transport Key Findings: Policy Considerations

5.14.2.1. UK ETS

See section 6.6.3 for an overview of the UK ETS. The scheme currently applies to sites with 20 MW or more of stationary combustion plant on-site once all individual units are aggregated together. Many smaller industrial sites (including Derry Refrigerated Transport) are currently not included. The UK government have committed to expanding the scope of the scheme in future and are currently consulting on what this expansion could look like. Lowering of the 20 MW threshold and removal/amendment of the <3 MW aggregation clause are both being considered. If this expansion occurs, Derry Refrigerated Transport among other sites not currently in the scheme may be exposed to carbon taxation. This will provide a significant additional financial incentive to decarbonise, however, due consideration must be given to the revisions and ensure small businesses finances are not stretched, as they are unlikely to possess the economic resilience of larger competitors.

5.14.2.2. Transport Service

Derry Refrigerated Transport have a transport service which fell outside of the scope of the BEIS IFP. Dedicated consideration of decarbonisation of their transport service will be required for the Derry Refrigerated Transport to fully meet Net Zero.

5.14.3. Derry Refrigerated Transport Key Findings: Cluster Access

There are currently no hydrogen or CCUS clusters located in Northern Ireland, and there are no plans available for development and installation of these networks. Neither hydrogen nor CCUS were suitable for the site regardless of cluster access.

5.14.4. Derry Refrigerated Transport Key Findings: Sub-metering

Derry Refrigerated Transport has capacity to submeter electrical load (already installed in switch-room), but it is not currently monitored and therefore has limited impact. The site was notified of the benefits of monitoring the existing metering for future reference.

5.14.5. Derry Refrigerated Transport Key Findings: Permitting Requirements

None of the roadmap options are expected to have additional permitting requirements compared to current site operations. Renewable installations must comply with local permitting and planning requirements.

5.14.6. Derry Refrigerated Transport Key Findings: Key Roadblocks

5.14.6.1. DNO Issues

The local DNO is NIE, and they are responsible for granting permissions for connection of new generation sources to the grid and grid updates. NIE have stated that, due to the uptake in renewables in the area, new applicants must be aware of the current fee to connect to the grid, as well as the timescale of the grid connection [20]. This may be prohibitive to all roadmap options. As such, Derry Refrigerated Transport may have limited autonomy over installation of renewables.

It is not currently possible to export additional generation in Northern Ireland due to grid constraints, therefore requiring all generation not used on-site to be curtailed. This limits the feasibility of large renewable installations due to the significant CapEx incurred for a lower carbon benefit than expected. Planning permission for installation of renewables can also be difficult to obtain in Northern Ireland, this may delay the installation of renewables and bring into question their overall feasibility.

5.14.6.2. Grid Connection Costs

Considerable changes to electricity generation and/or demand are likely to necessitate a new or upgraded electric grid connection. Grid connection upgrade costs are expected to be £300-450/kW. The upper bound is used as the local electricity grid is known to be constrained. The cost of this is expected to be considerable, estimated at £261,000 and £549,000 for Roadmap Options 1 and 3, and Roadmap Options 2 and 4 respectively. Evidently, these additional costs present a barrier to site decarbonisation. It should be noted that grid connection costs are highly-site specific and subject to discussion with the DNO. Early engagement with the DNO is advisable.

5.14.7. Derry Refrigerated Transport Feasibility of Roadmaps

Four decarbonisation roadmaps were produced for Derry Refrigerated Transport. Each roadmap option has significant uncertainties in timescales for grid connection. None of the options modelled are expected to meet the net carbon emission reduction target of 20% by 2025. However, all roadmaps would meet the 90% decarbonisation target of 2050. The performance of the four roadmap options presented are shown in Figure 5-26

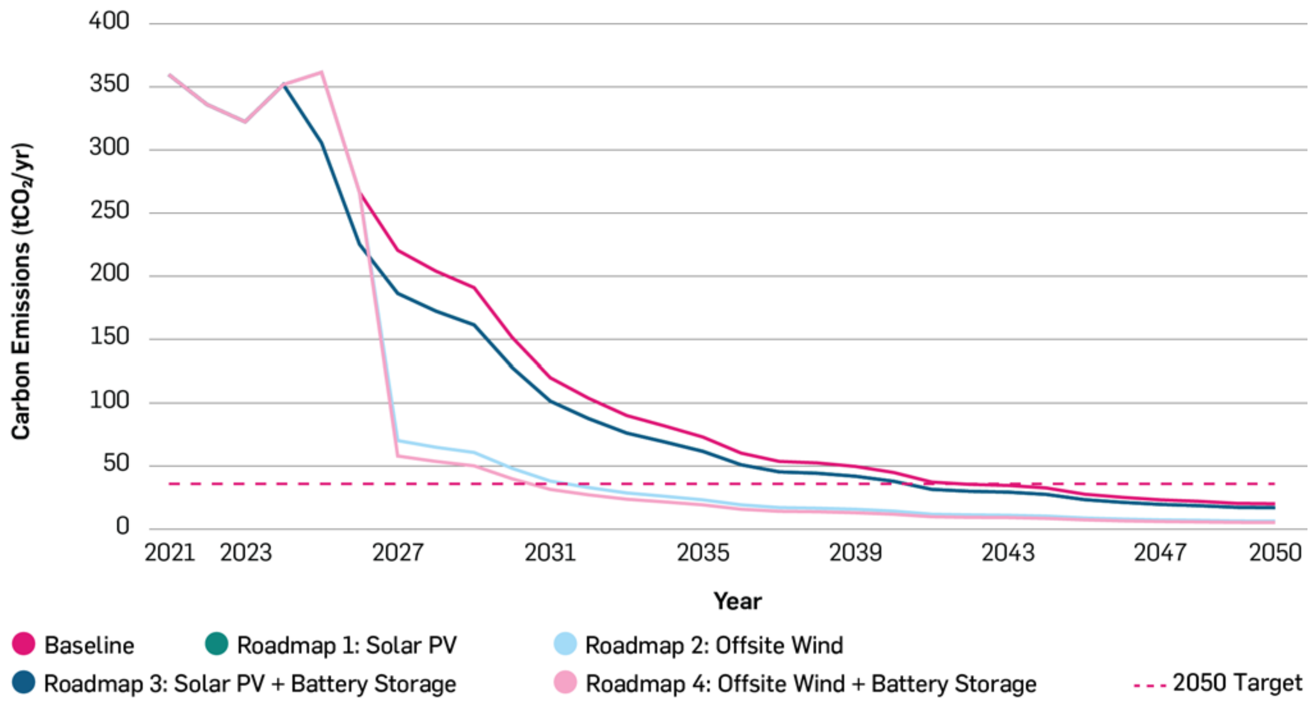


Figure 5-26 – Derry Refrigerated Transport Carbon Emissions: Comparison of Roadmap Options.

All roadmap options are deemed technically feasible at proposed year of install with respect to TRL.

Derry Refrigerated Transport has a higher electrical demand compared to the available land identified suitable for renewable energy. Utilising the land available on-site would not result in matching site demand. However, implementation of on-site solar will result in a sizeable reduction in emissions, as demonstrated in Roadmap 1. Off-site renewables may be accessed through obtaining a VPPA or forming a joint cluster with other companies on the industrial park.

Battery technology has a TRL of 9 and has a high round trip efficiency between 85%-90%. The technology is ideally suited for balancing intra-day peak electrical demands and capturing surplus renewable generation that can be used within the same 24-hour period and are not recommended for weekly or seasonal storage.

Therefore, installation of battery technology was considered worthwhile for use alongside both solar and wind renewable technology, to capture some of the curtailed generation and reduce daily electrical import.

For all intervention technologies, intervention dates applied within this study are provisionally aligned considering both equipment TRL and supporting infrastructure.

Roadmap Options 2 and 4 would produce the fastest decarbonisation, reaching the 90% decarbonisation 2050 target between 2031 and 2032. As the wind intervention present in Roadmap Options 2 and 4 reduces the electricity import value to negligible amounts during normal generation periods, any scope 2 emissions linked to electricity import decrease to zero after installation. Roadmap Options 1 and 3 would take longer to result in decarbonisation, with the 2050 target met between 2040 and 2041. Key performance metrics are displayed in Table 5-16.

Table 5-16 – Derry Refrigerated Transport Key Metrics for Roadmap Options 1-4.

	CO_2 Emissions in 2050 ($ktCO_2$/y) (% change)	CapEx (£M)	Abatement Cost (£/tCO_2)	Payback Period (years)
Roadmap Option 1	**0.0 (-95%)**	0.5M	-805	10.3
Roadmap Option 2	**0.0 (-98%)**	1.7M	-796	10.0
Roadmap Option 3	**0.0 (-95%)**	0.5M	-744	10.9
Roadmap Option 4	**0.0 (-99%)**	2.6M	-348	13.7

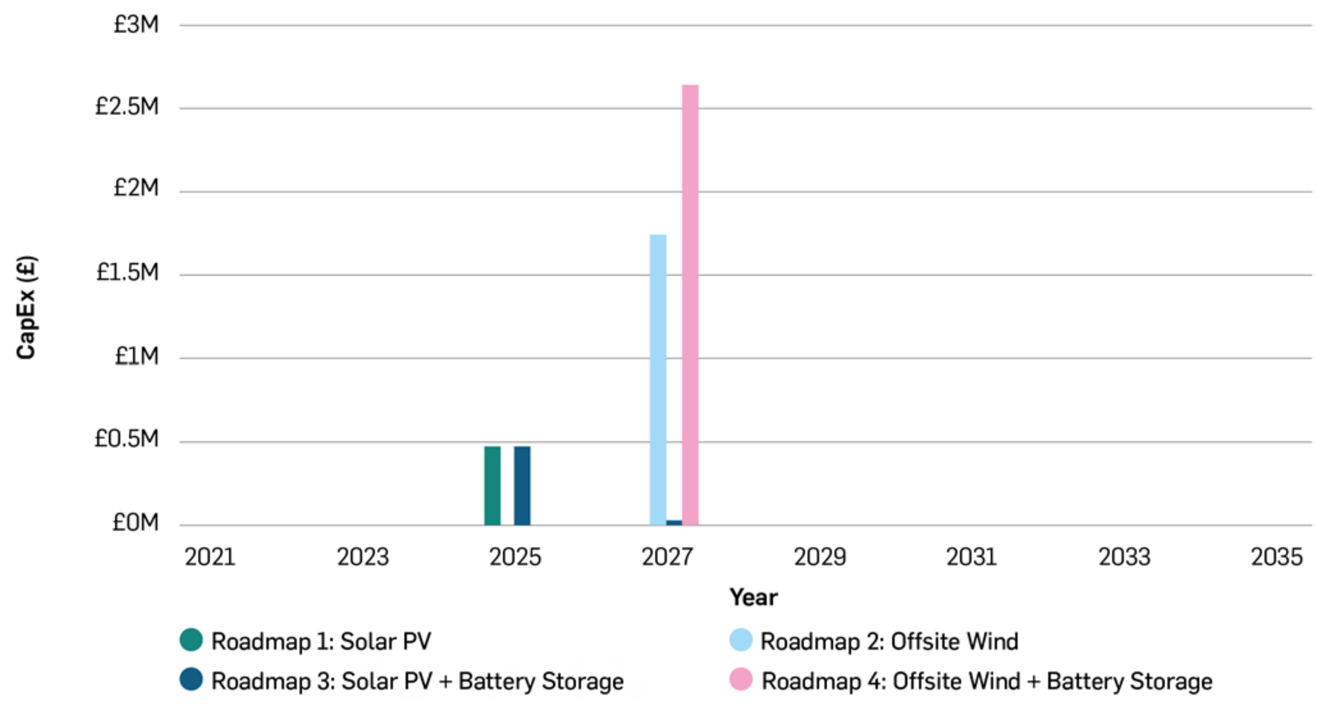


Figure 5-27 – Derry Refrigerated Transport CapEx Distribution: Comparison of Roadmap Options.

All options also produce an abatement saving from the reduction in CO_2, with the greatest savings resulting from Roadmap Option 2. CapEx costs are presented in Figure 5-27.

Figure 5-27 demonstrates the major cost variation between the solar and wind installations. The addition of the battery installation to Roadmap Option 4 further increases CapEx, leading to the largest upfront cost of £2.6M. In comparison, Roadmap Option 1 has the lowest upfront cost at £0.5M, including estimates for additional connections and infrastructure.

Compared to the baseline, each roadmap presents an OpEx saving, with the largest saving presented by those including the wind interventions (Roadmap Options 2 and 4) due to the drastic reduction in electrical import required, which makes up much of the current site OpEx. Realistic savings can also be made with both solar interventions, however, there is little difference between the two options, bringing into question the relevance of the battery installation for Roadmap 3, especially when considering its significant CapEx cost for negligible difference in OpEx savings.

5.15. NORTHERN IRELAND – FOOD PROCESSING SITE

The following section summarises the findings by AtkinsRéalis when considering routes to decarbonisation for a food processing site in Northern Ireland. The financial figures included do not represent investment decisions being taken by the site. The assumptions listed in section 2 should also be considered. All figures are advisory based on analysis undertaken at the time, various factors will affect the figures presented and further analysis is required before any investment decisions are taken.

5.15.1. Food Processing Site Summary of Roadmaps

The food processing site is located within Northern Ireland, in an industrial park alongside several other large manufacturers. The site focuses on the cooking and production of food products that are used in retailers across Europe and is primarily composed of a single main building holding the process lines, offices, and the despatch bay. There are also some separate smaller buildings including an effluent treatment plant, parking spaces and the under-commissioning combined heat and power plant. The site uses both natural gas and electricity therefore producing scope 1 and scope 2 emissions and aims to reduce its CO_2 emissions by 90% by 2050 in line with BEIS IFP targets.

In the baseline year of 2019, the site had an electrical import of 23,400 MWh, decreasing to an assumed 5,610 MWh in 2022 following the installation of a CHP plant. In comparison, in 2019 the site imported 53,300 MWh of natural gas increasing to an assumed 84,500 MWh with the CHP installation. As a result of this import, in the baseline year 14,700 tCO_2 was generated.

Three roadmap options were presented to the site:

- **Roadmap Option 1:** electrifying site boilers, removing the CHP and having electric boilers pick up the demand, installing off-site wind turbines and a heat pump.
- **Roadmap Option 2:** electrifying on-site boilers, removing the CHP, and having electric boilers pick up the demand, installing off-site solar panels and a heat pump.
- **Roadmap Option 3:** electrifying on-site boilers, fuel switching the CHP to hydrogen, installing off-site wind turbines and a heat pump.

Roadmap Option 1 would meet the 90% BEIS IFP emissions target with a 97% reduction in emissions by 2050. The option would require the highest CapEx of the three options, at £21.7M. Due to the cost of electricity exceeding the cost of natural gas, the OpEx after the removal of the CHP and full site electrification would be higher than the BAU forecast in 2050. As a result, the abatement cost is expected to be £101/tCO_2.

Roadmap Option 2 would meet the BEIS reduction target with a 96% reduction in carbon emissions by 2050. The option would require CapEx of £7.3M. Similar to Roadmap Option 1, due to the cost of electricity exceeding the cost of natural gas, the OpEx after the removal of the CHP and full site electrification would be higher than the BAU forecast in 2050. As a result, the abatement cost would be higher at £161/tCO_2.

Roadmap Option 3 would not meet the BEIS reduction target with an 83% reduction in carbon emissions. This option would fall short of the target due to the scope emissions associated with blue hydrogen and would require a CapEx of £15.7M. Due to the cost of both electricity and hydrogen exceeding the cost of natural gas, the OpEx after the removal of the CHP and full site electrification would be higher than the BAU forecast in 2050 and the abatement cost would be the highest of the three options, at £164/tCO_2.

Several key considerations were noted in the development of the roadmap options for the site:

- The lack of electricity export capacity in Northern Ireland limits the size of renewables that can be installed off-site without curtailing large amounts of generation.
- Lack of suitable hydrogen and carbon cluster for hydrogen fuel switching or CCUS and no timeline for when this could be installed.
- Lack of confidence in the reliability of the electricity grid making generating electricity on-site more desirable than increasing electricity demand.
- Considered likely that if electrifying the site, the DNO will not have sufficient headroom to support this.

5.15.2. Site Key Findings: Policy Considerations

See section 6.6.3 for an overview of the UK ETS. The scheme currently applies to sites with 20 MW or more of stationary combustion plant on-site once all individual units are aggregated together. Many smaller industrial sites are currently not included. The UK government have committed to expanding the scope of the scheme in future and are currently consulting on what this expansion could look like. Lowering of the 20 MW threshold and removal/amendment of the <3 MW aggregation clause are both being considered. If this expansion occurs, sites not currently in the scheme may be exposed to carbon taxation. This will provide a significant additional financial incentive to decarbonise, however, due consideration must be given to the revisions and ensure small businesses finances are not stretched, as they are unlikely to possess the economic resilience of larger competitors.

5.15.3. Site Key Findings: Cluster Access

There is no planned hydrogen or carbon clusters for Northern Ireland therefore limiting CCUS opportunities and significantly reducing the feasibility of hydrogen fuel switching. The cost for the site to privately build their own infrastructure for supply of hydrogen would likely prove cost-prohibitive unless cluster access was planned in the future.

5.15.4. Site Key Findings: Sub-metering

The site currently meters the main incomers and estimates the sub-metering data. In discussions with the site, examples were found where this estimation had proven inaccurate compared to the main site incomers that are used in the costings of their fuels. Accordingly, the site would benefit from upgrading or improving the accuracy their existing submetering to avoid data quality issues and to better understand the specific energy demands of each asset.

5.15.5. Site Key Findings: Permitting Requirements

The additional permitting requirements summarised in section 6.5 must be considered for Roadmap Option 3 due to the import, potential storage, and combustion of hydrogen. Roadmap Options 1 and 2 are expected to have no/minimal additional permitting requirements compared to current site operations. Renewable installations must comply with local permitting and planning requirements.

5.15.6. Site Key Findings: Key Roadblocks

There are several key roadblocks for the site including:

- Lack of suitable hydrogen clusters for hydrogen fuel switching or CCUS and no timeline for when this could be installed. It has been assumed in this report that there is sufficient hydrogen available to be procured. However, should this not be the case it could pose a major roadblock.
- No export capacity within Northern Ireland therefore prohibiting any potential revenue from export. This greatly reduces the suitability of solar panels as during the day at their peak generation all excess electricity must instead be curtailed. Thus the site is missing a substantial revenue stream from renewables. Considerable changes to electricity generation and/or demand are likely to necessitate a new or upgraded electric grid connection.
- It has been estimated that this could incur a cost of between £300-450/kW of extra capacity required. As a worst case scenario it was assumed that the current grid has no additional headroom than what is currently present. Thus, the additional capacity cost is estimated as £6.1M, £2.8M and £3.7M for Roadmap Options 1, 2 and 3 respectively for the renewable installations. To gain greater understanding of the costs involved, the DNO should be contacted as soon as possible to make an assessment on connection costs and timescales.

5.15.7. Site Feasibility of Roadmaps

Three decarbonisation pathways were produced for the site. Roadmap Options 1 and 2 would result in the fastest decarbonisation, reaching the 2050 BEIS target by 2037. Roadmap Option 1 would offer the highest decarbonisation potential owing to the larger amount of renewable electricity generated utilised on-site.

In contrast, Roadmap Option 3 would not reach the 2050 BEIS target, reaching a maximum decarbonisation of 83% by 2050. Figure 5-28 presents a summary of the carbon emissions over time for each roadmap option against the 2050 BEIS target of 90% decarbonisation.

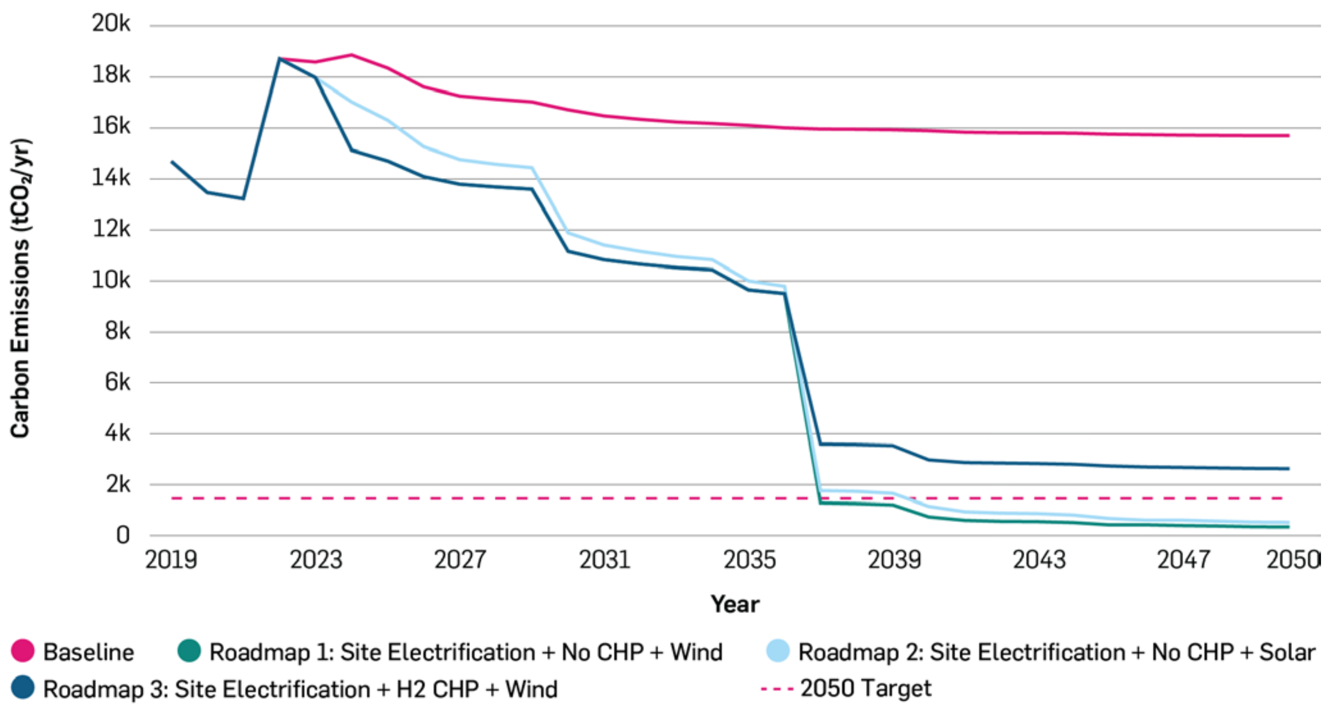


Figure 5-28 – Site Carbon Emissions: Comparison of Roadmap Options and BAU Forecast.

The use of air source heat pumps was investigated for replacing the localised natural gas boiler that supplies heat to the offices. Heat pumps are significantly more efficient than a conventional boiler and remove the use of natural gas, instead requiring a small quantity of electricity imported from the grid. Overall, the heat pump only reduces a very small proportion of site emissions, however, does target scope 1 emissions from reduction in fuel use. In addition, the heat pump has a low cost of carbon abated, would meet the heating requirements of the building, and could be integrated easily with current assets.

Electric boilers are an effective alternative to natural gas boilers, offering a typical efficiency of 99% compared to 85% for a conventional natural gas boiler. Additionally, they can operate to the required 270°C to produce steam or heat the thermal oil needed in the process and are fully commercially available. However, additional infrastructure might be required with the increased electrical load requiring higher maximum headroom in the future.

This includes examples of additional switchgear, transformers and high voltage cabling. Additionally, the orientation of electrode boilers is usually vertical compared to natural gas boilers (usually horizontal). Floor plan requirements may therefore be lower and access infrastructure such as ladders, and catwalks may need adjusting.

There is no suitable space on-site for wind turbines due to the large exclusion zone that would be required to install them. Accordingly, wind turbines were sized for off-site generation. Although the wind generation profile matches site demand well, there are periods when the turbines generate more electricity than required on-site, resulting in curtailed generation. Despite this, wind installations would still payback, making it financially viable despite the lack of electricity export capacity.

There is no suitable space available on-site for solar panels owing to the unsuitable nature of the buildings' roofs. Solar was only considered for off-site generation. Solar only generates within a certain window of time each day and so matches the 24-hour site demand poorly. Sizing for a larger solar array significantly increases CapEx, with only minimal improvements on electricity utilisation, and most of the generated electricity being curtailed. As there is no export capacity within Northern Ireland, this curtailed electricity has no revenue associated with it.

To remove the natural gas feedstock, switching the CHP off and instead rely on electric boilers to meet the site heat demand at the cost of an increased electrical load was investigated. This would drastically increase the site's electric import load and could potentially cause external infrastructure upgrades depending on the headroom required. It would also increase the site OpEx owing to the high price of electricity but would drastically reduce the site's emissions.

It is possible to replace the feedstock for the CHP with lower carbon fuel such as hydrogen. This would require either retrofitting the existing CHP to make it compatible with hydrogen or purchasing a "like-for-like" new turbine. However, there is large uncertainty associated with the availability of hydrogen or a hydrogen network located suitably close within Northern Ireland. It is likely that a suitable network to provide this quantity of hydrogen would not be available soon.

Key performance metrics for the three roadmap options are displayed in Table 5-17.

Table 5-17 – Site Key Performance and Cost Metrics for Roadmap Options 1-3.

	CO_2 emissions 2050 ($ktCO_2$) (% change)	CapEx (£M)	Abatement Cost (£/tCO_2)	Payback Period (years)
Roadmap Option 1	**0.4 (-97%)**	21.7	101	-
Roadmap Option 2	**0.6 (-96%)**	7.3	161	-
Roadmap Option 3	**2.5 (-83%)**	15.7	164	-

Table 5-17 shows that Roadmap Option 1 reduces emissions by the greatest amount by 2050. This is at the cost of a larger upfront CapEx of £21.7M per year compared to £7.3M and £15.7M in Roadmap Options 2 and 3 respectively. This is however balanced by the reduced OpEx compared to the other two options due to the greater capacity of wind causing less electricity to be imported from the grid. Roadmap Options 2 and 3 have a similar OpEx, with both rising significantly above baseline in 2037 following either removal of the CHP or installation of a hydrogen CHP respectively. For Roadmap Option 2 this increases the electrical load and as solar is not sufficient to meet this demand, results in increased electricity import from the grid. Similarly with Roadmap Option 3, hydrogen CHP supplies less electricity than the previous natural gas CHP and so this combined with the increased price of hydrogen compared to natural gas results in an OpEx increase. Figure 5-29 shows the CapEx distribution of the different options.

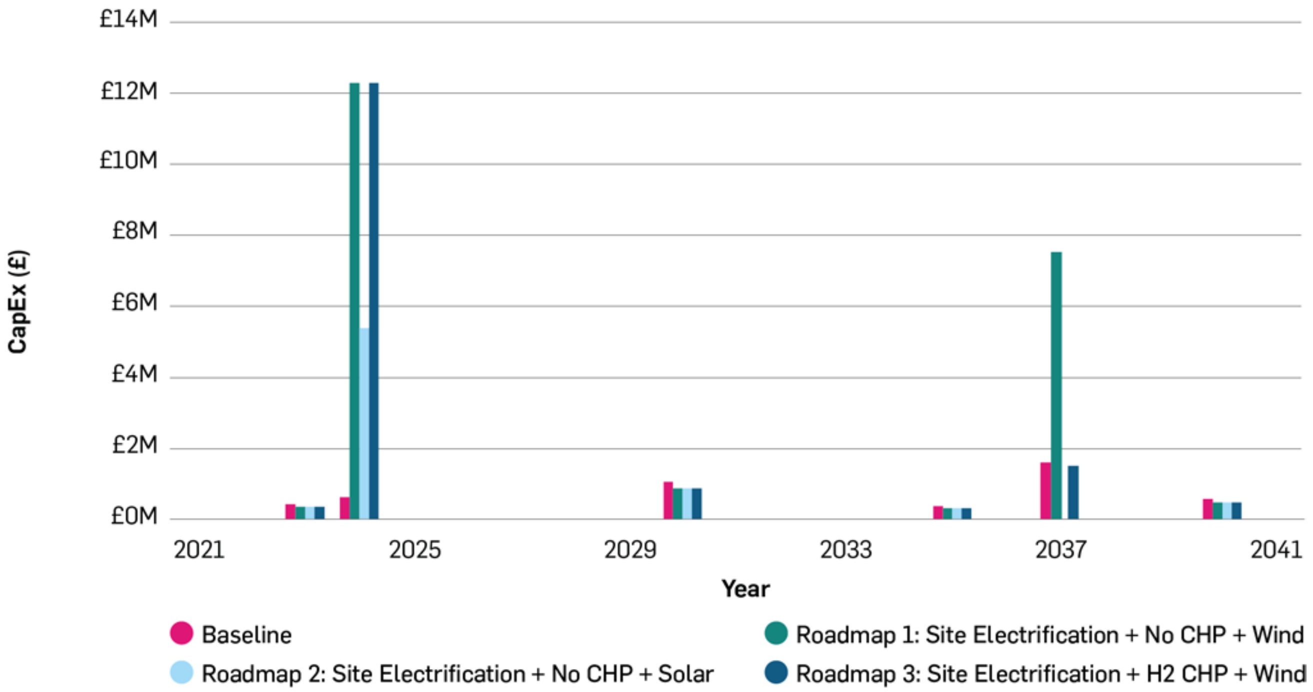


Figure 5-29 – Site CapEx Distribution: Comparison of Roadmap Options and BAU Forecast.

5.16. SUMMARY OF KEY DATA FROM ROADMAPS

Table 5-18 contains a summary of key metrics for each site. Cells highlighted green indicate that the relevant BEIS IFP decarbonisation target is met.

These targets are, 20% reduction in emissions by 2025, 66% by 2035 and 90% by 2050 (or site target). A hyphen (' – ') has been used in situations where additional infrastructure costs were not calculated and where payback is not expected to be reached by 2050.

Table 5-18 – Summary of Key Metrics from the Roadmaps Selected for Each Site.

Sector	Site	Roadmap Options	Baseline Year Selected	Baseline CO_2 Emissions ($ktCO_2/y$)	CO_2 Emissions in 2025 ($ktCO_2/y$) (% change)	CO_2 Emissions in 2035 ($ktCO_2/y$) (% change)	CO_2 Emissions in 2050 ($ktCO_2/y$) (% change)	Intervention CapEx (£M)	CapEx Including Additional Infrastructure Upgrades[15] (£M)	Abatement Cost (£/ tCO_2)	Payback Period (years)	Feasibility Rating (Low / Medium / High)
Chemicals	Dow Silicones UK	1 Burning Natural Gas with CCS	2020	176.1	155.4 (-12%)	89.1 (-49%)	24.6 (-86%)	115.3	-	-51	7.86	Medium
		2 Blue Hydrogen Fuel Switch			155.4 (-12%)	95.3 (-46%)	29.3 (-83%)	88.5	-	-32	56.33	Medium
		3 Site Electrification			155.4 (-12%)	89.1 (-49%)	6.4 (-96%)	54.2	105.2	-6	-	Medium
	Croda Europe	1 Site Electrification	2018	15.4	16.5 (7%)	3.3 (-79%)	0.6 (-96%)	3.1	7.2	62	-	Medium
		2 Blue Hydrogen Fuel Switch			16.5 (7%)	2.6 (-83%)	3.9 (-75%)	6.4	-	96	-	Medium
		3 Green Hydrogen Fuel Switch			16.5 (7%)	2.6 (-83%)	0.2 (-99%)	6.4	-	119	-	Medium
	Solenis	1 CCUS	2020	58.6	49.4 (-16%)	49.0 (-16%)	11.7 (-80%)	58.1	0	11	33.47	Medium
		2 Green Hydrogen Fuel Switch			49.4 (-16%)	46.7 (-20%)	0.6 (-99%)	22.1	0	83	-	Medium
		3 Site Electrification			49.4 (-16%)	49.0 (-16%)	3.5 (-94%)	8.6	28	13	-	Medium
Paper	Palm Paper	1 Off-Site Solar PV Generation and Electrification	2021	187.9	182.6 (-3%)	164.3 (-13%)	10.3 (-95%)	38.1	-	116	-	Medium
		2 Off-site Solar PV and Wind Generation and Electrification			182.6 (-3%)	164.4 (-13%)	10.0 (-95%)	55.3	-	110	-	Medium
		3 On-Site Solar PV Renewable Generation and Blue Hydrogen Fuel Switch			182.6 (-3%)	164.4 (-13%)	27.4 (-85%)	69.3	-	38	-	Medium
		4 On-Site Solar PV Renewable Generation and CCUS			182.6 (-3%)	163.5 (-13%)	15.6 (-92%)	125.1	-	35	-	Medium
		5 On-Site and Off-Site Solar Generation and Electrification (including supplementary firing)			182.6 (-3%)	138.6 (-26%)	10.3 (-95%)	39.5	-	89	-	Medium
		6 On-Site Solar PV Renewable Generation, Electrification and CCUS			182.6 (-3%)	164.4 (-13%)	12.2 (-93%)	115.1	-	38	-	Medium
	Essity	1 Off-site Solar PV PPA and Electrification	2019	82.1	58.1 (-29%)	25.4 (-69%)	3.4 (-96%)	25.7	-	116	-	High
		2 Off-site Wind and Electrification			58.1 (-29%)	24.7 (-70%)	3.0 (-96%)	63.8	-	45	-	Low
		3 Blue Hydrogen Fuel Switch and Solar PV			68.1 (-17%)	30.3 (-63%)	15.0 (-82%)	12.6	-	87	-	Low
	Kimberly-Clark Ltd	1 Hydrogen Fuel Switch, On-site Solar PV, and Wind PPA	2021	51.2	32.4 (-37%)	2.8 (-94%)	2.5 (-95%)	13.6	-	234	-	Medium
		2 Electrification, On-site Solar PV, and Wind PPA			31.6 (-38%)	6.8 (-87%)	3.6 (-93%)	17.7	-	130	-	Medium
		3 Hydrogen Fuel Switch, Electrification, On-site Solar PV, and Wind PPA			28.2 (-45%)	4.9 (-90%)	3.1 (-94%)	6.8	-	173	-	High
		4 Hydrogen Fuel Switch, Electrification, On-site Solar PV, and Wind PPA			35.8 (-30%)	4.8 (-91%)	3.1 (-94%)	24.4	-	197	-	Medium
		5 Hydrogen Fuel Switch, CCS, On-site Solar PV, and Wind PPA			20.9 (-59%)	5.4 (-90%)	5.0 (-90%)	26.6	-	148	-	Low

15 Additional infrastructure costs were not always calculated consistently across sites. Site input was factored into sizing, and subsequently some sites have had different rates applied. The purpose of presenting the infrastructure cost is to demonstrate magnitude of additional cost (largely electrical infrastructure costs) not factored into modelling. Abatement cost and payback were calculated based on modelling (i.e. does not account for additional infrastructure cost).

Sector	Site	Roadmap Options	Baseline Year Selected	Baseline CO_2 Emissions ($ktCO_2/y$)	CO_2 Emissions in 2025 ($ktCO_2/y$) (% change)	CO_2 Emissions in 2035 ($ktCO_2/y$) (% change)	CO_2 Emissions in 2050 ($ktCO_2/y$) (% change)	Intervention CapEx (£M)	CapEx Including Additional Infrastructure Upgrades[15] (£M)	Abatement Cost (£/ tCO_2)	Payback Period (years)	Feasibility Rating (Low / Medium / High)
Minerals	Churchill China UK	1 Blue Hydrogen Fuel Switch	2021	12.1	12.0 (-1%)	10.8 (-10%)	3.3 (-73%)	9.1	9.9	217	-	Medium
		2 Electrification			12.0 (-1%)	10.8 (-11%)	0.9 (-92%)	16.4	20.1	229	-	Medium
		3 Purchase of RGGOs			1.8 (-85%)	0.8 (-93%)	0.6 (-95%)	0	0	140	0	Low
	Imerys Minerals	1 Small-Scale Wind, Electrification & CHP Decommissioning	2019	28.3	27.4 (-3%)	4.0 (-86%)	2.8 (-90%)	2.7	-	-26	2.74	High
		2 Large-Scale Wind, Electrification & CHP Decommissioning			27.4 (-3%)	3.2 (-89%)	2.5 (-91%)	26.8	-	-63	5.41	High
		3 Wind and Solar PV, Electrification & CHP Decommissioning			27.4 (-3%)	3.7 (-87%)	2.7 (-91%)	17.3	-	-40	6.04	High
	Midland Quarry Products[16]	1 Electrification	2021	15.2	14.4 (-6%)	0.9 (-94%)	0.4 (-97%)	17.0	22.9	-80	7.18	Medium
		2 Fuel Switches to Natural Gas and Biodiesel			7.6 (-50%)	6.0 (-60%)	5.9 (-61%)	11.6	16.7	-102	5.65	High
Food	British Sugar	1 Electrification, Wind, Steam Drying of sugar beet pulp and Natural Gas Lime Kiln	2017/18	299.0	236.7 (-21%)	72.7 (-76%)	16.8 (-94%)	154.5	181.8 – 195.5	94	-	Medium
		2 Phased Hydrogen Fuel Switch, Wind, AD and Biogas			236.7 (-21%)	194.5 (-35%)	4.3 (-99%)	90.5	190.7 – 190.9	21	-	Low
	HJ Heinz Foods	1 Electrification and Solar PV	2021	45.1	43.6 (-3%)	5.6 (-88%)	1.5 (-97%)	5.7	17.6 – 23.5	121	-	Medium
		2 Phased Hydrogen Fuel Switch and Solar PV			43.6 (-3%)	11.7 (-74%)	0.3 (-99%)	20.0	20.2 – 20.3	153	-	Medium
Water	United Utilities	1 Blue Hydrogen Fuel Switch and CCUS	Financial Year 2022	5.8	5.6 (-3%)	1.4 (-76%)	7.4 (28%)	40.8	41.1	35,580	-	Low
		2 Biogas Fuel Switch and CCUS			1.0 (-82%)	0.3 (-96%)	0.1 (-98%)	0.3	-	-101	1	High
		3 Electrification and Solar PV PPA			5.6 (-3%)	1.2 (-78%)	0.4 (-94%)	3	-	1,868	-	Medium
Northern Ireland - Pharmaceuticals	Almac	1 Solar PV and Electrification via Heat Pumps and Electric Boilers	2020	11.9	13.4 (13%)	3.8 (-68%)	0.4 (-97%)	10.4	19.2	53	-	Medium
		2 Solar PV and Heat Pumps (retained oil backup)			13.5 (13%)	4.0 (-66%)	0.6 (-95%)	12.8	21.6	66	-	High
		3 Off-Site Wind and Heat Pumps (retained oil backup)			13.5 (13%)	3.2 (-74%)	0.4 (-97%)	44.1	62.6	13	-	Low
		4 Solar PV, Heat Pumps and Waste Heat Recovery using Heat Pumps			13.4 (13%)	4.0 (-66%)	0.6 (-95%)	14.4	24.1	65	-	Low
Northern Ireland - Transport	Derry Refrigerated Transport	1 On-Site Solar PV	2021	0.4	0.3 (-15%)	0.1 (-83%)	0.0 (-95%)	0.5	0.8	-805	10.27	High
		2 Off-Site Wind			0.4 (1%)	0.0 (-94%)	0.0 (-98%)	1.7	2.2	-796	10.01	Low
		3 On-Site Solar PV and Battery Storage			0.3 (-15%)	0.1 (-83%)	0.0 (-95%)	0.5	0.8	-744	10.86	Low
		4 Off-Site Wind and Battery Storage			0.4 (1%)	0.0 (-95%)	0.0 (-99%)	2.6	3.1	-348	13.72	Low
Northern Ireland - Food	Food Processing Site	1 Electrification: Off-site Wind, CHP Removal, Electric Boilers and Heat Pump	2019	14.7	13.1 (-11%)	9.2 (-37%)	0.4 (-97%)	21.7	27.8	101	-	Medium
		2 Electrification: Off-Site Solar PV, CHP Removal, Electric Boilers and Heat Pump			14.2 (-3%)	9.5 (-35%)	0.6 (-96%)	7.3	10.1	161	-	Medium
		3 Electrification and Fuel Switch: Off-Site Solar PV, Hydrogen CHP, Electric Boilers and Heat Pump			13.1 (-11%)	9.2 (-37%)	2.5 (-83%)	15.7	19.4	164	-	Medium

16 Note the final emissions target for MQP was amended to 90% reduction in CO_2 emissions by 2042 based on their internal target being more ambitious than the BEIS IFP 2050 target.

5.17. ADOPTION OF LOW TRL TECHNOLOGIES

As summarised in Table 5-18 and captured in Appendix B, the roadmaps produced in conjunction with the industrial partners did not feature any technologies with TRLs below 7. As part of the scope of the BEIS IFP, AtkinsRéalis did produce early-stage technology cards for lower TRL technologies, such as fuel cells, which were subsequently removed when the sites did not express further interest in pursuing these technologies (typically due to cost) or having them modelled as part of the resulting roadmaps. Furthermore, AtkinsRéalis targeted +/- 50% accuracy across the programme. Inclusion of low TRL technologies would present an inherent challenge to this as well as the overall feasibility of the roadmaps produced. Additional governmental financial support and/or technology accelerators to produce case studies on which sites could rely would help to increase the adoption of these technologies.

6. KEY SITE CONSIDERATIONS

This section summarises key considerations and roadblocks identified by AtkinsRéalis and sites during development of roadmap options. These considerations and roadblocks are expected to be applicable to industrial sites across the UK and inform the recommendations presented in section 8.

6.1. POLICY CONSIDERATIONS

6.1.1. Suitability of Renewables

Wind power was discounted in several roadmaps due to perceived difficulties around planning permission. The energy generation profile from wind power is well suited to the demand of sites with continuous operation, much more so than solar which has a typical bell curve generation output across a given day that is further impacted by seasons. Over the course of 2022, during this programme, onshore wind planning policy was amended. This should increase the feasibility of on-site wind power for the sites, benefiting decarbonisation.

Sites were encouraged to monitor planning policy associated with solar PV, particularly in relation to use of agricultural land.

On-site renewable electricity generation is expected to be less expensive and lower carbon than grid electricity in the short-term. To maximise renewable electricity generation potential (and therefore reduce OpEx and scope 2 emissions for sites, particularly when coupled with electrification of site processes), planning reform to remove perceived roadblocks will be required, but needs to be balanced alongside other considerations such as continuity of food supply, environmental impact and social challenges and public perspective.

6.1.2. Hydrogen versus Electrification

A key issue raised by sites is the lack of clarity and certainty around long-term government decarbonisation priorities and investment commitments. This has impacted sites' decision-making in the past and continues to hinder sites when considering significant decarbonisation investments, such as for the electrification of heat compared against a hydrogen fuel switch.

Sites also noted that equipment manufacturers are awaiting evidence of demand before they invest in developing electric or hydrogen equipment.

Some sites have noted that there is considerably more investment into hydrogen schemes than electric technologies. This is due to the required development of nascent market, where full chain development of the system is required, in comparison to the established electricity market. It is not an indication that hydrogen is more suitable to industry than electrification.

Electrification of heat is anticipated to be considerably less expensive per tonne of carbon abated (particularly when electricity is generated on-site) compared to using green hydrogen and marginally less expensive than blue hydrogen, despite the levies applied to grid-imported electricity.

It is assumed within the models that capture and storage of CO_2 at steam reformation plants is imperfect, meaning blue hydrogen alone cannot achieve the targeted decarbonisation (90% by 2050). While green hydrogen could bridge this emissions gap, the use of renewable energy in this way results in low overall system efficiency and in most cases could be more effectively used to directly electrify heat.

Evidently, both hydrogen fuel switching and electrification present unique benefits and challenges. These should be considered through further feasibility studies that consider the local availability of adequate grid connection and hydrogen supply.

6.1.3. Availability of RGGOs

Biomethane has only been included in roadmaps where no viable decarbonisation alternative could be identified. Concerns over the legitimacy of 'Net Zero' claims of biofuels were noted in section 4.5.2. Sites have expressed their concern over the timescales for which RGGOs will be available to industry. Clarity from government is required.

6.1.4. CHPs, AD and Future Policy

Several sites benefited from the CHPQA programme when installing CHPs. Other sites had been considering AD, although were partially dissuaded by decreasing government support.

While CHP technology and the CHPQA schemes are no longer relevant to Net Zero, it is a good example of how policy can effect change. Similarly, AD has now reached a level where it can operate with minimal subsidies. The support afforded these technologies should be reviewed and lessons from them identified and carried forward to support the development of the key decarbonisation technologies presented to sites through IFP.

6.1.5. Support with Applicability of Policies to their Sites

Several sites have indicated uncertainty around the applicability of certain government incentives and support to their sites, particularly when multiple schemes appear to overlap. Industrial sites would benefit from greater education on the available options and support mechanisms, with ease of access, transparency, and clarity on timelines.

6.2. BEIS FUNDING SCHEMES APPLICABLE TO SITES

To provide further support beyond the Scoping Phase of the BEIS IFP, sites were provided with recommendations on the BEIS funding schemes in the Net Zero Innovation Portfolio (NZIP) most applicable to their roadmaps. At least one funding scheme was considered applicable to each site, with the key schemes being:

1. **Industrial Fuel Switching Programme (IFS.02) –** now closed to applications: was deemed to be potentially applicable to at least one intervention for every site. The focus of phase 2 of IFS is on demonstration of the TRL 4-7 technologies; this aligns with the BEIS IFP objective of utilising low TRL technologies (noting the caveat discussed in section 5.17).
2. **Industrial Energy Transformation Fund (IETF) –** now closed to applications: was deemed to be applicable to 13 sites. In most cases sites' applications would centre around feasibility studies, engineering studies or deployment projects for deep decarbonisation interventions. These deep decarbonisation interventions largely involve electrification of heat, installation of heat pumps, hydrogen fuel switches in boilers, CHPs, direct heating, and on-site vehicles. Some sites may also be able to submit secondary applications centring around deployment of energy efficiency interventions.
3. **Next Generation CCUS –** now closed to applications: was deemed applicable to the four sites that include CCUS in their roadmaps.
4. **Phase 2 of the Red Diesel Replacement Fund –** now closed to applications: was recommended to Midland Quarry Products to support the electrification or biodiesel fuel switch of their on-site vehicles.

At time of writing application windows to many NZIP schemes have closed. No replacement schemes are expected to be announced until after the government funding review in 2025. Sites are reluctant to make the necessary investments in decarbonisation measures without certainty that government support will be available.

6.3. CLUSTER ACCESS

First deployment of large-scale CCUS and low carbon hydrogen focusses on industrial clusters. The clusters referred to throughout the BEIS IFP are shown in Figure 6-1. Two clusters – HyNet North-West and East Coast Cluster – are planned to be implemented by the mid-2020s. There will be potentially four further clusters by 2030. By 2050 there is potential for mainland UK-wide hydrogen and CO_2 pipeline infrastructure. An exception is Northern Ireland, where no Track 1 or 2 clusters are planned. Track 1 clusters refer to those planned to be completed by the mid-2020s and Track 2 clusters refer to those planned to be operational by 2030s [21].

Owing to proposed hydrogen infrastructure prioritising industrial hubs, dispersed sites are better placed to implement electrification.

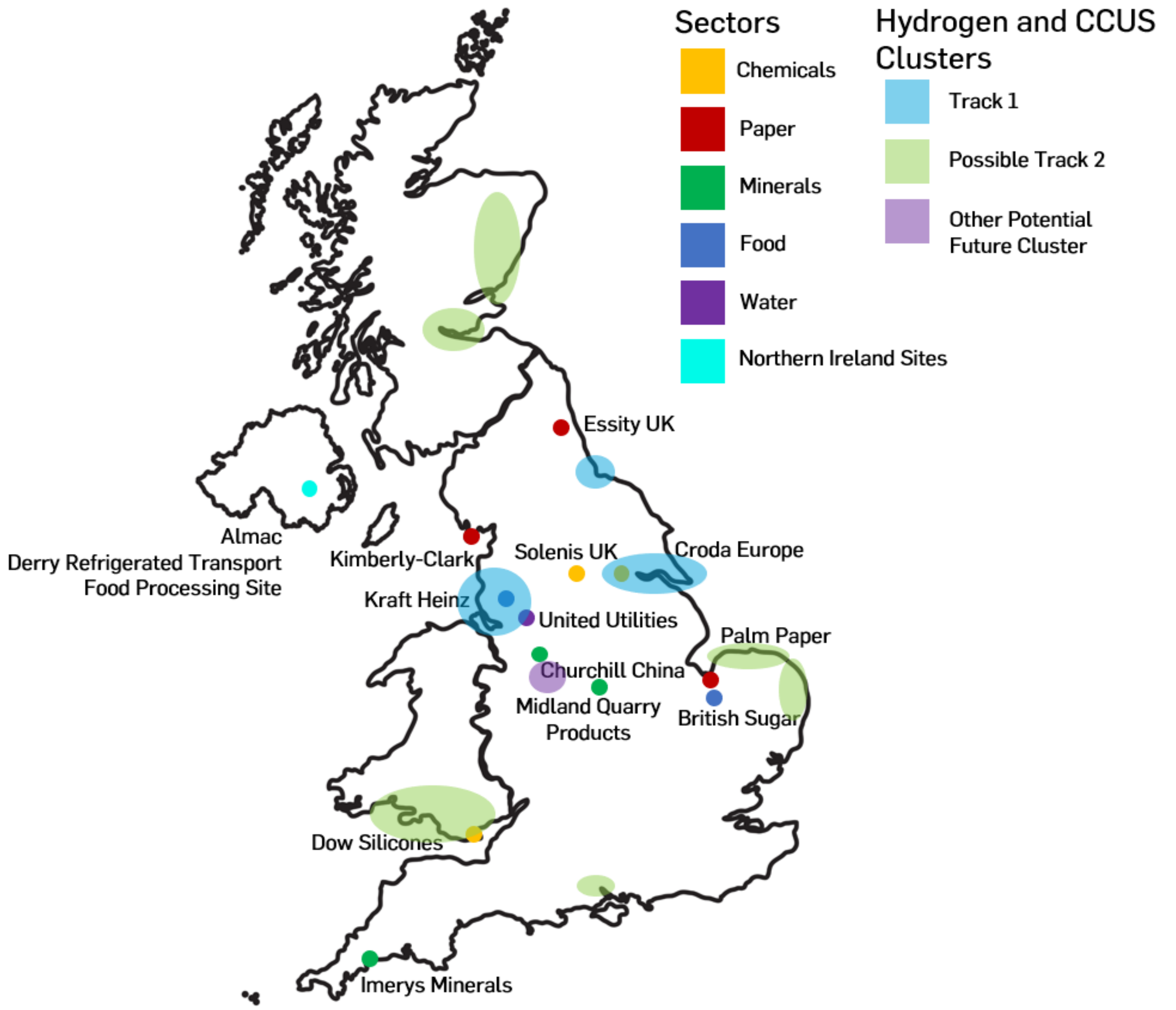


Figure 6-1 – Approximate Location of UK Industrial Clusters Relative to BEIS IFP Sites.

Roadmaps for 11 of the sites include hydrogen and/or CCUS interventions. As shown in Figure 6-1, many sites included in the BEIS IFP are not well co-located with Track 1 industrial clusters and are unlikely to have access to hydrogen or CCUS networks in the near term. Despite this many of the sites are already actively engaging with local Track 1 and 2 clusters, smaller-scale low-carbon hydrogen projects, or neighbouring sites for which dedicated infrastructure is proposed.

Hydrogen and CCUS were still considered for most sites in the BEIS IFP. Key exceptions where hydrogen and CCUS interventions have largely not been considered were sites located in Northern Ireland and Cornwall.

6.4. SUB-METERING

When AtkinsRéalis staff began visiting sites, it became clear that minimal sub-metering was needed and that most of the sites already had usable data or could utilise sensible assumptions to fill any gaps and provide the level of granularity required by the IDT. It was determined that sub-metering would cause lengthy delays without adding significant value to the project.

For sites moving to concept or feasibility stages, sub-metering is recommended to provide the suitable level of data granularity required to specify and design technology.

A good understanding of energy use is fundamental to the development of effective decarbonisation roadmaps. While most sites within the IFP were able to provide detailed data or develop workarounds, it is not expected this will be the case for all UK industry. Communicating the need for sites to understand, monitor and record their energy use is essential going forward.

6.5. PERMITTING REQUIREMENTS

Installation of hydrogen or CCUS requires consideration of new permitting approaches and safety systems. Regulations including but not limited to Dangerous Substances and Explosive Atmospheres Regulations, Explosive Atmospheres, Pressure Equipment Directive, COMAH and Hazardous Substances Regulations should be considered. The costs of ensuring compliance with these regulations are expected to be highly specific to sites and systems. These costs should be considered during the decision-making process. The same is not expected to be required for electrification interventions.

6.6. KEY ROADBLOCKS

6.6.1. DNO Barriers

Where sites are looking to decarbonise through electrification, they will likely require new or upgraded connections to the distribution, or transmission network, scale dependent. This is both costly and time consuming, being dealt with on a first-come-first served basis. This approach does not necessarily direct investment where it can achieve the best decarbonisation results. More strategic planning and directed investment would help to decarbonise key sites first.

Within Northern Ireland, the DNO has opposed additional decentralised electricity generation connection. Installation of renewable systems is expected to be economically challenging, with excess generation likely to be curtailed rather than exported. Given Northern Ireland has no planned CCUS or hydrogen pipelines, electrification is the primary decarbonisation option. The cost of grid electricity is higher than on-site generated electricity. As some of the Northern Ireland sites that participated in the BEIS IFP are located close together, they may benefit from forming an industrial cluster connected to a dedicated private wire network and renewable generation system.

A summary of DNO barriers for each site is provided in Table 6-1.

Table 6-1 – DNO Barriers to Adoption of Low Carbon Technologies Across the Sites.

Industry	Site	DNO Issue
Chemicals	Dow Silicones	Limited electricity import and export capacity.
	Croda	No formal comment/engagement from the DNO. Limited electricity import and export capacity.
	Solenis	Limited electricity import and export capacity.
Paper	Palm Paper	No formal comment/engagement from the DNO but given the level of electrification recommended across the site, the site is likely to exceed existing electrical capacity imposed by the DNO.
	Essity	Limited electricity import and export capacity.
	Kimberly-Clark	Limited electricity import and export capacity.
Minerals	Churchill China	Based on prior engagement, the local DNO are not expected to carry out grid upgrades that will increase local capacity until 2028.
	Imerys Minerals	Good working relationship with DNO, however still constrained. Large private wire network offers some resilience in this respect.
	Midland Quarry Products	Limited electricity import and export capacity. The electric technologies (particularly industrial vehicles) are not expected to be available until beyond 2032, meaning grid upgrades are not expected to be a limiting factor on electrification.
Food	British Sugar	Limited electricity import and export capacity.
	Heinz	Limited electricity import and export capacity.
Water	United Utilities	Limited electricity import and export capacity.
Northern Ireland – Pharmaceuticals	Almac	Limited import and no additional export capacity and there is no timeline indication from the DNO as to when (or if) this will be increased.
Northern Ireland – Transport	Derry Refrigerated Transport	Limited import and no additional export capacity and there is no timeline indication from the DNO as to when (or if) this will be increased.
Northern Ireland – Food	Food Processing Site	Limited import and no additional export capacity and there is no timeline indication from the DNO as to when (or if) this will be increased.

6.6.2. Site Approach to Return on Investment

Sites have investment models that include internal return on investment thresholds for projects. These are often dictated by parent companies. Decarbonisation interventions, particularly at lower TRL, are unlikely to meet these thresholds meaning sites will not implement these roadmaps. Management of companies' expectations of the return on investment that can be expected from decarbonisation technologies may be necessary. This should be in addition to, not in place of, government financial incentives.

6.6.3. UK ETS

The UK ETS currently applies to sites with 20 MW or more (on a net/lower heating value fuel input basis) of stationary combustion plant on-site once all individual units are aggregated together. There is a clause which excludes individual units <3 MW from the aggregation. Therefore, many smaller industrial sites or sites with lots of small assets are currently not included.

The UK government have committed to expanding the scope of the scheme in future to hit national emissions reductions targets. The government are currently consulting on what this expansion could look like. Lowering of the 20 MW threshold and amendment of the <3 MW aggregation clause are both being considered. It is likely that over the period 2025-2030, such qualifying criteria will be lowered, meaning many sites not currently in the scheme will be exposed to carbon taxation.

Expansion of the scheme would mean more sites would start paying for their scope 1 emissions at the UK ETS market rate. This would provide a significant additional financial incentive to decarbonise and enhance low carbon technology payback rates. However, defining the exact revised qualifying criteria and date from which it applies is currently purely speculation and will become clearer over the next year when the government release further details.

There are a few smaller sub-schemes within UK ETS for the smallest eligible sites, for example the small emitter opt-out. These operate slightly differently and can result in reduced cost exposure for these sites. However, it is possible these reduced cost schemes may close by the end of the decade.

6.6.4. Land Constraint

Several interventions face space constraints, which is expected to be especially pertinent for sites considering CCUS. If CO_2 is to be exported, additional loading facilities will also need to be integrated into the site footprint. Early engagement with vendors is recommended to determine the feasibility of installing interventions given the space available on sites.

6.7. ENGAGEMENT OF SITES WITH THE BEIS IFP

Had there been a full set of industrial partners involved in the Scoping Phase of the BEIS IFP (40 sites), BEIS would have had more freedom to set hard cut-off dates and remove sites from the programme that did not comply with deadlines. AtkinsRéalis were very flexible with submission deadlines as well as the quality and format of data provided given only 15 sites were involved in the programme.

Lowering the 10 ktCO_2/y emissions threshold may have enabled more sites to participate in the programme.

Throughout the programme there were difficulties obtaining adequate data on existing energy assets in a timely manner. While this is often a challenge faced in site engagement, it highlights the need for sites to have a good grasp of their energy use. Sites that have provided the most accurate data and wider considerations about their site have received better tailored, site-specific roadmap reports.

From a technical perspective, many sites appreciated the general overview of the decarbonisation and energy-efficiency technologies considered. These sites usually had an awareness of the technologies discussed but not a deep technical understanding. Comparing technology costs, at least in orders of magnitude, was found to be a valuable insight for the sites.

While most sites were well engaged and enthusiastic about the process, there was widespread acknowledgement that decarbonisation efforts were likely to encounter challenge at board level. Further to this, several sites were enrolled in the BEIS IFP by a parent company, rather than the application originating from the on-site team. In these instances the site teams had a poor understanding of commitment expectations from the outset and a steep learning curve, although most were able to accommodate this. Notably, sites that have had a key point of contact who was passionate and focussed on decarbonisation have enabled the most efficient production of roadmaps.

To enable the transition to Net Zero, companies are going to have to shift their cultural attitude towards decarbonisation. Cultural leadership should come from the top and engage the wider company, not just key stakeholders with a focus on aiming high. There is a need for companies to strategically align their thinking, both internally and with other companies (e.g. clusters, sectors). Individuals should be engaged and empowered to tackle any challenges they encounter. Most companies in the industrial sector should have a good grasp on how to achieve this, given the historical shift in health and safety culture in UK industry.

7. FINDINGS

The BEIS IFP programme sought to support decarbonisation of UK industry, with a focus on dispersed industrial sites. 15 sites, covering seven different sectors, participated in the BEIS IFP Scoping Study. The aim was to develop bespoke decarbonisation roadmaps for each site. The roadmaps targeted 20% CO_2 emissions reduction by 2025, 66% by 2035 and 90% by 2050, relative to a baseline set by each site.

7.1. SITE FINDINGS

49 roadmap options were produced for the 15 sites involved in the BEIS IFP. All sites were provided with at least one decarbonisation roadmap that met the ultimate decarbonisation target of 90% reduction in CO_2 emissions by 2050. Higher TRL technologies were selected for the roadmaps, typically owing to the higher costs and lower accuracy and feasibility of roadmaps associated with lower TRL technologies.

7.1.1. Chemicals Sector

Nine roadmap options were presented to three chemicals sites. None of the roadmap options met the 2025 emissions target, ultimately being constrained by availability of hydrogen or CCUS pipelines, or electricity grid connection and equipment TRL.

Despite the high CapEx of CCUS, the roadmap options proposed to Dow Silicones and Solenis that considered CCUS had the lowest abatement costs of all the roadmap options presented to these sites. The CCUS roadmap options were two of only three expected to achieve payback. Off-site infrastructure costs were not accounted for. Neither of these options met the BEIS IFP emissions targets, being constrained by the efficiency of carbon capture technology. Should capture efficiencies improve through 2050, CCUS would present an effective decarbonisation option for these sites and potentially other similar ones in the chemicals sector.

The other roadmap options presented to the chemicals sites centred on electrification and hydrogen fuel switches. Although there was some variability, largely the hydrogen fuel switches resulted in higher CapEx and abatement costs than electrification (although grid connection costs were excluded).

None of the roadmap options centred around blue hydrogen are expected to meet the 2050 BEIS IFP emissions target. The options centred around green hydrogen are expected to almost achieve Net Zero by 2050. All the electrification options met the 2050 emissions target.

Given electrification is expected to be possible for these sites, direct electrification of heat could be a more efficient use of renewable electricity than green hydrogen.

7.1.2. Paper Sector

14 roadmap options were presented to the three paper sites. All but two roadmap options are expected to achieve the 2050 emissions target, with seven options expected to achieve all three targets. None of the options are expected to achieve payback for the sites.

Roadmap options including CCUS were presented to Palm Paper and Kimberly-Clark. These are expected to have some of the lowest, albeit positive, abatement costs of all the roadmap options presented to the paper sites. In conjunction with on-site renewables, all three CCUS roadmap options are expected to achieve the 2050 emissions target.

Two roadmap options centred around blue hydrogen were presented to Palm Paper and Essity, these are expected to have low overall abatement costs but would not meet any of the emissions targets. The options involving green hydrogen fuel switches (phased switching) are expected to have much higher abatement costs than blue hydrogen but would meet all three emissions targets.

Site electrification in conjunction with on-site and off-site renewables and PPAs were explored extensively for the paper sector. The overall abatement costs of these roadmap options were highly variable, with some being the highest presented to the paper sites. All electrification options are expected to achieve the 2050 emissions target, with some meeting all three targets. Whilst the CapEx of electrification is high, off-site renewables in particular present a very strong financial case resulting in a reduction in OpEx when compared to the BAU forecast.

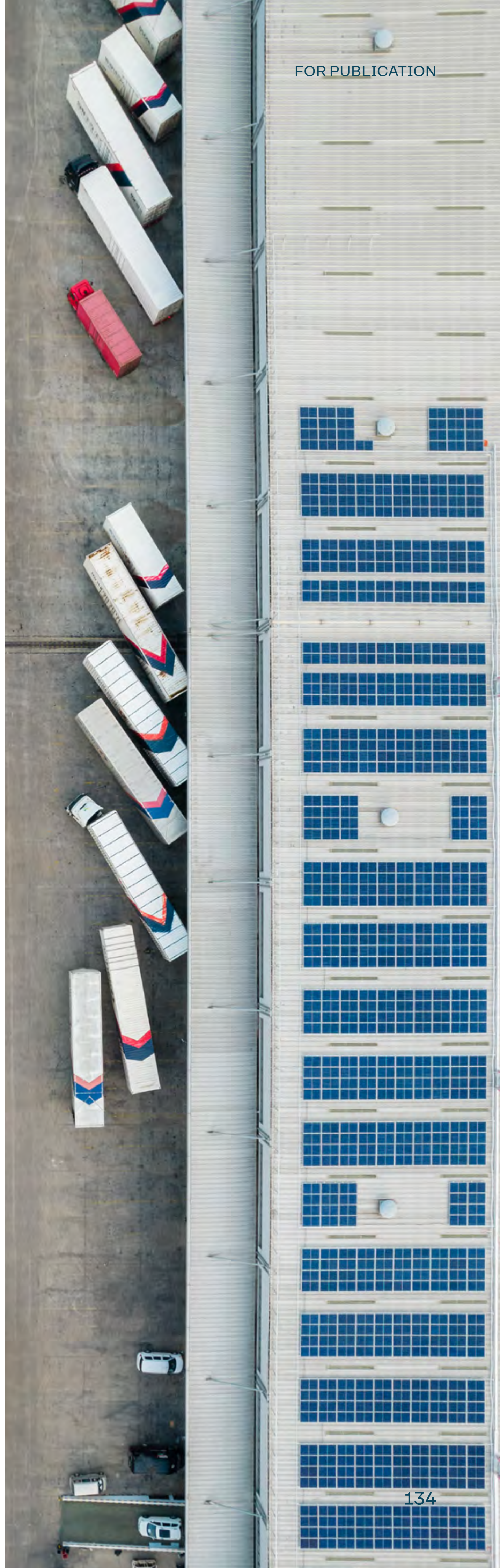
7.1.3. Minerals Sector

Eight roadmap options were presented to the three minerals sites. Six roadmap options are expected to achieve the 2050 emissions target, with five expected to meet both the 2035 and 2050 targets. Six of the options presented are expected to achieve payback within a decade. Several of the key interventions (e.g., electrification of heat and vehicles) are not expected to be implemented until the 2030s due to constraints on the electricity grid and technology advancement. The two options presented to the minerals sites not expected to achieve payback both involve extensive kiln equipment replacement with high associated CapEx.

No CCUS options were presented to the minerals sites due to their relatively small scale, dispersed assets being unsuitable for carbon capture.

One blue hydrogen option was proposed. This is not expected to meet any of the emissions targets or achieve payback but was explored at the request of the site.

The five electrification options presented are all expected to meet at least the 2050 emissions target and achieve payback due to negative abatement costs (excluding the kiln option discussed above).



Two options that considered the use of biofuels were presented. One involved biodiesel use in vehicles (in combination with natural gas use), which would enable an almost immediate fuel switch provided that adequate biodiesel could be procured. Ultimately the decarbonisation potential of this option is constrained based on the emissions factor of natural gas. For other minerals sites (e.g. quarries) that have a finite life and currently use diesels and oils, similar fuel switches may present a viable short-term decarbonisation route.

The other option that considered use of biofuels was the purchase of RGGOs as a bridging option for kiln decarbonisation. This is not considered a suitable industry-wide or long-term option, but for hard to decarbonise sites or technologies at an appropriate scale, it may present a useful interim option until kiln decarbonisation technologies become more economically viable. Whilst the CapEx is zero for this option, the cost of purchase of RGGOs would significantly increase OpEx.

7.1.4. Food Sector

Four roadmap options were presented to the two food sites (the food site in Northern Ireland is discussed separately). All are expected to meet at least the 2050 emissions target but not achieve payback.

Two roadmap options considered phased hydrogen fuel switches based on the expected availability of blue and green hydrogen. Both options are expected to almost achieve Net Zero by 2050. The high cost of hydrogen for British Sugar is expected to be somewhat offset by the production of biogas on-site, meaning the overall abatement cost of this option is low, albeit still positive. In comparison the hydrogen option presented to Heinz has a very high cost of abatement.

It may be cost effective for other food sites that have a biogenic source of fuel to explore the installation of AD and biogas-fired assets in the near-term. Although, the cost and site-specific implementation challenges should be considered in dedicated feasibility studies. Hydrogen fuel switches may also be explored in conjunction.

The two electrification options presented are expected to meet the 2050 emissions target. Abatement costs are expected to be considerably higher than the option involving AD but lower than the 100% hydrogen option.

7.1.5. Water Sector

Three roadmap options were presented to the only water site involved in the BEIS IFP. The roadmaps only consider a small subset of total site CO_2e emissions, owing to the exclusion of greenhouse gases other than CO_2 from the BEIS IFP.

Biogas fuel switching (using on-site biogenic fuel sources) with CCUS is expected to be the lowest cost option and would meet all three of the emissions targets. This is the only option expected to achieve payback (in under one year).

Blue hydrogen fuel switching with CCUS was the highest cost option by a considerable margin and the ultimate decarbonisation potential is constrained by scope 2 emissions associated with blue hydrogen.

The electrification option was expected to have a relatively high cost of abatement (but still considerably lower than blue hydrogen and CCUS) but would achieve the highest level of decarbonisation.

7.1.6. Northern Ireland Sites

11 roadmap options were presented to the three sites located in Northern Ireland. All options centre around electrification. All but one of the options are expected to meet the 2050 emissions target, with four of those expected to achieve payback within 15 years or less.

Two options involving battery storage were presented to the same site. Abatement costs were negative for all options presented to this site. The options involving battery storage presented the highest abatement costs for the site. These are the only instances in the BEIS IFP roadmaps where battery storage was incorporated, as it was not considered financially viable for larger sites. For smaller sites, battery storage may present a useful technology to support renewable generation.

Of the electrification options, the ones involving air source heat pumps have relatively high CapEx and high overall abatement costs, meaning none are expected to achieve payback.

One roadmap also involves installation of a hydrogen CHP. This is expected to have the highest cost of abatement overall, with procurement of hydrogen also being an issue due to the lack of planned hydrogen and CCUS clusters in Northern Ireland.

All roadmap options include renewable electricity generation. As previously discussed, Northern Ireland Electricity Networks (the DNO) is striving for a centralised electricity network meaning connection of renewables to the grid may be challenging and excess generation would likely be curtailed rather than exported. As some of the sites involved in the BEIS IFP are located close together, there is a strong case for the sites to form an industrial cluster. The cluster could fund the installation of renewables connected to the sites by a private wire network. It may be prudent for other sites within Northern Ireland (and other areas of the UK where the grid is constrained) to consider the formation of a similar type of cluster, possibly including green hydrogen generation.

7.2. STRATEGIC FINDINGS

During the development of roadmaps in collaboration with the sites, several roadblocks to decarbonisation were identified, many of these recurrent.

The most common and pressing block to progressing decarbonisation ambitions across the sites was the constraint on electricity grid infrastructure. This restricted most sites in adding renewable technologies to their on-site generation or electrifying existing assets. The Northern Ireland DNO has been known to express a strong preference for centralised energy generation, which limits viability of renewable capacity given surplus generation would need to be curtailed.

Challenges around hydrogen and CCUS infrastructure were also clear. Whilst the sites that participated in the BEIS IFP are considered to be dispersed sites, many had already begun engaging with local hydrogen and CCUS clusters about potential connection in future. As this infrastructure does not yet exist, the utilisation of these technologies on-site will be constrained by the development of this infrastructure.

As sites consider the relative benefits of electrification, hydrogen and CCUS, many noted the considerable investment hydrogen schemes are due to receive when compared to electrification and CCUS. Sites generally understood that while there is a requirement for government to support hydrogen projects in establishing a new market, this is not an indication that hydrogen is more suitable for industrial decarbonisation than electrification. Clearer communication on this may be necessary along with emphasis on the need for site-specific feasibility studies to be performed. Feasibility studies could also provide greater insight into the impact of high energy prices caused by the ongoing energy crisis.

Clearer indication from government on policy around CHPs, RGGOs, REGOs and planning for renewables would also aid sites in selecting long-term decarbonisation pathways. In the case of planning, previous planning policy inhibited wider adoption of wind technologies, despite the generation profile often matching site demand far better than the typical bell-curve seen with solar PV systems. Recent planning reform should have alleviated this.

Due to these concerns, most sites had not implemented deep decarbonisation solutions, particularly where technologies were not expected to achieve payback or meet internal return on investment requirements. Energy efficiency options on the other hand were found to have been widely implemented, with many sites having undertaken "quick win" energy efficiency projects, such as installing LED lighting. Several sites also have existing plans to implement further decarbonisation projects such as waste heat recovery.

The work completed through the BEIS IFP has identified important challenges facing UK dispersed industrial sites as they decarbonise. Support is required from the government for the research, technology, and industrial communities. The continued engagement of sites with the programme has demonstrated that with adequate support, such sites are proactive in their decarbonisation efforts.

8. CONCLUSIONS AND RECOMMENDATIONS

8.1. CONCLUSIONS AND RECOMMENDATIONS FOR SITES

No single roadmap option was recommended preferentially, with this study being provided as an indication of potential pathways to decarbonise sites and their associated feasibilities. The outputs should be used to guide the sites investigation of optimal pathways, with key technologies presented.

While leadership in policy and support for decarbonisation should come from government, this should be done with a view to empower companies to take initiative and be ambitious in meeting Net Zero goals.

At these early stages, companies should be considering how they might go about achieving a shift in culture, from individuals' perspectives to entire sites and throughout sectors and wider industry. Strong parallels might be drawn between what is required in pursuit of decarbonisation and what has been achieved in health and safety. Net Zero represents an inevitable paradigm shift, and sites will have to ask themselves going forward: 'can we afford not to do this?'.

In assessing their attitudes towards Net Zero, companies should give consideration to how they intend to promote these initiatives and projects technically and financially, how they can benefit from and leverage emerging opportunities, and how they might be impacted by changing public perceptions.

In the execution of decarbonisation, modelling and planning will lay much of the groundwork, which will only be possible with good sub-metering and understanding of energy use. Once roadmaps have been established, early engagement with vendors and crucial infrastructure operators is recommended to provide greater certainty on site-specific feasibility, efficiency and cost of technologies included in the roadmaps.

Sites are recommended to gather site-specific information on external infrastructure as a priority to inform decision-making. Early engagement with the local DNO is necessary when considering electrification.

For clustering this would involve engagement with local industrial operators to understand the scope for shared assets, networks, and synergies. For sites considering hydrogen fuel switches or CCUS, review and consideration of safety, environmental, and permitting rules and regulations is advisable. Familiarisation with local planning requirements and constraints is necessary for project development generally.

For sites looking to fuel switch to biofuels, procurement of adequate supply of these fuels is likely to be the greatest challenge. Where a source of biogenic fuel is available on-site, use of this fuel to produce biogas for use in combustion plant offers a low cost, effective decarbonisation option. For hard to decarbonise sites (or sites for which decarbonisation options are low TRL), purchase of RGGOs may offer a useful bridging option but this cannot be relied upon in the long-term or at an industry-wide scale.

With more certainty in their plans, sites should be ambitious with their targets. Projects can be developed following traditional engineering methodologies (Concept Design, Front End Engineering Design, Detailed Design, Commissioning).

8.2. CONCLUSIONS AND RECOMMENDATIONS FOR GOVERNMENT

If Net Zero is to be achieved in industry, decisive action is required.

> **With proper investment in infrastructure, suitable policy support from government, and appetite and investment from industry, many sectors could realistically look to target decarbonisation by 2040; there are no technological barriers to this. Government should consider the benefits and opportunities this might present, including alleviating pressure on other sectors' decarbonisation efforts, development of an upskilled and professional UK workforce, and international economic and political benefits of acting as a global leader in decarbonisation.**

The greatest blocker sites have faced, and the most recurrent, have been the timescales and cost of grid upgrades. The grid appears heavily constrained at both transmission and distribution levels (surplus generation and surplus consumption problems vary geographically). The concern of blackouts which has been raised over the past 12 months is not only telling of the state of the grid, but it also underscores wider issues around energy resilience and security.

In the transition to Net Zero, the strain placed on the grid will increase severalfold, from sources beyond simply industry. A national strategy focussed on the grid upgrades required to achieve Net Zero is essential. The benefits of a systems approach would be numerous, including allowing for targeted allocation of funding, cost savings, and clarity for sites looking to decarbonise. Similar issues were encountered for hydrogen and CCUS infrastructure, however the challenges faced are more complex given that national infrastructure does not yet exist, and its development is both uncertain and expected to be costlier than electrical grid upgrades.

If suitable reinforcement of the electricity network was not an issue, sites would be in a much better place to push for electrification of assets, potentially allowing many sites to achieve decarbonisation before 2040. The same might be achieved for hydrogen if infrastructure was in place, however there are other challenges faced in the form of technology readiness – whereas many processes can be electrified now, commercial deployment of hydrogen equipment is in many instances years away. The Future System Operator (FSO) recommended in Ofgem's 2021 review of the UK energy system would be well placed to manage the strategic development of such infrastructure [22]. With speed and action critical to the delivery of Net Zero, establishing this independent FSO should be considered both a priority and major milestone.

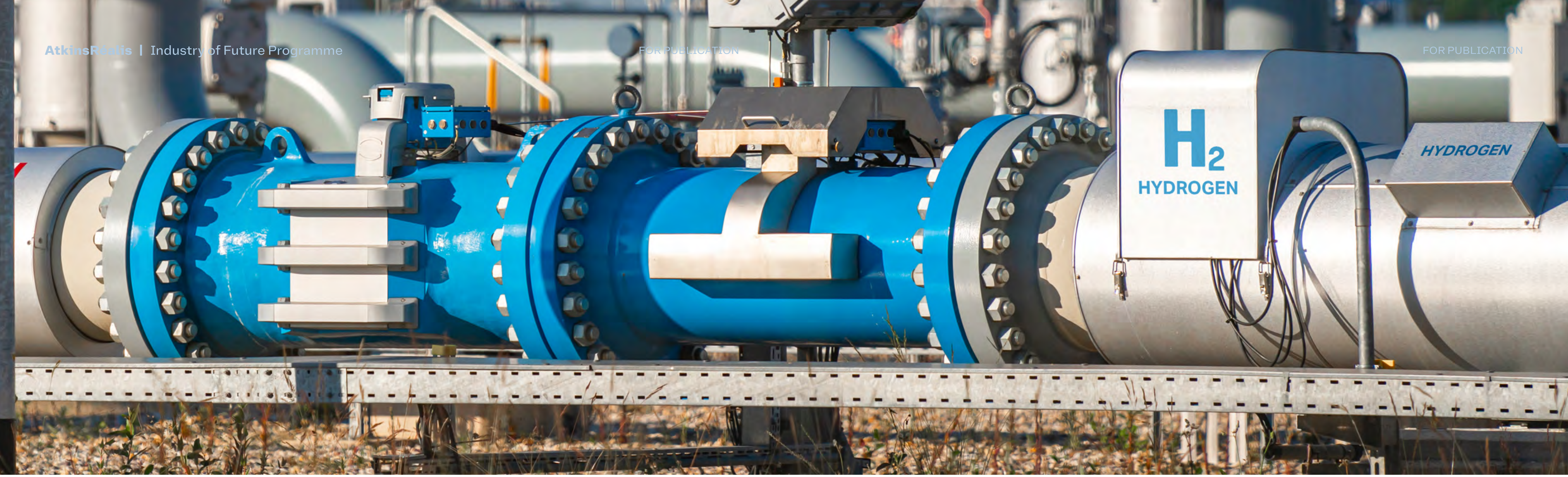
Decarbonisation of sites before 2040 might seem ambitious given 20 of the 49 roadmaps did not meet 66% decarbonisation by 2035, however many of these pathways were constrained by access to key infrastructure. This study has neglected to examine the impact that an accelerated rate of decarbonisation might have. Execution of electrification on-site in 2025 offers 10 years of savings against one executed in 2035.

Second to infrastructure issues as a roadblock outside control of sites was a lack of clear strategy from government. While such decisions require sufficient supporting evidence, a balance must be struck, with due consideration given to the compounding cost that delay might incur.

Further uncertainty is inherent in the forecasting of future energy costs. Execution of the IFP has necessitated the development of an economic baseline to allow for financial comparison between competing technologies, particularly electrification, hydrogen and CCUS. The costs of this study were guided by HM Treasury's Green Book. A deeper review of this data is recommended, along with sensitivity analysis which should aim to establish a number of levelised cost and price tracks for each to offer a better sense of certainty and enable companies to make strategic decisions and invest sooner.

With proper investment in infrastructure, suitable policy support from government, and appetite and investment from industry, many sectors could realistically look to target decarbonisation by 2040; there are no technological barriers to this. Government should consider the benefits and opportunities this might present, including alleviating pressure on other sectors' decarbonisation efforts, development of an upskilled and professional UK workforce, and international economic and political benefits of acting as a global leader in decarbonisation.

FOR PUBLICATION



8.3. ENABLING DECARBONISATION EFFORTS

Further to major points highlighted above, there were numerous smaller learnings which have come to light over the course of the IFP.

More could be done to strengthen ties between government and industry. Sites would benefit from education on decarbonisation options open to them and strategies to achieve decarbonisation; while ultimately, they are responsible for their own success in this regard, government should consider what messages it wishes to emphasise to industry. At this stage focus is recommended on promoting a shift in company culture, promoting early planning, and providing support for cross-industry information sharing. Later, support from government might look to consider the formation of smaller industrial hubs and pushing industrial sites to work collaboratively with other local sites.

There is also ripe opportunity to leverage the operational expertise of sites. Throughout the IFP programme those sites which were invested in the process added significant and valuable contributions which proved useful not only in decarbonising their own site, but which had wider industry and cross-industry benefit.

The BEIS IFP did not consider some key industrial sectors, namely concrete/cement and steel. These are major emitters of CO_2 with much of its production linked to their processes, rather than from production of heat as has predominantly been the case with sites investigated in this programme. These sectors would benefit from a dedicated investigation or programme. It is recognised that the few steel sites in the UK are already well progressed in discussions with the government on decarbonisation plans.

Expanding the scope of the UK ETS may help combat the lack of payback associated with many of the electrification, hydrogen fuel switching and CCUS interventions. It is expected that recent revision of onshore wind planning policy will also help combat lack of payback associated with electrification options.

If there are to be future programmes of a similar nature to the BEIS IFP it is recommended that clear commitment expectations are set to the key point of contact at each site. Deadlines should be hard cut-offs, with other sites available to be substituted onto the programme should sites miss initial deadlines. This should allow for the efficient running of programmes with high quality site-specific data.

Engaging sites considered hard to decarbonise that have not previously participated in government programmes to inform them of future programmes is strongly recommended. This may encourage more sites to proactively engage with equipment vendors, local clusters and DNOs, all of which are important in timely decarbonisation. Engagement with industry and professional bodies to which these sites belong, as well as broader engineering and scientific bodies, could be useful in leveraging the wealth of knowledge available, especially given the rapid developments seen within the decarbonisation space.

The BEIS IFP has demonstrated that decarbonisation of industry by 2050 is not only technically possible, but also might be considered unambitious. While roadblocks exist for both sites and government, the challenges they present, and the solutions to these, are well understood.

The focus of this programme has primarily fallen on technological feasibility, with input from respective sites to ensure the roadmap options presented align with their strategic vision, as well as other factors which influence site operations (e.g. safety).

The economic analysis presented is intended to allow for comparison between competing technologies and does not consider the wider impact on the UK economy. There is little weight attributed to important political factors such as energy security, availability of skilled workers or wider public perception.

Government priority should be to develop policy that empowers industry to achieve decarbonisation targets and invest in the infrastructure that will be critical in enabling Net Zero. There should be a push for more ambitious targets with consideration to the wider implications that the energy transition will have for the UK. Site priority should at this stage be focussed on shifting attitudes at all levels to drive for these Net Zero targets, laying the groundwork for their own decarbonisation efforts and interfacing with infrastructure providers, equipment manufacturers and other businesses within and beyond their sector. While there is concern about the cost of decarbonisation, companies would do well to consider the opportunities presented, as those who are proactive, and pragmatic will lead their industry from the front.

9. REFERENCES

[1] HM Government, “Climate Change Act 2008,” 2008. [Online]. Available: https://www.legislation.gov.uk/ukpga/2008/27/contents.

[2] BEIS, “Guidace: UK Low Carbon Hydrogen Standard: Emissions Reporting and Sustainability Criteria,” 2022. [Online]. Available: https://www.gov.uk/government/publications/uk-low-carbon-hydrogen-standard-emissions-reporting-and-sustainability-criteria.

[3] BEIS, “Notice: Apply for the Industry of Future Programme: Industrial Sites Competition,” 2021. [Online]. Available: https://www.gov.uk/government/publications/industry-of-future-programme-ifp.

[4] Greenhouse Gas Protocol, “The Greenhouse Gas Protocol Corporate Standard,” 2015. [Online]. Available: https://ghgprotocol.org/corporate-standard.

[5] HM Government, “Industrial Decarbonisation Strategy,” 2021. [Online]. Available: https://www.gov.uk/government/publications/industrial-decarbonisation-strategy.

[6] International Energy Agency, “ETP Clean Energy Technology Guide,” [Online]. Available: https://www.iea.org/articles/etp-clean-energy-technology-guide.

[7] BEIS, “Collection: Government Conversion Factors for Company Reporting of Greenhouse Gas Emissions,” 2022. [Online]. Available: https://www.gov.uk/government/collections/government-conversion-factors-for-company-reporting.

[8] BEIS, “Hydrogen Production Costs 2021,” 2021. [Online]. Available: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1011506/Hydrogen_Production_Costs_2021.pdf.

[9] HM Government, “Net Zero Strategy: Build Back Greener,” 2021. [Online]. Available: https://www.gov.uk/government/publications/net-zero-strategy.

[10] Crown Commercial Service, “Introduction to Power Purchase Agreements,” 2020. [Online]. Available: https://assets.crowncommercial.gov.uk/wp-content/uploads/Power-Purchase-Agreements-PPA-An-Introduction-to-PPAs.pdf.

[11] K. Gamage, “Numerical Methodology for Feasibility Analysis of Ground Source Heat Pumps,” 2014. [Online]. Available: https://www.researchgate.net/publication/265250440_NUMERICAL_METHODOLOGY_FOR_FEASIBILITY_ANALYSIS_OF_GROUND_SOURCE_HEAT_PUMPS.

[12] HM Government, “UK Hydrogen Strategy,” 2021. [Online]. Available: https://www.gov.uk/government/publications/uk-hydrogen-strategy.

[13] SINTEF, “Hydrogen: The Future Is Green, But The Path There Is Multicoloured,” [Online]. Available: https://blog.sintef.com/sintefenergy/gas-technology/hydrogen-the-future-is-green-but-the-path-there-is-multicoloured/.

[14] McCarthy, Napier & Smart, “Written evidence submitted by the HyTrEc2 consortium (UK partners),” [Online]. Available: https://committees.parliament.uk/writtenevidence/7104/html/.

[15] Irena, “Green Hydrogen Cost Reduction; Scaling up Electrolysers to meet the 1.5°C Climate Goal,” 2020. [Online]. Available: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Dec/IRENA_Green_hydrogen_cost_2020.pdf?rev=4ce868aa69b54674a789f990e85a3f00.

[16] Confederation of Paper Industries and Fichtner, “Electrification of UK Paper Mills,” 2022. [Online]. Available: https://thecpi.org.uk/library/PDF/Public/Publications/Reports/UK%20Paper%20Mills%20Grid%20Connection%20Assessment.pdf.

[17] Institution of Engineering and Technology, “Electric Vehicle Charging Equipment Installation,” 2020. [Online]. Available: https://electrical.theiet.org/wiring-matters/years/2020/80-may-2020/the-iet-code-of-practice-for-electric-vehicle-charging-equipment-installation-4th-edition/.

[18] Health and Safety Executive, “Charging batteries for electrically powered vehicles,” Date unavailable. [Online]. Available: https://www.hse.gov.uk/pubns/guidance/sr18.pdf.

[19] National Grid, “Network Capacity Map,” 2022. [Online]. Available: https://www.nationalgrid.co.uk/our-network/network-capacity-map-application.

[20] Northern Ireland Electricity Networks, “Small and Large Scale Generation Connections,” 2021. [Online]. Available: https://www.nienetworks.co.uk/connections/generation-connections/small-large-scale.

[21] BEIS, “Guidance: October 2021 update: Track-1 Clusters Confirmed,” November 2021. [Online]. Available: https://www.gov.uk/government/publications/cluster-sequencing-for-carbon-capture-usage-and-storage-ccus-deployment-phase-1-expressions-of-interest/october-2021-update-track-1-clusters-confirmed.

[22] Ofgem, “Proposal for a Future System Operator role - Decision,” April 2022. [Online]. Available: https://www.ofgem.gov.uk/publications/proposal-future-system-operator-role-decision.

[23] HM Government, “Energy White Paper: Powering our Net Zero Future,” 2020. [Online]. Available: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/945899/201216_BEIS_EWP_Command_Paper_Accessible.pdf.

APPENDICES

APPENDIX A: DATA SOURCES

Table A-1 contains a list of sources utilised by AtkinsRéalis to develop the technology cards/data bank that supports the calculations within the IDT – please note this is not an exhaustive list.

Table A-1 – Sources Advised to Use to Develop the Technology Cards/Data Bank.

British Library ETHOS
British Library on Demand
Directory of Open Access Journals (DOAJ)
Elsevier - Open Access Journals
Emerald Insight
Google Scholar
ICE Virtual Library
IEA - International Energy Agency
Ingenta Connect
Journals TOCs - free collection of scholarly journals 'Table of Contents'
McGraw-Hill Education - Access Engineering
OSTI.GOV
ProQuest
Professional Membership Bodies e.g. Knowledge Hub - IChemE, Library and Archive - IMechE, Energy Institute Matrix
ScienceDirect.com | Science, health and medical journals, full text articles and books.
AtkinsRéalis Library Services > Journal subscriptions
Springer - Open Access journals
Wiley - Open Access journals
Wiley Online Library

APPENDIX B: TECHNOLOGIES WITHIN SCOPE AND EXCLUDED TECHNOLOGIES

Table B-1 – Technologies Considered in the BEIS IFP Scoping Study.

Card Number	Used/Not Used	Technology Title	Min TRL	Max TRL
BAU 1	Used	Natural Gas Boiler	-	9
BAU 2	Used	Natural Gas Turbine CHP	-	9
Biomass 1	Used	Biomass Steam Boiler	-	9
CCUS 1	Used	CO_2 Absorption - Generic Solvents	7	9
Energy Efficiency 1	Used	Organic Rankine Cycle	-	9
Energy Storage 1	Used	Battery – Lithium Ion	8	9
External Infrastructure	Used	Summary	N/A	N/A
External Infrastructure	Used	Electrification	N/A	N/A
External Infrastructure	Used	Hydrogen Infrastructure	N/A	N/A
Heating and Cooling 1	Used	Electrical Steam Boiler	-	9
Heating and Cooling 2	Used	Electrode Boiler	-	9
Heating and Cooling 3	Used	Air Source Heat Pump	-	9
Heating and Cooling 4	Used	Ground Source Heat Pump	-	9
Heating and Cooling 5	Used	High Temperature Heat Pump	6	8
Heating and Cooling 6	Used	Waste Heat Low Temperature Heat Pump	-	9
Heating and Cooling 7	Used	Electric Process Heaters	7	9
Hydrogen 4	Used	Hydrogen Boiler	7	8
Renewables 1	Used	Onshore Wind	-	9
Renewables 2	Used	Photovoltaic	-	9
BAU	Not used	Reciprocating Engine	N/A	N/A
Biomass	Not used	Biomass Boilers – small-scale	N/A	N/A
Biomass	Not used	Biomass Boilers - medium scale	N/A	N/A
CCUS	Not used	CO_2 Membrane separation	N/A	N/A
CCUS	Not used	Oxy-Fuel Combustion	N/A	N/A
CCUS	Not used	CO_2 Adsorption - Solid Sorbents	N/A	N/A
CCUS	Not used	CO_2 Absorption - Aqueous Potassium Carbonates	N/A	N/A
CCUS	Not used	CO_2 Liquefaction	N/A	N/A
CCUS	Not used	Direct Air Capture	N/A	N/A
Energy Efficiency	Not used	Mechanical Vapor Recompression	N/A	N/A
Energy Storage	Not used	Sensible heat storage	N/A	N/A
Energy Storage	Not used	Latent heat storage – Phase Change Materials	N/A	N/A
Heating and Cooling	Not used	Evaporative Cooling	N/A	N/A
Hydrogen	Not used	Fuel Cell - Alkaline	N/A	N/A
Hydrogen	Not used	Fuel Cell - Solid oxide fuel cell	N/A	N/A
Hydrogen	Not used	Hydrogen Reciprocating Engine Combustion (100% H2)	N/A	N/A
Hydrogen	Not used	Hydrogen Gas Turbine – Simple Cycle	N/A	N/A
External Infrastructure	Not used	CO_2 Infrastructure	N/A	N/A

AtkinsRéalis

atkinsrealis.com