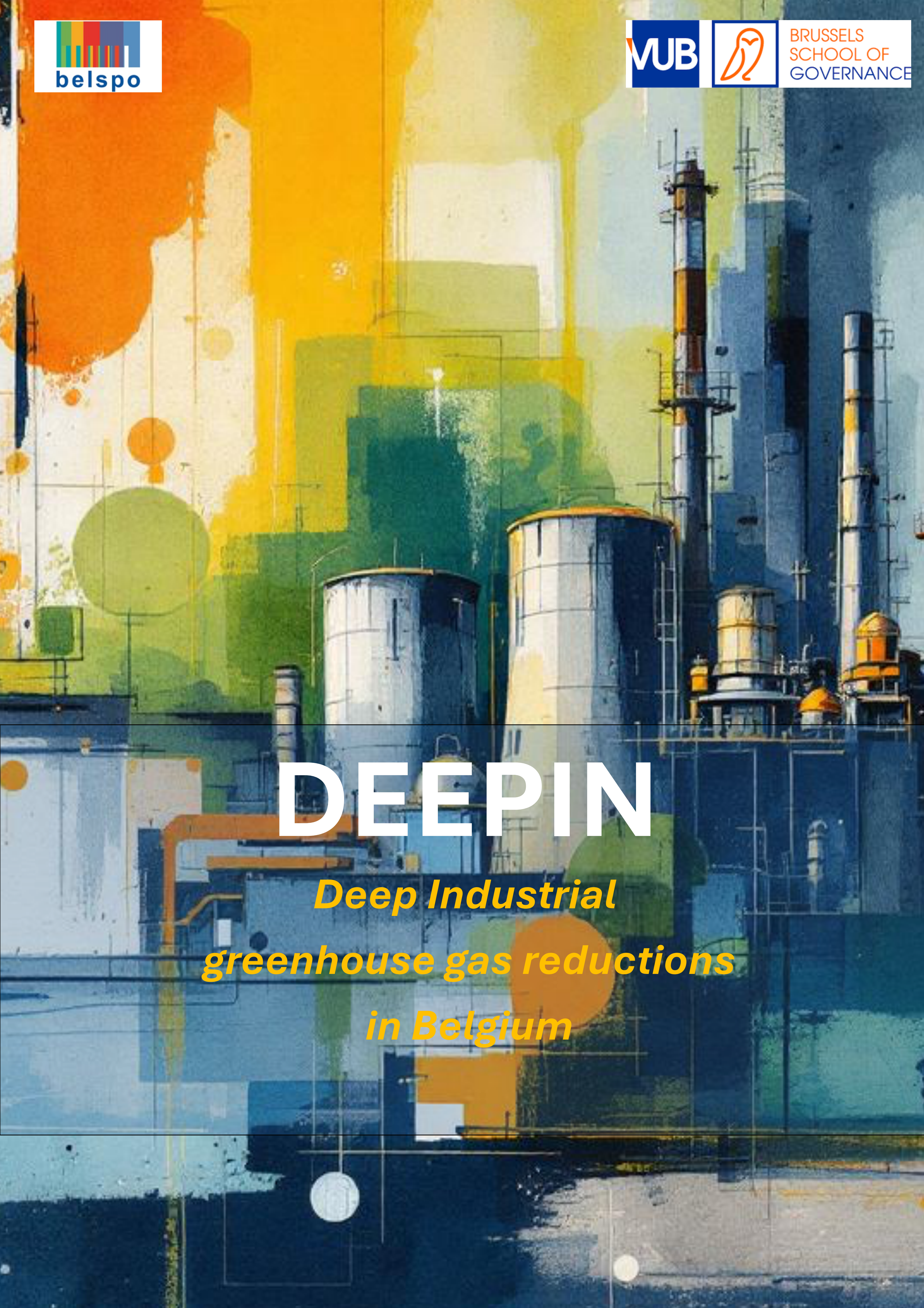

DEEPIN

Deep Industrial greenhouse gas reductions in Belgium

The DEEPIN project is BELSPO Science4Policy flash project on the request of the Federal Public Service Health, Food chain safety and Environment . The S4Policy Programme aims to provide a range of tools to support decision-making by the federal government and Federal Public Services (FPSs), based on scientific knowledge.

About the Brussels School of Governance (VUB)

The Brussels School of Governance (BSoG) is an alliance between the Institute for European Studies (VUB) and the Vesalius College. Located in the heart of Europe, the Brussels School of Governance is a leading hub for interdisciplinary teaching and innovative research. The BSoG strives to understand and help address the major societal challenges of our time — from migration and diversity to digital and green transitions, climate change, the evolving global economy, as well as geopolitical competition.

Authors:

Tomas Wyns (corresponding author: tomas.wyns@vub.be),

Stijn Van der Perre

Gauri Khandekar

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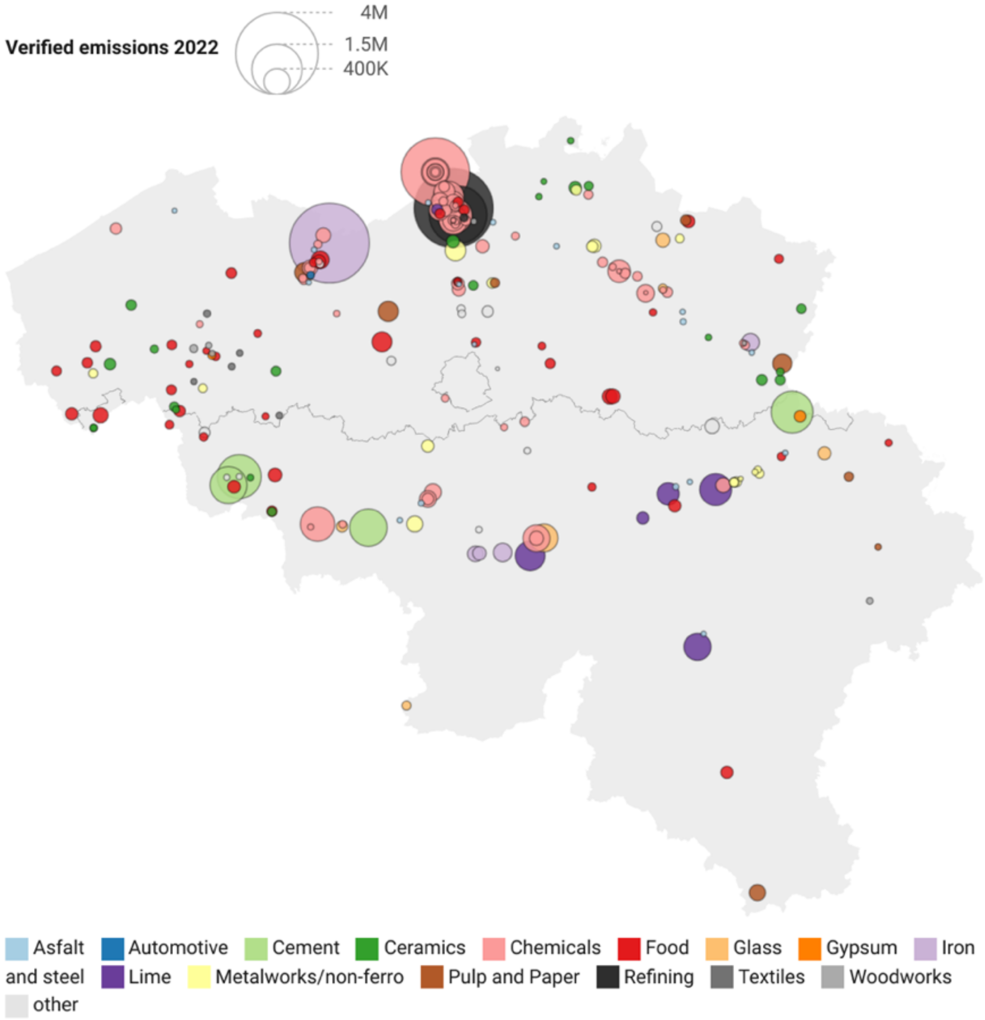
Executive summary

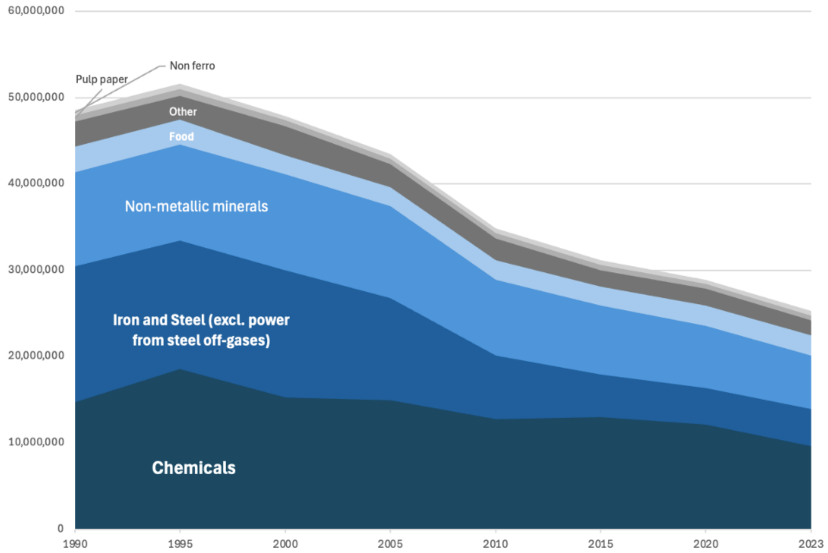
The DEEPIN research project has the goal to provide a rigorous, Belgium-specific assessment of industrial decarbonisation options that can plausibly deliver deep greenhouse gas (GHG) reductions by 2040–2050. It translates a large technology evidence base into investment-relevant insights, sectoral pathways, and concrete policy priorities, recognising Belgium's industrial strengths, its infrastructure constraints, and the urgency created by EU climate targets and the EU Emissions Trading System (ETS).

Belgium's industry accounts for around 30 Mt CO_2-eq emissions —about 28% of national emissions. Three sectors drive more than 80% of industrial GHGs: chemicals (~33%), steel (~28%), and non-metallic minerals (mainly cement and lime; ~21%). Emissions are geographically concentrated in Flanders—particularly in the Antwerp and Ghent clusters and along the Albert Canal—with significant process-industry emissions in Wallonia (cement, lime, ammonia).



EU ETS installations industry and 2022 emissions (sources: EUTL/VUB). For iron and steel this excludes emissions from waste gases for power production.

Since 1990, industrial emissions have fallen by almost half, due to efficiency gains, fuel switches, reduction of non-CO_2 greenhouse gases and structural changes—notably blast furnace closures in the steel sector. Yet what is left is harder to abate: high-temperature heat, carbon-intensive feedstocks, and (unavoidable) process emissions. Decarbonising these emissions is a different kind of challenge. It demands infrastructure that does not yet exist at scale (CO_2 transport and storage, much larger clean power supply and grid capacity), new technologies approaching market readiness (e.g., high-temperature electrification, hydrogen-based direct reduced iron), and carefully sequenced investment decisions.



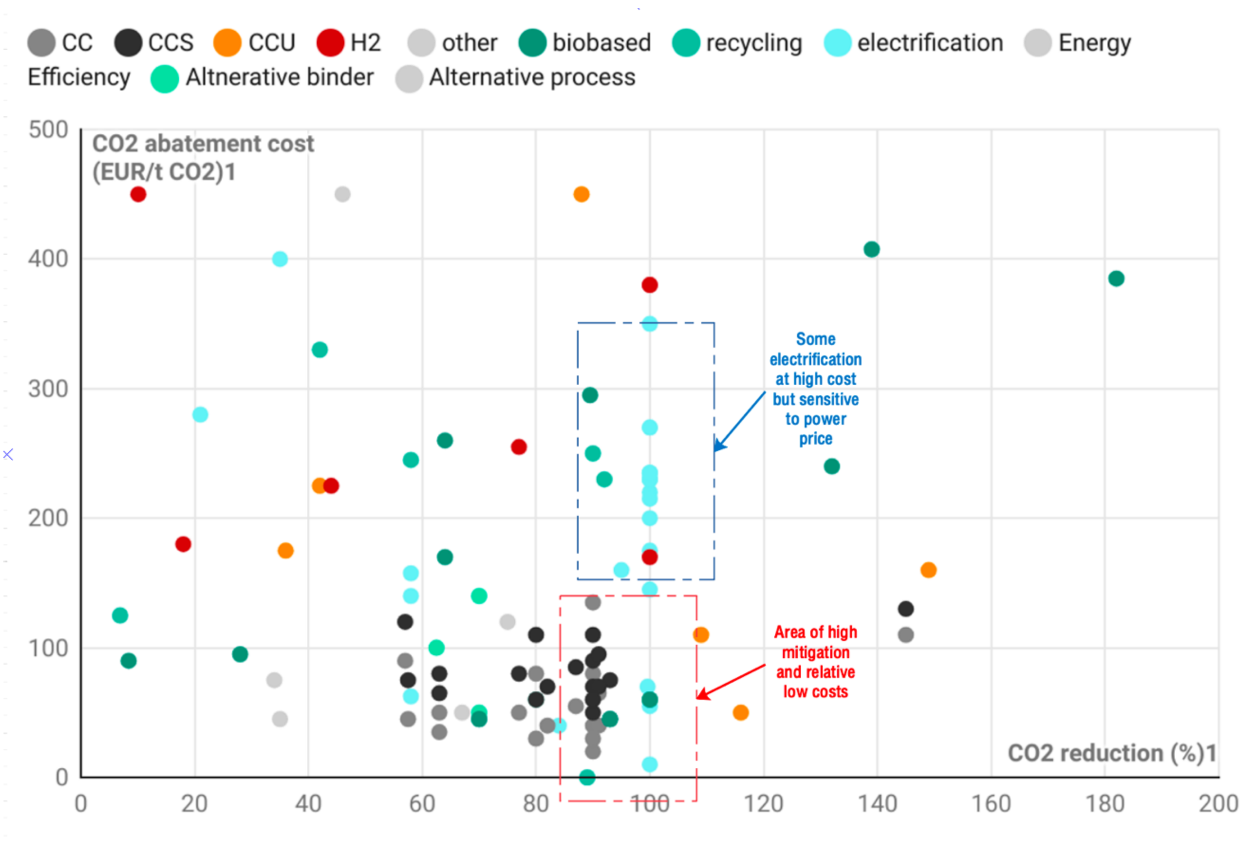
Evolution of industrial greenhouse gas (GHG) emissions (t CO_2-eq) - Source: Belgium, 2024, CRT

The DEEPIN project screened over 180 decarbonisation options and retained those likely to reach Technology Readiness Level (TRL) 9 by 2040, or already there. This yielded 114 technologies considered potentially deployable in Belgium by that time, of which around 90 underwent detailed techno-economic assessment. Options failing this maturity filter remain relevant post-2040 but were not assumed to contribute materially to achieving deep emission reductions.

The techno-economic analysis standardised assumptions to enable fair comparison across options. Costs were indexed to 2025. Base energy prices assumed electricity at €60–90/MWh and natural gas at €25–35/MWh. Direct electrification was assessed assuming zero-carbon electricity in the base case, with sensitivity to present grid intensity; carbon capture assumed 90% capture unless specified. Abatement cost is expressed as €/tCO_2 avoided versus an incumbent benchmark; Scope 1 and 2 emissions are covered. Because both electrification economics and net abatement are highly sensitive to power price and carbon intensity, DEEPIN includes targeted sensitivity analyses. Accounting treatment matters for CCU; the study distinguishes cases in which utilised CO_2 could or could not count toward mitigation.

Technologies were then filtered for Belgian relevance: Is the process present in Belgium? Are feedstocks and inputs (including clean energy) plausibly available at scale? Are the infrastructure preconditions (CO_2 transport/storage, hydrogen corridors, additional power production, high-voltage and distribution networks) realistic on relevant timelines?

DEEPIN's key message is that deep reductions - on the order of 90% versus 2005 - are technically and theoretically possible by 2040–2050 with technologies likely to be commercially ready in time. However, achieving such outcome in Belgium will critically depend on enabling strict conditions and policies such timely infrastructure development, credible long-term economics for low-carbon assets, and governance that can coordinate complex cross-sector system changes.



Overview of industrial mitigation technologies (% reduction (x-axis), Abatement cost (y-axis)) colored by technology type.

What will get us to deep reductions: sector insights

Chemicals

Belgium's relatively large and integrated chemicals sector is both the biggest opportunity and the most complex decarbonisation case. The backbone consists of near-term capture at high-concentration sources (e.g., hydrogen production via steam methane reforming and ethylene oxide), expansion of advanced plastics recycling, progressive electrification of heat, and strategic use of CO_2-to-methanol as a platform for circular olefins and aromatics as hydrogen and rules mature.

Full electrification of steam cracking is technically promising but highly sensitive to electricity price and grid carbon intensity. At power prices above ~€40/MWh, abatement costs rise sharply for electric naphtha cracking; at current Belgian grid intensity, net reductions (including the indirect emissions from electricity use) are still positive for naphtha steam cracking but may not be for ethane cracking without cleaner power. Low- to medium-temperature heat can be electrified quickly via heat pumps and e-boilers and can be made more cost-effective where waste heat can be harvested.

Conventional CO_2 capture at high-CO_2 streams is relatively low-cost and technically feasible today. By contrast, the CO_2 utilisation (CCU) options are generally expensive unless accounting recognises the climate service performed by durable utilisation, or unless the route creates permanent mineralisation. CCU pathways such as CO_2-to-methanol enable loop-closing for polymers, but need affordable green hydrogen and clear, credible CO_2 accounting rules.

Biomass and waste-derived feedstocks can substitute for fossil naphtha in limited volumes to make basic chemicals. Chemical recycling can be an essential complement to mechanical recycling in Belgium's polymer cluster but needs to develop value chains and deal with higher costs compared to virgin plastics production.

Steel

Belgian steel can decarbonise by combining near-term retrofits with structural process change. In the near-term blast-furnace retrofits with bio-carbon or hydrogen co-injection and top-gas recycling with amine capture can collectively reduce emissions substantially at comparatively low €/tCO_2, provided pipe-to-port CO_2 transport exists.

A more structural shift will happen by replacing the current blast furnaces with the direct reduced iron (DRI) plus electric arc furnace (EAF) route. Natural gas DRI with post-combustion capture is commercially viable now and a strong early mover where gas logistics allow. Progressively adding hydrogen increases ambition. Pure green hydrogen DRI can achieve near-complete abatement once hydrogen is affordable and DR-grade pellet quality is assured. Scrap-based EAF remains the least-carbon route wherever scrap quality and availability permit.

In the longer-term new electro steel-routes (molten oxide electrolysis; hydrogen-plasma smelting) are promising but depend on cheap, abundant clean power.

Cement and lime

There is no credible cement pathway to net-0 emissions without large-scale carbon capture for process emissions. A full toolset includes replacing part of the energy and CO_2 intensive Portland cement production with clinker substitution, novel binders and concrete/cement recycling. The use of alternative fuels and selected electrification are essential to reduce combustion emissions. Coupling electrification with capture of process CO_2 can deliver deep emission reductions. Mineralisation (e.g., Carbstone) offers a durable CCU niche where alkaline waste streams are available.

Pulp and paper

This sector's emissions are dominated by energy rather than process chemistry and already uses significant bioenergy. Rapid electrification of heat (heat pumps and e-boilers), valorisation of by-products (black liquor gasification; lignin separation; pyrolysis) and energy efficient water removal from pulp can deliver deep reductions. Several promising efficiency innovations are maturing (e.g., advanced dewatering and low-temperature pulping), with transformative potential in the 2030s.

Glass, ceramics, non-ferrous metals

These diverse sectors are smaller in aggregate but share common themes.

Glass: Sequentially combine higher recycled glass rates, digital process control, waste heat recovery (cullet/batch preheating, organic Rankine cycle), progressive electrification/electric boosting, and CCUS for process CO_2 within industrial clusters.

Ceramics: Most emissions arise from drying and firing. Focus first on process integration via heat recovery and preheated combustion, selected electrification of dryers and some kilns, drop-in low-carbon gases where available, and raw material optimisation to trim process CO_2. Site dispersion and low flue gas concentrations make CCS generally impractical.

Non-ferrous metals: Electrified melting and induction heating are already widely used for recycling metals; decarbonisation is tied to the power system and, for some processes, to cluster-level CCUS and/or use of alternative fuels.

Cross-cutting industrial heat

Electrification of low- and medium-temperature heat stands out as a "no-regret" measure. Industrial heat pumps routinely deliver large emission reductions at relative low abatement costs. The indirect emissions (related to electricity use) remain lowe even at current power grid intensities. To be economic attractive it is essential to make sure that the electricity price is less than 3 times that of natural gas. High-temperature electrification is technically feasible, but costs and CO_2 benefits depend on cheap, clean power and where possible thermal storage integration. Hydrogen or ammonia should be reserved for use cases that truly require a flame or a reducing atmosphere, but are suboptimal given their cost and infrastructure needs. Some high temperature processes (e.g. naphtha steam cracking) could choose carbon capture (and storage) as mitigation option if more cost effective compared to direct electrification and when CO_2 infrastructure is already available.

The sequencing is clear

The remainder of this decade must initiate large-scale deployment of low-/medium-temperature electrification; fit carbon capture technologies at high-concentration CO_2 sources; retrofit blast furnaces for carbon capture and feed replacement; scale advanced plastics recycling; and pursue clinker substitution and concrete/cement recycling. In this timeframe the final investment decisions for CO_2 backbones to ports and storage, and for major clean power and grid expansions have to be executed.

The 2030s are the "build decade": bring online DRI-EAF capacity, expand high-temperature electrification where economically justified, scale capture across cement/lime and selected chemicals and steel units within clusters, and commercialise novel processes in development now.

The 2040s deliver breadth and depth: broaden high-temperature electrification as power systems expand and become cheaper; rely on mature CO_2 networks for residual process emissions; integrate negative emissions (e.g. BECCS, mineralisation) and selective CCU to deal with the remaining greenhouse gas emissions.

Enabling deep industrial emission reductions in Belgium

Infrastructure

Two time-critical networks determine feasibility: a CO_2 transport and storage chain that connects major point sources to ports and North Sea storage, and a step-change in clean power capacity and grids. A Belgian CO_2 backbone to harbours by ~2035 is a precondition for cement, steel and chemicals to make capture decisions; clean power build-out and reinforcement of transmission and distribution grids must keep pace with electrification of industry and the broader economy. Industrial clusters should be equipped as multi-vector energy hubs integrating power, heat, hydrogen, and CO_2 management. Shared utilities—steam, oxygen—can reduce duplication and system costs.

Investment

Even with ETS pricing, most deep-decarbonisation options face cost premiums today. Carbon pricing will help, but major options—CCS, high-temperature electrification, hydrogen-DRI—need additional de-risking until costs fall. Contracts for Difference (CfDs) and the Innovation Fund can bridge viability gaps for first commercial plants. Reforming energy taxation to narrow the electricity–gas price gap is essential to make electrification competitive. Green public procurement and product standards for low-carbon steel, cement and chemicals can create early markets. Faster, coordinated permitting for priority infrastructure can unlock private capital earlier and cheaper.

Innovation

Belgium should focus scarce innovation budgets on moving late-stage options across the demonstration-to-commercialisation frontier: high-temperature electrification in cement, glass and chemicals; CCUS integration into cluster value chains (including methanol and aromatics pathways); and high-yield mechanical and chemical recycling platforms. Federal and regional programmes should be tightly aligned with EU instruments (Horizon Europe, Innovation Fund, IPCEIs) to leverage scale and cross-border cooperation.

Integration and governance

Industrial decarbonisation is not a collection of stand-alone projects; it is a coupled system of energy, heat, molecules and materials. Coordinated planning is needed to avoid stranded investments and to exploit synergies (e.g., waste heat matching, shared pipelines, integrated storage). Belgium's split competences require a governance arrangement that can set shared priorities and sequence decisions across federal and regional levels. A national transition council could steer spatial planning for CO_2 backbones, prioritise grid reinforcements, and coordinate cluster-level development. Cross-border coordination with neighbouring countries along EU CO_2 and hydrogen corridors is essential to reduce capital costs and ensure interoperability.

Where to start?

What policymakers can do first: no-regret and time-critical actions Several measures are robust to uncertainty and should proceed at pace.

Scale industrial heat pumps and hybrid e-boilers wherever practical, coupled with waste heat recovery and thermal storage to improve economics and grid flexibility.

Commit, the remainder of this decade, to a Belgian CO_2 backbone connecting major emitters to ports and to North Sea storage capacity, with a clear regulatory model and risk-sharing framework that enables early users to move without prohibitive network-access charges.

Lock in a power-system trajectory compatible with industrial electrification: additional domestic clean generation and import capacity, and reinforcement of transmission and distribution networks in and around industrial clusters. Reduce the structural electricity–gas price gap for industry through targeted tax and levy reform.

Create early, credible demand for low-carbon materials via public procurement and pilot product standards, anchored in transparent certification.

Accelerate permitting for nationally strategic infrastructures and first-of-a-kind industrial projects through integrated spatial planning and streamlined procedures.

Provide clarity on CO_2 accounting for CCU to enable investment decisions in circular carbon pathways; align with EU rules as they emerge.

The bottom line

With decisive policies on infrastructure, investment de-risking, innovation deployment and system integration, Belgium can deliver deep industrial decarbonisation while preserving its strategic industrial base.

For policymakers, the most valuable intervention is to deliver the common goods - CO_2 and power networks, credible markets for low-carbon products, and a governance framework that sequences investments coherently. If these enablers are in place by the mid-2030s, Belgian industry can remain competitive in a climate-neutral Europe.

1. Introduction

1.1. Project Overview and Strategic Importance

The DEEPIN project represents a comprehensive initiative to identify, assess, and prioritize climate-friendly industrial technologies specifically within the Belgian context, addressing one of the most critical challenges facing European industry in the transition toward climate neutrality. As industrial sectors collectively account for a substantial portion of global greenhouse gas emissions, with concentration in energy-intensive industries such as steel, chemicals and cement the development of effective decarbonisation strategies has become increasingly urgent for meeting international climate commitments and maintaining industrial competitiveness.

Belgium's industrial landscape presents unique opportunities and challenges for implementing deep emission reduction technologies. The country's strategic location within Europe, well-developed industrial infrastructure, and concentration of energy-intensive manufacturing facilities position it as both a critical player in European industrial decarbonisation and a potential testing ground for innovative climate technologies. However, the specific characteristics of Belgian industry, including its energy supply systems, infrastructure constraints, and economic framework, require tailored assessment approaches to identify the most viable pathways for achieving substantial emission reductions.

The DEEPIN project addresses this need through systematic mapping and evaluation of industrial decarbonisation technologies, focusing specifically on solutions that can achieve deep greenhouse gas emission reductions while remaining economically and technically feasible within Belgium's industrial context. The project's comprehensive approach encompasses technology identification, techno-economic assessment, and mitigation impact evaluation, providing stakeholders with information necessary to help make informed decisions about industrial decarbonisation investments and policy interventions.

1.2. Research Framework

The DEEPIN project is structured around three fundamental research questions that guide its assessment approach. First, the project seeks to identify technologies capable of achieving deep greenhouse gas emission reductions in energy intensive industries, focusing on solutions that can deliver the substantial decarbonisation required to meet climate objectives such as the EU’s 2050 net-0 emissions target. Second, it performs a techno-economic assessment of key technologies, evaluating the CO_2 avoidance cost. Third the project assesses the technologies which can be applied in Belgium and possible mitigation impact for Belgium.

The project's methodology uses a systematic four-component approach encompassing scope definition, technology selection, assessment frameworks, and mitigation impact evaluation. Technology selection relies on comprehensive data sources including a home-grown technology database, the International Energy Agency (IEA) clean energy technology guide, sectoral roadmap studies, company project information, and peer-reviewed scientific literature. This multi-source approach ensures comprehensive coverage of both established and emerging technologies while maintaining scientific rigor in technology evaluation.

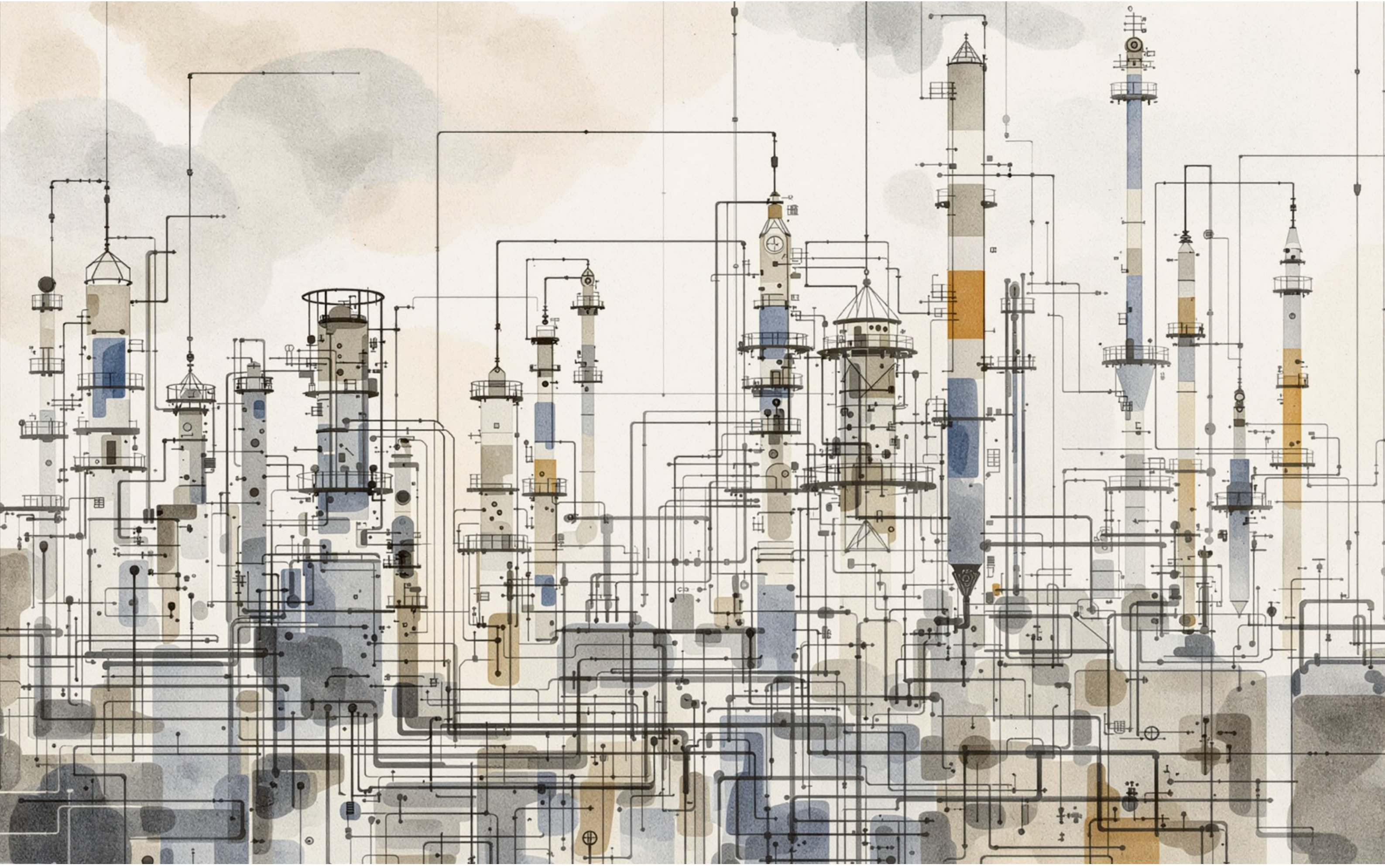
A critical component involves establishing realistic technology readiness criteria, specifically requiring technologies to achieve Technology Readiness Level (TRL) 9 by 2040. This criterion ensures that selected technologies represent viable near-term deployment options rather than speculative future possibilities, aligning assessment focus with the urgent timeline required for industrial decarbonisation. Additionally, the methodology incorporates specific Belgian context restrictions, evaluating whether sectors or processes are present domestically, whether technologies are viable at large scale within Belgium, and whether necessary infrastructure and feedstock resources are available.

1.3. Structure of this report

This report begins with the methodology chapter, which explains the framework for technology selection and assessment. This section also explains the standardised parameters used to calculate CO_2 mitigation potential and costs, ensuring a consistent evaluation process across all sectors.

The core of the report is a series of sector-specific technology assessments. Individual sections in chapter 3 provide an examination of greenhouse gas mitigation technologies for the chemical industry, iron and steel production, cement and lime and pulp and paper manufacturing. There is further a consolidated overview of several other sectors, including glass, and ceramics and non-ferrous metals production. Complementing these, the next sections provide a cross-cutting analysis of industrial heating solutions and a technical review of carbon capture technologies. A subsequent sensitivity analysis section explores how the viability of electrification is influenced by critical variables like electricity price and grid carbon intensity.

The report concludes by synthesizing these findings for the Belgian context. This final section identifies the most promising technologies for deployment by 2040, evaluates their sectoral and collective potential, and outlines the essential enabling conditions required for success. It ends with a forward-looking set of strategic policy recommendations designed to guide and accelerate the industrial transition for Belgium.



2. Methodology

2.1. Project Scope and Framework

The DEEPIN project methodology is structured around three core components that provide a comprehensive approach to mapping climate-friendly industrial technologies in the Belgian context: technology selection, assessment and mitigation impact evaluation. The technology selection and assessment focusses on different industrial sectors with but with additional horizontal technology assessments added for industrial heat applications, carbon Capture and Storage/Utilization (CCUS), and hydrogen production technologies. The project's scope is defined to address the specific research questions while maintaining practical applicability to Belgian industrial conditions. This includes establishing clear boundaries for technology evaluation, considering the unique characteristics of Belgium's industrial landscape, and ensuring that assessments reflect realistic implementation scenarios within the national context.

The sectoral scope of the project has a prime focus on the large emitting sectors such as chemicals, steel, cement and lime. The refinery sector is not explicitly treated in this project given that it is part of the energy transformation sector, but also because its main processes are implicitly covered by the chemicals industry's processes. Non-ferrous metals, glass, food and ceramics are not assessed in as much detail as the larger industries. However, many of the mitigation technologies in these sectors are also implicitly covered a specific cross sectoral assessment of industrial heat technologies.

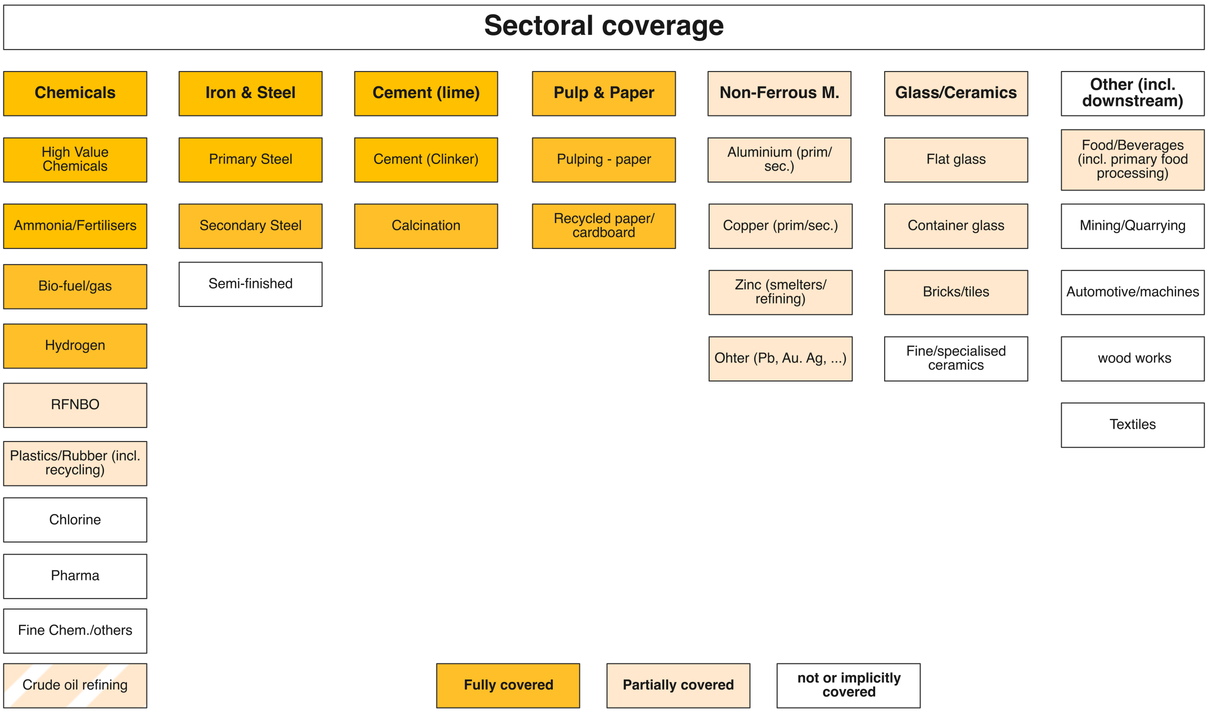


Figure 1: Sectoral scope of DEEPIN project

2.2. Technology Selection Methodology

Data Sources and Information Gathering

The technology selection process relies on a comprehensive array of information sources to ensure complete coverage of available and emerging technologies. Primary sources include the home-grown (BSOG-VUB) technology database, and the latest version of the International Energy Agency's (IEA) energy technology perspectives' (ETP) Clean Energy Technology Guide[1], providing standardized technology assessments and readiness levels.

Additional sources encompass various roadmap studies conducted at sectoral and national levels, direct information from companies and industrial sectors, and peer-reviewed scientific literature. This multi-source approach ensures that both established technologies and emerging innovations are captured within the assessment framework, providing a comprehensive view of available decarbonisation options.

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[1] IEA, 2025

Technology Readiness Level Criteria

A critical component of the selection methodology involves establishing Technology Readiness Level (TRL) criteria that align with realistic deployment timelines. The project applies a specific selection criterion requiring technologies to achieve technology readiness level (TRL) 9 (i.e. the technology is proven in its operational environment) by 2040. In practice this requirement is translated to selecting technology with current TRL of 6 or above. For large industrial processes, moving from pilot stage to large scale demonstration and first of a kind operation (including optimisation and process integration) takes time. Setting the cut-off point at 2040 also allows time for deployment of mature technologies before 2050 and for technologies that are slower to mature to have an impact after 2040.

Belgian Context Considerations

The methodology incorporates considerations relevant to the Belgian industrial context. These include evaluating whether sectors or processes are present within Belgium's industrial landscape, as certain technologies may be irrelevant if the corresponding industrial activities do not exist domestically.

Infrastructure considerations form another crucial restriction criterion, examining whether technologies require new or expanded infrastructure for implementation. This includes evaluating requirements for CCUS infrastructure, hydrogen distribution networks, electrical grid capacity for electrification technologies, and other supporting systems necessary for technology deployment.

Energy and feedstock availability represents an additional restriction factor, assessing whether sufficient affordable and sustainable energy sources and raw materials are available to support technology implementation at scale. This consideration is particularly important for energy-intensive technologies or those requiring specific feedstock inputs that may not be readily available in the Belgian market.

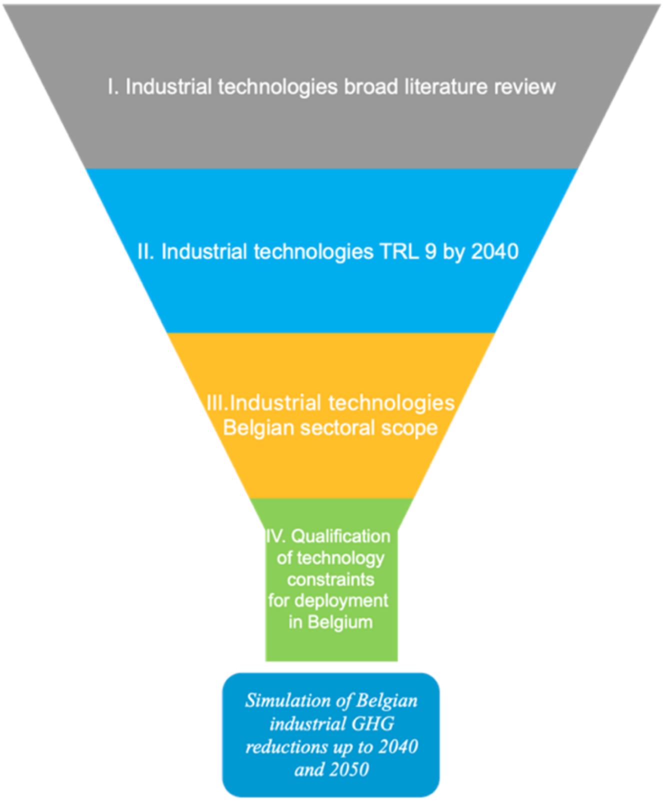

Figure 2: Technology funnel approach of DEEPIN project

2.3. Techno-Economic Assessment Framework

Emission Calculation Methodology

The assessment framework employs specific methodologies for calculating CO_2 emissions across different technology categories. For electricity-intensive processes, the methodology assumes access to green or renewable electricity with zero carbon footprint under optimal scenarios, reflecting the potential for complete decarbonisation through renewable energy integration. However, the report provides a sensitivity analysis calculating the indirect (electricity use related) emissions for a selection of technologies at a range of CO_2 intensities for power production.

Carbon Capture, Utilization (CCU) technologies are evaluated with the possibility of negative emissions under optimal scenarios[2]. However, accounting rules for CCU at EU level are still under development.[3] To accommodate for this uncertainty, this study split

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[2] i.e. the use of biogenic or air captured CO_2 and long-term storage in materials.

[3] The European Commission is assessing how to account for emissions from non-permanent CCU products and fuels as part of the upcoming ETS review in 2026.

some CCU technologies into options that allow or don't allow negative emission accounting.

Most CO_2 capture technologies are assessed assuming 90% capture efficiency unless otherwise specified, providing a standardised basis for comparison while acknowledging that actual performance may vary depending on specific implementation conditions and technology maturity. The CO_2 capture technologies will not represent the full costs for companies to mitigate their CO_2 emissions. Next to capturing the CO_2, there are costs for liquefaction, transportation and long-term storage. This can add around €30/t CO_2 (€15/t CO_2 for transport and around €15/t for storage) to the mitigation costs.[4] In this report both the capture cost and the full capture, transport and storage costs are separately shown for a selection of technologies.

Cost Assessment Parameters

The economic assessment methodology establishes standardized cost parameters to ensure consistent evaluation across technologies. European Union Emissions Trading System (ETS) prices are not included in the cost calculations for technologies. However, the cost per tonne avoided CO_2 can be compared with current (and future) EU carbon prices to assess their viability.

Energy pricing assumptions include electricity costs ranging from €60-90/MWh and natural gas prices of €25-35/MWh, reflecting realistic energy cost scenarios for Belgian industrial operations. The report provides also a sensitivity test at different electricity costs to show the impact on the CO_2 avoidance cost.

Biomass costs are derived from literature values, though complete uniformization is not possible due to the heterogeneous nature of biomass feedstocks and regional availability variations.

All production costs are indexed to 2025 levels to provide current economic relevance and facilitate comparison with contemporary investment decisions. This indexing approach ensures that assessments reflect current economic conditions rather than historical cost structures that may no longer be applicable.

The literature sources and calculation methods for the technology assessments in this report can be found in the addendum to this report: "**DEEPIN – Technology Assessment - Addendum**".

Analytical Formulas and Metrics

The methodology employs standardized formulas for calculating key performance metrics across all technologies. CO_2 mitigation potential is calculated as the difference

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[4] European Technology Platform for Zero Emission Fossil Fuel Power Plants, 2011

between incumbent technology emissions and new technology emissions, expressed per unit of product or energy delivered (t CO_2/t product or t CO_2/GJ).

CO_2 reduction percentage is determined by comparing the emission difference to incumbent technology emissions, providing a relative measure of decarbonization potential. CO_2 mitigation cost is calculated as the ratio of additional total cost to avoided CO_2 emissions, expressed in €/t CO_2 avoided[5], enabling economic comparison across different decarbonization options.

- CO_2 mitigation potential = $\frac{\mathrm{CO_2,em\ (incumbent)} - \mathrm{CO_2,em\ (new\ tech)}}{\mathrm{t\ product\ or\ GJ\ energy\ delivered}}$ [t CO_2/t product or t CO_2/GJ]
- CO_2 reduction = $\frac{\mathrm{CO_2,em\ (incumbent)} - \mathrm{CO_2,em\ (new\ tech)}}{\mathrm{CO_2,em\ (incumbent)}}$ [%]
- CO_2 mitigation cost = $\frac{\mathrm{total\ additional\ cost}}{\mathrm{avoided\ CO_2\ emissions}} = \frac{\mathrm{cost\ (new\ tech)} - \mathrm{cost\ (incumbent)}}{\mathrm{CO_2,em\ (incumbent)} - \mathrm{CO_2,em\ (new\ tech)}}$ [€/t CO_2 avoided]

The assessment relies primarily on literature-based data rather than proprietary process modelling. However, data is adapted to reflect similar energy prices for electricity and natural gas across all technologies, ensuring consistent economic evaluation conditions.

The CO_2 footprint assessment encompasses Scope 1 and Scope 2 emissions unless otherwise specified, covering direct emissions from industrial processes and indirect emissions from electricity consumption. For certain technologies, broader system boundaries may be applied to capture upstream emissions from fuel production and combustion or downstream impacts from product use.

As mentioned before, some of the technologies that can use (e.g. biogenic, or air captured) CO_2 to make products or materials, are split into two options: one where the utilised CO_2 is fully accounted (resulting in negative emissions) and a one where this is not the case.

2.4. Mitigation Impact Assessment for Belgium

Sectoral Emission Analysis

The mitigation impact methodology begins with comprehensive assessment of sectoral emissions using national databases and reporting systems. This includes analysis of data reported to European Union institutions and the United Nations Framework

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[5] In the case of carbon capture, the cost for CO_2 capture is calculated, but to achieve full mitigation these emissions will need to be transported and stored. These costs need to be added to the CO_2 capture cost. For the purpose of this report both the Carbon Capture and the Carbon Capture and Storage costs are considered.

Convention on Climate Change (UNFCCC), ensuring alignment with official emission inventories and accounting methodologies.

Technology Impact Evaluation

Expert opinion is used to assess the potential impact of selected technologies on Belgian industrial emissions. This assessment enables evaluation of multiple technology options while maintaining sufficient detail to inform policy and investment decisions.

Each technology group (e.g. electrification, CCU, CSS, ...) is evaluated on the extent to which it can contribute to 2040-2050 mitigation goals, but also what the boundary conditions are for application in Belgium. This is followed by a similar analysis but from a sectoral perspective. Finally, a brief overarching simulation using a heuristic approach demonstrates the theoretical mitigation potential for Belgium.

Policy Recommendations

The policy recommendations are designed to address identified barriers to technology deployment while leveraging Belgium's specific industrial strengths and infrastructure capabilities. They consider both technology-specific support measures and broader systemic changes needed to enable widespread industrial decarbonisation, ensuring that recommendations are both technically sound and, in theory, feasible within the Belgian policy context.

3. Belgian industry overview

Industry in Belgium is responsible for around 30 million tonne (Mt) CO_2-eq[6] greenhouse gas emissions, not including the indirect emissions associated with power production. This represents around 28% of the total Belgian greenhouse gas emissions.[7]

The largest emitting sectors are chemicals (33%), steel (28%) and the non-metallic mineral sector (21%) of which cement, and lime production constitute the largest part. In total these represent over 80% of the Belgian industrial greenhouse gas emissions.

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[6] This includes the emissions related to power production from steel production waste gases.

[7] Belgium, 2024. 2022 data

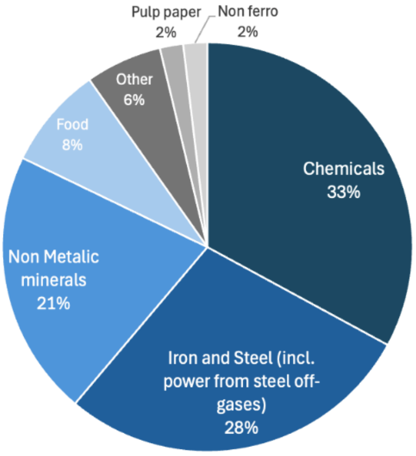

Figure 3: Share of industrial greenhouse gas emissions in Belgium (2023) - Source: European Environment Agency, Belgium, 2024, common reporting table CRT to UNFCCC[8]

Since 1990 industrial greenhouse gas emissions have declined by almost 50%.[9] All sectors saw notable reductions, but the most dramatic decrease happened in the steel industry (-73%). The latter is largely coming from major closures of blast-furnaces (and steel production in Belgium) between 1990 and 2010.

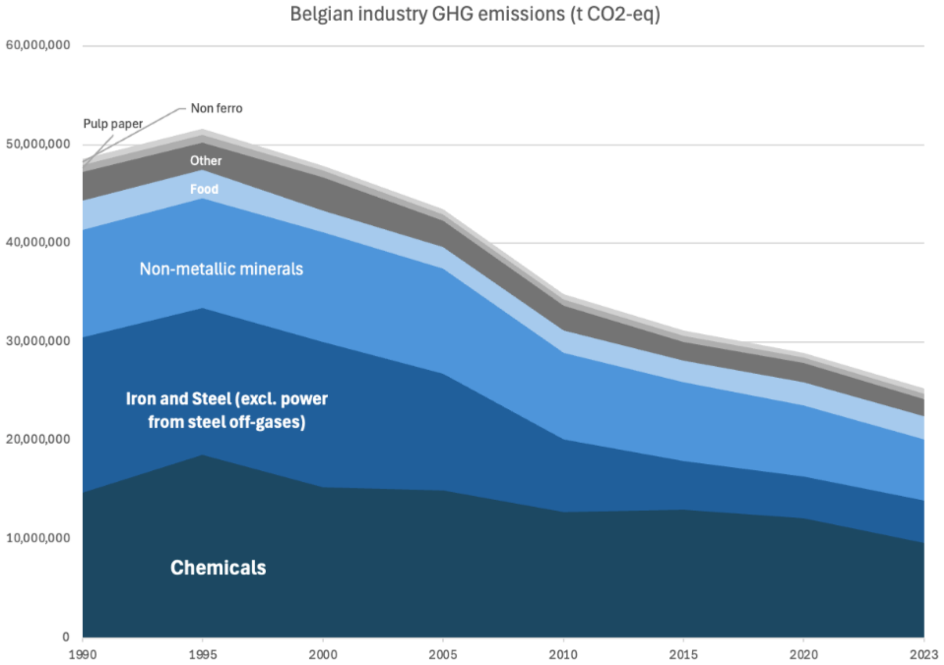

Figure 4: Evolution of industrial greenhouse gas (GHG) emissions (t CO_2-eq) - Source: Belgium, 2024, CRT

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[8] Ibid.,

[9] 48% reduction in 2023, excluding the emissions from steel waste gases in power production.

Over the last 3 decades industrial production has declined in most sectors with steel the most outspoken moving from almost 12 Mt production per year in 1990 to 8 Mt in 2022. Cement and lime production also noted important production drops over this period. While the production drops can explain part of the emission reductions, the overall picture is more nuanced with production efficiency, fuel changes and reduction of non-CO_2 greenhouse gases also contributing. One notable exception to these production evolutions is the petrochemical industry which noted important expansions in Port of Antwerp in the 1990-ies.

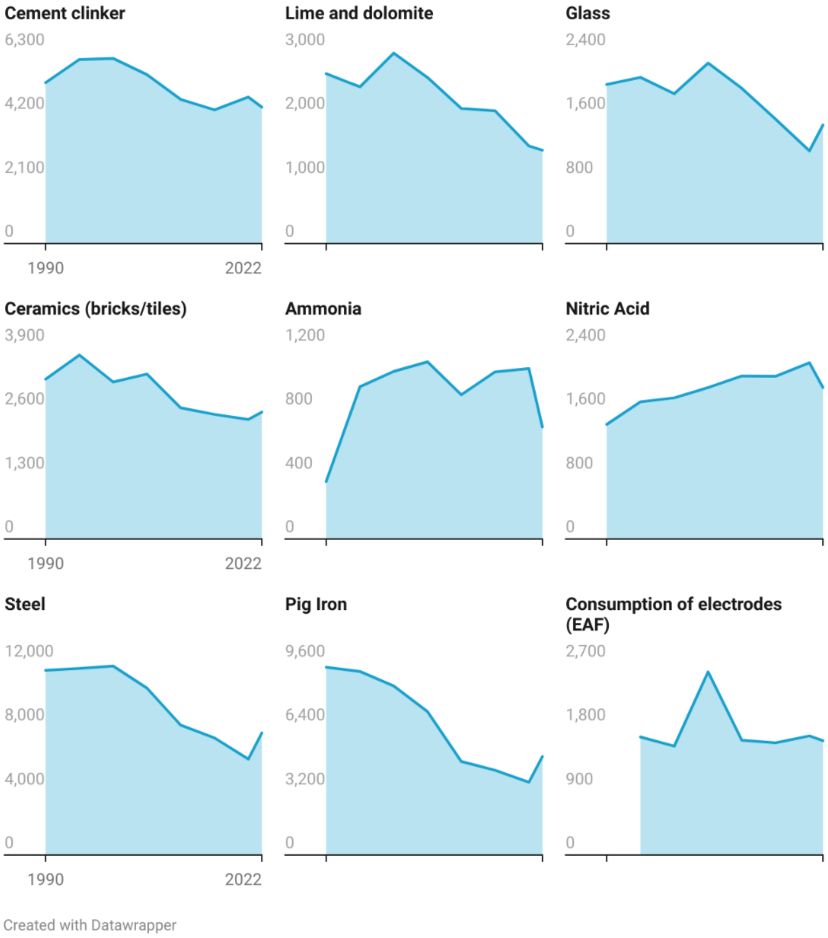

Figure 5: Evolution of industrial production in Belgium for cement, lime, glass, ceramics, ammonia, nitric acid, steel, pig iron and electrodes used in EAF (kt). Source: Belgium, 2024, CRT

Geographically most industrial emissions occur in the Flemish region via steel and chemicals production. Large concentrations of industrial emission sources can be seen around the ports of Antwerp and Ghent and the Albert Canal. In the Walloon region the main emissions come from cement, lime and ammonia production. Food production, ceramics, textiles and ceramics have more distributed sites across the country.

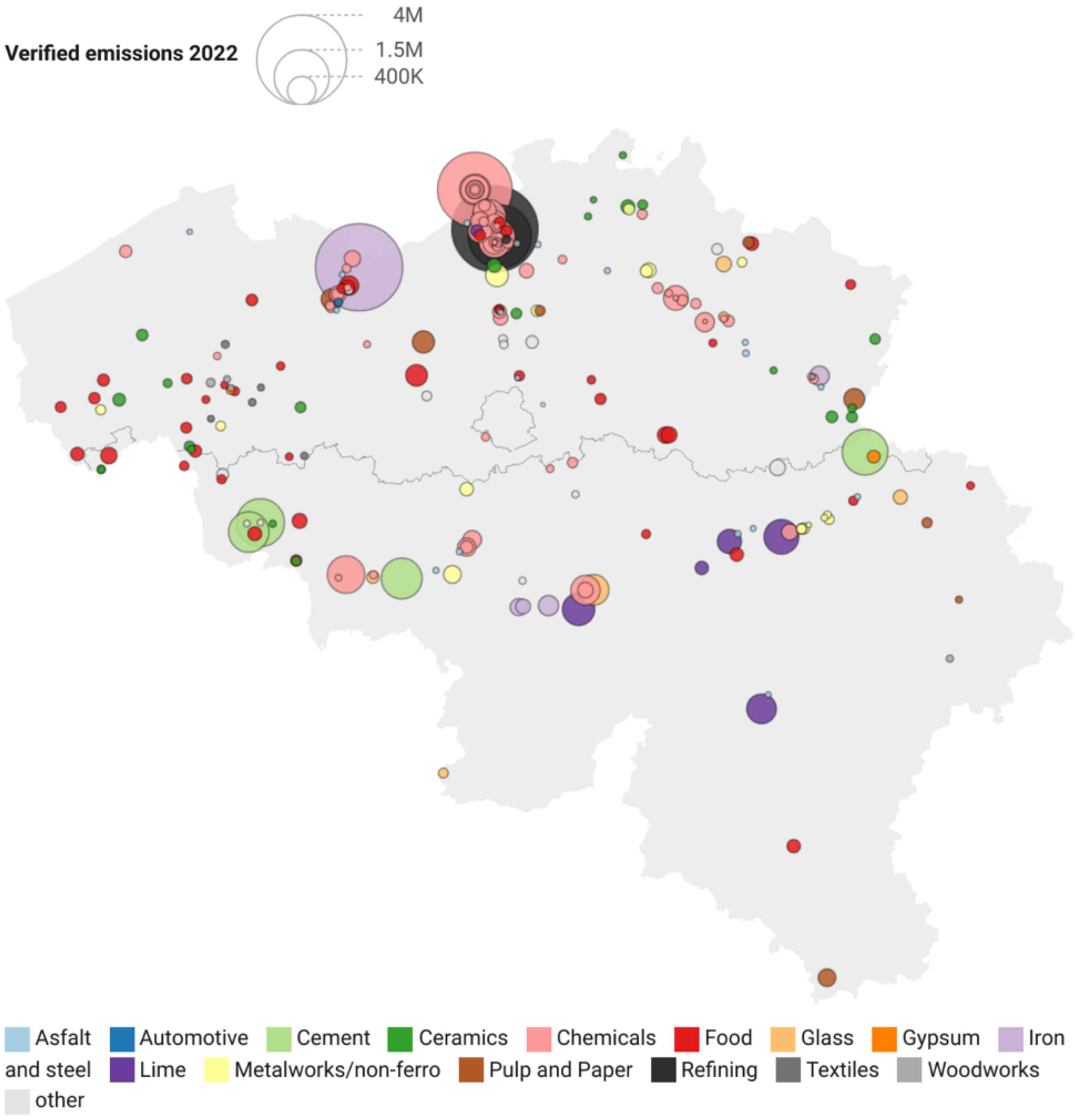

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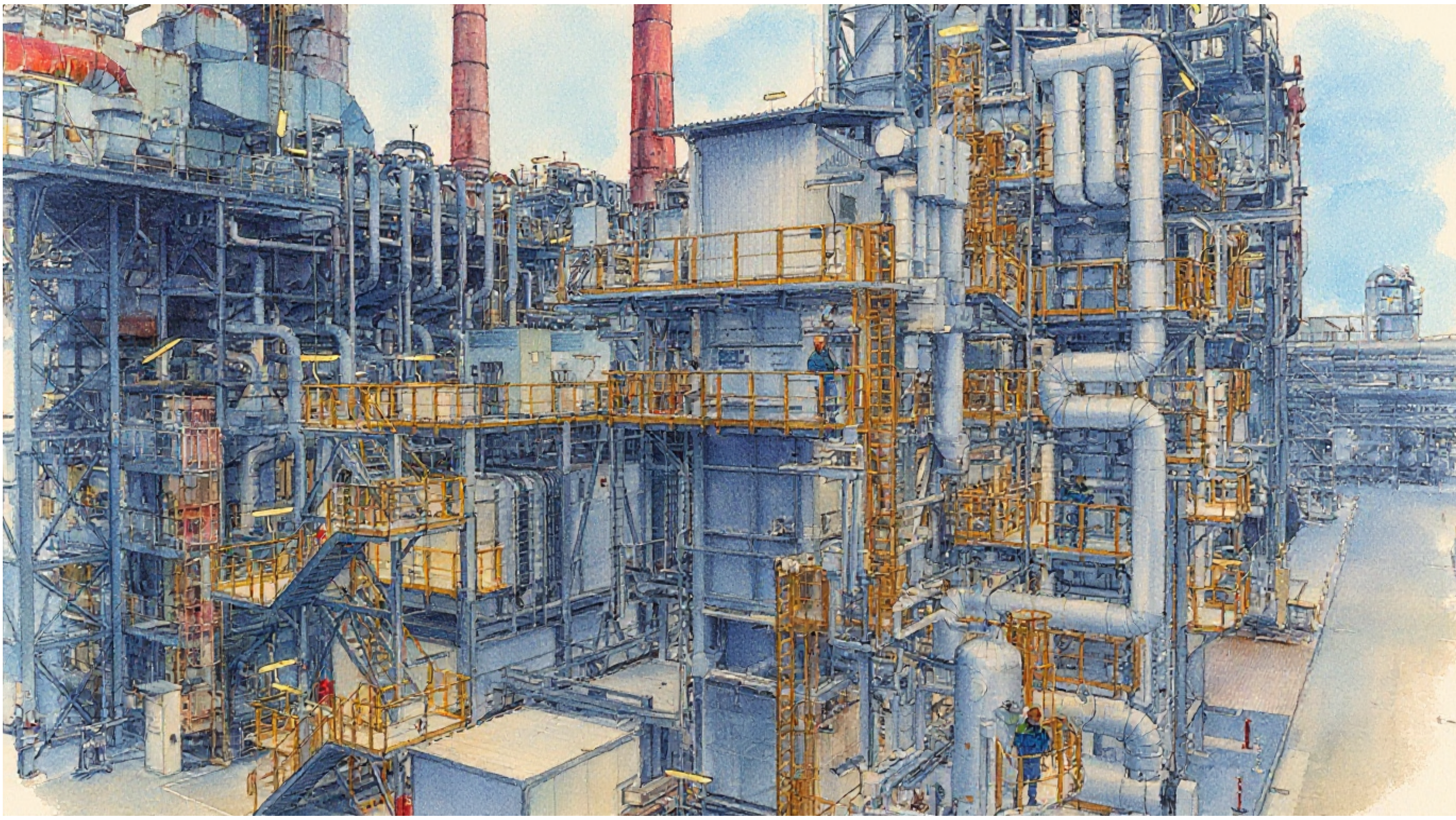
Figure 6: EU ETS installations industry and 2022 emissions (sources: EUTL/VUB). For iron and steel this excludes emissions from waste gases for power production.



4. Chemical industry

4.1. Introduction to the sector and main processes

Industry Overview

In 2021, total GHG emissions from the chemical industry in the EU amounted to 155 Mt CO_2-eq or almost 5% of total GHG emissions in the EU.[10] In Belgium this share is significantly higher, 10% of total Belgian GHG emissions, demonstrating the relatively large size of the industry in Belgium. The chemical industry contributes around 33% to the industrial greenhouse gas emissions in Belgium.

The main processes driving these emissions are petrochemicals production and production of ammonia, together with emissions associated with energy use (combustion of fossil fuels) in these and other chemical production processes.

In 2023 GHG emissions related to chemicals production were 34% lower compared to 1990 levels. However, 2023 saw important reductions in production related to the ongoing energy crisis. In 2022 the emissions were 17% lower compared to 1990. The latter reductions happened even with major growth in production (of basic chemicals) since 1990. The majority emission reductions between 1990 and 2022 can be attributed to the reduction in non-CO_2 greenhouse gases (e.g. N_2O and fluorinated greenhouse gases) and the more efficient use of energy in the industry. Over the same time there was

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[10] European Environment Agency, 2025

an increase in overall energy consumption, particularly in non-energetic applications (e.g. naphtha feedstock). This increase is primarily attributed to the expansion of basic chemicals via new or expanded steam cracker units in the 1990-ies.

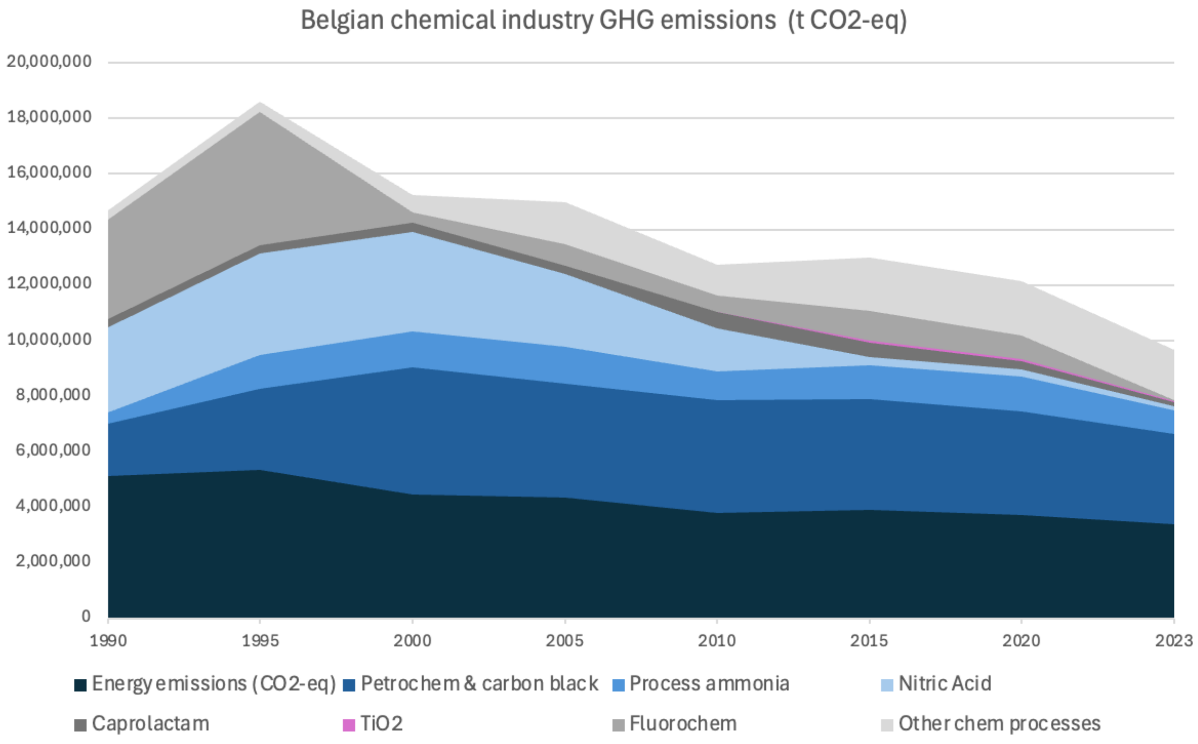

Figure 7: Evolution of Belgian chemical industry GHG emissions (t CO_2-eq). Source: Belgium, 2024, CRT

In Belgium, the estimated production of High Value Chemicals (HVCs) from steam cracking and propane dehydrogenation is around 5.5 Mt per year. With 5 Mt produced in Flanders (most in Port of Antwerp) and around 300 kt in the Walloon region olefins in the smaller Feluy cluster.[11] Specifically, this 5 Mt HVC production is estimated to consist of around 43% ethylene, 32% propylene, 5% butadiene and 19% BTX.[12]

HVCs, which form the backbone of chemical value chains in Belgium, particularly for polymer production, but also for most of the other parts of the chemical value chain (e.g. man-made fibres, glues, lubricants, paints, pesticides, pharmaceuticals, ...)

Total amount of polymers produced in Belgium (with most of this production taking place in Flanders) was 9.8 Mt in 2018; polypropylene and polyethylene constitute the largest categories of these polymers. Other polymers, such as those based on vinylchloride (e.g.,

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[11] The HVC capacity is expected to rise by 1 Mt (ethylene) in 2026-2027 with the addition of a new ethane cracker. On the other hand, in 2025 one of the smaller naphtha steam crackers was taken offline.

[12] Wyns, T. and Khandekar, G. 2020. These figures are derived from calculations using literature, including a model for a German steam cracker, and data from the Flemish energy balance and EU ETS emission reports

PVC), styrene (PS), and polyurethane, are also produced at significant scales, ranging from 500 kt to 1,000 kt per year.[13]

Ammonia, a major component for fertilisers and some polymers, also saw important production growth in Belgium (from 360 to 1000 kt between 1990 and 2020). Recently, following the energy cost crisis, production declined to around 700 kt following the closure of some production processes.

4.2. Key Chemical Production Processes

4.2.1. Steam Cracking for Olefins and Aromatics Production

The production of olefins and aromatic compounds through steam cracking represents one of the most fundamental and energy-intensive processes in the petrochemical industry. These high-value chemicals form the building blocks for many downstream products, from plastics and synthetic fibres to pharmaceuticals and specialty chemicals.

Steam cracking utilises various hydrocarbon feedstocks, typically smaller paraffins containing two to ten carbon atoms. The most common feedstocks include ethane, propane, liquefied petroleum gas (a mixture of propane and butane), and naphtha[14]. These feedstocks are primarily derived from crude oil distillation processes, hydraulic fracturing operations, or as valuable by-products from the thermal or catalytic cracking of heavier hydrocarbon fractions.

The steam cracking process itself involves mixing these hydrocarbon feedstocks with steam in specialized tubular reactors designed for operating at temperatures above 800°C with extremely short residence times. The steam serves multiple critical functions: it acts as a diluent to control reaction rates and influence product composition, while simultaneously preventing the formation of undesirable carbon deposits (cokes) that could damage equipment or reduce efficiency. The chemical reactions proceed through a complex free radical mechanism, initiated by the thermal breaking of carbon-carbon bonds, followed by beta-scission reactions that yield olefins and generate new, shorter-chain radicals. The reaction sequence terminates when radicals either combine with each other or undergo hydrogen transfer reactions to form stable paraffins or olefins.[15]

The product portfolio from steam cracking includes several high-value chemicals, most notably ethylene, propylene, 1,3-butadiene, and the BTX aromatics group (benzene, toluene, styrene, and xylene). The specific composition of the product mixture depends

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[13] Wyns, T. and Khandekar, G., 2020.

[14] comprising C5-C10 hydrocarbons

[15] Almuqati et al., 2024

heavily on the feedstock selection; for instance, naphtha-based crackers typically yield a higher proportion of BTX aromatics, while ethane or propane feedstocks favour the production of smaller olefins.

An alternative process is propane dehydrogenation (PDH), which specifically converts propane to propylene and hydrogen. This highly endothermic process requires multiple high-temperature reactors operating at 550-700°C in series configuration with intermediate heating stages, followed by sophisticated low-temperature downstream processing for product separation and purification.[16]

The energy consumption and carbon emissions associated with steam cracking vary significantly depending on the feedstock used. Naphtha steam crackers demonstrate CO_2 emissions of approximately 0.8 to 1.2 tonnes per tonne of HVC produced, with a specific energy consumption ranging from 12-13 GJ per tonne of HVC product. The energy distribution shows that roughly 60% is consumed in the cracking sections themselves, while the remaining 40% is utilized in downstream separation and purification processes. Ethane steam crackers operate more efficiently, producing only 0.4 tonnes of CO_2 per tonne of high-value chemicals with an energy consumption of 9-10 GJ per tonne HVC. Propane steam crackers fall between these extremes, generating 0.8 tonnes of CO_2 per tonne of product with energy consumption of 10-11 GJ per tonne. The propane dehydrogenation process shows higher emissions intensity at 0.8 tonnes of CO_2 per tonne of HVC produced, with energy consumption ranging from 11-13 GJ per tonne.[17] [18]

4.2.2. Hydrogen Production via Steam Methane Reforming (SMR)

Hydrogen production represents one of the most carbon-intensive processes in the chemical industry, primarily due to the widespread use of steam methane reforming as the dominant production technology. This process, while technically mature and economically efficient, inherently generates substantial CO_2 emissions as a direct consequence of the chemical reactions involved.

Steam methane reforming utilises methane as the primary feedstock, though higher alkanes such as naphtha can also be employed. The hydrogen produced through fossil fuel reforming is classified as "grey" hydrogen, while production from coal feedstocks yields "black" hydrogen, which typically results in approximately double the CO_2 emissions compared to grey hydrogen production.

The steam methane reforming process encompasses two primary chemical reactions. The initial reaction involves methane reacting with steam at temperatures between 800-

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[16] Broeckhoven, K. et al., 2022.

[17] Ibid.,

[18] Wyns, T, and Khandekar, G., 2020

1000°C using a nickel catalyst supported on a porous substrate, producing carbon monoxide and hydrogen.[19]

The thermal energy required for the steam reforming reaction can be supplied through two distinct approaches. The single-step process involves partial oxidation of methane by introducing air or oxygen directly into the reactor, while the two-step process relies on external heat sources. For applications requiring maximum hydrogen yield, such as ammonia synthesis, the process typically employs multiple reactors operating at progressively lower temperatures to optimize the water-gas shift reaction. For the use of SMR hydrogen in ammonia production downstream processing involves the full removal of CO_2 using amine-based absorption and/or pressure swing adsorption (PSA) systems.

The environmental impact of hydrogen production through steam methane reforming is substantial, with CO_2 emissions reaching approximately 9 tonnes per tonne of hydrogen produced. The specific energy consumption amounts to 23 GJ per tonne of hydrogen, though when accounting for the energetic value of the methane feedstock, this figure increases dramatically to 158 GJ per tonne H_2.[20]

Hydrogen serves as a critical raw material for numerous industrial applications, including ammonia production for fertilizers, hydrodesulfurization processes for crude oil refining, hydrocracking operations, methanol synthesis, and Fischer-Tropsch reactions for producing synthetic lubricants and fuels. The carbon monoxide co-product from steam methane reforming also finds applications in phosgene and methanol production.

4.2.3. Ammonia Production via the Haber-Bosch Process

Ammonia is mostly used in the production of fertilisers, but it is also an important feedstock in production of amines for e.g. caprolactam production and in urea and melamine production. In Belgium annual ammonia production is currently around 700 kt.[21]

The Haber-Bosch process synthesizes ammonia from nitrogen and hydrogen using a porous iron catalyst under demanding operating conditions of 450-550°C and 150-350 bar pressure. Industrial ammonia plants are typically integrated with steam methane reforming units to ensure reliable hydrogen supply. The carbon emissions associated with ammonia production range from 1.6 to 1.8 tonnes of CO_2 per tonne of ammonia for combined steam methane reforming and ammonia synthesis operations. The specific

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[19] According to the equation: $CH_4 + H_2O \rightleftharpoons 3H_2 + CO$. The carbon monoxide produced can subsequently undergo the water-gas shift reaction with additional steam to generate more hydrogen and carbon dioxide: $CO + H_2O \rightleftharpoons CO_2 + H_2$. When both reactions proceed to completion, the overall process converts methane and steam into hydrogen and carbon dioxide: $CH_4 + 2H_2O \rightleftharpoons 4H_2 + CO_2$.

[20] Broeckhoven, K. et al., 2022.

[21] Belgium, 2024

energy consumption reaches 14 GJ per tonne of ammonia, increasing to 35 GJ per tonne when accounting for methane feedstock energy content.[22]

Ammonia production happens via the Haber-Bosch process where hydrogen and nitrogen (from the air) are forced to bind together at high temperature and pressure with use of a metal catalyst. The reaction is highly exothermic with excess heat (around 4 GJ/t NH_3)[23] often used for steam and/or power production.

Ammonia production comes with emissions of N_2O, a powerful greenhouse gas, almost all of which can be catalytically removed. This is a commercially available and relative cheap mitigation technology, currently applied in Belgium.

Per tonne ammonia around 1.3 t CO_2 process emissions occur and 0.6 t CO_2 emissions related to combustion.[24] The process emissions have a high CO_2 concentration given that CO_2 contaminates the Haber-Bosch process' catalyst and hence needs to be removed completely. Ammonia plants hence produce large flows of almost pure CO_2 gases, which are well suited for carbon capture and storage or utilisation (CC(U)S).[25]

Approximately 80% of global ammonia production serves nitrogen fertilizer applications, including direct ammonia application, ammonium nitrate synthesis, and urea production. Additional applications encompass nitric acid manufacturing, plastic production (particularly acrylonitrile), and explosive manufacturing. Urea production involves reacting ammonia with CO_2 in a two-step heterogeneous process at 180-200°C and 180-200 bar without catalysts, requiring an additional 3.29 GJ per tonne of urea, primarily as process steam.[26]

4.2.4. Chlorine Production Through Electrolysis

Chlorine (Cl_2) production via the chlor-alkali process represents a unique case in chemical manufacturing due to its already high degree of electrification. This process involves the electrolysis of aqueous sodium chloride solutions, generating chlorine, hydrogen, and sodium hydroxide.[27]

The electrolysis occurs in specialized membrane cells where chloride ions undergo oxidation to chlorine at the anode, while water reduction produces hydroxide ions and hydrogen gas at the cathode. Ion-selective membranes permit sodium ion transport while preventing anion diffusion, ensuring product separation and purity.

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[22] Broeckhoven, K. et al., 2022

[23] Batool & Wetzels, 2019

[24] Ibid.,

[25] Ibid.,

[26] Broeckhoven, K. et al., 2022

[27] According to the reaction: $2NaCl + H_2O \rightleftharpoons Cl_2 + H_2 + 2NaOH$.

The process demonstrates relatively low carbon emissions of 0.4 tonnes CO_2 per tonne of chlorine in Belgium (131 g CO_2/kWh)[28], though this increases to an EU average (258 g CO_2/kWh[29]) of 0.8 tonnes CO_2 per tonne, reflecting the strong dependence on regional electricity grid carbon intensity. With approximately 95% of the 11 GJ per tonne specific energy consumption derived from electricity, this process is already well-positioned for decarbonization through renewable energy adoption.[30]

The hydrogen by-product of chlorine production typically finds applications in hydrochloric acid production, ammonia synthesis, hydrogen peroxide manufacturing, or energy generation through combustion.

Chlorine is used in the production of polyvinylchloride (PVC), hydrochloric acid (HCl) and has uses in pesticide and pharmaceutical value chains.

4.2.5. Methanol Production Through CO Hydrogenation

Methanol production represents another significant process in the chemical industry, primarily accomplished through the hydrogenation of carbon monoxide sourced from synthesis gas. Alternative production routes utilizing CO_2 as feedstock exist but require substantially more hydrogen input and involve preliminary reverse water-gas shift reactions, making them less economically attractive under current conditions. While there is no significant methanol production in Belgium at this time, methanol can become an essential stepping stone molecule in a net-0 emissions chemicals industry as a replacement of e.g. naphtha.

Traditional methanol synthesis[31] utilizes zinc oxide/chromium oxide catalysts operating at approximately 400°C and 300 bar pressure. More modern processes employ highly active copper-based catalysts that enable operation under more moderate conditions of 250°C and 50 bar, offering improved energy efficiency and reduced capital costs.

The carbon footprint of methanol production ranges from 0.8 to 1.0 tonnes of CO_2 per tonne of methanol for integrated steam methane reforming and methanol synthesis operations. This emission intensity is significantly lower than hydrogen production due to methanol's higher molecular weight (32 g/mol), which provides better carbon efficiency. The specific energy consumption amounts to 12.5 GJ per tonne of methanol, increasing

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[28] Nowtricity, 2024

[29] European Environment Agency, 2025

[30] See: Nowtricity, 2024 and European Environment Agency, 2025

[31] The methanol synthesis process involves two main chemical reactions. The primary reaction converts carbon monoxide and hydrogen directly to methanol: $CO + 2H_2 \rightleftharpoons CH_3OH$. A secondary reaction pathway involves CO_2 hydrogenation: $CO_2 + 3H_2 \rightleftharpoons CH_3OH + H_2O$. These reactions can be conducted under different operating conditions depending on the catalyst system employed.

to 37.5 GJ per tonne when including the energy content of the methane feedstock.[32] Methanol serves as a versatile chemical intermediate with applications spanning multiple industries. Major uses include polyurethane manufacturing, but methanol can also become a key molecule for olefins production via the methanol-to-olefins (MTO) process.

4.3. Mitigation technologies

The chemical industry's reliance on fossil feedstocks and high-temperature processes results in significant greenhouse gas (GHG) emissions. This study identified 69 technology options[33] that can help the chemicals industry achieve climate neutrality via a portfolio of solutions, spanning from feedstock switching (including biomass use and the utilisation of CO_2) and process electrification to carbon capture and storage and advanced recycling of polymers. Each option has been mapped against its technology-readiness level (TRL), indicative abatement cost and specific CO_2-saving potential. The overview below synthesises the main findings.

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[32] Broeckhoven, K. et al., 2022

[33] Including variations on similar options such as carbon capture with and without storage or utilization (accounting).

Figure 8: Taxonomy of technologies and mitigation options for olefins, aromatics and polymers. Sources: IEA clean energy technology guide, BSOG-VUB

4.3.1. Feedstock Shift

Biomass as feedstock

Substituting fossil feedstock can be an important element in deep greenhouse gas mitigation in the chemical industry. The two main options are to use bio-based or waste derived feedstock or use captured CO_2.

Ammonia via Biomass Gasification (TRL 5): Biomass is gasified to yield hydrogen-rich syngas for ammonia synthesis via the Haber-Bosch process. This pathway can cut up to 64% of CO_2 emissions compared to conventional natural gas routes. However, scale is a limitation due to biomass availability and logistics.

Bio-based Aromatics (BTX) (TRL 4-6): Benzene, toluene, and xylenes—critical for plastics and synthetic fibres—can be derived from lignin or sugars using catalytic, pyrolytic, or Diels-Alder routes. While technical potential is high (including negative emissions via storage of biogenic carbon in materials), costs remain significant due to processing complexity.

Bioethanol and Bio-Ethylene (TRL 9): Fermentation of sugar/starch crops into ethanol, followed by dehydration to ethylene (a key building block for plastics), is a mature route in Brazil and increasingly elsewhere. When accounting for biogenic carbon sequestration, this pathway provides strong emissions savings but competes with food production for land.

Biomass to naphtha and other feedstock: Biomass can via gasification and e.g. the Fischer-Tropsch (TRL 9) process be turned into naphtha or other feedstock which can be used in naphtha steam crackers.

Collectively, bio-routes are limited by land use, biodiversity concerns and alternative uses such as bio-fuels[34]. To ensure longer-term reduction benefits it is important to steer the processes towards products in which carbon remains locked for years—aromatics, polyols, structural polymers—rather than short-lived fuels.

CO_2 as feedstock (Power-to-X, CCU)

CO_2-to-Methanol and Methanol-to-Chemicals: Renewable hydrogen (from water electrolysis) is combined with captured CO_2 to produce methanol—a versatile platform chemical. Methanol can then be converted via catalytic processes into olefins (MTO) or aromatics (MTA), closing the carbon loop. These routes are already at demonstration scale (TRL 7–8) but are capital intensive.

Direct Electrochemical CO_2 Reduction: Early-stage (TRL 3–4) processes can convert CO_2 directly into ethylene or other hydrocarbons (e.g., formic acid, methanol, ethanol,

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[34] Such as the growing demand for sustainable aviation and shipping fuels.

propanol) using renewable electricity. While theoretically promising (with up negative emissions potential if all CO_2 input is counted) selectivity, efficiency, and cost are ongoing barriers. Direct electro-reduction of CO_2 to ethylene is the holy grail—a single step, no fossil input feed. Laboratory cells hit 60% selectivity, but catalyst life, membrane stability and power economics keep the technology below TRL 4 and above 500 EUR/t avoided CO_2 for now. Still, its potential makes sustained R&D vital.

4.3.2. Process Energy Transformation: Electrification & Alternative Heating

Electrified Steam Cracking: Traditionally, steam crackers for olefins (ethylene/propylene) are fired by natural gas at temperatures >800°C. Emerging technologies (TRL 6)—resistive heating, induction, or rotor-based reactors[35]—offer ways to electrify these units using renewable energy. Partial electrification (preheating) is already feasible; full electrification promises up to 100% CO_2 cuts but depends on clean grid electricity.

Electrifying other (lower temp.) chemical processes (TRL 8-9): Most processes in the chemical sector requiring heat input can in theory be electrified. For low to medium temperatures this includes the use of e-boilers, heat pumps (with use of waste heat recovery) and chemical heat pumps (driven by different temperatures in reversible reactions). A broader industry wide assessment of industrial heat (incl. electrification) technologies is presented in chapter 11.

Plasma Reactors: Plasma-assisted methane pyrolysis splits methane into hydrogen and solid carbon without direct CO_2 emissions (TRL 7/8 – for methane pyrolysis). Another example is a plasma catalytic reactor to convert methane into acetylene and then ethylene (<TRL 4). These are advancing rapidly but require further scale-up. Plasma assisted gasification (TRL 4) can also be an efficient alternative to produce syngas from waste streams.

Hydrogen & Synthetic Fuels as Combustion Fuel: Replacing natural gas in furnaces/boilers with green hydrogen or synthetic methane can immediately cut combustion emissions, though retrofits and synthetic fuel costs (directly related to electricity costs for hydrogen production) are challenges.

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[35] Coolbrook developed a rotor-based steam cracking reactor, claiming a higher olefin yield than traditional steam crackers. Also theoretic modelling confirms the slightly different product output with higher olefin yield, but also lower BTX yield." See: Van der Perre et al., 2024

4.3.3. Carbon Capture (and Storage)

Carbon capture (with storage) looks like the fastest way to tackle today's process emissions from steam methane reformers, ethylene oxide production and, to lesser extent, olefin steam crackers. Commercial amine scrubbing already captures CO_2 from hydrogen plants (TRL 9+). Using capture technology to all Belgian SMRs would remove roughly 1 Mt CO_2 yr^{-1} at a cost of 35–95 EUR/t CO_2.

Newer variants can push costs down or capture rates up. Cryocap™ (Air Liquide, TRL 8-9) freezes CO_2 out of hydrogen off-gas and relies mainly on electricity rather than steam[36], while calcium-looping pilot in Spain demonstrate 90 % capture with lower energy penalties.[37] Emerging "gas-switching reforming" promises cost-efficient CO_2 capture but is still at laboratory scale (TRL 3-4).[38] All routes converge on the same bottleneck: they need access to pipelines and North Sea storage, as well as plant space for solvent columns, oxygen plants or solid-sorbent handling. Securing that infrastructure is therefore a decisive factor for investments by the chemicals industry.

The above-mentioned capture costs do not represent the full costs for companies to mitigate their CO_2 emissions. Next to capturing the CO_2, there are costs for liquefaction, transportation and long-term storage. This can add around 30 EUR/t CO_2 (15 EUR/t CO_2 for transport and around 15 EUR/t for storage) to the mitigation costs.[39]

Chapter 12 gives a more detailed assessment of carbon capture technologies.

4.3.4. Chemical recycling

While mechanical recycling is valuable for extending the lifespan of plastics and is an energy-efficient process, it often leads to a downgrading of polymers and reduced product quality, thereby necessitating new plastic inputs. From a life-cycle perspective, avoiding the incineration of plastics and re-integrating plastic waste into the production of virgin plastic is crucial, which is where chemical recycling plays an essential role.

Chemical recycling encompasses various technologies that break down polymers into monomers or petrochemical feedstocks.

Depolymerisation (chemolysis)

Chemolysis, also known as solvolysis, depolymerizes plastics into their original monomers using specific solvents at relatively low temperatures (100-300°C). This

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[36] Air Liquide Engineering & Construction, 2024
[37] Arias, B., 2024
[38] Nazir, S. M.,et al., 2020
[39] European Technology Platform for Zero Emission Fossil Fuel Power Plants, 2011

method is already commercially applied for PET and is being demonstrated at a pilot scale for polystyrene. However, it is not suitable for all polymer types, such as polyethylene or polypropylene.[40]

Pyrolysis, catalytic cracking and gasification

Pyrolysis is another energy-intensive process that operates at moderate to high temperatures (500°C, 1-2 atm) in the absence of oxygen, converting difficult-to-depolymerize mixed plastic waste into gas, oils, and solid char, where the pyrolysis oil can then be further processed into a naphtha substitute.

Catalytic cracking offers improved selectivity and lower energy consumption compared to pyrolysis, enabling the production of specific fuels or commodity chemicals at reduced temperatures (300-350°C).[41]

Hydrocracking is a variant of catalytic cracking that incorporates hydrogen, leading to a higher quality naphtha yield with an improved hydrogen-to-carbon ratio and lower aromatic content, making it suitable for mixed plastic waste, though it involves higher operational costs due to hydrogen production and high pressures.

Finally, gasification converts solid waste into a syngas mixture (comprising CO_2, CO, H_2, CH_4, and other light hydrocarbons) at temperatures ranging from 700-1200°C via partial oxidation. This syngas can then serve as a feedstock for methanol synthesis, which can subsequently be converted into olefins or aromatics.[42] This process can also be electrified via plasma driven reactors.

While energy intensive, these methods avoid landfilling and/or incineration of waste emissions. However, to ensure that recycled carbon does remain in materials, the conversion of plastics to synthetic oils for combustion (i.e. energy supply applications) should be avoided.

4.3.5. New processes

Beyond carbon capture and feedstock and energy substitutions lie entirely new chemical production processes.

Oxidative dehydrogenation (ODH, TRL 3-4) converts ethane or propane directly to olefins at 400°C, eliminating the furnace emissions of steam cracking. However single-pass selectivity and catalyst durability remain challenges. Metal-oxide chemical-loop ODH, plasma coupling of methane or electro-conversion of ethane each carry similar promise

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[40] Wyns, T. and Khandekar, G., 2020

[41] Ibid.,

[42] Ibid.,

and similar uncertainties (TRL 3-4). None is likely to be commercial before 2040, but all could enable net-negative olefins when paired with biogenic feed or captured CO_2.[43]

Solid State Ammonia Synthesis (SSAS) produces ammonia directly from N_2 and H_2O, without intermediate steps. Direct electrochemical ammonia synthesis in molten-salt electrolytes and on membranes are under development. This could potentially reduce electricity consumption by up to 30%. The TRL of solid-state ammonia synthesis is estimated at 3–5. Improvements are required to improve the ratio of NH_3 to H_2, material durability and conditions of operation (pressure and temperature).[44]

4.3.6. Hydrogen production

The sections below discuss the options for climate friendly hydrogen production. For this report hydrogen production is seen as an energy transformation technology and not as a mitigation technology as such. However, due to the importance of hydrogen in the industrial transition (especially as feedstock), the technology options for clean hydrogen production are summarised below.

Overall, a diverse landscape of hydrogen production technologies, ranging from mature (TRL 9) methods such as SMR with carbon capture to early-stage research (TRL 2-3) such as some electrochemical and photo-catalytic processes. While fossil fuel-based methods with CCS are currently more cost-effective due to lower natural gas prices in some regions, decreasing CAPEX and increasing efficiencies of electrolysis-based methods are expected to make renewable electricity-based hydrogen more affordable by 2030-2035 under the essential condition of low electricity prices.

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[43] Ibid.,

[44] Amar, A., et al., 2011

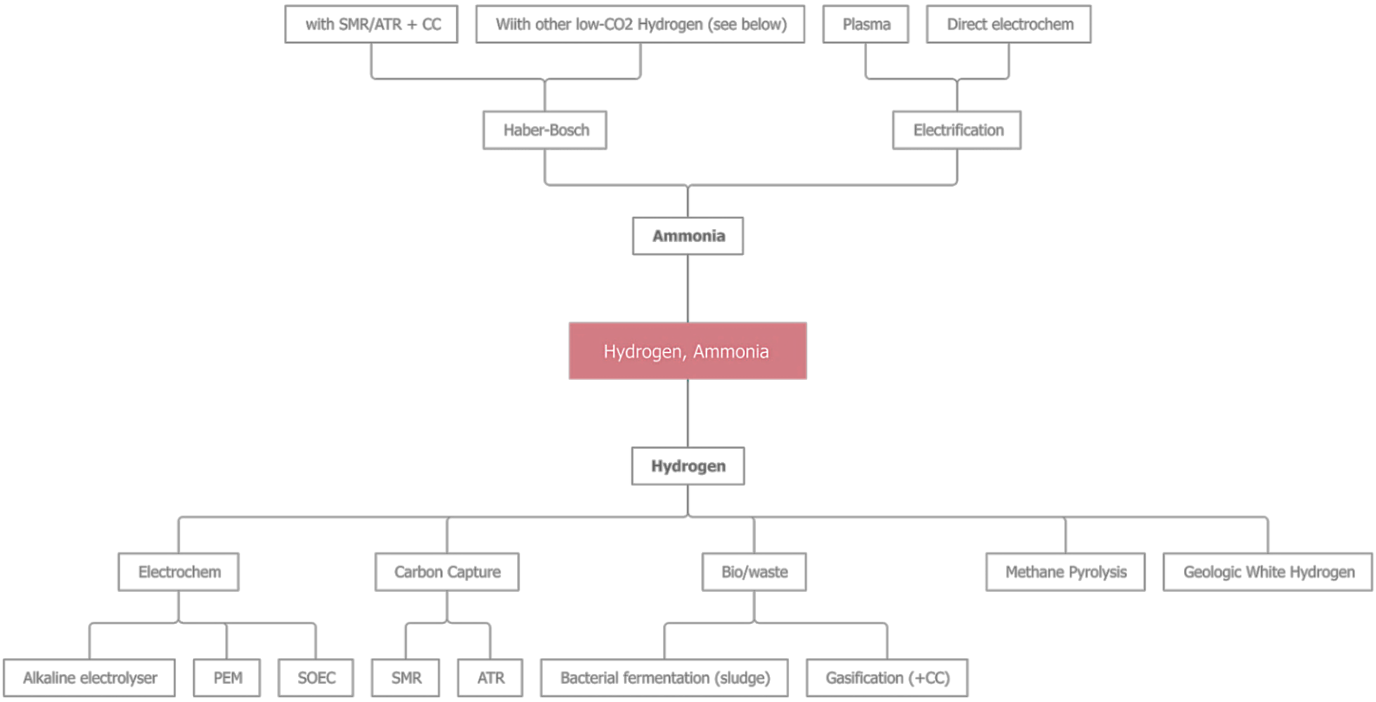

Figure 9: Taxonomy of technologies options for Hydrogen and ammonia production. Sources: BSOG-VUB, IEA clean energy technology guide

Steam Methane Reforming (SMR) with carbon capture (Blue Hydrogen)

To reduce its carbon footprint, SMR can be combined with Carbon Capture (CC). This integrated process, with a TRL of 7-8, can capture up to 89% of CO_2 emissions, reducing them to approximately 0.98 t CO_2/t H_2, though it requires additional energy (around 14 GJ/t H_2).[45]

Another methane-based option is Autothermal Reforming (ATR) with CC, which uses pure oxygen instead of air, leading to higher CO_2 concentrations that are easier to capture. ATR with CC is at TRL 7-8, can capture up to 95% of CO_2 emissions (resulting in 0.64 t CO_2/t H_2), and requires about 3.4 MWh-electricity/t H_2 for oxygen production, in addition to approximately 124 GJ CH_4/t H_2. [46]

Gas Switching Reforming (GSR), a promising chemical looping reforming technology (TRL 3-4), offers inherent CO_2 capture (up to 96%) and flexibility to switch between power and H_2 production.[47]

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[45] Van der Perre, S., Wyns, T. 2022, T. Industrial Tech. Database V6

[46] Ibid.,

[47] Ibid.,

Methane pyrolysis

Methane Pyrolysis is a highly endothermic process (TRL 3-8[48]) that decomposes methane into hydrogen and solid carbon without CO_2 emissions. It requires about 19 GJ/t H_2, and its economic viability often depends on the valorisation of the solid carbon by-product, for example, in production of construction materials, batteries or carbon fibre.[49]

Electrolytical hydrogen

Electrolysis-based hydrogen production is a rapidly advancing field. Alkaline electrolysis (TRL 7-9) is a mature technology, currently requiring 50-73 MWh-electricity/t H_2, with efficiency projected to improve by 2030.[50]

Proton-Exchange-Membrane (PEM) electrolysis (TRL 7-8 or 8-9) offers good dynamic behaviour for integration with variable renewable electricity, consuming 47-73 MWh-electricity/t H_2, with projected improvements to 44-53 MWh/t H_2 by 2030.[51]

Solid-Oxide Electrolysis (SOE) (TRL 6-7) is the most electrically efficient, requiring 37 MWh-electricity/t H_2, but operates at high temperatures (700-1000°C), making it suitable for integration with industrial waste heat sources.[52]

An advanced form, Solid Oxide Electrolysis Cell (SOEc) for co-electrolysis of CO_2 and H_2O, is at TRL 3-4 and produces syngas with energy consumption of 36.7 MWh-electricity/t H_2.[53]

Photo-catalytic hydrogen

Beyond electrolysis, Photo-catalytic Water Splitting (TRL 2-3) uses solar light energy with photocatalysts to produce hydrogen from water. It has low efficiencies but offers a direct method for hydrogen production. Photo-electrolysis (TRL 3-4), uses photo-electrochemical cells with semiconductors immersed in an electrolyte. [54]

Bio-based hydrogen

In the realm of bio-based hydrogen production, Aqueous Phase Reforming (APR) is a developing technology that processes oxygenated hydrocarbons from renewable biomass to produce hydrogen at lower temperatures than conventional methods. It has been commercialized for sorbitol and glucose. Biomass Gasification via Dual Fluidized Bed (DFB), at TRL 5, uses woody biomass to produce hydrogen and syngas, with an energy use of 25.8 GJ/t H_2. A more advanced variant, Sorption Enhanced Reforming (SER) (TRL 3), can achieve higher H_2 content and lower tar content, requiring 10 GJ/t H_2.

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[48] Monolith is producing hydrogen and carbon black with its plasma based reactors. Monolith, 2025

[49] Ibid.,

[50] Ibid.,

[51] Ibid.,

[52] Ibid.,

[53] Ibid.,

[54] Wyns, T. and Khandekar, G., 2020

Additionally, biogenic hydrogen production from photolytic biomass, such as purple phototrophic bacteria using sewage, is at TRL 3.[55]

Dry reforming of methane

Beyond conventional methane reforming, Dry Methane Reforming (DMR) reacts CH_4 with CO_2 to produce syngas, offering a pathway for CO_2 utilization. Its TRL is estimated at 4-6, and it requires about 4.2 GJ/t H_2 [56]. Specific CO_2 emissions are considered very low if the unreacted CO_2 is captured and recirculated, and energy is supplied from renewable electricity. A plasma-assisted variant of DMR (TRL not specified) has a CAPEX of 23.8 million EUR and consumes 49.7 kWh/kmol syngas.[57]

White hydrogen

White hydrogen, also referred to as natural or geologic hydrogen, is hydrogen found in underground deposits and formed through geological processes such as serpentinization or radiolysis. Unlike green hydrogen (produced via electrolysis using renewable energy) or blue hydrogen (derived from fossil fuels with carbon capture), white hydrogen is naturally occurring and requires no energy-intensive production methods. However, its extraction and commercialization are still in early stages. The technology readiness level (TRL) for white hydrogen production is generally considered to be between 3 and 5, indicating that it is still in the research, development, and early prototype phases. Most current efforts are focused on exploration, pilot projects, and validating extraction techniques, rather than large-scale commercial deployment. The cost of white hydrogen production is not yet well established due to its nascent stage. [58]

4.4. Mitigation technologies summary

4.4.1. Technology Readiness Levels

Figure 10 shows the assessment of the Technology Readiness Level (TRL) for a wide range of decarbonization technologies in the chemical sector. Established technologies, such as steam methane reforming (SMR) with various carbon capture options, as well as several forms of chemical and polymer recycling, are shown at high TRLs (8–11), indicating they are commercially available or close to full market deployment. The full value chain for carbon capture and storage has been set at TRL 7, because it has yet to be demonstrated at large scale.[59] Similarly, ammonia production using electrolytic hydrogen powered by renewables, and certain bioethanol and depolymerization

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[55] Van der Perre, S. and Wyns, T., 2022

[56] or approximately 200 GJ CH_4/t H_2 plus 17 MWh/t H_2 electricity for heat

[57] Van der Perre, S. and Wyns, T., 2022

[58] Aimikhe, V. J., & Eyankware, O. E., 2023, p.64-79.

[59] This is more an infrastructure and cost challenge, not R&D.

processes, also exhibit advanced TRL scores, reflecting significant progress toward industrial application.

Other transformative pathways—such as electrified steam cracking, methanol-to-olefins with electrification, advanced gas fermentation concepts, and routes relying on CO_2 utilisation or biomass gasification—are clustered at lower TRL values (4–7). These approaches are generally in the early or advanced pilot phase and will require further research, development, and scaling before they can contribute meaningfully to sector-wide decarbonisation.

Finally, there are promising new chemical processes such as electrochemical olefins production and oxidative dehydrogenation that still must move beyond TRL 4. These will most likely not contribute to mitigation in the chemicals industry before 2040.

Figure 10: TRL assessment of chemical sector mitigation technologies. Sources: IEA clean energy technology guide and BSOG-VUB industrial technologies database

4.4.2. Mitigation potentials and abatement costs

Figure 11 sets out the cost-effectiveness versus the mitigation potential of various decarbonisation technologies for the chemical industry.

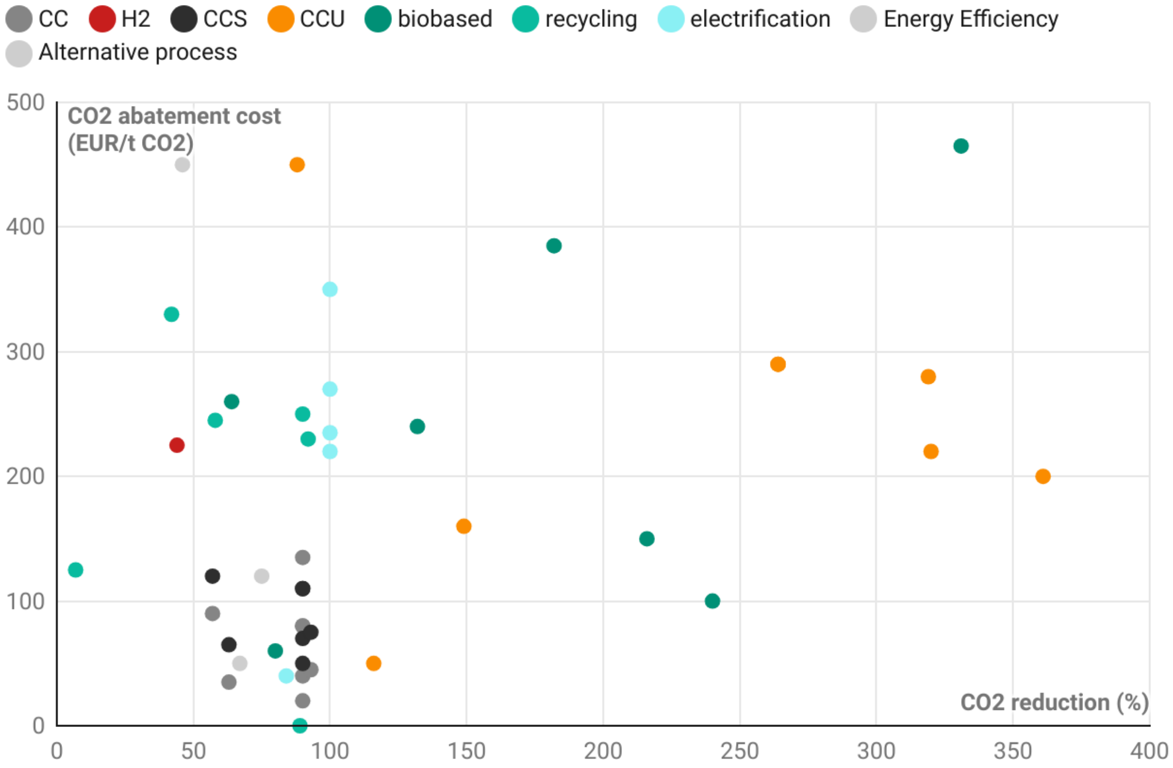

Figure 11: CO_2 reduction versus abatement costs. Reductions larger than 100% mean CO_2-negative chemicals in their production phase (i.e. acting as a carbon sink). General assumption is the use of fully renewable electricity (0 gCO_2/kWh). Sources: IEA clean energy technology guide, BSOG-VUB, diverse.

The most affordable solutions on the chart, such as carbon capture and some process improvements, tend to cluster below €100 per tonne of CO_2 abated and can deliver substantial reductions. The most transformative options—particularly advanced CCU and biobased processes—offer abatement levels exceeding 100%. These higher numbers assume that all biogenic carbon or utilised (e.g. air captured) CO_2 is fully credited as avoided fossil emissions, an approach that requires rigorous carbon accounting to ensure genuine climate impact (i.e. by ensuring long-term residence of carbon in materials).

Electrification technologies, which are also prominently represented, show significant potential for deep CO_2 reductions, often in the 60–100% range. However, their cost-effectiveness is highly sensitive to electricity prices; in this analysis, a renewable electricity price of €60–80/MWh is assumed. If electricity prices were higher, the abatement costs for electrification would increase accordingly, potentially shifting their position on the cost curve. A deep dive showing the impact of power prices on a selection of technologies can be seen in chapter 13.

Overall, while low-cost options are crucial for near-term progress, scaling up breakthrough technologies—especially those with very high abatement potential—will require targeted innovation, supportive policy frameworks, and affordable clean energy to become viable at scale.

A detailed overview of the mitigation potential per technology and the abatement costs are given in figures 12 and 13 below.

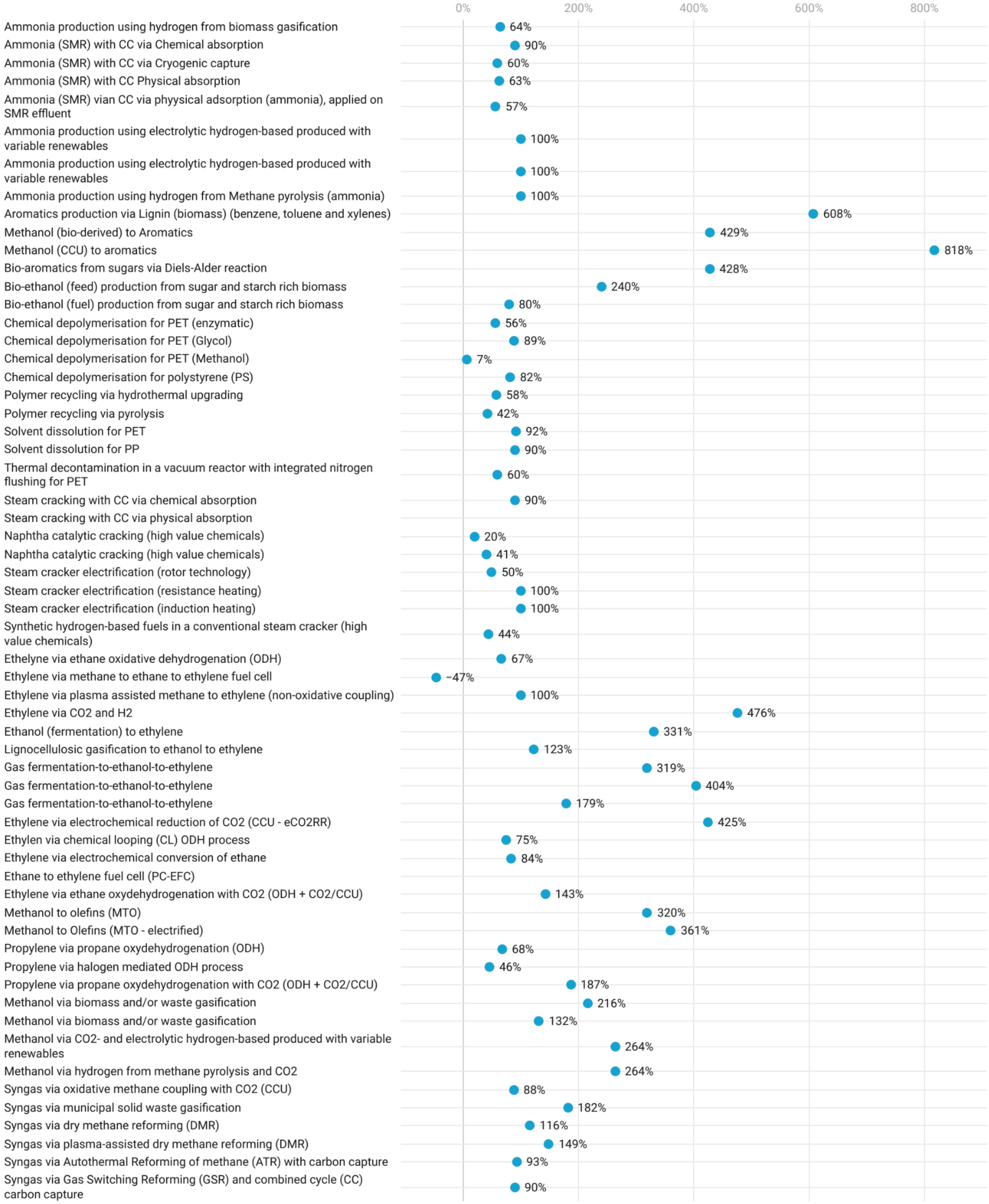

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Figure 12: CO_2 abatement potential chemical industry technologies (% reduction vs incumbent technology). Sources: BSOG-VUB, Diverse

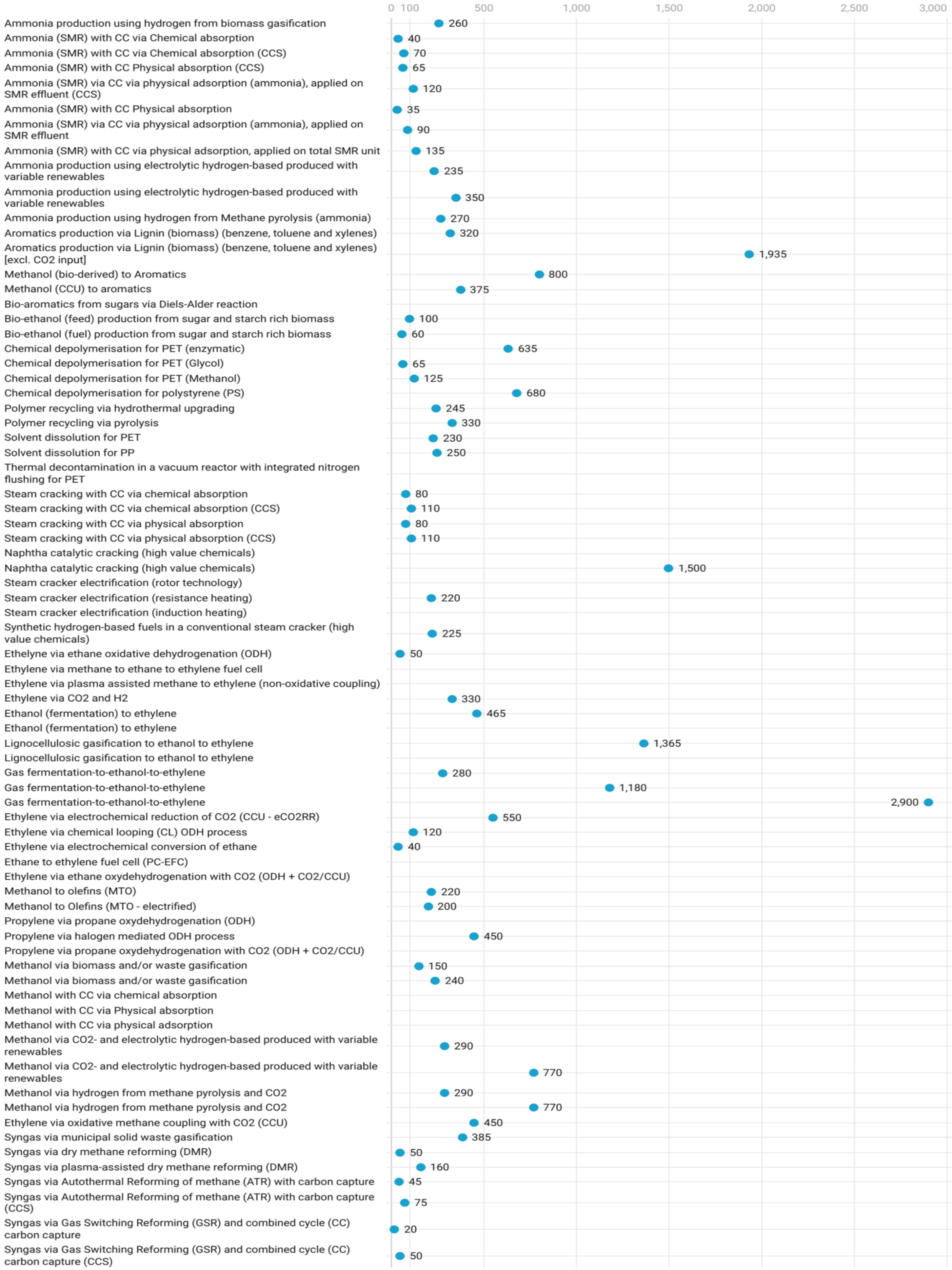
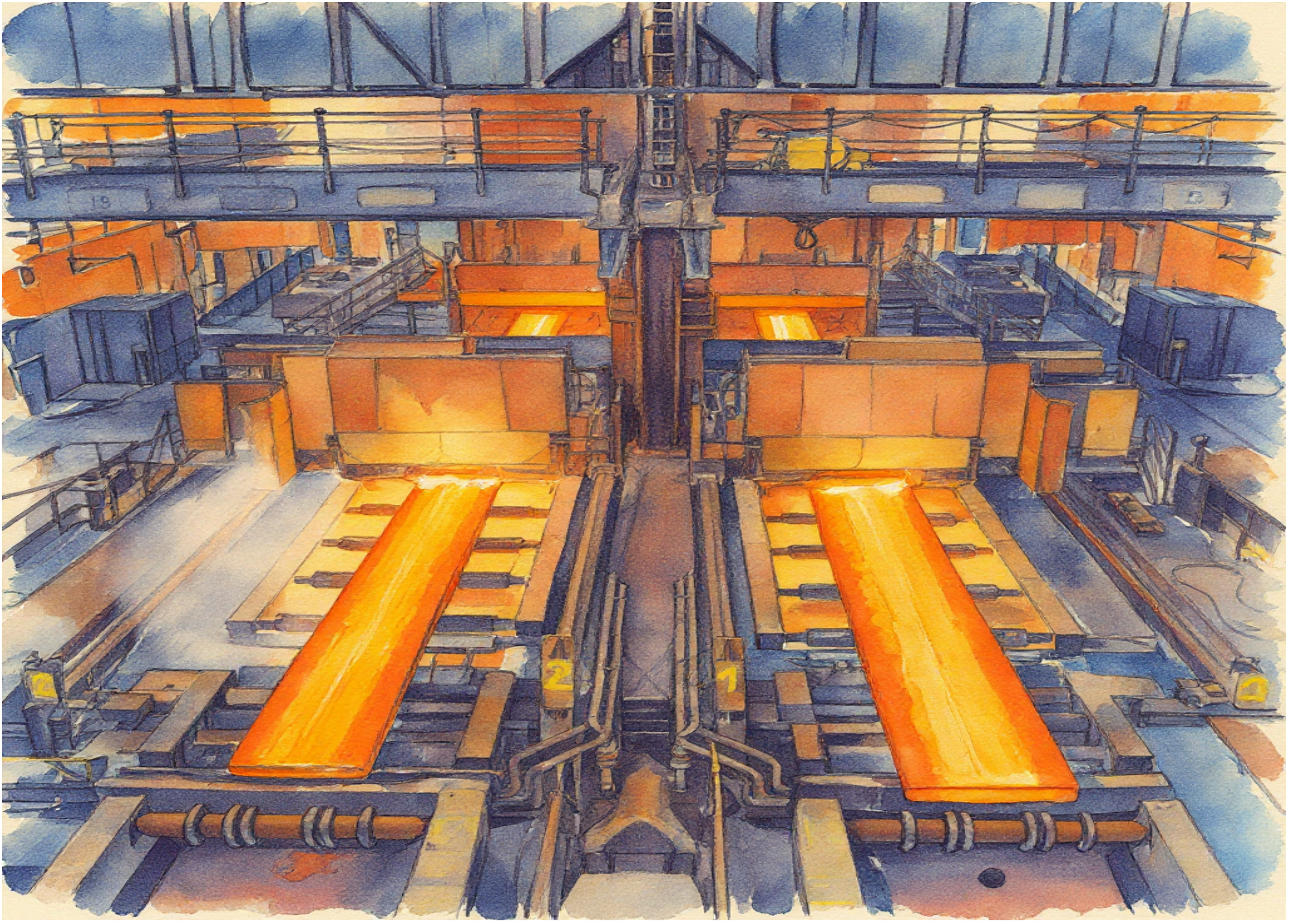


Figure 13: CO2 abatement costs for chemical industry mitigation technologies. €/t CO2 avoided compared to incumbent technologies. Diverse sources

4.4.3. Pathway to net-0 emissions chemicals

A credible pathway to climate-neutral chemicals production is technologically within reach, but not straightforward. It starts with carbon capture and storage retrofits for high concentration process emissions, electrification of low to medium temperature heating and creating the supply chains advanced recycling the remainder of this decade. In the period 2030-2040 further scaling of electrification and the use of alternative feedstocks (e.g. bio-based or recycled) and maximisation of recycling are essential. After 2040 utilisation of CO_2, high temperature electrification and completely new process technologies (e.g. electrochemical) can bring the industry close to climate neutrality. However, access to infrastructure (e.g. CO_2), affordable clean power and robust and cost-effective supply chains for biomass and circular polymers will be essential.



5. Iron and Steel

5.1. Introduction to sector and main processes

Industry Overview

The steel industry stands as one of the most significant contributors to global industrial carbon dioxide emissions, representing a critical challenge in the worldwide effort to achieve climate neutrality. Steel production accounts for approximately 5% of the EU's greenhouse gas emissions.[60]

Between 1990 and 2022 steel production in Belgium went down by 34% (from 11.5 Mt to 7.6 Mt). Pig iron production (from blast furnaces) reduced by almost 50% over the same period (from 9.4 to 4.9 Mt). The large reduction in production is due to the closure of blast furnaces in the Walloon region over the past 30 years. Belgian steel production currently accounts for around 5% of EU total steel produced.[61]

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[60] Joint Research Centre, 2022

[61] Eurofer, 2025

Greenhouse gas emissions from steel production in Belgium (around 8 Mt CO_2)[62] account for around 7% of the total Belgian emissions.[63] When excluding the emissions from power production from the use of steel waste gases, the total GHG emissions from steel production went down by more than 70% between 1990 and 2023.

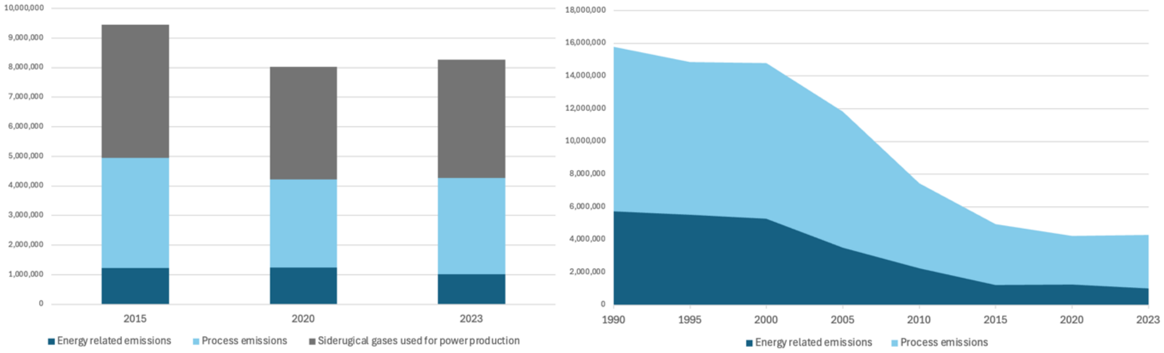

Figure 14: Evolution of GHG emissions of steel production in Belgium (t). Left: GHG emissions between 2015-2023, including use of steel waste gases in power production. Right: GHG emissions between 1990 and 2023 excluding use of steel waste gases for power production.) Source: Belgium, 2024, CRT and EU ETS reporting.

5.2. Steel production processes

The steelmaking process typically follows a structured approach consisting of three fundamental stages: raw materials preparation, iron making, and steel making. Each stage presents unique opportunities and challenges for emissions reduction, with the choice of production route significantly influencing the overall carbon footprint of the final steel product.

5.2.1. Blast Furnace and Basic Oxygen Furnace[64]

The Blast Furnace and Basic Oxygen Furnace (BF-BOF) route represents the dominant steel production technology within the European Union, accounting for approximately 55% of total steel production in the region[65]. This BF-BOF approach to steelmaking has been refined over decades to achieve high productivity and product quality, though it remains fundamentally dependent on coal-based carbon inputs that generate substantial CO_2 emissions.

The process begins with the production of metallurgical coke, a high-carbon fuel produced by heating coal in specialized coking ovens under oxygen-free conditions. This thermal treatment drives off volatile compounds and impurities, leaving behind a porous,

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[62] Including the use of steel waste gases for power production

[63] Belgium, 2024

[64] Broeckhoven, K., et al., 2022

[65] With 45% of EU steel produced via Electric Arc Furnaces (EAF). Eurofer, 2025

carbon-rich material with the high strength and reactivity required for blast furnace operations. The coking process itself represents an energy-intensive preliminary step that contributes to the overall carbon footprint of the BF-BOF route.

Within the blast furnace, the prepared coke is combined with iron ore and limestone in carefully controlled proportions. The combustion of coke provides the thermal energy necessary to reach the extreme temperatures required for iron ore reduction, while simultaneously generating carbon monoxide through partial oxidation reactions and the Boudouard equilibrium[66]. This carbon monoxide serves as the primary reducing agent, chemically converting iron oxides in the ore to metallic iron while producing CO_2 as a byproduct.

The blast furnace produces molten pig iron with a high carbon content, typically ranging from 3-5%, which must be refined to achieve the carbon specifications required for different steel grades. This refinement occurs in the Basic Oxygen Furnace, where pure oxygen is injected at high pressure into the molten pig iron. The oxygen reacts with excess carbon, converting it to carbon monoxide and carbon dioxide, which are removed as off-gases. This process allows precise control of the final carbon content while maintaining the molten state necessary for continuous steel production.

The environmental impact of the BF-BOF route is substantial, with total CO_2 emissions ranging from 1.7 to 1.9 tonnes per tonne of steel produced. These emissions stem from multiple sources: the coking process, carbon combustion for thermal energy, the chemical reduction of iron ore using carbon-based reducing agents, and the decarburization reactions in the basic oxygen furnace.

5.2.2. Direct Reduction of Iron ore[67]

The Direct Reduced Iron (DRI) with Electric Arc Furnace (EAF) route represents an alternative approach to steel production that offers potential advantages in terms of carbon emissions reduction, though it introduces different energy requirements and economic considerations. This technology maintains iron ore in its solid state throughout the reduction process, contrasting with the molten iron production characteristic of blast furnace operations.

In the DRI process, natural gas serves as the primary reducing agent, replacing the coal-based carbon used in traditional blast furnace operations. The natural gas undergoes both steam reforming and dry reforming reactions to generate the reducing gases required for iron ore conversion. Steam reforming[68] produces hydrogen and carbon

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[66] the dynamic balance between carbon, carbon dioxide, and carbon monoxide at high temperatures

[67] Broeckhoven, K. et al., 2022

[68] $CH_4 + H_2O \rightarrow CO + 3H_2$

monoxide, while dry reforming[69] additionally consumes CO_2 that might otherwise be emitted, contributing to overall emissions reduction. These reducing gases chemically convert iron oxides to metallic iron while maintaining the solid state of the material.

The direct reduced iron produced through this process requires further processing in an Electric Arc Furnace to achieve the final steel product. The EAF utilizes electrical energy to generate the extreme temperatures necessary for melting and refining the DRI, allowing for precise control of steel composition and properties. This electrical heating eliminates the need for carbon-based fuel combustion during the melting phase, though the carbon intensity of the electricity supply significantly influences the overall environmental impact.

The carbon emissions associated with the DRI-EAF route typically range from 1.2 to 1.4 tonnes of CO_2 per tonne of steel when utilizing natural gas as the reducing agent. These emissions are notably lower than the BF-BOF route, primarily due to the elimination of coking operations and the potential for CO_2 consumption through dry reforming reactions. However, the actual emissions performance depends heavily on the carbon intensity of electricity used in the EAF operations, creating a direct link between steel production emissions and regional electricity grid characteristics.

5.2.3. Secondary steel production via electric arc furnaces[70]

The production of steel from scrap materials using Electric Arc Furnace (EAF) technology represents the most environmentally favourable approach to steel manufacturing currently available at industrial scale. This process leverages the inherent recyclability of steel, which can be repeatedly melted and reformed without degradation of its fundamental properties, making it an ideal candidate for circular economy principles in heavy industry.

The scrap-based EAF process involves the direct melting and refining of collected steel scrap in an electric arc furnace, eliminating the need for primary iron ore reduction entirely. The electric arc furnace generates the intense heat required for melting through electrical arcs struck between graphite electrodes and the metallic charge. This electrical heating provides precise temperature control and eliminates the combustion-related emissions associated with fuel-based heating systems.

The environmental advantages of scrap-based steel production are substantial, with total CO_2 emissions typically ranging from 0.4 to 0.6 tonnes per tonne of steel produced. This dramatic reduction compared to primary steel production routes reflects the elimination of iron ore reduction reactions, coking operations, and most fuel combustion

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[69] $CH_4 + CO_2 \rightarrow 2CO + 2H_2$

[70] Broeckhoven, K., et al., 2022

processes. The remaining emissions primarily stem from electricity consumption for arc furnace operations, electrode consumption, and minor process-related sources.

The carbon intensity of electricity supply plays a crucial role in determining the ultimate environmental performance of scrap-based steel production. In regions with high renewable electricity penetration or low-carbon electricity grids, this route can approach net-zero emissions, making it a key technology for achieving climate-neutral steel production. The potential for decarbonisation through renewable electricity integration positions scrap-based EAF production as an important option for the steel industry's transition to climate neutrality.

However, the scrap-based route faces practical limitations related to scrap availability and quality. The global steel scrap supply depends on the retirement of existing steel products, creating a time lag between steel production and scrap availability. Additionally, certain steel applications require virgin materials to meet stringent quality specifications, limiting the complete substitution of primary production with recycling. These constraints mean that while scrap-based production will play an increasingly important role in sustainable steel manufacturing, it cannot entirely replace primary steel production in the near term.

5.3. Mitigation technologies[71]

European blast-furnace / basic-oxygen-furnace (BF-BOF) sites still emit about 1.8-1.9 t CO_2 for every tonne of hot-rolled coil. Roughly three quarters stem from the coal and coke that both fire and chemically reduce iron ore; the remainder comes from electricity, ancillary fuels and flared off-gases. This report identified 27 mitigation options[72]. When organised by technology type, these show credible but infrastructure-hungry routes from today's high-carbon steel making to climate neutrality by mid-century.

The carbon-intensive BF-BOF route, can replace part of the coal used but will in the end need carbon capture with utilisation and storage to achieve deep emission reductions.

The DRI-EAF route offers a lower-carbon alternative for primary steel production with potential for further emissions reduction through renewable electricity, hydrogen-based reduction and/or carbon capture.

The scrap-based EAF route provides the most immediate pathway to low-carbon steel production, with scalability limited primarily by scrap availability rather than technological constraints.

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[71] Mitigation technologies are selected from the IEA's clean energy technology guide

[72] With split between carbon capture and the full carbon capture and storage value chain.

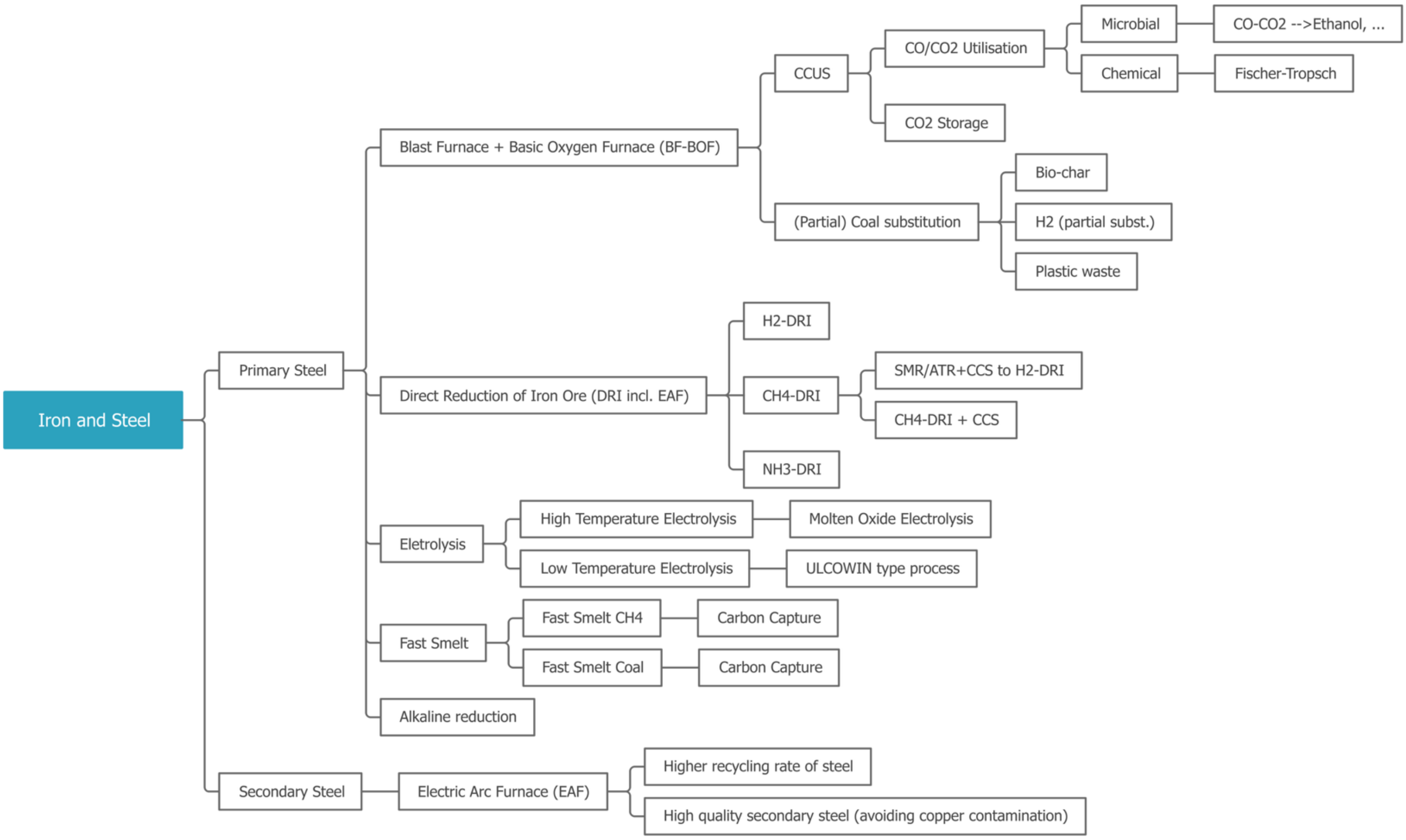

Figure 15: Mitigation technologies for iron and steel production. Sources: IEA, ETP clean energy technology guide and BSOG-VUB

5.3.1. Material efficiency

Squeezing more performance from today's assets Material efficiency is the quiet giant in the toolbox. Simply using less primary metal—through near-net-shape casting, advanced forming or additive manufacturing—avoids 7-14 % of cradle-to-gate emissions. Because the saved material never reaches the furnace, the abatement cost is close to zero; however, benefits depend on customers changing design rules and standards, something steelmakers can only enable, not dictate.

5.3.2. Blast furnace retrofits

Inside the blast furnace itself, two quick retrofits dominate. Bio-coal injection replaces pulverised coal with torrefied wood pellets. Deployed at ArcelorMittal Ghent (TRL 8-9), it removes 5-28% of total emissions for roughly €95/t CO_2 avoided. Sustainability certification and competition with biomass power plants limit volume, but the hardware can be rolled out in months. Hydrogen co-injection (TRL 7) delivers comparable savings (7-18%) by replacing 20-50% of tuyere coal with green H_2. At €66/MWh renewable power the abatement cost is about €180/t CO_2 avoided—expensive today, but the retrofit buys operational experience ahead of deeper hydrogen use.

Amine scrubbing for carbon capture, combined with Top-Gas Recycling can bolt directly onto an existing BF-BOF train (TRL 5). By cleaning and recycling the upper part of the furnace gas, 25-60% of site emissions can be captured at €45/t CO_2 avoided—one of the lowest costs in heavy industry. To this cost the further cleaning, transport and storage cost of CO_2 needs to be added.

Utilisation of CO or CO_2 from steel production is also an option. The Steelanol unit ArcelorMittal in Ghent (TRL 8) ferments CO and CO_2 into ethanol, with maximal potential of reducing emissions by roughly 42%.[73] Another CCU option for steel off-gases is the catalytic synthesis to methanol or Fischer-Tropsch liquids, achieving 36 and 19% avoided CO_2, respectively. Both routes become attractive only when renewable hydrogen falls below €2/kg; at current prices, abatement costs range from €175 to 360 per t CO_2 avoided.

5.3.3. DRI and EAF options

A permanent break with cokes is possible via direct-reduced iron plus an electric-arc furnace (DRI-EAF). Three options have been considered. Natural gas DRI with post-combustion capture is completely commercial and quickly deployable (TRL 9). Once amine capture is added to the shaft furnace, up to 80% of site CO_2 can be eliminated for €80-130/t CO_2 avoided. Hydrogen gas blends (≈70% H_2, 30% CH_4) can be a stepping-stone for regions whose hydrogen supply will take a decade to mature (TRL 7-8). They cut 48-77% of emissions, but relatively expensive with around €255/t CO_2 avoided. Pure green hydrogen DRI, piloted by HYBRIT and H_2 Green Steel (TRL 6-7), pushes abatement to 98-100% and the avoidance cost lands near €150/t CO_2.[74] The main technical barrier is feedstock because only high-grade, low-phosphorus pellets work reliably in DRI processes. This can be mitigated by upgrading the iron feedstock or by using alternative processes[75].

5.3.4. Breakthrough electrification

Electro-smelting can be the long-term “silver bullet”. Molten-oxide electrolysis (MOE) dissolves iron ore in a slag and uses electric current—rather than carbon—to strip out the oxygen. Laboratory cells have clocked 5000 hours of continuous operation at >1500 °C (TRL 5-6). If powered by renewables, the theoretical footprint is zero and modelling

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[73] Assuming full scale conversion of steel off-gases with additional use of hydrogen. The smaller scale Steelanol project at ArcelorMittal in Ghent currently reduces emissions by 120 kt CO_2 out of 8 Mt total emissions.

[74] Assuming an electrolyser efficiency of 50 MWh/t H_2 production, renewable power at €50/MWh and €1.9–2.8/kg H_2.

[75] Wimmer, G. et al., 2024 discuss a new type of furnace (smelter) that enables the use of lower grade ores for hydrogen direct reduction of iron ore.

suggests €55-140/t CO_2 avoided once 1 Mt/year modules are achieved. Alternative low-temperature aqueous electro-plating and hydrogen-plasma smelting offer similar reductions but remain proof-of-concept (TRL 4-5). Their viability therefore hinges on the ability to cost-effectively scale up and the electricity costs. Large scale deployment likely after 2040, not before.

5.3.5. Other advanced options

A handful of options hold dramatic promise yet lack data. Thermochemical CO_2 looping via perovskites could in theory recycle furnace CO_2 into fresh reducing gas, slashing emissions by 94%, but has yet to operate beyond grams per hour. Ammonia-based DRI would mirror hydrogen performance if green ammonia can be imported at scale.

5.3.6. Mitigation technologies for steel overview

Technology Readiness

In general, there is a limited but broad spectrum of technologies that is market ready or close to it (TRL 7-9). This includes most retrofits to existing blast-furnaces. Clean hydrogen based DRI is expected to move from TRL 6 to 9 over the next 5-10 years. Some promising electro-steel technologies and alternative capture methods might need more time to reach market readiness. The use of scrap in EAF is a mature technology and can, depending on supply, be increased.

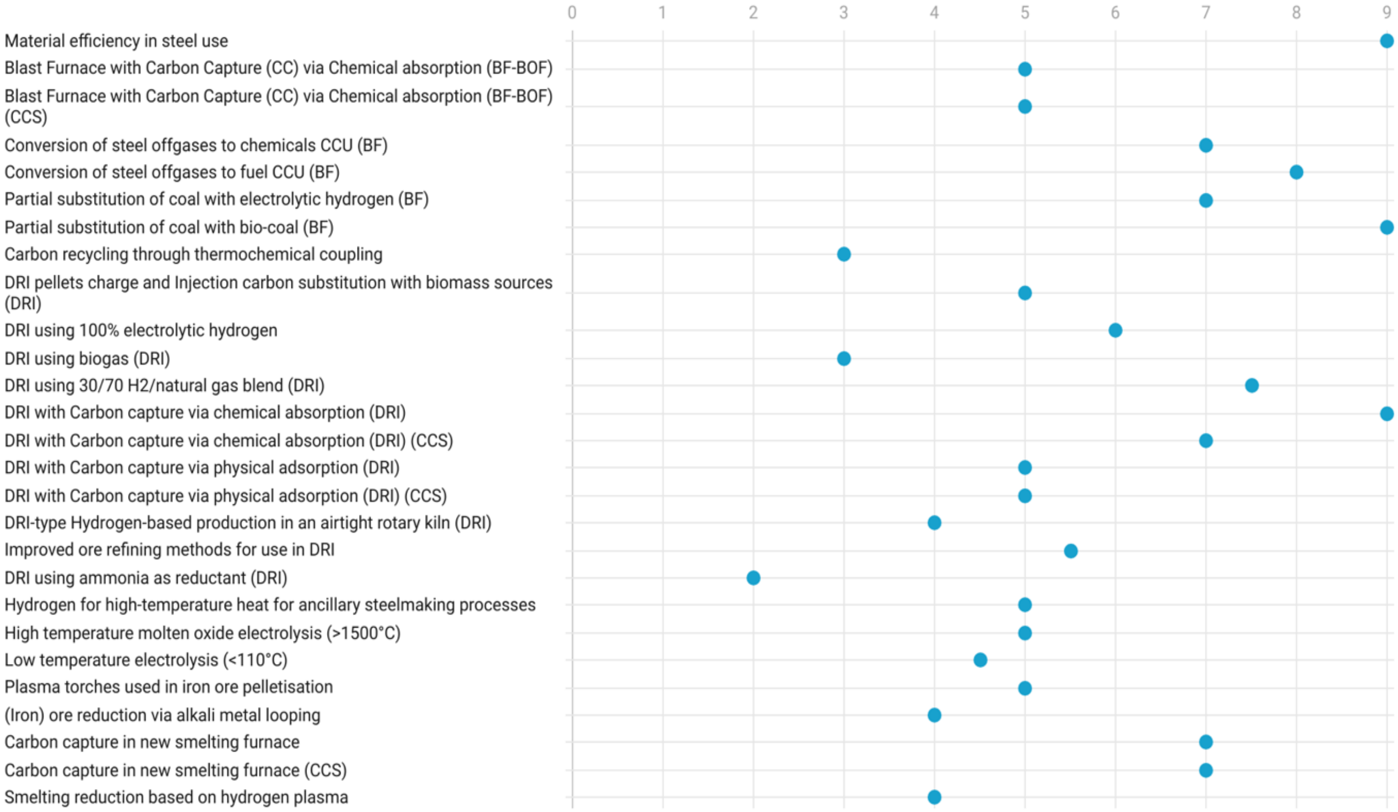

Figure 16: TRL assessment of clean steel making technologies. Source: IEA, ETP, Clean energy technology guide

Mitigation potential and abatement cost

The use of carbon capture looks like the least costly option at the moment, with DRI and carbon capture likely having a bigger mitigation impact. Use of hydrogen in DRI is highly dependent on electricity prices for hydrogen production but will still be a relative expensive option compared to incumbent production. It does however lead to deep emission reductions. Cost of substitution of coal of gas by biomass fall in between the above-mentioned options. The mitigation impact is limited. Additional use of scrap is a cost-effective option with deep reduction impact (if primary steel is replaced). It is however limited by the availability of scrap.

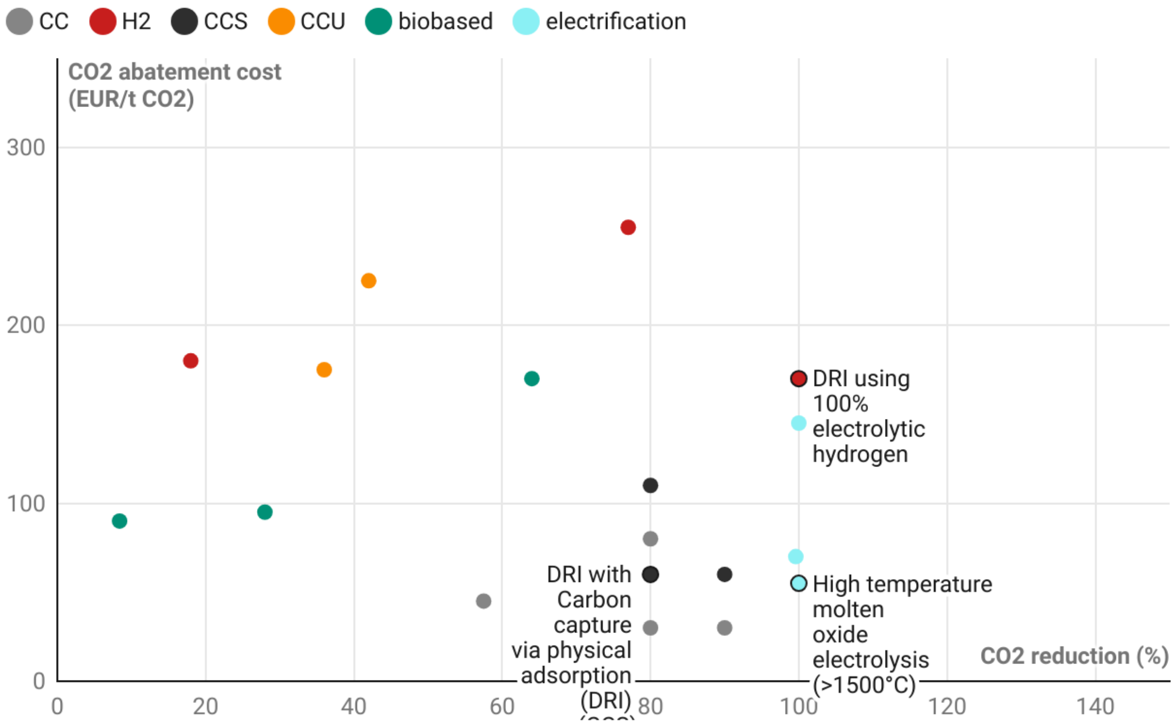

Figure 17: CO_2 reduction versus abatement costs for steel mitigation technologies. General assumption is the use of fully renewable electricity (0 gCO_2/kWh). Sources: IEA clean energy technology guide, BSOG-VUB, diverse.

5.3.7. Pathway to net-0 emissions for iron and steel

Technically, the European steel sector can reach net-zero well before 2050. On the short-term, material efficiency, higher use of scrap steel and partial fuel switches can have an important mitigation impact. As from 2030 more radical changes to steel production are required such as large-scale investments in DRI complexes using hydrogen or making use of carbon capture and storage. Post-2040, more radical innovations such as fully electrified ironmaking can emerge together with enhanced deployment of hydrogen and CCS based DRI

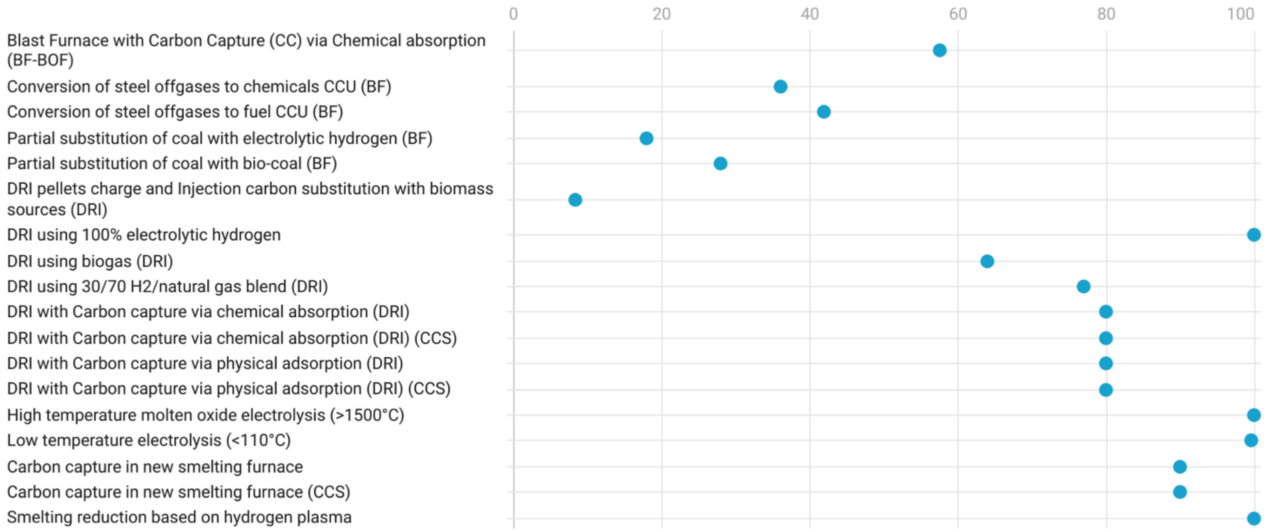

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Figure 18: Mitigation assessment of steel making technologies (% reduction compared to incumbent technology). Sources: IEA clean energy technology guide, BSOG-VUB, diverse

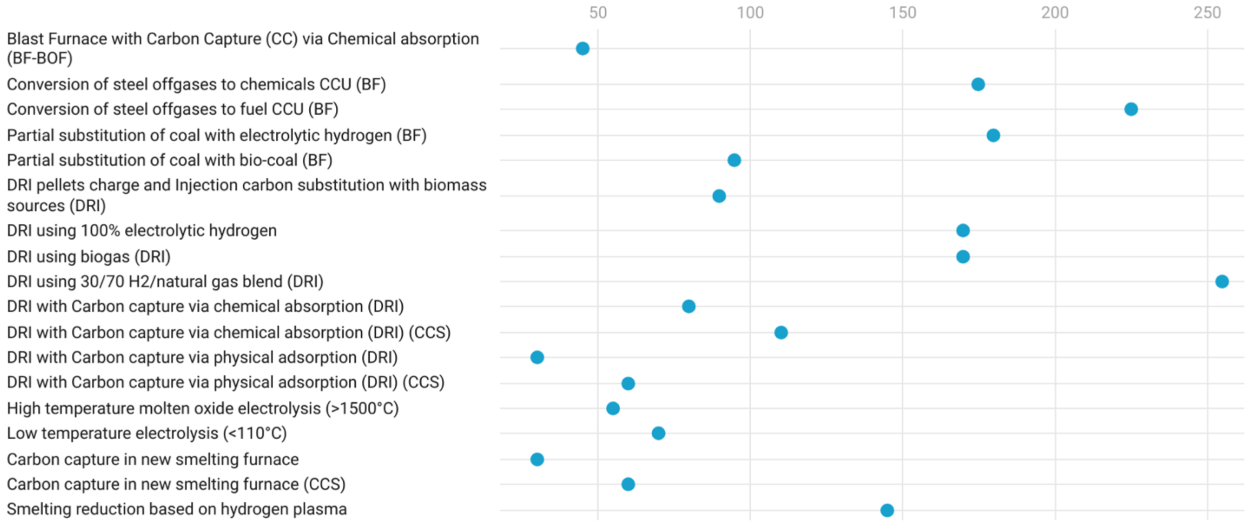

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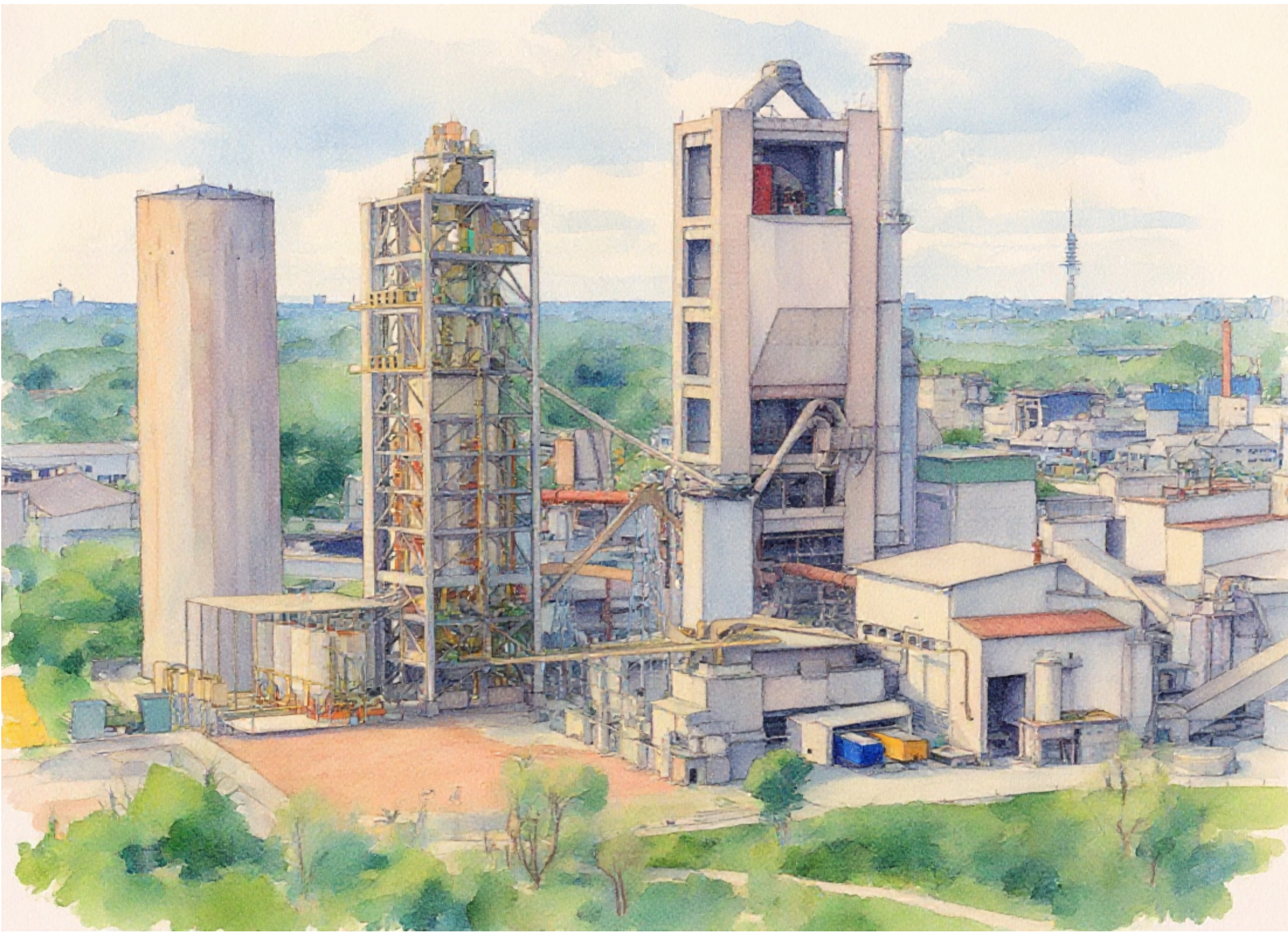
Figure 19: CO2 abatement costs vs incumbent technology (€/t CO2 avoided). Sources: IEA clean energy technology guide, BSOG-VUB, diverse



6. Cement and lime

6.1. Industry overview

The cement industry represents one of the most fundamental sectors in global construction and infrastructure development, with Ordinary Portland Cement (OPC) serving as the predominant product variant worldwide. This essential building material forms the backbone of modern construction, enabling the creation of concrete structures that define contemporary urban landscapes and industrial facilities. However, the production of cement carries significant environmental implications due to both the chemical processes involved and the substantial energy requirements necessary for manufacturing.

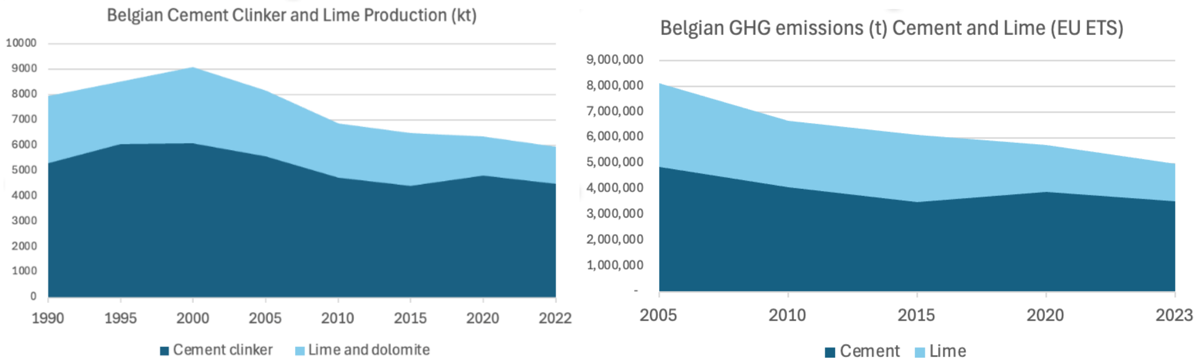


Figure 20: (left) Cement and lime production Belgium (1990-2022) (kt). (right) GHG emissions from cement and lime in Belgium (1990-2023, t). Source: Belgium, 2024, CRT

Between 2005 and 2022 the production of cement clinker and lime reduced by 19% and 44% respectively. In the same timeframe the greenhouse gas emissions came down by 28% and 55%, pointing to higher efficiency but also the use of alternative fuels.

6.2. Key processes in cement production

The production of Ordinary Portland Cement relies on a carefully selected combination of raw materials, each contributing specific chemical components essential for the final product's performance characteristics. Limestone, chemically composed of calcium carbonate ($CaCO_3$), serves as the primary source of calcium oxide, which forms the foundation of cement's binding properties. Clay materials provide essential silica (SiO_2) and alumina (Al_2O_3) compounds that contribute to the cement's strength development and durability characteristics. Additionally, sand contributes supplementary silica content, helping to achieve the precise chemical composition required for optimal cement performance.

The transformation of these raw materials into finished cement occurs through a sophisticated multi-stage process that combines precise chemical reactions with intensive thermal treatment. Each stage of production presents unique technical challenges and environmental considerations, with the overall process requiring careful optimization to balance product quality, energy efficiency, and environmental impact.

6.2.1. Limestone Calcination Process

The calcination of limestone represents the most chemically and environmentally significant stage in cement production, fundamentally altering the raw material's chemical structure while generating substantial CO_2 emissions as an unavoidable byproduct. This process involves the thermal decomposition of calcium carbonate through an intensely endothermic reaction that requires minimum temperatures of 850°C to proceed at industrially viable rates.

During calcination, calcium carbonate undergoes dissociation according to the chemical equation: $CaCO_3 \rightarrow CaO + CO_2$. This reaction is thermodynamically unfavourable at lower temperatures, necessitating the substantial energy input required to reach and maintain the minimum temperature threshold. The endothermic nature of the reaction means that continuous heat input is required not only to reach the activation temperature but also to supply the energy absorbed by the chemical transformation itself.

The CO_2 generated during calcination represents what is termed "process emissions" – carbon dioxide that results directly from the chemical transformation of raw materials rather than from fuel combustion. These process emissions are considered unavoidable under current cement production technology, as the calcination reaction is essential for producing the calcium oxide required for cement's binding properties. The stoichiometric relationship between calcium carbonate decomposition and CO_2 generation means that approximately 440 kilograms of CO_2 are produced for every tonne of calcium carbonate processed, representing a fundamental constraint on cement production's carbon footprint.[76]

6.2.2. Clinker Formation

Following calcination, the resulting calcium oxide must be chemically integrated with the silicate, aluminate, and ferrite compounds present in the clay and sand components. This stage involves complex solid-state reactions that occur at elevated temperatures, creating the intermediate compounds that will ultimately provide cement's hydraulic properties – its ability to harden and gain strength when mixed with water.

The formation of cement clinker involves the creation of several key mineral phases, each contributing specific performance characteristics to the final product. Tricalcium silicate (C3S) and dicalcium silicate (C2S) provide the primary strength-developing components, while tricalcium aluminate (C3A) and tetracalcium aluminoferrite (C4AF) contribute to early-age strength development and influence the cement's setting characteristics. The precise formation of these phases requires careful control of temperature, residence time, and chemical composition throughout the production process.[77]

The chemical reactions involved in clinker formation are highly temperature-dependent, with different mineral phases forming at specific temperature ranges. This temperature sensitivity necessitates precise thermal management throughout the kiln system to

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[76] Andrew, R. M. (2019).
[77] Gineys, R., Garcia-Diaz, I., Garcia, J., & Alvarez, M. (2016).

ensure complete reaction and optimal mineral phase development. Incomplete reactions or improper phase formation can significantly impact the final cement's performance characteristics, making process control critical for both product quality and production efficiency.

The sintering stage represents the culmination of the thermal treatment process, occurring at approximately 1450°C at the discharge end of the rotary kiln system. At these extreme temperatures, the mineral components undergo final consolidation and crystal structure development, creating the dense, hard clinker nodules that will subsequently be ground to produce finished cement.

The rotary kiln system employed for sintering represents one of the most energy-intensive unit operations in industrial manufacturing. These massive cylindrical vessels, often exceeding 100 meters in length and 4 meters in diameter, rotate slowly while materials move counter-current to hot combustion gases generated by natural gas combustion. The counter-current flow arrangement maximizes heat transfer efficiency while ensuring uniform heating of the material charge.

The combustion system providing thermal energy for sintering typically utilizes natural gas as the primary fuel, though alternative fuels including coal, petroleum coke, and various waste-derived fuels may also be employed. The combustion gases must reach temperatures exceeding 2000°C at the burner flame to provide sufficient heat transfer to raise the solid materials to the required sintering temperature. This extreme temperature requirement represents a significant technical challenge for fuel substitution efforts, as alternative fuels must be capable of achieving these temperature levels while maintaining stable combustion characteristics.[78]

6.2.3. Final Processing and Product Preparation

The final stage of cement production involves the mechanical processing of cooled clinker to create the finished cement product. The sintered clinker, which emerges from the kiln as hard, marble-sized nodules, must be ground to a fine powder to activate its hydraulic properties and enable effective mixing with water during concrete production.

The grinding process typically employs ball mills or vertical roller mills to achieve the required particle size distribution, with finished cement particles averaging 10-50 micrometers in diameter. This fine grinding is essential for cement performance, as the surface area available for hydration reactions directly influences the rate and extent of strength development in concrete applications.

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[78] Madlool, N.A., Saidur, R., Hossain, M.S. and Rahim, N.A. (2011)

During the grinding stage, various additives are incorporated to optimize the cement's performance characteristics. Gypsum ($CaSO_4 \cdot 2H_2O$) represents the most common additive, serving as a set retarder that controls the rate of cement hydration and extends the working time available for concrete placement and finishing. The precise dosage of gypsum must be carefully controlled to balance workability requirements with strength development characteristics.

Additional supplementary cementitious materials may also be incorporated during grinding, including fly ash, slag, limestone, or pozzolanic materials. These additions can improve specific performance characteristics while potentially reducing the overall environmental impact by partially substituting clinker content. However, the incorporation of supplementary materials must be balanced against performance requirements and regional availability constraints

6.3. Emissions and energy use[79]

The environmental impact of cement production is characterized by substantial CO_2 emissions ranging from 0.9 to 1.0 tonnes of CO_2 per tonne of cement produced. This emission intensity places cement production among the most carbon-intensive industrial processes globally.

The distribution of CO_2 emissions within cement production reveals the fundamental challenge facing industry decarbonization efforts. Process emissions resulting from limestone calcination account for the largest share of total emissions, representing 55-60% of the carbon footprint. These emissions are inherent to the chemical transformation required for cement production and cannot be eliminated through conventional efficiency improvements or fuel switching strategies.

Combustion-related emissions from fuel consumption for thermal energy represent approximately 35% of total CO_2 emissions. These emissions result from the burning of natural gas, coal, or alternative fuels to provide the thermal energy required for calcination and sintering operations. Unlike process emissions, combustion-related emissions offer potential reduction opportunities through fuel switching, energy efficiency improvements, or alternative heating technologies.

The remaining 5-10% of emissions typically stem from electricity consumption for grinding operations, material handling, and auxiliary systems. While representing a smaller fraction of total emissions, these indirect emissions are directly influenced by the carbon intensity of regional electricity grids and offer opportunities for reduction through renewable energy adoption.

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[79] Based on Broeckhoven, K., et al. (2022)

The specific energy consumption for cement production thermal processes amounts to approximately 3.7 GJ per tonne of cement, reflecting the substantial energy requirements for achieving the extreme temperatures necessary for calcination and sintering. This energy intensity places cement production among the most energy-demanding industrial processes, with thermal energy representing the dominant component of overall energy consumption.

The distribution of energy consumption within cement production is heavily weighted toward thermal applications, with the rotary kiln system consuming the majority of process energy. The endothermic nature of limestone calcination (> 850°C) requires continuous energy input to maintain reaction rates, while the high-temperature sintering process demands additional energy to achieve and maintain the 1450°C temperatures required for proper clinker formation.

Electrical energy consumption, while representing a smaller fraction of total energy use, remains significant due to the mechanical energy required for raw material preparation, clinker grinding, and material handling operations. The fine grinding required for finished cement production is particularly energy-intensive, with modern grinding systems incorporating energy recovery and optimization technologies to minimize electrical consumption.

6.4. Mitigation options[80]

An assessment of about 30 low-carbon technologies shows that the cement and concrete sector already possesses, or will soon possess, technical solutions covering both process- and fuel-related CO_2 emissions. Because cement is currently among the three largest industrial sources of greenhouse gases in Belgium and the EU, rapid uptake of some of these options is essential. For ease of comparison the technologies have been grouped into 4 complementary decarbonisation levers:

A detailed assessment of about 30 low-carbon technologies shows that the cement and concrete sector already possesses, or will soon possess, technical solutions covering both process- and fuel-related CO_2 emissions. Because cement is currently among the three largest industrial sources of greenhouse gases in Belgium and the EU, rapid uptake of some of these options is essential. For ease of comparison the technologies have been grouped into five complementary decarbonisation levers.

- Material efficiency and circularity
- Clinker substitution and novel binders
- Low-carbon heat and fuels

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[80] Mitigation options selected from the IEA’s ETP clean energy technology guide. IEA, (2025)

- Carbon capture, utilisation and/or storage

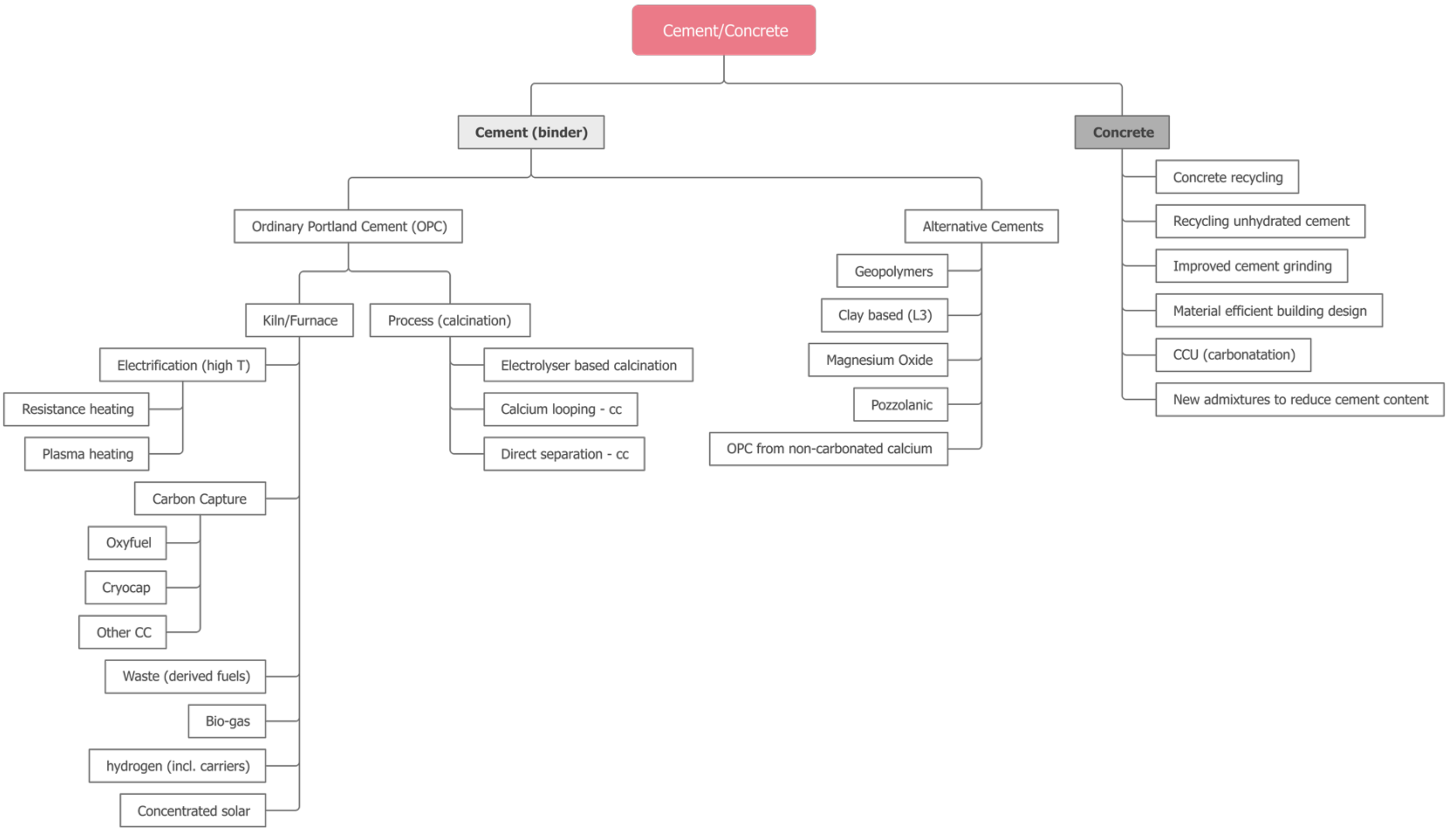

Figure 21: Cement sector mitigation options. Based on IEA ETP clean energy guide and BSOG-VUB

6.4.1. Material efficiency and circularity

Four technologies target the demand side of clinker. High-TRL concrete and cement recycling recovers either un-hydrated cement or CaO from end-of-life concrete, enabling substitution of up to 20% of virgin clinker and lowering emissions by roughly 0.2 t CO_2 per tonne of product (≈ 20%). Advanced grinding techniques and “right-sizing” of structural elements add a further 1–5% saving at negligible cost. In combination, circularity measures can trim 20–30% of scope-1 + 2 emissions and are therefore regarded as “no-regret starters”.

6.4.2. Clinker substitution and novel binders

Process emissions are attacked directly by lowering or eliminating the clinker content. Mature (TRL 9) supplementary cementitious materials (SCM) (pozzolans, geopolymers) are able to cut 30–70% of CO_2 at €50–60/t avoided. Carbonated calcium-silicate cements achieve similar reductions but at higher cost because of premium feedstocks. Breakthrough routes—magnesium-silicate cements or Portland cement produced from non-carbonate calcium sources—have the potential for net-zero or even net-negative footprints, albeit from a low TRL base and at €100–160/t CO_2 avoided. Cross-cutting measures such as clinker micronisation and proprietary admixtures can lower the clinker factor by about 70% with moderate capital needs. Established SCMs could realistically halve sectoral emissions during the 2030s; the more radical binders could push the envelope further after 2040 once durability standards and supply chains are proven.

6.4.3. Low-carbon heat and fuels

Combustion for kiln heat represents ~40% of total cement emissions. Seven options were analysed. Direct electrification or concentrated solar heat (TRL 5–6) can replace part or all fossil fuel use, providing 20–34% total abatement. Present CO_2 avoidance costs remain high— €75–120/t for CSP and about €280/t for resistance- or plasma-based electrification—but decline steeply with cheaper renewable power. Electro-decarbonation of limestone in an electrolyser (TRL 4) could theoretically remove 96% of CO_2 by supplying $Ca(OH)_2$ and hydrogen fuel to the kiln. At today's maturity, hydrogen, biogas, e-methane and waste-derived fuels can be deployed immediately: they deliver 7–10% savings when blended at 20–30% and are cost-competitive except for green hydrogen (€450–500/t CO_2 avoided).

6.4.4. Carbon Capture, Utilisation and Storage (CCUS)

Even after maximum circularity and binder substitution, 30–40% of emissions remain. Eight capture routes form the backbone of deep decarbonisation. Conventional solvent absorption, calcium looping, oxyfuel variants, cryogenic separation and novel adsorbents (all TRL 6–7) capture 63–91% of the total CO_2 emissions at €40–80/t CO_2 avoided; chemical absorption sits at the upper end of that range. Direct-separation calcination (Leilac-type) isolates pure process CO_2 and integrates well with electrified heat, giving 63% abatement when fitted to one-fifth of the limestone stream. Membrane systems are less mature (TRL 4) but could greatly simplify retrofits once performance improves.

Facility-scale CCS can reduce process emissions with 90% or more but presupposes CO_2 transport and storage infrastructure.

In terms of CO_2 utilisation, mineralisation is considered as one of the key technologies for CCU in the cement sector. Only one technology in the dataset is already commercial at scale: the Carbstone process permanently mineralises CO_2 into aggregates by reacting it with steel slag. At TRL 9 it delivers a net-negative footprint (-0.08 t CO$_2$ per tonne product) and costs €110–115/t avoided. Deployment is limited by available alkaline waste but offers attractive synergies with the steel sector.

6.5. Cross-cutting considerations

The least-cost measures today (recycling, pozzolans, waste fuels) are also the most commercial. Many alternative binders require fly ash, slags or specific minerals that may be scarce; diversification of precursor streams is important.

Carbon capture (and storage) will be an essential part of cement and lime decarbonisation due to the high process emissions. It is at relatively high TRL and mitigation costs are not very high. Essential is the development of infrastructure that enables cement and lime producers to transport the captured CO$_2$ off site. Some captured CO$_2$ can be used in the mineralisation process of construction materials or at the concrete setting stage.

The remaining emissions from high temperature heating are more challenging. Here high-temperature electrification or use of biomass will be important. However, for electrification the technology needs to mature further and become more cost-efficient. Affordable clean electricity will be essential. Biomass can be a more cost-effective option but costs and availability might be an issue and will be location dependent.

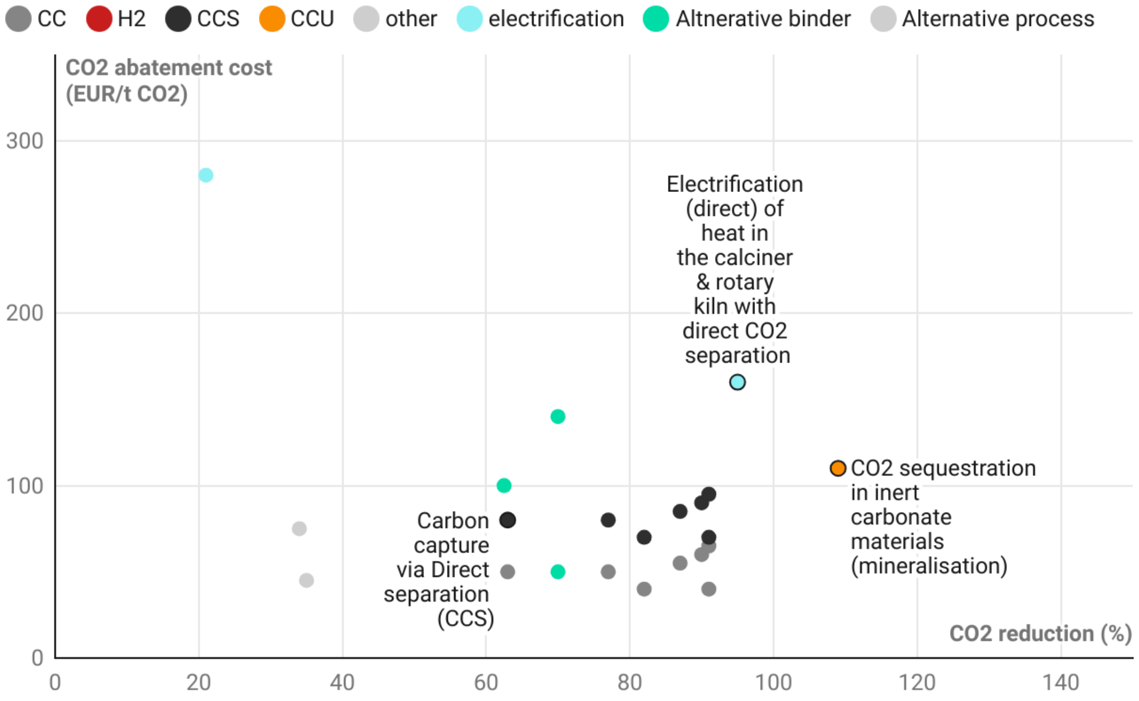

Figure 22: CO$_2$ reduction versus abatement costs for cement/lime mitigation technologies. General assumption is the use of fully renewable electricity (0 gCO$_2$/kWh). Sources: IEA clean energy technology guide, BSOG-VUB, diverse.

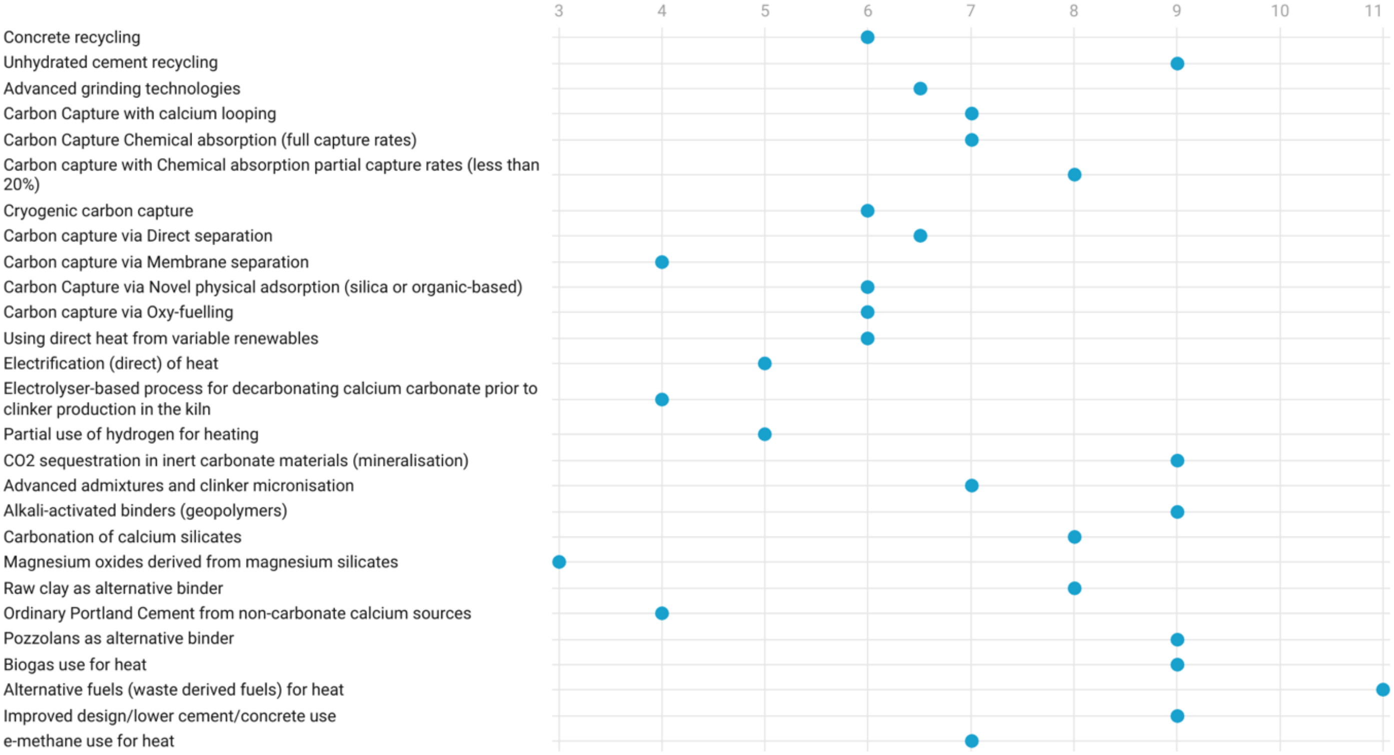

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Figure 23: TRL for cement GHG mitigation technologies. Sources: IEA clean energy technology guide, BSOG-VUB

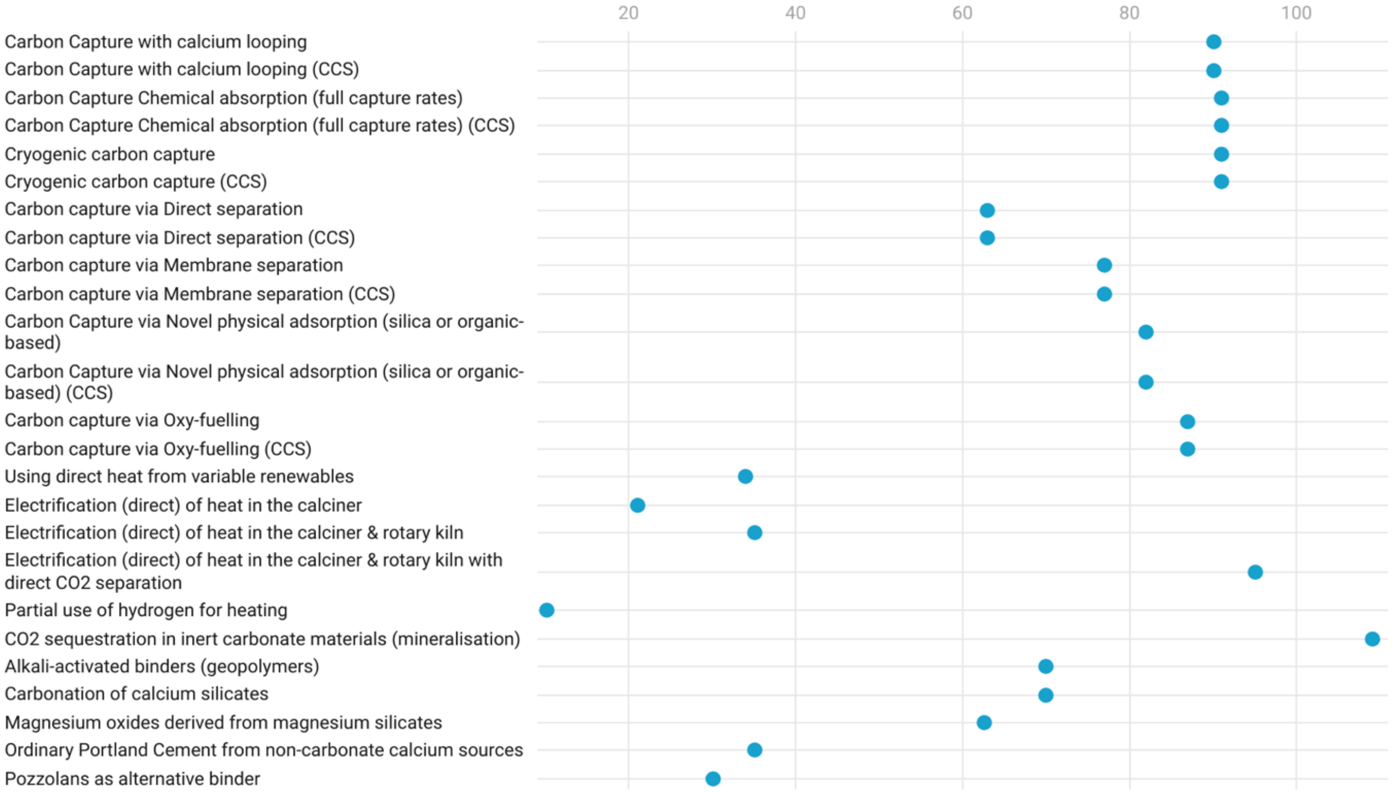

Figure 24: GHG reduction potential of cement production technologies (% reduction compared to incumbent technology). Sources: BSOG-VUB, diverse

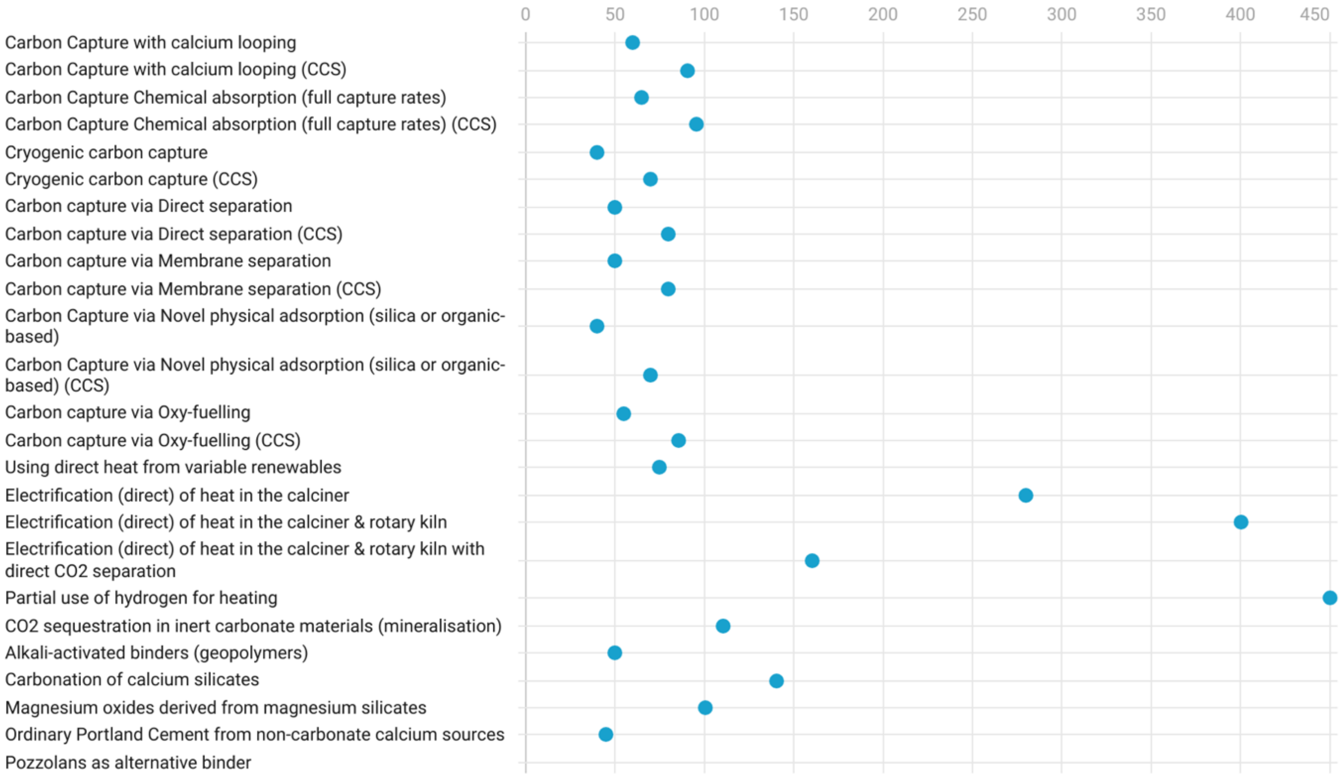

Figure 25: Mitigation cost of cement sector technologies (€/t CO2 avoided). Sources: BSOG-VUB, diverse

7. Pulp and paper

7.1. Industry overview

In 2023, Europe's pulp and paper industry emitted 86.4 million tonnes of CO_2, a figure that accounts for approximately 0.8% of total EU CO_2 emissions in 2022. Emissions primarily come from energy generation (steam and electricity) used in the production process, as well as direct fuel use in drying and pulping.

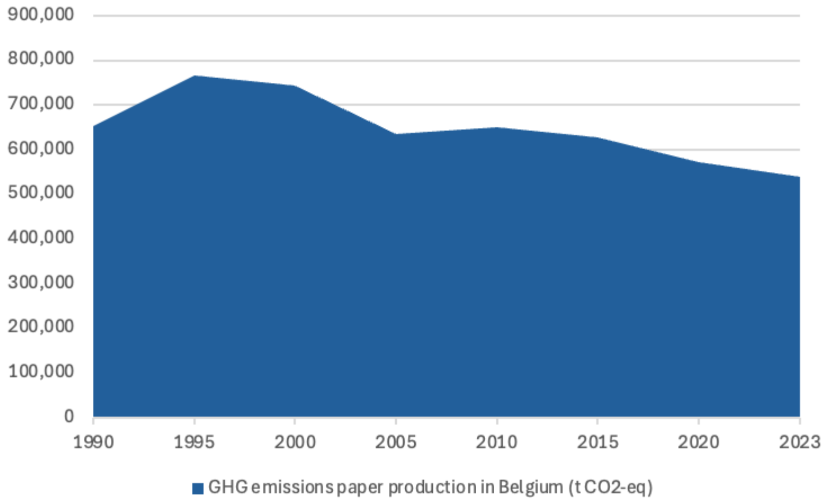

Figure 26: Belgian Pulp and Paper production GHG emissions 1990-2023 (t CO_2-eq). Source: Belgium, 2024, CRT

The direct greenhouse gas emissions related to pulp and paper production in Belgium are around 550 kt CO_2-eq or less than 2% of industrial greenhouse gas emissions. Since 1990 these emissions have come down by around 15%.

7.2. Pulp and paper production process

Pulp and paper production converts wood and other fibrous materials into pulp and, subsequently, into paper products. The process can be broadly divided into pulp production, paper production, and finishing operations.

Pulp production is the first and most energy-intensive stage, accounting for approximately 62% of the total energy use and 45% of greenhouse gas (GHG) emissions in the paper-making process.[81] The primary methods for producing pulp are mechanical pulping, chemical pulping, and recycled pulping.

In mechanical pulping wood logs are debarked and chipped, then ground into pulp using mechanical refiners. This process yields high quantities of pulp, but results in shorter fibres and lower strength compared to chemical pulping. Energy consumption is high due to the mechanical force required, but chemical usage is minimal.[82]

In chemical pulping wood chips are cooked in a solution of sodium hydroxide and sodium sulfide (white liquor) at high temperatures (150–180°C) and pressures. This process dissolves lignin, separating the fibres and producing strong, high-quality pulp. The spent cooking liquor, known as black liquor, is concentrated and burned in a recovery boiler to generate steam and electricity, while also recovering chemicals for reuse. The kraft process is the most widely used chemical pulping method, accounting for most of the global pulp production.[83] [84]

Recycled paper is repulped in water, screened, and cleaned to remove contaminants such as ink, adhesives, and plastics. The process requires less energy and fewer chemicals than virgin pulping, resulting in lower GHG emissions (408 kg CO_2-eq/tonne for recycled pulp vs. 508 kg CO_2-eq/tonne for kraft pulp).[85]

Once pulp is produced, it is further processed into paper through bleaching, formation and finishing. Pulp may undergo bleaching to achieve the desired brightness. Chlorine dioxide, hydrogen peroxide, or oxygen are commonly used bleaching agents. The pulp slurry is next diluted with water and fed onto a moving wire mesh, where water is drained, and a continuous paper web is formed. The web is pressed to remove additional water

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[81] Ma et al., 2018
[82] Id.
[83] BioResources, n.d.
[84] IEA, n.d.
[85] Ma et al., 2018

and then dried using steam-heated rollers or air dryers. Drying is the most energy-intensive step in paper production, accounting for a significant portion of the total energy use.[86] Finally, the dried paper is smoothed, coated (if required), and wound into rolls or cut into sheets. Coating and finishing processes may involve additional energy and chemical inputs.

Pulp and paper making is an energy-intensive process, with energy requirements varying by process and product type. Pulp production uses 10-20 GJ/t, paper production 5-7 GJ/t and integrated mills 14-25 GJ/t.[87]

The average emissions are 951 kg CO_2-eq/tonne of paper produced (cradle-to-gate).[88] However, the sector is unique in its substantial use of renewable energy, primarily biomass (e.g., black liquor, bark, and wood residues), which accounts for approximately 60% of its energy needs. The remaining 40% is typically met by fossil fuels, predominantly natural gas.[89]

7.3. Mitigation options

The path to decarbonization in the pulp and paper industry differs from the industrial on addressing process emissions, the main challenge for pulp and paper lies in eliminating remaining fossil fuel use.

From leveraging traditional by-products in novel ways to implementing cutting-edge electrification solutions and developing revolutionary efficiency improvements, the industry has multiple options for decarbonization. This report examines these technological solutions across three key categories: valorisation of paper making by-products, electrification and carbon capture solutions, and efficiency-improving technologies. Each category presents unique opportunities and challenges, collectively offering a comprehensive roadmap toward a more sustainable future for paper production.

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[86] IEA, n.d.

[87] Global Efficiency Intelligence, n.d.

[88] Ma et al., 2018

[89] IEA, n.d.

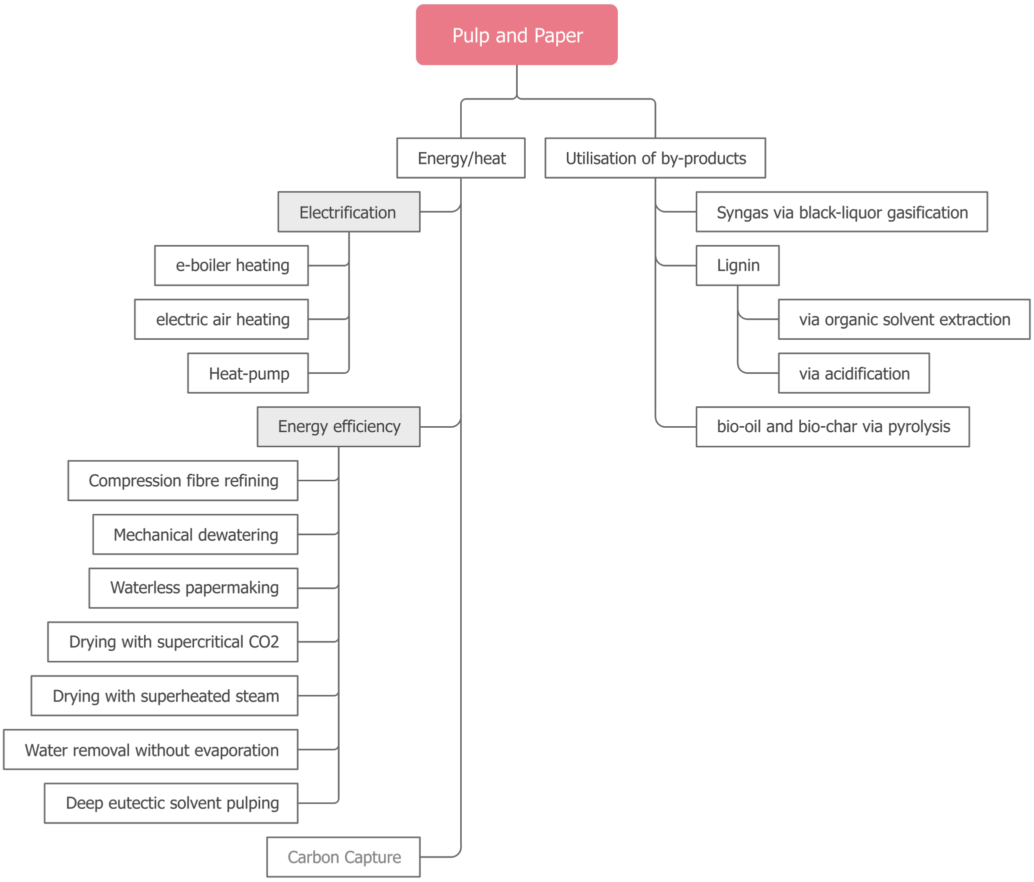

Figure 27: Mitigation options for pulp and paper. Based on IEA ETP Clean energy technology Guide

7.3.1. Valorisation of Paper Making By-products

The pulp and paper industry generates valuable by-products that can be effectively utilized to reduce carbon emissions. Black liquor gasification, a commercially mature technology (TRL 9), stands out as a leading solution. By converting black liquor to chemicals and fuels via synthesis gas and replacing traditional recovery boilers, this process achieves remarkable CO_2 reductions of 85-94% (compared to fossil methanol production, and gasoline production + use). While the abatement costs range from €90-500/t CO_2, the technology's dual benefit of emissions reductions (via avoidance of combustion) and energy recovery makes it particularly attractive.

Lignin extraction represents another significant opportunity, with two main approaches. The commercially available precipitation and acidification method achieves 135-143% CO_2 reduction (when compared to conventional combustion of lignin and accounting the biogenic CO_2 as stored in materials) with abatement costs between €395-420/t CO_2. A more experimental organic solvent-based extraction method, though still under development at TRL 5, shows even greater potential with 156-187% CO_2 reduction (when compared to conventional combustion of lignin and accounting the biogenic CO_2 as stored in materials), albeit at higher abatement costs of €535-1010/t CO_2.

Pyrolysis of by-product streams complements these technologies by converting various side streams into bio-oil and biochar. This commercial-ready solution delivers 59-75% CO_2 reduction (compared to a well-to-wheel footprint of fossil fuels) with abatement costs ranging from €335-790 per tonne CO_2, offering flexibility in handling different water content materials.

7.3.2. Electrification and Carbon Capture

Electrification presents multiple pathways for decarbonization. Electric air heating, a mature technology, offers 50-65% CO_2 reduction with abatement costs around €140 per tonne CO_2. This solution's ability to use renewable electricity and manage load distribution makes it particularly attractive for immediate implementation.

Electric boilers provide similar emission reductions (50-65%) with slightly higher abatement costs (€155-160 per tonne CO_2 avoided). These systems achieve 99% thermal efficiency in steam production for drying processes. Heat pumps, though less mature at TRL 7, show promise with comparable emission reductions but potentially lower abatement costs (€10-115 per tonne CO_2 avoided), though they require specific process adaptations.

Carbon capture technology, while still developing at TRL 5, offers exceptional potential with 90-200% CO_2 reduction (boundaries based on only fossil CO_2 capture, and fossil and biogenic CO_2 capture). With abatement costs of €105-115 per tonne CO_2, this technology is particularly promising due to the industry's significant bioenergy use, enabling Bioenergy with Carbon Capture and Storage (BECCS).

7.3.3. Efficiency-Improving Technologies

Several technologies are emerging to improve the efficiency of pulp and paper production processes. Compression fibre refining (TRL 5) focuses on reducing fibre damage through decreased shear forces, improving overall energy efficiency. New mechanical dewatering approaches, including ultrasound-assisted and vacuum-controlled pressing, offer significant energy savings by improving water removal efficiency.

Looking further ahead, several revolutionary concepts are under development. Waterless paper making, though still at TRL 4, could potentially reduce energy consumption by 70% by eliminating water-based processes. However, maintaining proper fibre bonding remains a significant challenge. Deep eutectic solvent pulping offers another promising avenue, enabling low-temperature operation and reduced energy consumption in the pulping process.

More experimental technologies include supercritical CO_2 drying and advanced water removal methods using electro-osmosis. These early-stage innovations (TRL 2-4) could potentially achieve up to 90% drying energy savings, though significant development work remains before commercial implementation is possible.

7.3.4. Overall considerations

The decarbonisation of pulp and paper production has three important sides. First the increased use of electricity for low-temperature heat (e.g. via heat pumps). A technology that can be deployed on short term but needs favourable economic conditions (e.g. smaller price gap between gas and electricity). Secondly the increased investment in new energy savings technologies which should become available over the next years or decade. Some of these will require a major overhaul of the existing installations and can therefore have a high investment cost. Thirdly the increased valorisation of paper production by products (e.g. lignin) which can contribute to emission reductions in other sectors (e.g. chemicals).

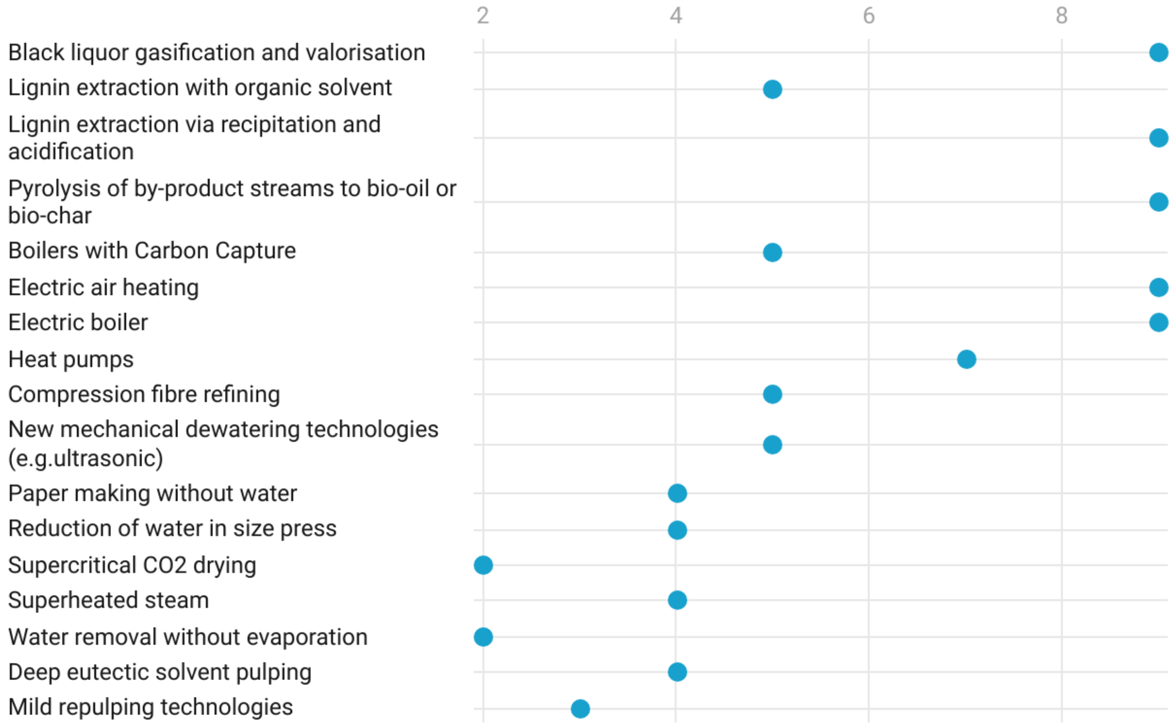

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Figure 28: TRL of pulp and paper mitigation technologies. Source: IEA clean energy technology guide

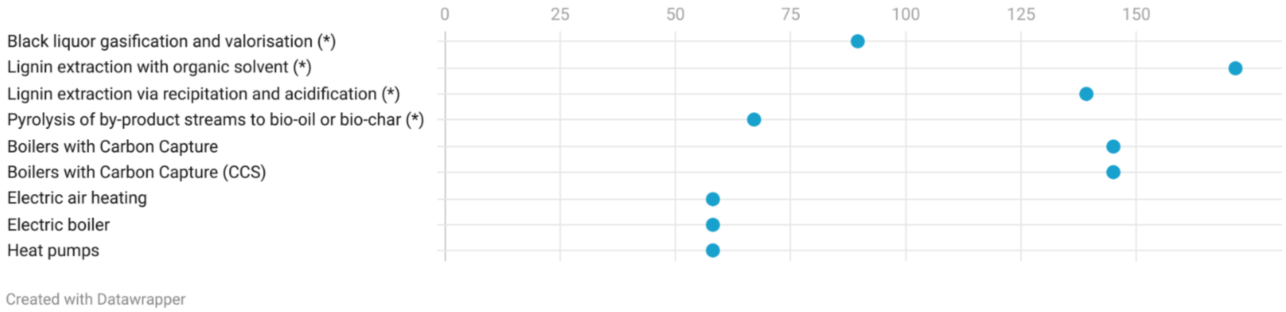


Figure 29: Mitigation potential paper technologies (% CO_2 reduction vs incumbent paper technology. (*) vs combustion or chemicals production.)

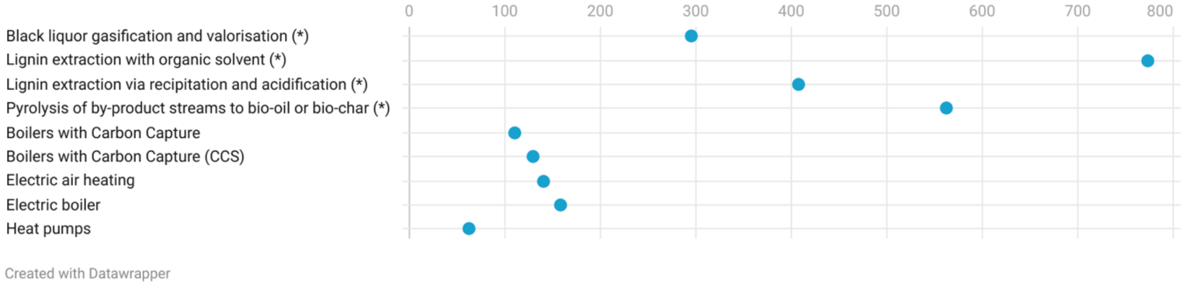
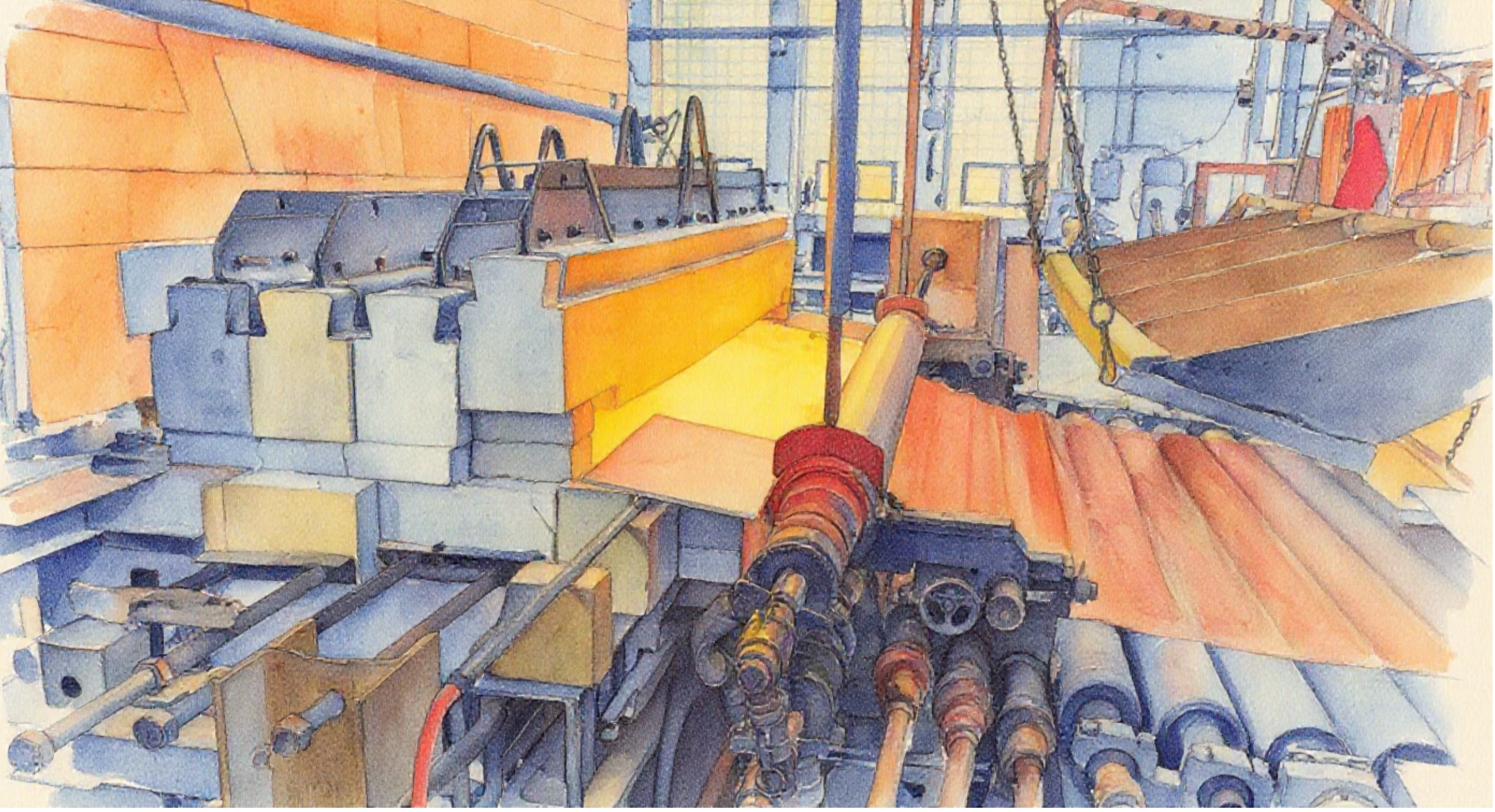


Figure 30: Mitigation cost of paper technologies (€/t CO_2 avoided vs incumbent paper technology. (*) vs combustion or chemicals production.)



8. Glass

8.1. Industry overview

The two major products in the glass industry are flat glass and container glass, but the sector is diverse with e.g. production of glass fibre and specialty glass for e.g. the pharmaceutical industry and solar panels. The glass industry produces EU around 10 Mt of flat glass and 24 Mt container glass (for food and beverages) each year.[90] [91] In Belgium the total glass production is around 1.5 Mt per year.[92]

The total greenhouse gas emissions of glass production in the EU are around 18 Mt CO_2.[93] The industry has already significantly reduced its CO_2 emissions per output by 43% between 1990 and today, mostly due to fuel shift (to natural gas), the increased use of recycled glass and general efficiency improvements.[94] In Belgium the greenhouse gas emissions of glass production are around 600 kt CO_2-eq.[95] Approximately 75% of these emissions come from the use of natural gas to heat melting furnaces, while the remaining 25% are "process emissions" released from raw materials carbonates.

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[90] Glass for Europe, 2020

[91] FEVE, 2022

[92] Belgium, 2024

[93] Zier, M., et al., 2021

[94] Glass for Europe, 2020

[95] 2023 data of glass production covered by the EU ETS in Belgium. Source: EEA (2025)

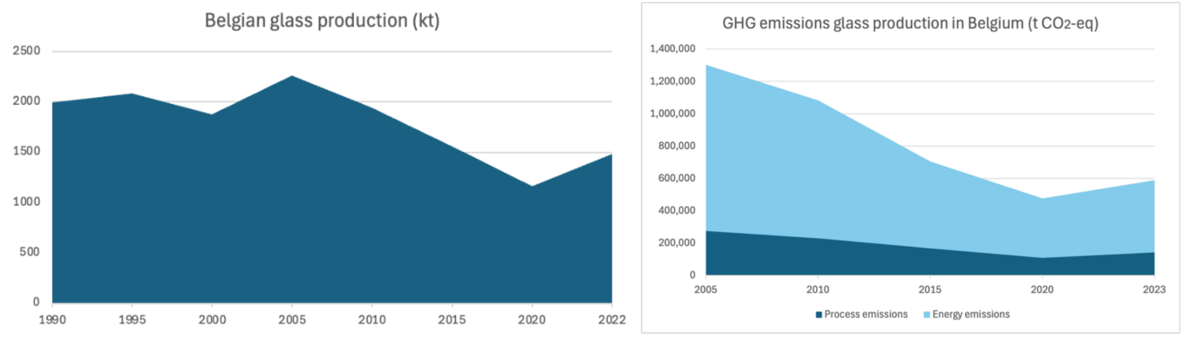

Figure 31: Left: Belgian glass production (1990-2022, kt). Right: GHG emissions glass production in Belgium (t CO_2-eq). Sources: Belgium, 2024, CRT and EEA.

8.2. Production process

Glass manufacturing is an energy-intensive process that produces essential materials for construction, packaging, and other applications. The production process consists of several key stages, each contributing to the final product's quality and environmental footprint.

The process begins with raw material preparation, combining silica sand (70-74%), soda ash (Na_2CO_3), limestone ($CaCO_3$), and dolomite. Recycled glass (cullet) can constitute 20-80% of input materials, significantly reducing energy requirements and emissions. These materials are precisely weighed and mixed before entering the furnace.

The melting process is the most energy-intensive component, accounting for 50–85% of the total energy required and occurring at temperatures between 1200 and 1600°C.[96] The molten glass undergoes fining to remove bubbles and ensure homogeneity before forming.

Forming processes differ between flat and container glass. Flat glass production employs the float process, where molten glass flows onto a tin bath, creating perfectly flat surfaces. Container glass uses Individual Section (IS) machines to form bottles and jars. Both products undergo careful annealing to remove internal stresses and surface treatments for final quality.

Energy consumption varies by product type, with flat glass requiring 6.5 GJ/tonne glass and container glass consuming 3.6 GJ/tonne. The industry's carbon footprint comprises both process and energy-related emissions. Process emissions from raw material decomposition account for 0.15-0.20 t CO_2/t glass. Energy-related emissions vary between products, with flat glass generating 0.40-0.54 t CO_2/t and container glass producing 0.30-0.40 t CO_2/t. The total carbon footprint ranges from 0.60-0.80 t CO_2/ t flat

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[96] Zier, M., et al., 2021

glass and 0.40-0.60 t CO_2 /t container glass. These figures can vary significantly based on facility age, technology employed, and cullet usage rates.[97]

8.3. Mitigation options and technologies

The glass industry continues to explore decarbonisation options, including fuel substitution, increased use of recycled glass, improved energy efficiency measures and CC(U)S.

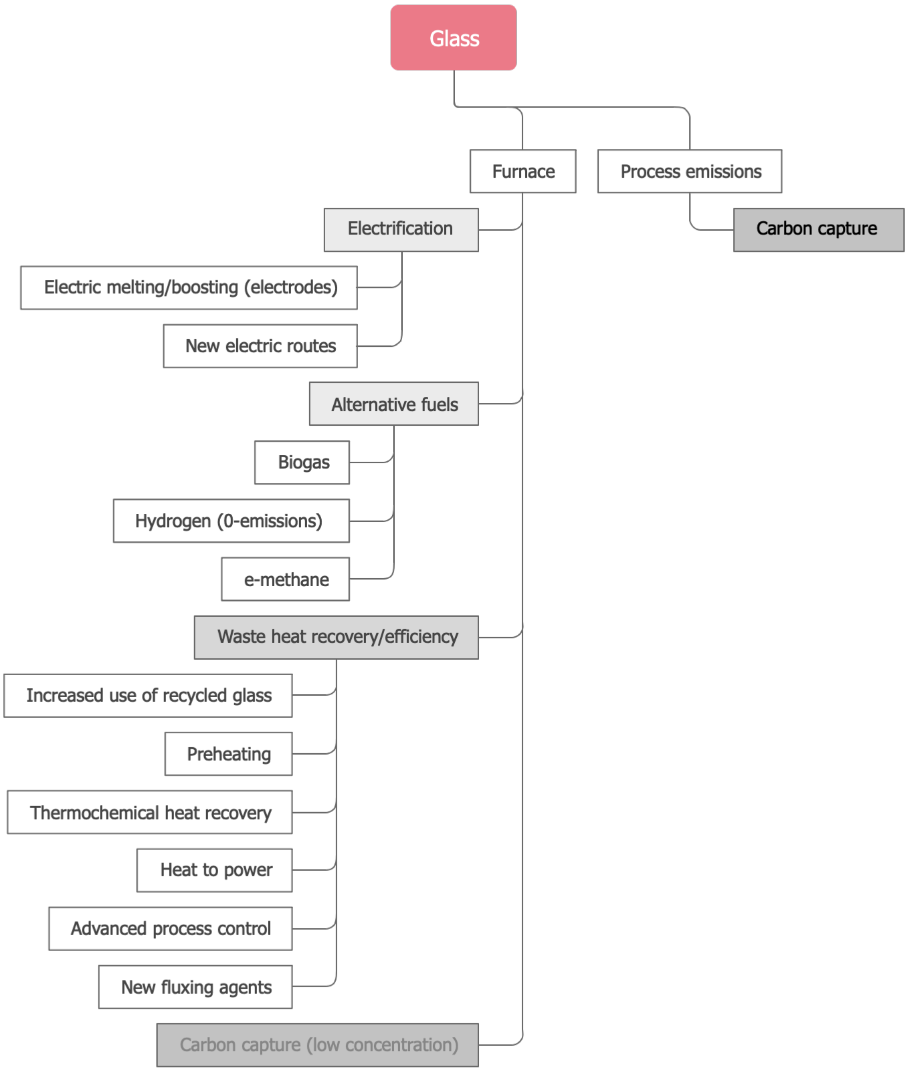

Figure 32:Mitigation options for glass production (based on: Zier, M. et al, 2021 and Glass for Europe, 2020)

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[97] Ibid.,

8.3.1. Fuel substitution

Hydrogen (TRL 3–4)

When produced renewably, H_2 enables near-zero combustion CO_2. Combined with oxyfuel it eases downstream capture and lowers flue-gas dilution.[98] Practical combustion changes (flame velocity, NOx) must be managed experimentally. Current renewable H_2 prices make it expensive.[99]

Synthetic methane (TRL 9[100])

Methane produced from green H_2 + CO_2 can be used as a drop-in fuel and allows near-zero lifecycle CO_2 if feedstocks are low-carbon. However, production is energy-intensive and presently costly.[101]

Biogas / biomethane (co-firing, TRL 5–6)

Co-firing biogas can cut combustion emissions but supply is limited and gas composition variability can complicate furnace control.[102]

8.3.2. Electrification

Electric melting / electric boosting (TRL 6–7)

Submerged-electrode electric furnaces exhibit much higher thermal efficiency (electric furnaces reported ~85% vs regenerative gas furnaces ~45%) and eliminate combustion emissions when powered by renewables. Specific energy consumption falls across the capacity range.[103] Key constraint are the electricity price and grid capacity. Current electricity costs often make electric melting uneconomic without low-cost renewables or policy support.

Emerging electric routes (microwaves TRL 2–3; plasma TRL 3–4)

High theoretical efficiency and rapid heating are reported in lab/pre-industrial trials but scale-up, uniformity and cost issues remain.[104]

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[98] Zier, M., et al., 2021

[99] Ibid.

[100] Synthetic methane is produced via the Sabatier (methanation) process, a known process in the chemicals industry with TRL 8-9. Arvis, S. M., & Samsatli, S., 2018, p. 46–68

[101] Zier, M., et al., 2021

[102] Ibid.

[103] Ibid.

[104] Ibid.

8.3.3. Waste heat recovery (WHR) and Heat-to-Power (HtP)

Cullet preheating (TRL 8)

Using flue heat to warm cullet yields fuel savings of ~12–18% in reported installations and can increase pull rate (~8% reported).[105]

Fuel and oxygen preheating (TRL 6–7)

For oxyfuel furnaces, combined preheating can yield additional fuel savings (~8–10%); demo projects report modest net CO_2 reductions once oxygen production electricity is counted.[106]

Thermochemical heat recovery (TRL 4–5)

Designed for oxy-fuel furnaces, thermochemical heat recovery (TCR) reforms part of the flue stream to a higher-value syngas and can cut fuel use by about 20% vs oxy-fuel baseline (≈ 30% vs air-regenerative); combined with cullet preheating models suggest 29% fuel savings.[107]

Heat-to-Power (ORC TRL 8; Steam turbine TRL 9)

The organic rankine cycle (ORC) converts mid-temperature exhaust into electricity with typical efficiencies 15–19% for 400–500°C streams (CAPEX ≈ €1500–3000/kW). Steam turbines can be more efficient (~30%) but need higher temperatures and greater auxiliary systems.[108]

8.3.4. Process intensification and operational measures

Advanced process control (TRL 7–8)

Model-based control and image analysis often yield 2–3% energy savings, faster payback (months), and improved product stability — a high-value, low-risk near-term measure.[109]

Pelletisation and selective batching (TRL 5–6)

Pelletisation can improve melting kinetics (~7% savings alone; combined with preheating possibly 18–20%); selective batching/spray drying shows literature claims of 20–33% melting gains but requires significant preprocessing energy — techno-economic viability is site-specific.[110]

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[105] Ibid.

[106] Ibid.

[107] Zier, M., et al., 2021

[108] Ibid.

[109] Ibid.

[110] Ibid.

Submerged combustion melting (TRL 3–4)

Direct submerged burners offer strong heat transfer and short residence times with estimated energy savings of 5–7.5% vs advanced oxy-fuel, but fining/refining challenges limit applicability for high-quality flat glass.[111]

Fluxing agents (e.g., small lithium additions TRL 4–5)

Small lithium additions (≈ 0.03–0.2%) can lower melting temperature and SEC by roughly 4 to 10%, but commodity price and availability risk constrain broad roll-out.[112]

8.3.5. Increased use of recycled glass (TRL 9)

Increasing cullet input is one of the most direct, low-risk levers. A 10% increase in cullet by weight typically improves energy efficiency by 2.5–3%.[113] Glass for Europe estimates an additional maximum of about 7% CO_2 reduction for flat glass if end-of-life collection improved substantially.[114] The barrier is collection/sorting infrastructure and the high optical/quality requirements for flat glass cullet.[115]

8.3.6. Carbon capture, utilisation and/or storage (CCUS, TRL 5-7)

CCUS addresses the unavoidable process CO_2 from carbonates (≈ 25% of flat-glass CO_2). Technically feasible at scale only when supported by cluster CO_2 transport/storage infrastructure; cost, energy penalty and social acceptance remain major hurdles. Oxyfuel and low-N_2 flue streams improve capture economics, making CCUS more viable when combined with oxyfuel/TCR and clustered industrial hubs.[116] [117]

8.3.7. Priorities and integrated pathway (recommended sequencing)

On the near term (next 5 years) the sector must maximise cullet (recycled glass) use where quality allows and deploy efficiency measures such as advanced process control (APC) and further digitalisation.[118] [119] Energy efficiency measures such as (ORC) are implemented depending on capex and rate of returns.

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[111] Ibid.
[112] Ibid.
[113] Zier, M., et al., 2021
[114] Glass for Europe, 2020
[115] Ibid.
[116] Zier, M., et al., 2021
[117] Glass for Europe, 2020
[118] Ibid.
[119] Zier, M., et al., 2021

Over the next 5-15 years hybrid electric boosting will be scaled up and progressively electrify melts where low-carbon electricity is available and affordable. Where oxygen supply and CCUS infrastructure are planned thermochemical heat recovery and oxyfuel retrofits can be considered with carbon capture.[120]

Around 2040 the full transition of high-temperature heat to green hydrogen and/or near-100% renewable electricity for electric melting where grid/infrastructure supports it will become possible. For remaining process emissions carbon capture can be deployed at sites in larger industrial clusters.[121]

The most robust strategy combines maximising circularity (cullet), widespread digital process optimisation (APC), staged deployment of waste heat recovery (preheating, ORC/TCR), and a phased shift to low-carbon energy carriers (electricity, hydrogen) with CCUS for residual process emissions. Policy support (infrastructure, CO_2 pricing, investment incentives for electrification and CCUS) and coordinated value-chain action (collection, standardisation of cullet quality) are decisive to unlock the technical potential outlined above.[122]

Significant barriers include the need for extensive transport and storage infrastructures, technical constraints for disseminated units (space limitations, presence of acidic compounds, low CO_2 concentration), limited market demand for captured carbon, and societal acceptance. Carbon cleaning is also an extremely energy and water-intensive process. For scaling, clusters of CO_2 producing sites are needed, rather than small separate units.

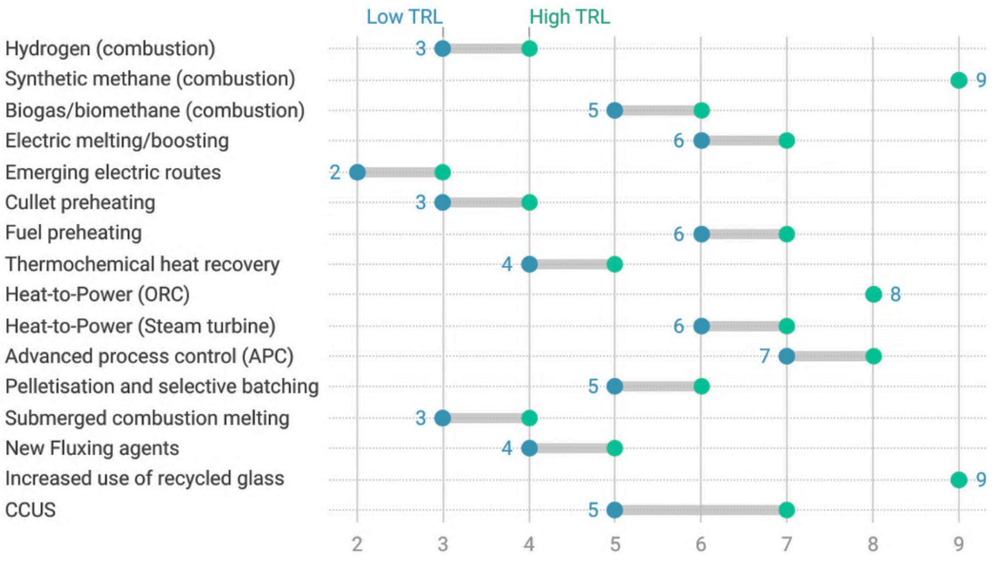

Figure 33: Glass mitigation options Technology Readiness Levels (source: Zier, M. et all, 2021)

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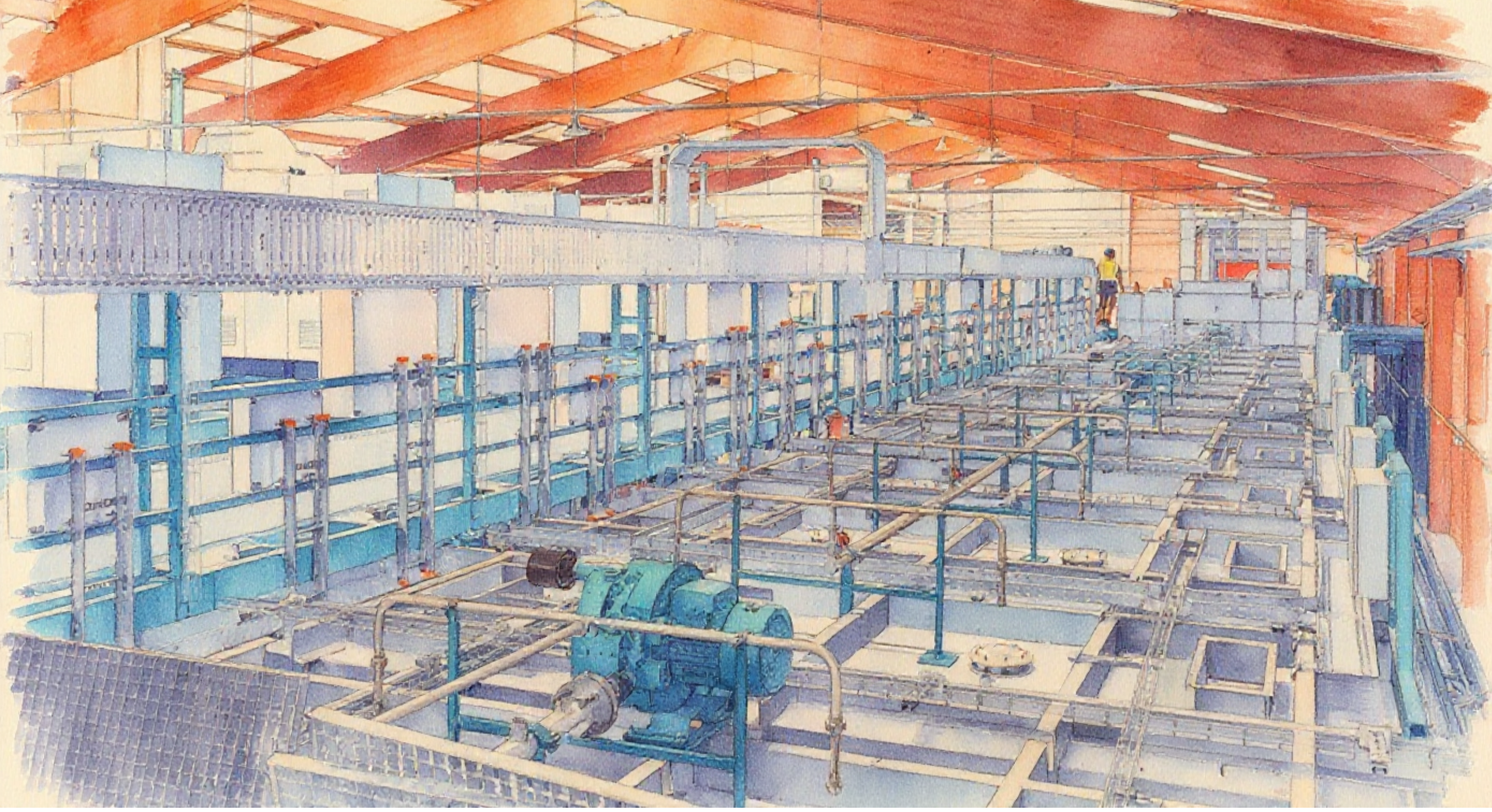
[120] Ibid.

[121] Zier, M., et al., 2021 and Glass for Europe, 2020

[122] Idib.



9. Ceramics

9.1. Industry overview

The EU ceramics industry represents a diverse sector; from tiles, bricks and tableware products, to technical ceramics used in high-tech applications and refractory materials enabling the use of kilns for high temperature materials production.

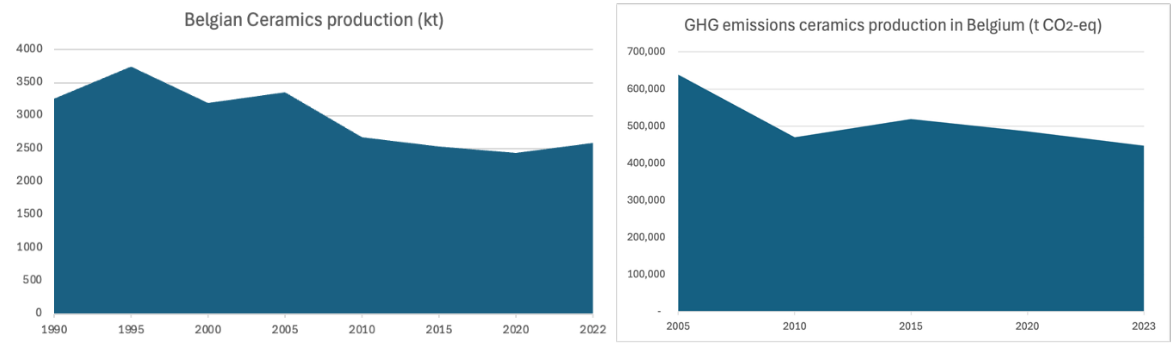


Figure 34: (left) Belgian ceramics production (1990-2022). Source: Belgium, 2024, CRT. (right) GHG emissions of (EU ETS) ceramics production in Belgium (2005-2023). Source: EEA

Total GHG emissions from the European ceramic industry amount to 19 million tonnes of CO_2 annually, which is roughly 1% of Europe's total industrial emissions covered by the EU Emissions Trading System (ETS). On the other hand, being mostly composed of SMEs and small emitters, ceramic installations represent 10% of all industrial installations under the ETS.[123] The greenhouse gas emissions of ceramics production covered by the EU ETS in Belgium are around 500 kt CO_2-eq (2023).[124]

9.2. Production process[125]

Ceramics are primarily made from mined materials such as clay, bauxite, and magnesite, along with water, fire, and air. The raw materials are transported to the ceramic plant and stored. In the raw materials' preparation stage powdered base materials, binders, and stabilizers are mixed. The preparation can be done through dry or wet milling, with wet milling being the most popular method.

Next, the mixture of raw materials is shaped into objects, often involving water for thorough mixing and shaping. Common forming methods include isostatic or uniaxial semi-dry pressing of granulate material with low moisture content; plastic forming by extrusion, wheel throwing, and plastic pressing; and forming by pressure casting of suspensions or air slip casting. Advanced (high-tech) ceramics applications also increasingly utilise 3D printing.

After shaping, water is removed from the products in dryers, typically through convection, where heated air is circulated around the ceramics. Heat from the kiln's cooling zone can sometimes be recovered and used for drying. Reducing water content in the shaped product is critical as most energy in dryers is used to evaporate this water.

Before the main firing, unfired products are heated from ambient temperature to about 800°C. This stage, known as outgassing, prevents defects like bubbles, pinholing, bloating, glaze porosity, and colour differences at higher temperatures. For glazed products at this stage a surface treatment is applied.

The firing (sintering) is a crucial and energy-intensive stage where products are heated in kilns at high temperatures, often ranging from 800 to 2500°C for days (or even weeks). Refractory and technical ceramics may require electric arcs to reach even higher temperatures, up to 2750°C. During firing, ceramic materials undergo physio-chemical transformations and reduce their porosity. Multiple-stage firing processes are often used for products like wall and floor tiles, sanitaryware, household ceramics, and technical ceramics. The firing stage alone accounts for about 75% of the total energy cost and more than 50% of all required energy during manufacturing.

After firing, the products are gradually cooled from their peak temperature to near ambient temperature. Some advanced ceramic applications may undergo machining

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[123] Ceramunie, 2021
[124] EEA, 2025
[125] Based on Furszyfer Del Rio, D. D., et al., 2022 and Cerame-Unie, 2021.

and/or polishing to meet specific engineering design criteria. Finally, products are inspected for defects and separated into trade categories before being packaged.

The thermal stage, which includes both drying and firing, represents the most energy-demanding phase, consuming between 60-85% of the total energy used in production. Current industry standards reveal that tile production requires 5.5-7.0 GJ per tonne, while brick manufacturing consumes 2.0-3.5 GJ per tonne. These processes operate at remarkably high temperatures, ranging from 900°C for bricks to 1200°C for tiles, with complete production cycles typically lasting 24-48 hours, including necessary cooling phases.[126]

Natural gas continues to dominate as the primary energy source, accounting for 80-85% of energy consumption, with electricity making up the remainder. This heavy reliance on fossil fuels presents both significant challenges and opportunities for future decarbonization efforts. In EU ceramics production, about 64% of CO_2 comes from fuel combustion for drying and firing, 19% is indirect (mainly electricity), and 17% are process emissions from mineral decarbonation.[127]

9.3. Mitigation options[128]

The sector is actively pursuing several decarbonisation pathways. Energy efficiency improvements represent the most immediate opportunity, with manufacturers implementing advanced kiln designs, heat recovery systems, and process optimizations. Alternative fuels and technologies are also gaining traction, including promising trials with hydrogen fuel integration, electric kiln development, and biomass fuel adoption. Additionally, raw material innovation is emerging as a crucial area for environmental improvement, with manufacturers exploring low-carbon clay formulations and increased incorporation of recycled materials.

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[126] Based on Furszyfer Del Rio, D., et al., 2022

[127] Ceramunie, 2021

[128] The mitigation options are based on Ceramunie, 2021 and Furszyfer Del Rio, D., et al., 2022

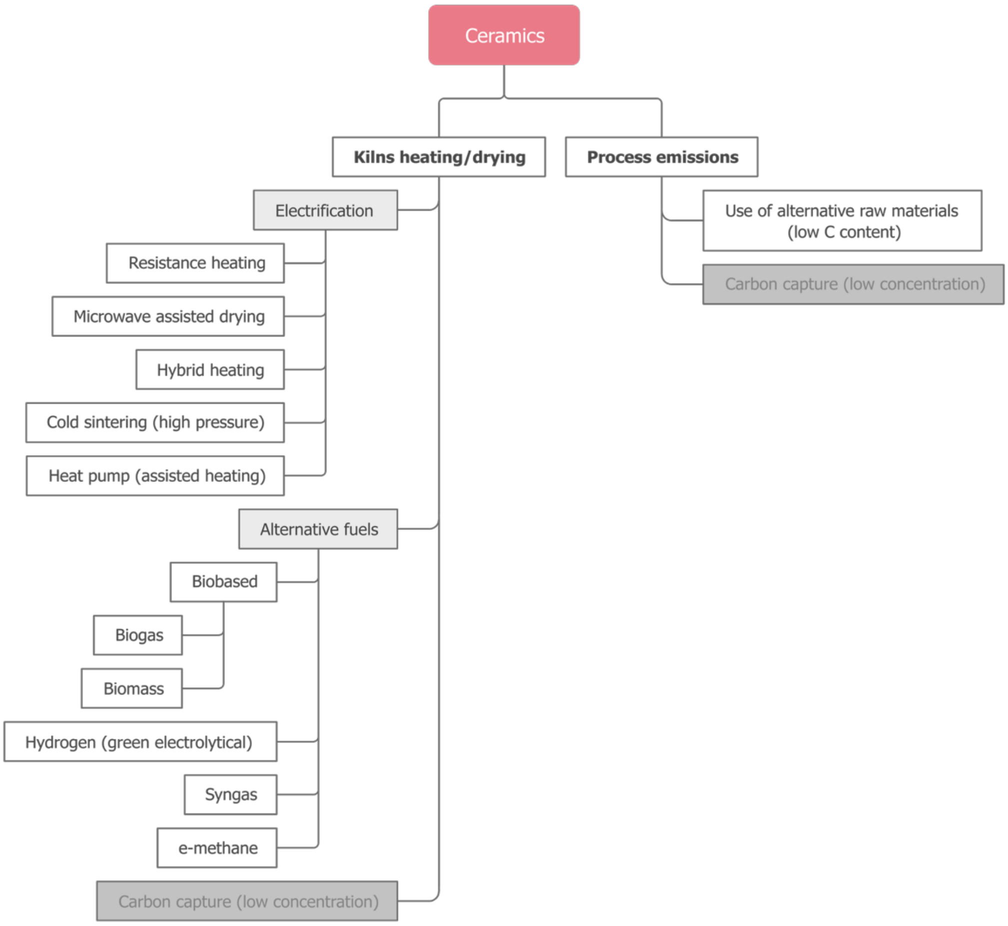

Figure 35: Ceramics greenhouse gas mitigation options (based on: Furszyfer Del Rio, D., et al., 2022 and Ceramunie, 2021)

9.3.1. Electrification

Kiln electrification

Electric kilns can replace gas firing with direct electric resistance or other electrothermal heating for dryers and kilns. Electric heating can deliver precise heat profiles, but continuous, large tunnel kilns are not yet widely electrified in mainstream bricks/tiles production (TRL 5-8)[129]; small batch/technical ceramics often are (TRL 8-9). If powered with low-carbon electricity, electric kilns can abate most combustion emissions at the site.

The technology is currently expensive in due to high capital investment, high electricity prices (compared to natural gas) and lack of indirect cost compensation under the EU ETS in some Member States.

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[129] Wienberger launched a full electric brick kiln in Austria and a brick slip line in Kortemark, Belgium. Wienerberger, 2024 and Wienerberger, 2022

Microwave-assisted drying (and firing) (TRL 8-9)

Microwave-assisted (TRL 8-9) drying reduces drying times dramatically. It can lead to large energy cuts in drying with 40–50% energy use reduction for drying in specific trials due to cycle times up to 8x faster. Firing assistance is reported in niche cases, but not mainstream (TRL 3-4). For drying the cost savings can be significant.

Hybrid heating (TRL 6-8)

Hybrid heating (e.g., gas heat plus heat pumps, CHP and waste heat integration) combines conventional burners with heat pumps or CHP and systematic waste heat recirculation to preheat combustion air and dryer air. Hybrid dryers/kilns use gas-driven or electric heat pumps to lift recovered low-grade heat. Energy savings up to ~65% cited for hybrid dryer concepts; hot-air recycling and preheated combustion air deliver 15–30% fuel cuts; integrated heat recovery across dryers/kilns routinely saves 25–60% in case studies. The TRL is 6–8 with numerous industrial demonstrations (e.g., full-scale heat pipe heat exchangers; hybrid dryer concepts piloted).

Heat pumps (assisted heating for dryers) (TRL 6-8)

Mechanical heat pumps provide hot air for dryers and recover low-grade waste heat from kilns/cooling zones. As part of hybrid systems, energy savings up to ~65% reported; sizable cuts to combustion emissions for drying. TRL: 6–8 (pilots and early commercial integrations). Moderate CAPEX; paybacks can be attractive where waste heat is well matched. Qualitative: moderate cost.

Cold sintering (< TRL 4)

Experimental cold sintering (at high pressure and low temperature) densifies certain ceramic chemistries below ~200°C using a transient liquid phase and pressure (solution-precipitation), drastically reducing required firing energy. Potentially very large energy reduction for applicable compositions; currently limited to specific materials/parts and far from mainstream bricks/tiles/refractories (< TRL 4).

9.3.2. Alternative fuels

Biogas/biomethane (biobased) (TRL 8-9)

Biogas can substitute natural gas with minimal burner/controls changes compared to H_2. Compatible with existing gas infrastructure where available. It can reduce most combustion emissions substantially. TRL: 8–9 (technology mature; supply scale varies by region). There is an OPEX premium versus natural gas; overall moderate to high cost depending on supply contracts.

Solid biomass (TRL 6-7)

Direct biomass combustion or gasification-derived fuel. For many kilns, a full switch requires new burners and kiln designs. Similar potential to biogas on the combustion share; depends on sustainable sourcing and combustion performance. TRL: 6–7 (retrofitting challenges noted; "full switch not possible without novel kilns"). Cost: Variable; can be moderate where local residues exist, but with logistics and quality constraints. Qualitative: moderate with supply risk.

Hydrogen (green electrolysis) (TRL 5-7)

Use low-carbon H_2 as a high-temperature fuel in burners but needs H_2-capable burners, safety systems, and supply. Mitigation impact: Can abate most combustion emissions; NOx control and burner redesign required. Impact depends on green H_2 availability. TRL: 5–7 for direct firing in mainstream ceramics (pilots underway); higher in some fuel cell/ancillary uses, but that is outside firing. Cost: High today (fuel cost and hardware); infrastructure/storage also add cost.

Syngas from waste/biomass; green synthetic methane (e-methane) (TRL 7-9)

Thermochemically derive syngas from biomass/waste or use e-methane produced with green H_2 and captured CO_2. End-use like natural gas. Potentially large on combustion emissions; depends on lifecycle carbon intensity. TRL: Syngas end-use 7–8; e-methane end-use 8–9. Cost: Syngas moderate to high; e-methane high.

9.3.3. Abatement of Process emissions

Use of alternative raw materials (low C content) and dematerialisation (TRL 8-9)

Reduce carbon-bearing additives, optimise clay mixes toward low-carbonate sources, increase recycled inputs (tile sludge, glass cullet, bottom ash, paper sludge, marble waste, etc.), and reduce material intensity. Several substitutions lower vitrification temperature, cutting fuel too.

Direct process-CO_2 cuts up to ~10% by switching to low-carbonate clays. Where fluxing wastes lower firing temperature by 100–200°C, additional fuel CO_2 savings accrue. Dematerialisation and product redesign further reduce both process and combustion CO_2.

TRL: 8–9 for many substitutions (multiple industrial trials/case studies documented); ongoing optimisation remains. Cost: Often low or even cost-saving (less virgin raw material; lower firing energy). However, substitutions need to be available and compatible with quality of end products.

Carbon capture (low-concentration flue gases) (TRL 3-7)

Post-combustion CO_2 capture from diluted kiln/dryer exhausts, followed by transport and storage or utilisation. Potentially captures residual combustion and process CO_2; however, site scale, flue characteristics and dispersion of plants make this impractical for most of the sector in the near to medium term. There is caution for limited applicability and very high costs for this industry. TRL: 5–7 for capture technologies in general; 3–5 for widespread deployment in ceramics given site constraints. High (CAPEX/OPEX, transport and storage); unlikely to be viable for typical ceramic plants in the near term.

9.4. Conclusions

On the short term the priorities for greenhouse gas mitigation in ceramics are high TRL technologies that enable energy savings in kilns and dryers. This includes waste heat recirculation, preheated combustion air and use of heat pumps for drying. Raw material optimisation to trim process CO_2 and lower firing temperatures.

Alternative low-carbon fuels where infrastructure and supply chains mature.

The use of biogas, where available is also a nearer-term option. While hydrogen and e-methane will depend on developments of infrastructure.

Gradual electrification of selected kilns and most dryers where low-carbon, competitively priced power is accessible will likely happen over the next 10-15 years.

Wider electrification of continuous kilns contingent on power-system decarbonisation and cost. Carbon capture remains niche for ceramics due to scale and flue dilution, though it may suit a few larger, co-located sites with shared CO_2 infrastructure.

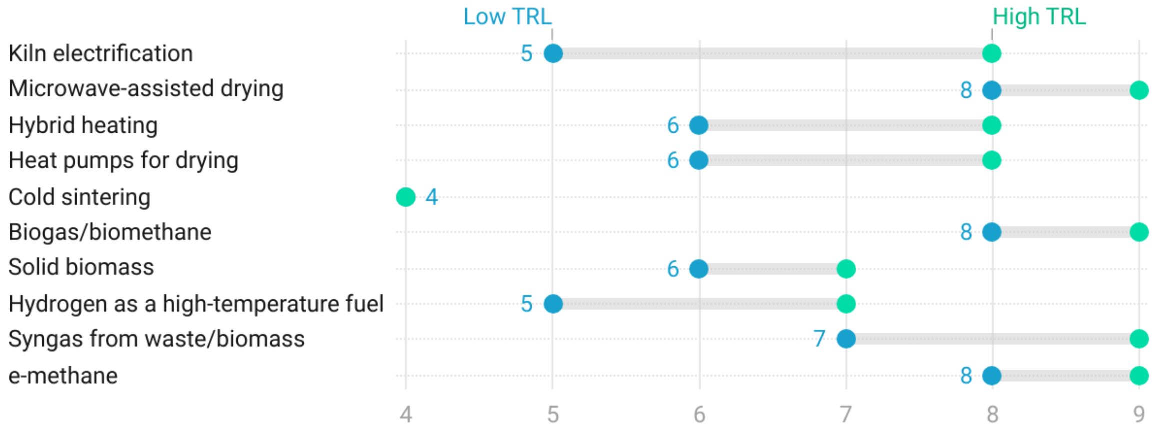

Figure 36: Ceramics mitigation technologies, technology readiness levels (sources: Furszyfer Del Rio, D., et al., 2022 and Ceramunie, 2021)

10. Non-ferrous metals

10.1. Sector overview[130]

The EU's non-ferrous metals (NFM) industry is a large, integrated ecosystem spanning primary smelting/refining, high-end multi-metal recycling and downstream fabrication. While Europe mines only a small share of global ores and is highly import-dependent for concentrates (≈ 80% for major base-metal ores), it retains significant primary capacity in several base metals and is a global leader in secondary production. In 2016, EU primary output across NFMs was about 7.4 Mt (≈ 3.7% of world total), with notable shares in copper (13.1% of global primary), zinc (13.4%), nickel (9.6%), lead (9.4%) and aluminium (4%). Secondary production is particularly strong: the EU produced about 3.0 Mt of secondary aluminium (≈ 30% of global secondary), 0.73 Mt of secondary copper (≈ 26%), and 0.30 Mt of secondary zinc (≈ 19%). Europe's multi-metal plants recover over 20 elements from complex residues (slags, sludges, waste of electronic and electrical

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[130] This chapter draws upon the report Wyns, T. and Khandekar, G., 2019

equipment (WEEE)), making circularity a strategic supply pillar alongside primary smelting.

NFMs are the most electro-intensive of the energy-intensive industries: electricity accounts for about 58% of their final energy use, so indirect (power-related) CO_2 is material. Even so, total EU NFM greenhouse gas emissions (direct + indirect) fell by about 61% between 1990 and 2015, with direct emissions down ~65% and indirect down ~56%, helped by process upgrades and a 40% fall in the EU grid's carbon intensity over the period. Decarbonised power is the single biggest lever—zero-carbon electricity alone would cut sector emissions by roughly four-fifths versus 1990 if direct emissions remained at 2015 levels. At metal level, EU aluminium emissions dropped ~62% (1997–2015) as perfluorcarbons (PFCs)[131] were almost eliminated (−98%) and anode/process control improved; zinc emissions fell ~38% (1990–2015) as production shifted from the coke-intensive Imperial Smelting Furnace (ISF) route to the more electric Roasting-Leaching-Electrolysis (RLE) process; and copper's CO_2 intensity declined ~40% (1990–2015) via widespread flash smelting, oxygen enrichment and efficiency gains, even as electro-refining raised the electricity share. By contrast, silicon and ferro-alloys retain significant process CO_2 from carbothermic reduction.

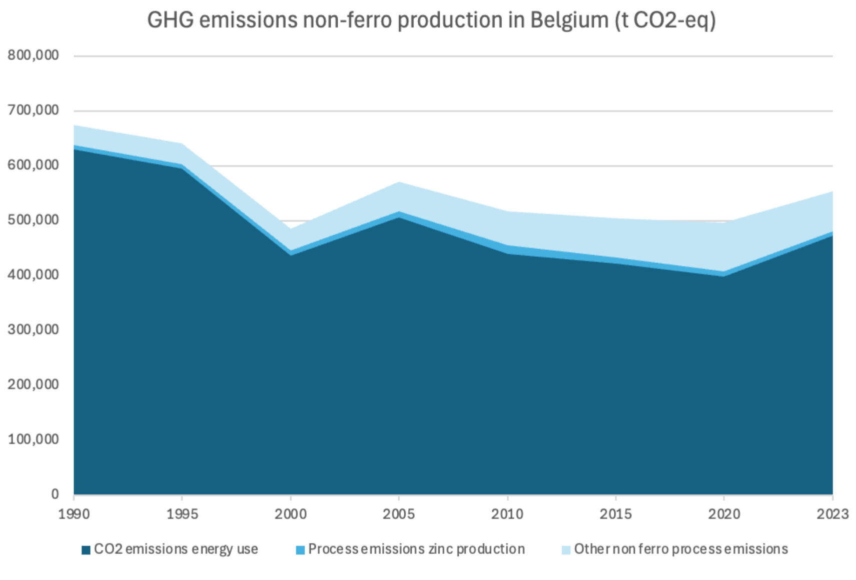

Figure 37: GHG emissions of non-ferrous metals production in Belgium 1990-2023 (Source: Belgium, 2024, CRT).

In Belgium the non-ferrous metals sector consists of zinc, copper, secondary aluminium and a growing recycling activity for precious metals. In the period 1990-2023 GHG emissions of non-ferrous metals in Belgium went down by around 20%.

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[131] Perfluorocarbons (PFCs) may be generated during the current primary aluminium reduction process. These greenhouse gases possess an extremely high global warming potential, most of them are approximately 10,000 times more powerful than CO_2. (IPCC Global Warming Potential Values, 2024)

10.2. Non-ferrous metals processes

Primary aluminium is made by refining bauxite to alumina (Bayer process) and smelting alumina in cryolite by Hall-Héroult electrolysis with consumable carbon anodes. It is highly electro-intensive (about 14–16 MWh per tonne Al) and generates direct CO_2 from anode consumption (historically also PFCs, now largely abated in the EU).

Secondary aluminium uses sorted scrap melted in suitable furnaces; it requires orders of magnitude less electricity (≈ 0.12–0.34 MWh/t) and avoids the mining and refining stages. Downstream, casting, rolling and extrusion define product performance and influence recyclability.

Copper is predominantly produced via pyrometallurgy: flotation concentrates are flash-smelted and converted to blister copper, then electro-refined to 99.99% cathode. Total energy use is around 12 GJ/t (≈ 3.3 MWh/t), with about 1.5 MWh/t as electricity for electro-refining; modernised lines are even more electrified. Hydrometallurgy (SX-EW) leaches low-grade or oxide ores and electrowins copper at higher electricity use but very low direct emissions; it is typically sited near mines and is rare in the EU.

Zinc is mainly produced by Roasting-Leaching-Electrolysis (RLE): concentrates are roasted to ZnO, leached and purified, and zinc is electrowon (≈ 4.2 MWh/t); the legacy Imperial Smelting Furnace (ISF) is far more CO_2 and energy-intensive and has largely closed in Europe.

Recycling is central across non-ferrous metals: high-purity process scrap is looped back; end-of-life flows (e.g., ELVs, building products, packaging) feed secondary smelters; zinc from galvanised steel returns as EAF dust and is recovered via Waelz and RLE routes. European multi-metal plants recover over 20 elements from complex residues (slags, sludges, WEEE), making circularity a strategic supply pillar.

10.3. Mitigation technologies and pathways

Because EU non-ferrous production is 50–60% electricity by final energy, decarbonising the power system drives the majority of (indirect) emission reductions. Zero-carbon electricity alone would cut the sector's total (direct + indirect) emissions by roughly four-fifths versus 1990. Delivering this requires competitively priced, reliable clean power, facilitation of long-term (clean) power purchase agreements (PPAs), and the ability for electro-intensive sites to provide demand response without being penalised by grid tariffs. Aluminium and zinc facilities already act as "virtual batteries", modulating tens of megawatts with fast response; scaling this lowers system costs and indirectly lowers abatement costs for industry.

10.3.1. Process innovations

Process innovations can remove residual process CO_2 and lower energy use. In aluminium, inert (non-carbon) anodes and wettable/inert cathodes would eliminate anode CO_2 and PFCs while improving cell efficiency; TRL is reaching higher levels (around 7-8) with demonstrations underway. Complementary measures—better anode geometries, vertical electrode designs, dynamic magnetic fields, and lower-temperature operation—offer further single-digit to low-double-digit electricity savings. A more radical but early-stage route is molten-salt electrolysis for copper (one-step, SO_2-free smelting and refining), which could halve energy use compared with pyrometallurgy; it remains at low TRL. In zinc, the major mitigation has already occurred by shifting from ISF to RLE; further gains come from cellhouse efficiency, oxygen production optimisation, and residue valorisation. Across metals, greater use of hydrometallurgical and bio-leaching routes for suitable ores and residues shifts energy from fuels to electricity and reduces combustion emissions.

10.3.2. Electrification

Electrification beyond electrolysis targets thermal steps and auxiliaries. Electric heating (induction, resistance) can displace natural gas in casting, annealing, dryers, boilers and onsite utilities where temperature and duty cycles allow. The business case improves when paired with waste heat recovery and thermal storage. In smelting and slag-treatment lines, electrified equipment and higher oxygen use can reduce fossil firing; however, economics are sensitive to the electricity–gas price gap.

10.3.3. Fuel and reductant switching

Fuel and reductant switching is complementary. Replacing coke with natural gas where feasible reduces CO_2; biogenic carbon (charcoal, torrefied biomass) is already used in some ferroalloys and silicon furnaces and can be expanded subject to sustainability and quality constraints. Hydrogen can, in principle, replace carbon as a reductant in specific pyrometallurgical steps (e.g., copper fire-refining), and it offers synergies where oxygen from electrolysis is valuable; thermodynamics limit its universal use (e.g., for Mn, Cr, Si oxides), and cost/availability remain barriers.

10.3.4. Carbon capture, utilisation and storage

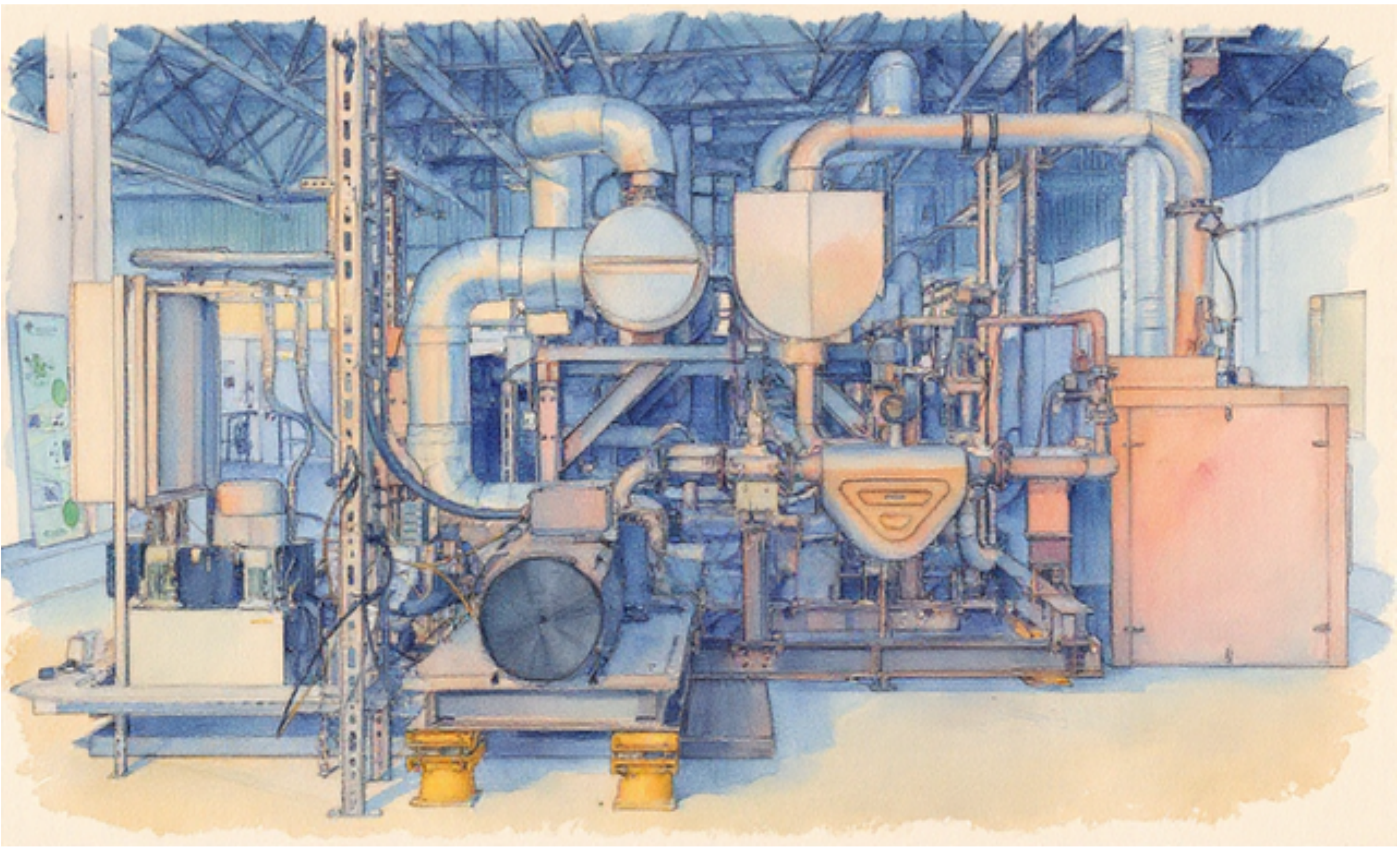
Carbon capture, utilisation and storage is selective but important. Non-ferrous sites are smaller than steel or cement, so stand-alone CCS is rarely first-choice. Exceptions exist: silicon and ferroalloys emit high-CO_2 off-gases conducive to efficient capture; coupling bio-carbon with CCS can yield net-negative direct emissions. Aluminium pot gas is dilute (~4% CO_2), implying high capture cost (~€100/t for absorption), and inert anodes would render capture largely redundant there. Practically, CCS becomes attractive where smelters sit inside clusters that will anyway build CO_2 transport and storage.

10.3.5. Circularity and enhanced recovery

Circularity and enhanced recovery both cut lifecycle emissions and strengthen security of supply. State-of-the-art plants extract metals from red mud, jarosite, fayalitic slags, EAF dusts and waste of electronic and electrical equipment (WEEE). Hydrometallurgical innovations are advancing (mostly TRL 2–5) and can deliver high yields at lower CO_2 than pyrometallurgy alone. On WEEE, shifting from incineration to pyrolysis plus hydrometallurgy, or full hydromet./bioleach flowsheets, reduces energy and direct CO_2 while improving precious-metal recovery. Upstream, high-throughput alloy-specific scrap sorting (LIBS, X-ray, adjustable magnetic fields, robotics) enables product-to-product recycling, elevates secondary feed quality and lowers remelt penalties.

10.3.6. System integration

System integration unlocks additional “no-regret” measures. Waste heat exports to district heating can be sizeable where clusters exist (e.g., sulphuric-acid plant heat from copper smelting), delivering scope-2/3 benefits. Participating in ancillary services and flexibility markets reduces total system costs and, with appropriate regulation, lowers the effective abatement cost of electrification inside plants.



11. Industrial Heat

11.1. Introduction[132]

In the EU fuels combustion, primarily to supply heat, provide 65-70% of the final energy consumed in industry (feedstocks excluded). Overall, industry is the third-largest energy user in Europe, after transport and households, making up 25% of total final demand. Most of the energy in the industrial sector is used for heat in industrial processes, predominantly generated by burning gas, coal, and oil. This reliance on fossil fuels means process heat is responsible for about 75% of industrial greenhouse gas emissions.[133] [134]

This report analysed around 20 alternatives (derived from the IEA's clean energy technology guide) that can eliminate a large share of this footprint. They fall into three families: electrification, biomass and renewable molecules.

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[132] The selection of mitigation technologies is based on the IEA's clean energy technology guide. IEA, 2025
[133] Rosenow, J., et al., 2024
[134] Madeddu, S. et al., 2020

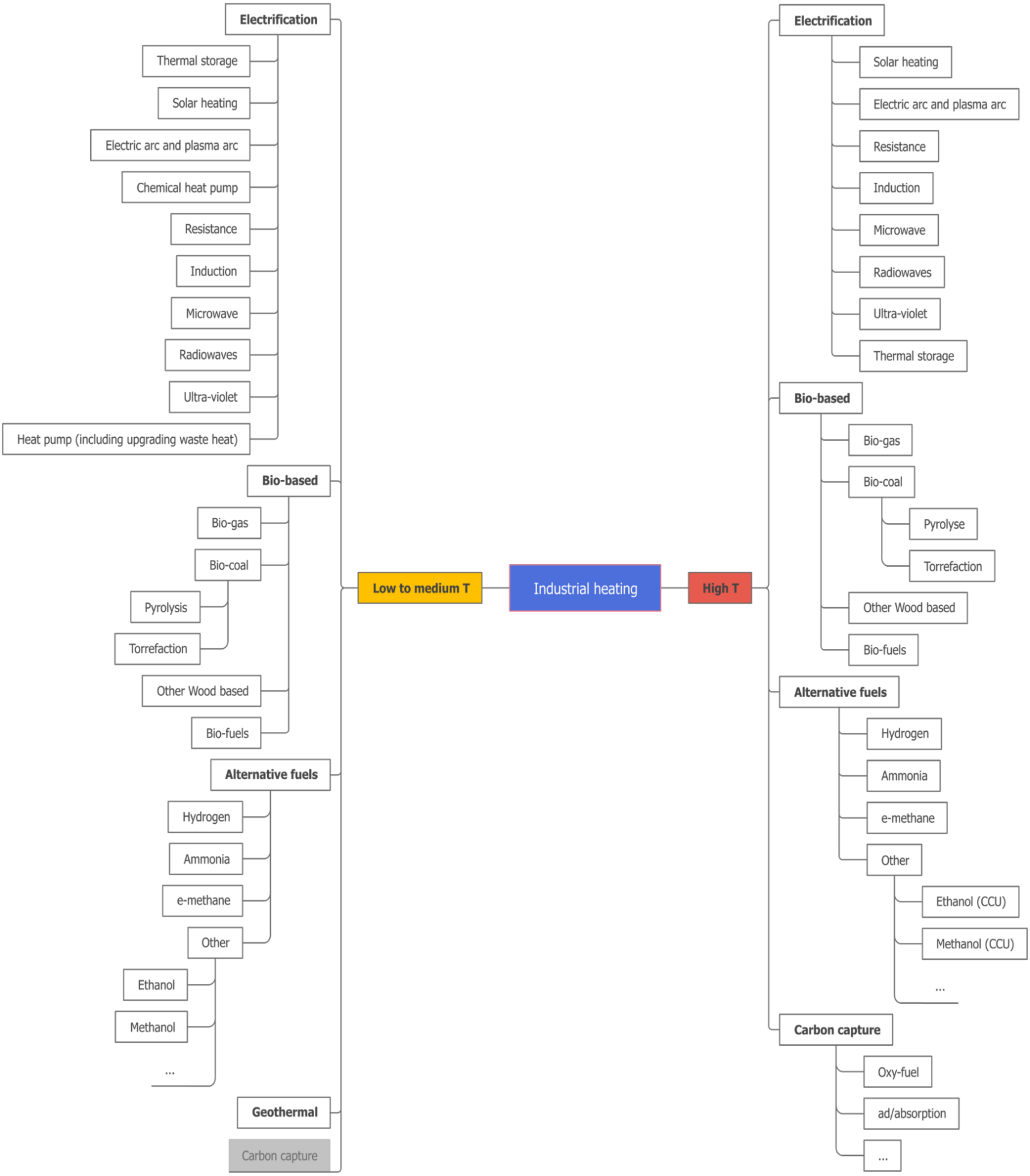

Figure 38: Industrial Heat Technolgies (Source: IEA, 2025, BSOG-VUB).

11.2. Electrification of heat

As of 2020, only 3% of industrial process heat in the EU was electrified. However, 60-78% of process heat could be electrified today using commercially available technologies. This potential rises to 90-99% with technologies expected to be mature by 2035. The potential for process heat electrification varies by sector and temperature needs. For instance, 37% of process heat demand is for temperatures below 200°C, which can be electrified with highly efficient technologies like heat pumps. Even demand for heat over 500°C (52%) can increasingly be met through electrification.[135] [136]

11.2.1. High-temperature (≥ 700°C)

Electric arc / plasma furnaces (TRL 3-9):

Long proven in secondary steel and titanium, now explored for cement and alumina sintering. CAPEX ≈ €1500/kW; avoidance cost ~€270/t CO_2 at €70/MWh.

Induction melting (TRL 10)

Commercial for non-ferrous and special-steel casting. Costs span €230–430/t CO_2 avoided depending on the duty cycle; efficiency ~90%.

Microwaves & radio frequency (TRL 6-9)

Microwaves & radio frequency provide volumetric heating for ceramics (drying or assisted), food or some chemical powders. Similar costs to induction but favourable where fast thermal ramp-up is valuable.

Rotary compression heater (Coolbrook RDH, TRL 6):

A fan-type electric gas heater reaching 1700°C with projected CAPEX €500/kW and 95% efficiency (≈ €175/t CO_2 avoided). Cement calciner pilots scheduled 2026-27.

Thermo-chemical storage / calcium looping (TRL 4)

Thermo-chemical storage / calcium looping stores cheap off-peak electricity as reaction heat and releases 400–875°C when needed (€215–660/t CO_2 avoided). Promising for batch operations.

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[135] Rosenow, J. et al., 2024

[136] Madeddu, S. et al., 2020

11.2.2. Medium- to low-temperature (< 400°C)

Infra-red, heat pumps (> 100 kW) and heat-storage blocks are already commercial. Large heat pumps achieve the lowest cost in the entire dataset (€10–115/t CO_2 avoided) when a low-temperature waste heat source is available but top out at ~150°C unless paired with steam ejectors. UV curing delivers zero-on-site emissions in coatings and packaging, but data gaps preclude cost assessment.

Heat pumps operate by transferring heat from a lower-temperature source to a higher-temperature destination, rather than generating heat directly through combustion. Their efficiency is measured by the Coefficient of Performance (COP), which is the ratio of heat output to electricity input. Industrial heat pumps frequently achieve COPs of 2 to 4, equivalent to an efficiency of 200–400%. Suppliers are developing and offering industrial heat pumps that target temperatures up to 280°C, and potentially as high as 400°C. This makes them especially valuable in sectors such as food and drink, paper, and chemical industries. To achieve high COPs at high temperatures, industrial heat pumps often need to utilize waste heat of a sufficient temperature to minimize the necessary temperature lift. Heat pumps are commercially available with growing installation rates across Europe. They are considered "mature technologies" for the electrification of low- and medium-temperature processes.[137]

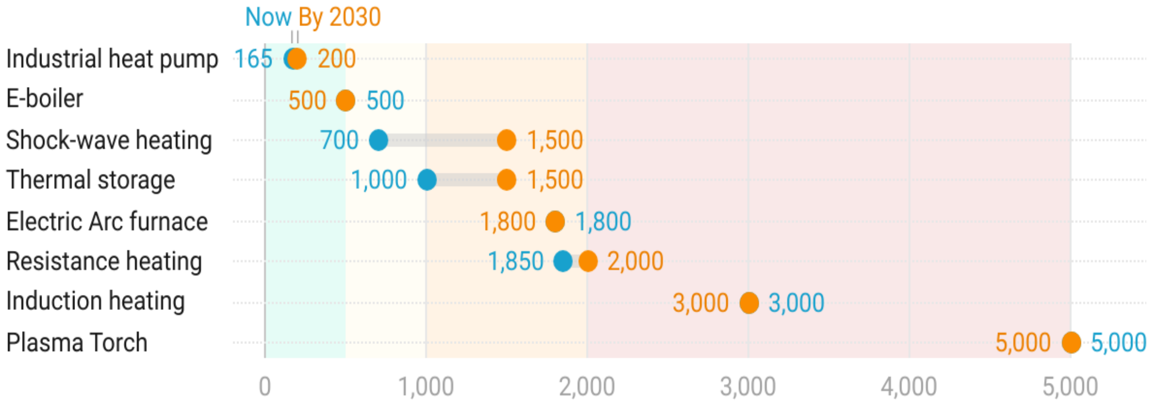

Figure 39: Temperature ranges (˚C) of electrification technologies (blue: now, orange: expected by 2030). Source: Rosenow, et al., 2024

11.3. Renewable molecules – green H_2 & NH_3

Hydrogen-fuelled burners and oxy-burners are technically “ready” for both medium (< 400°C) and high-temperature (> 700°C) service; 100% hydrogen cuts on-site CO_2 by up to 100%. The barrier is economics: with €70/MWh electricity, translate into abatement

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[137] Rosenow, J. et al., 2024

costs of €560-600/t CO_2. Ammonia shows similar abatement (provided that only renewable electricity is used for NH_3 production) but also high costs (€380–620/t).

11.4. Bio-based drop-ins

Ready-to-use biomass substitutes provide an immediate decarbonisation lever with limited equipment change-out. Charcoal / “bio-coal” from pyrolysis (400–800°C) offers 89–93% CO_2 reduction versus gas/coal at attractive costs of €45–95/t CO_2 avoided; torrefied pellets (200–400°C) deliver 56–70% at €45–105/t CO_2 avoided.

Biomethane, upgraded from anaerobic digestion or gasified residues, saves 42–58% but is expensive (€530–720/t CO_2 avoided) because feedstock is scarce can already be valued in the power or transport market. Deployment where availability is possible and affordable and prioritise installations that cannot electrify easily on short term (e.g. lime and cement kilns, ceramic and glass).

11.5. Solar process heat

Concentrated Solar Power (CSP) with heliostats is technically able to generate 800–1000°C air or molten-salt streams (TRL 6); climatic conditions make it irrelevant for Belgium and most of North-West Europe but more relevant for the Mediterranean region.

11.6. Thermal storage and enabling technologies

Heat-storage blocks (ceramic, molten salt or chemical) increase utilisation of intermittent renewable power and can shave peak electricity tariffs. Danish concrete pit storage (65 MWh-th) and Q-Pinch chemical heat pumps (10 MW-th) are commercial today and achieve high round-trip efficiencies (i.e. heat output compared to the heat input) of 80–90% with negligible direct emissions.

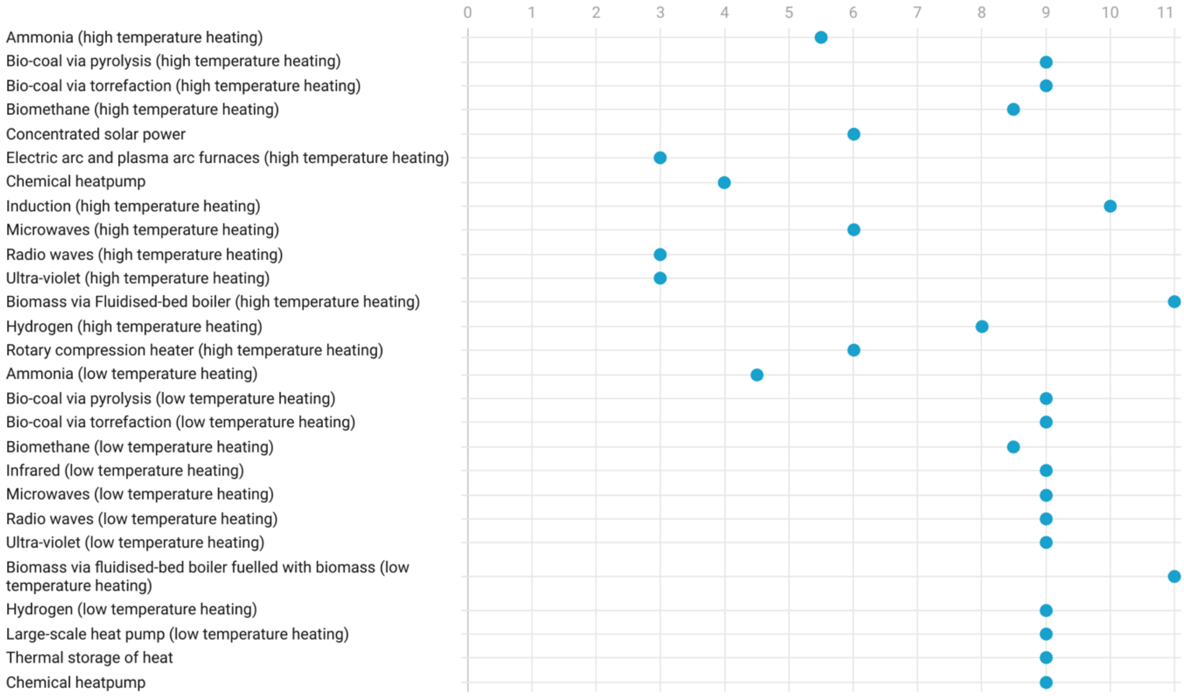

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Figure 40: TRL of industrial heat technologies. Source: IEA ETP clean energy technology guide

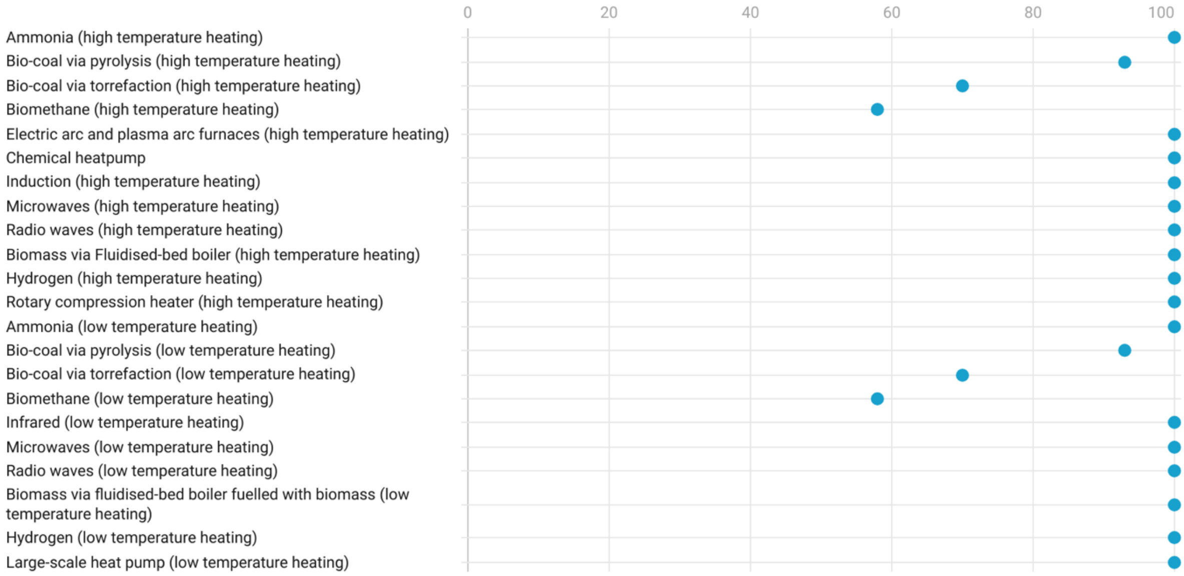

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Figure 41: Industrial heat mitigation technologies (% CO_2 reduction vs incumbent combustion). Source: IEA ETP clean energy technology guide, BSOG-VUB, diverse

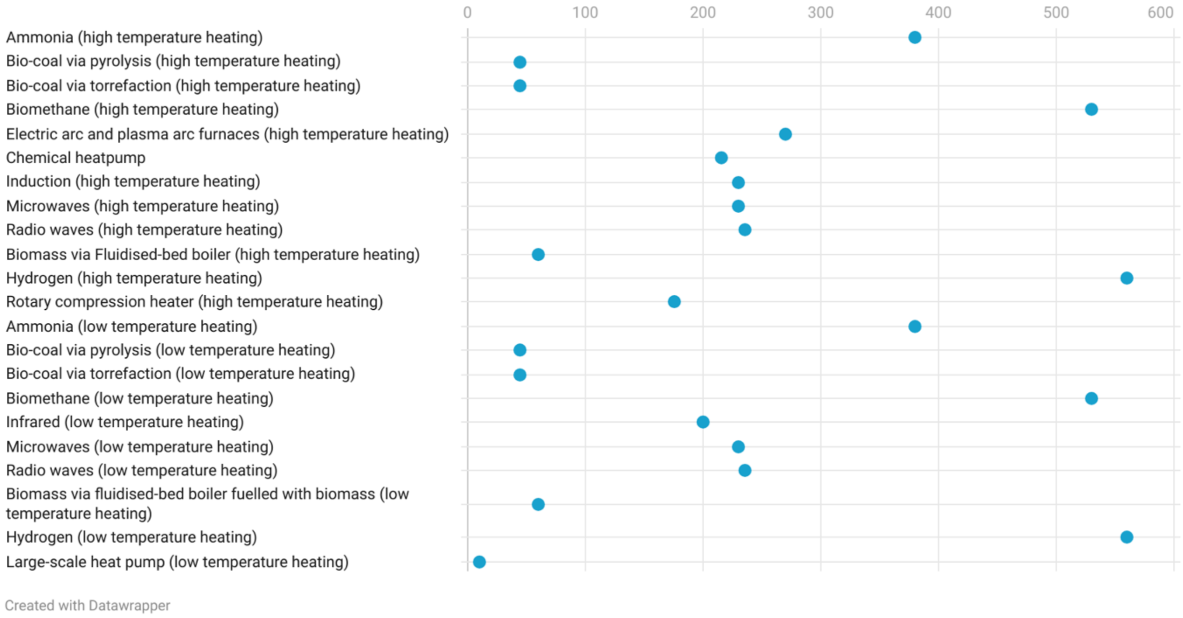
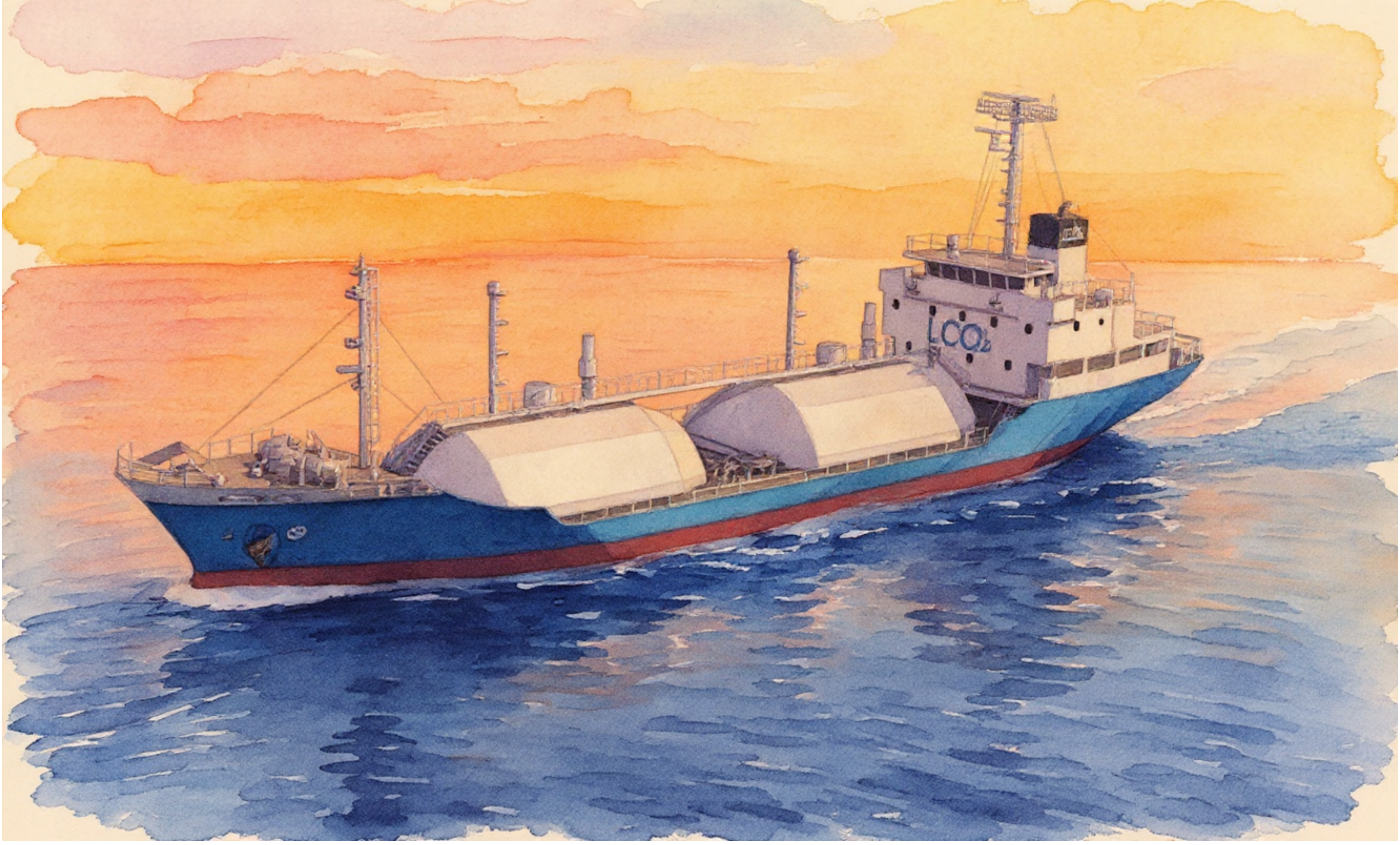


Figure 42: Industrial heat mitigation technologies' cost €/t CO_2 avoided vs incumbent combustion. Source: IEA ETP clean energy technology guide, BSOG-VUB, diverse



12. Carbon capture

12.1. Introduction

There are two approaches to handle CO_2 emissions from point sources: Carbon Capture and Storage (CCS) and Carbon Capture and Utilization (CCU). In the former, the removed CO_2 from the emission source is stored in stable, underground geological formations, on- or offshore, whereas in the latter it is reused for the production of chemicals, fuels or building materials (figure 43). A crucial step in this CO_2 value chain is the capture and separation of CO_2 from industrial flue gases, being the most energy intensive and most complex step. Other important steps in the CCUS value chain often include extra purification to meet pipeline specifications and compression to the required operating pressure. A key challenge in the further development of a European-wide CO_2 transport network is the lack of a universally agreed-upon set of conditions for CO_2 pipelines, particularly regarding the acceptable composition of the transported CO_2.

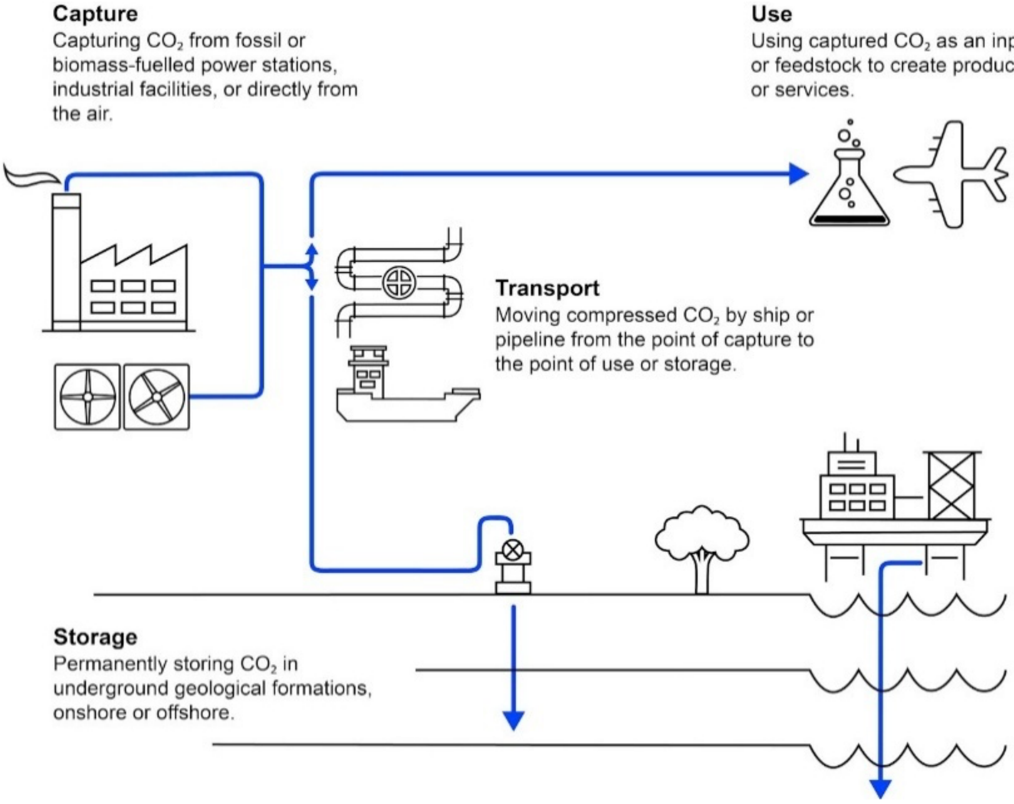


Figure 43:Schematic representation of the CCU and CCS options starting from carbon capture. .[138]

Generally, there are three main approaches to CO_2 capture, displaying different characteristics when it comes to CO_2 concentration, contaminants, temperature, pressure etc. (figure 44)[139] [140]

Post-Combustion Capture

Removal of CO_2 from flue gases, produced by combustion of fossil fuels or biomass in air. A typical flue gas contains mainly CO_2, N_2, O_2 and H_2O, and can in most cases be retrofitted on existing installations.

Pre-Combustion Capture

The fuel is first converted into syngas (mainly CO_2 and H_2) through gasification or reforming processes, which is then separated to use the purified H_2 as fuel or feedstock in various applications. While potentially cheaper than post-combustion (due to higher CO_2 concentrations), it faces challenges in retrofit and scaling up.

Oxyfuel Combustion Capture

It first separates air into almost pure O_2 and N_2 and then performs the combustion with only the fuel and the pure O_2 (instead of air). This results in a flue gas that contains very

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[138] IEA, 2021
[139] IPCC, 2005
[140] Amer, Lahijani, Mohammadi, & Mohamed, 2024

high concentrations CO_2, in combination with water that can be easily removed from the flue gas through cooling and condensation. The downside of this process is the energy intensive air separation step into O_2 and N_2,but has the advantage of eliminating NO_X emissions due to the removal of N_2.

The above categories are centered around combustion processes, although not all large CO_2 emission points include fuel combustion processes. Besides CO_2 emissions from energy consumption, there are also industrial process emissions, resulting from chemical transformations of raw materials to create chemicals/products. These inherent emissions are responsible for more than 15% of the total emissions in Belgium in 2023.[141] Examples are; CO_2 from lime decomposition in cement manufacturing, CO_2 as a byproduct during fermentation processes for food and drink production, CO_2 from ethylene oxide production, CO_2 released during steelmaking, natural gas purification, ammonia production from natural gas etc. CO_2 capture from industrial process streams employs the same basic capture methods of the above-mentioned categories.

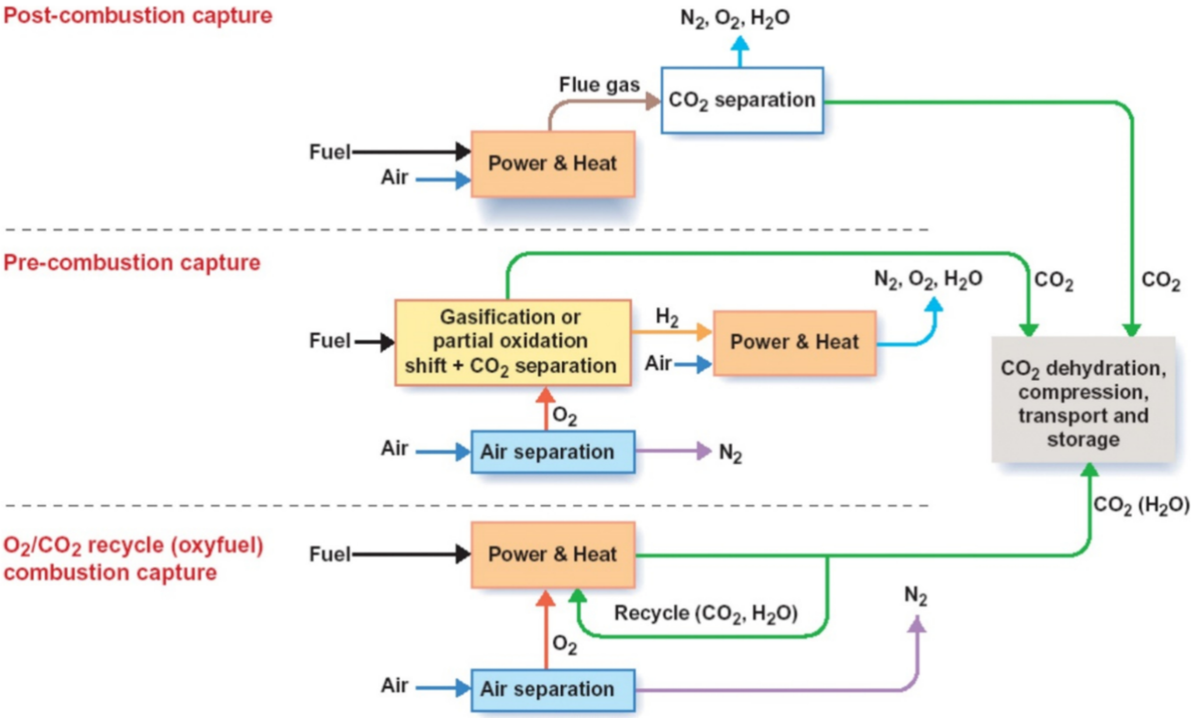

Figure 44: Different approaches to CO_2 capture systems for combustion (fossil fuels and/or biomass) and process emissions[142]

The energy consumption for CO_2 capture, also mentioned as carbon capture (CC), depends on the CO_2 concentration of the gas stream. For low concentrations this is around 5-6 GJ/t CO_2, whereas for higher concentrations around 2 GJ/t CO_2. Various industrial process emissions display higher concentrations than standard combustion processes. Figure 45 gives an overview of typical CO_2 concentrations from the production

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[141] Van de V. & FOD Volksgezondheid, 2025

[142] Amer, Lahijani, Mohammadi, & Mohamed, 2024

of different chemicals/materials with their corresponding capture cost. Most combustion processes (if combustion happens without addition of oxygen) have low concentrations (max. 10-15 vol%, as seen in the flue gases of a naphtha steam cracking unit, a gas-fired power plant (CCGT-NG) or oil refineries).[143][144]

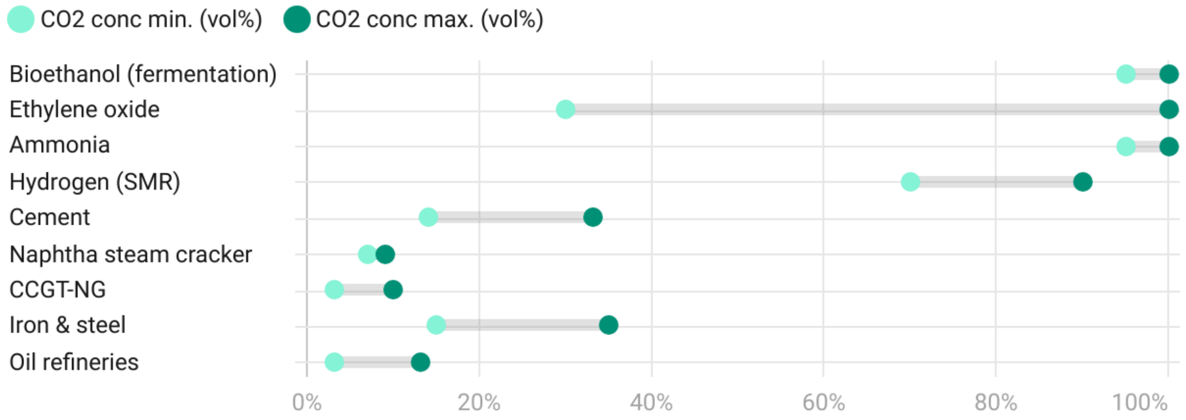

Figure 45: CO2 concentration and corresponding CO2 capture cost for different chemicals and sectors (values were deliberately rounded up to account for non-recent cost data)

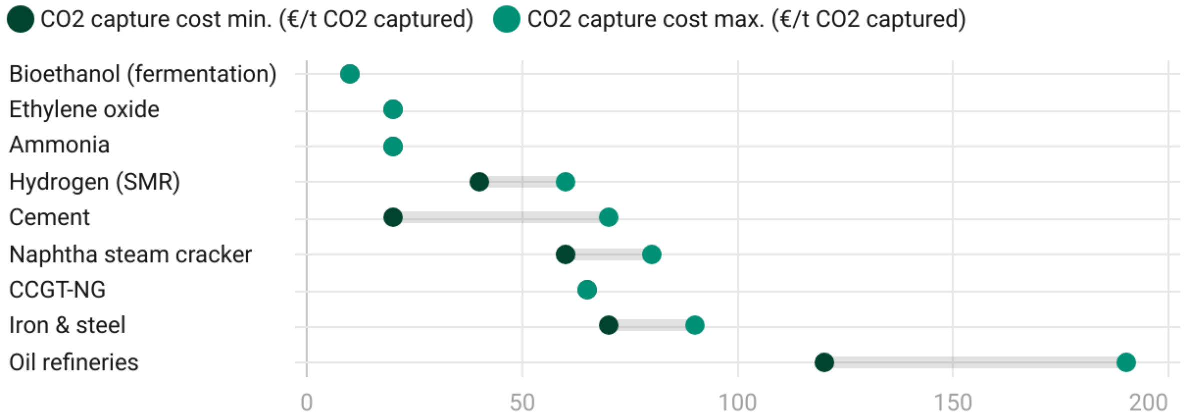

Figure 46: CO capture costs for different processes. (€/t CO2 captured)

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[143] Wyns, & Khandekar, 2020.

[144] Van Dael, 2018

12.2. Types of CO_2 capture technologies

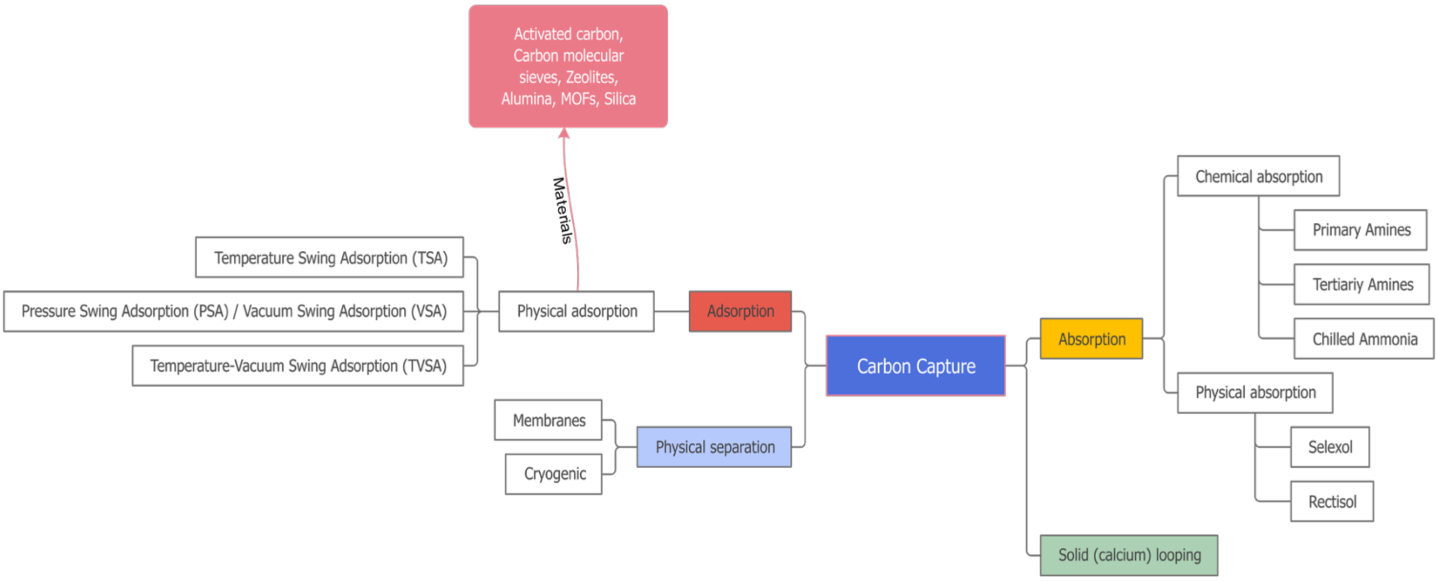

Figure 47: Types of CO2 capture technologies

12.2.1. Absorption

The absorption capture technology is a widely used and common separation method for industry applications in the petroleum, coal, natural gas power plants, and chemical industries in the context of CO_2 removal. Absorption refers to the process where a gas (in this case, CO_2) is transferred from the gas phase into a liquid solvent. This can occur via chemical reactions (chemical absorption) or physical solubility (physical absorption), depending on the solvent properties and process conditions. First, the flue gas stream must be cooled down. Subsequently, it is inserted into an absorber column where the CO_2 is absorbed into a liquid (the absorbent). The lean flue gas is then released, and the CO_2-rich absorbent liquid is transferred into a stripper column, where the solvent is regenerated by heat or pressure change. Conversely, the absorbent liquid is transferred back into the absorber column for another cycle.[145]

Chemical absorption

Chemical absorption involves a chemical reaction between CO_2 and reactive solvents, forming compounds that can be regenerated by applying heat. This is the most mature and commonly used CO_2 capture technique, especially in post-combustion flue gas treatment. Aqueous amines have the ability to establish a strong interaction with CO_2, and have emerged as the reference solvents for CO_2 absorption. Typical amines used for

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[145] Dutcher, B. et al., 2015, p. 2137–2148

chemical absorption are monoethanolamine (MEA, a primary amine) and methyl diethanolamine (MDEA, a tertiary amine). Current research focuses on developing alternative absorbents like amine blends, chilled ammonia, or ionic liquids.[146]

Physical absorption

Physical absorption is based on the physical solubility of CO_2 in the solvent under high pressure. No chemical reaction takes place, so CO_2 can be released by simply reducing the pressure or raising the temperature, making regeneration less energy-intensive. In industry, several solvents are used for physical absorption of acidic gases (CO_2 and H_2S), such as chilled methanol in the Rectisol process and dimethyl ether of polyethylene (DMPEG) in the Selexol process. These processes are particularly suitable for high-pressure gas streams, such as those found in pre-combustion capture or natural gas sweetening.[147]

Table 1: Advantages and limitations of CO_2 capture via absorption.[148]

	Advantages	Limitations
CHEMICAL ABSORPTION		
Primary amine	+ High absorption efficiency + Commercially available and well-understood (benchmark)	– High regeneration energy (steam demand: 3-5 GJ/t CO_2) – Solvent degradation over time – Corrosiveness and sensitivity to impurities
Tertiary amine	+ Low regeneration energy + High loading capacity	– Slow reaction kinetics – Less suitable for low-pressure systems unless blended
Chilled ammonia	+ Low solvent degradation + High CO_2 removal efficiency	– Risk of ammonia slip and emissions – Requires cooling infrastructure
PHYSICAL ABSORPTION		
Selexol	+ Removes multiple contaminants simultaneously + Lower regeneration energy compared to amines	– Efficiency drops at low pressures – Requires compression and cooling
Rectisol	+ Very high gas purification capability + Effective for sour gas treatment	– Requires deep chilling (down to -60°C) – Expensive and complex system

12.2.2. Physical adsorption

In contrast to the absorption carbon capture, where a liquid dissolves CO_2, adsorption is the deposition of CO_2 on a solid surface. Also here, adsorption can happen in two different ways: (i) chemical adsorption or chemisorption where the CO_2 creates new covalent bonds with the surface, and (ii) physical adsorption or physisorption which creates no new bonds between the solid and CO_2 on the surface. Physisorption is based

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[146] Thiedemann & Wark, 2025

[147] Ibid.,

[148] IPCC, 2005, Dutcher, B. et al., 2015, and Khan et al, 2023

on weak Van der Waals interactions, which influence the energy demand for the regeneration process. The regeneration energy demand for physisorption is lower than for chemisorption due to the less strong interaction of the gas molecules and the solid surface. This is one of the reasons that current research is more focused on physical than chemical adsorption. The desorption process in terms of material regeneration can be performed in different ways (figure 48)[149]

- via heat in a temperature swing adsorption (TSA);
- via pressure differences in a pressure swing adsorption (PSA), where vacuum swing adsorption (VSA) is a variation on it (operates at (near) atmospheric pressure and utilizes a vacuum for desorption);
- via a combination of temperature and pressure in temperature vacuum-pressure swing adsorption (TVPSA).

New alternative electrical heating methods for TSA are being explored in electric swing adsorption (ESA), which uses the Joule effect, induction heating, or microwave heating. These techniques could offer distinct advantages over the more traditional adsorbent regeneration techniques in terms of energy efficiency, faster heating rate, and simple and compact equipment designs.[150]

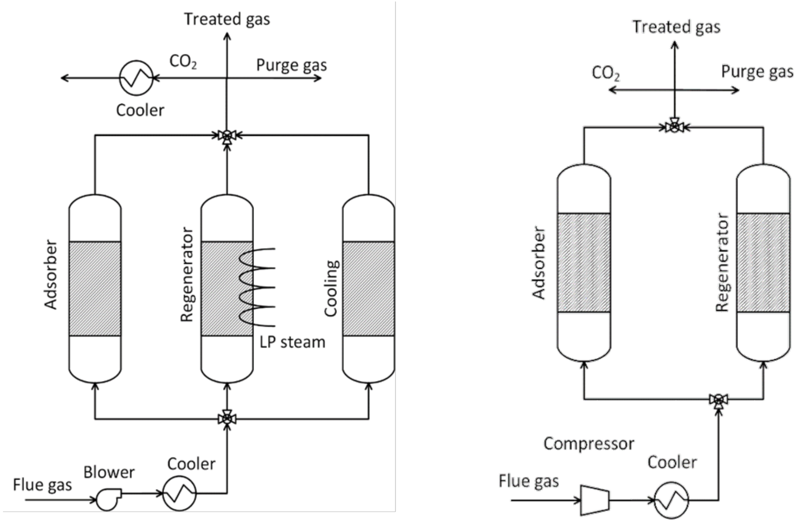

Figure 48:Temperature swing adsorption (TSA) unit and (right) pressure swing adsorption (PSA) unit

Common adsorbents used in these (physical) adsorption processes are porous materials with a high internal surface area, such as activated carbon (AC), carbon molecular sieves (CMSs), zeolites, alumina, metal–organic frameworks (MOFs), and silica-based

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[149] Thiedemann & Wark, 2025

[150] Gomez-Rueda, Y. et al., 2022

materials. Water and other contaminants (e.g. SOx or NOx in flue gases) can impact the performance of some of these adsorbent materials.[151]

Table 2: Advantages and limitations of CO_2 capture via physical adsorption.[152]

	Advantages	Limitations
PHYSICAL ADSORPTION		
TSA	+ High selectivity + High purity	– Long cycle times (heating & cooling) – Significant energy demand for heating, but lower compared to absorption (steam demand: 2.5-4 GJ/t CO_2)
PSA (& VSA)	+ Simple process with rapid cycles + No heat input required	– Less suitable for low-pressure systems (ideal for high-pressure feed gas) – Lower CO_2 purity compared to other methods
TVSA	+ More energy-efficient than TSA alone + Enables lower regeneration temperatures (could make use of low-grade waste heat)	– Requires vacuum systems and more complex controls

12.2.3. Physical separation

Membranes are specially manufactured materials that allow the selective permeation of a gas through them (figure 49). The selectivity of the membrane to different gases is intimately related to the nature of the material, but the flow of gas through the membrane is usually driven by the pressure difference across the membrane. Therefore, high-pressure streams are usually preferred for membrane separation. There are many different types of membrane materials that may find application in CO_2 capture systems to isolate CO_2 from a range of high-concentrated process streams, up-concentration of CO_2 from flue gases (post-combustion) or to preferentially separate H_2 from a CO_2-rich syngas gas stream. Examples are mixed matrix membranes (MMMs), polymers of intrinsic microporosity membranes (PIMs), metal–organic-frameworks (MOFs), ceramics, composites, or hollow fibres of different plastic materials. Current CO_2 applications of membrane separation include natural gas or biogas purification. A large worldwide R&D effort is in progress aimed at the manufacture of more suitable membrane materials for CO_2 capture in large-scale applications.[153]

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[151] Thiedemann & Wark, 2025

[152] Thiedemann & Wark, 2025, Khan et al, 2023, Gomez-Rueda, Y. et al., 2022, and Osman et al., 2021

[153] IPCC, 2005, & Thiedemann & Wark, 2025

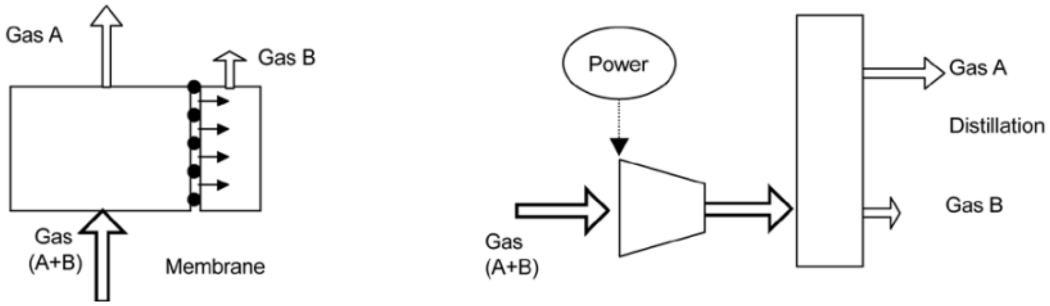

Figure 49: (left) Separation with a membrane and (right) separation by cryogenic distillation.[154]

The technology of cryogenic distillation is based on the simple concept of separating components based on their different physical properties, such as their boiling point. A gas can be made liquid by a series of compression, cooling and expansion steps. Once in liquid form, the components of the gas can be separated in a distillation column. This type of operation is currently carried out commercially on a large scale, e.g. in an air separation unit to isolate pure O_2 as seen in the oxyfuel combustion process. Cryogenic carbon capture involves cooling the gas mixture to very low temperatures, where CO_2 will condense into a liquid or solid (desublimation) while other gases remain in a gaseous state. The desublimation temperature of CO_2 is around -78.5°C at atmospheric pressure. It can be used to separate impurities from relatively high purity CO_2 streams (e.g. from oxyfuel combustion) or for CO_2 removal from natural gas or synthesis gas that has undergone a shift conversion of CO to CO_2 (e.g. H_2 production via SMR or pre-combustion capture).[155] Air Liquide has developed several CryoCap™ technologies to capture CO_2 from various industrial gas streams using cryogenic processes.[156] These technologies are designed to be tailored to specific industrial sources and differ based on the composition of the off-gas and the origin of CO_2:

- CryoCap™ H_2: applied for H_2 production via SMR (up to 60% of the overall CO_2 emissions)
- CryoCap™ FG: applied for flue gases/off-gases with CO_2 content ≥ 15% (e.g. cement, refineries, SMR flue gas)
- CryoCap™ Oxy: applied for oxyfuel combustion (e.g. cement, lime, power plant)
- CryoCap™ Steel: applied for steel off-gases from blast furnace

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[154] IPCC, 2005
[117] IPCC, 2005, and Thiedemann & Wark, 2025
[156] Air Liquide, 2022.

Table 3: Advantages and limitations of CO_2 capture via physical separation methods.[157]

	Advantages		Limitations
PHYSICAL SEPARATION			
Membranes	+ Compact and scalable + No chemical solvents needed		– Moderate selectivity and performance – Sensitive to contaminants and temperature
Cryogenic	+ Produces very pure CO_2 + Well-suited for oxyfuel combustion and fermentation streams (high concentrations)		– High energy requirements for refrigeration – Additional CO_2 separation technology needed when starting from low concentrations streams or flue gas to minimize energy needs (hybrid setup)

12.2.4. Solid looping

Another emerging solid carbon capture process traps CO_2 via a carbonization step of calcium, called calcium looping or calcium cycling (figure 50). The principle behind this carbon capture technique is the reversible reaction of CaO forming $CaCO_3$ with CO_2 in an exothermic reaction ($CaO + CO_2 \rightleftharpoons CaCO_3$). First, the flue gas is inserted in the carbonator reactor, which has temperatures ranging from 600 to 700°C. The resulting carbonate is transferred in a cyclone to separate the solid from the cleaned flue gas. Furthermore, in the calciner, with temperatures from 900 to 950°C, the $CaCO_3$ is then regenerated back to CaO, and pure CO_2 is released. An obvious challenge of this process is the energy required to reach the high temperatures for the endothermic calcination step. However, some of the heat generated from the carbonation step can be used to lower the energy requirement of the calcination. Therefore, integration into high-temperature processes like cement, steel or power production can be favourable.[158]

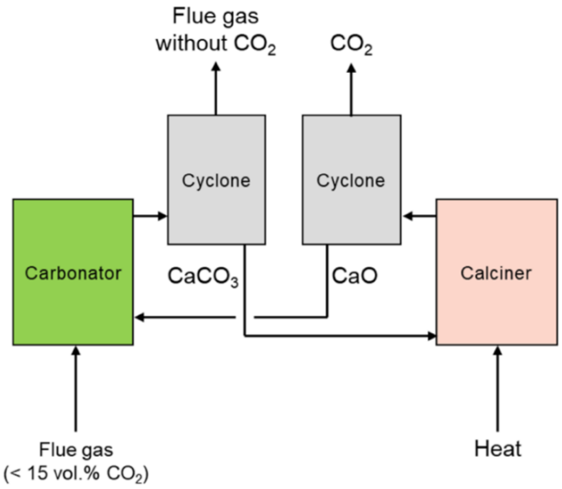

Figure 50. Simplified flowsheet of CO_2 capture via calcium looping.[159]

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[157] Thiedemann & Wark, 2025, Khan et al, 2023, and Osman et al., 2021

[158] Thiedemann & Wark, 2025

[159] Ibid.,

Table 4: Advantages and limitations of CO_2 capture via calcium looping.[160]

	Advantages	Limitations
SOLID LOOPING		
Calcium looping	+ High capacity and fast reaction kinetics + Uses abundant and inexpensive materials + Cost could be 50% cheaper than amines	– Material sintering and deactivation over multiple cycles (20-30) – High-temperature operation increases energy demands

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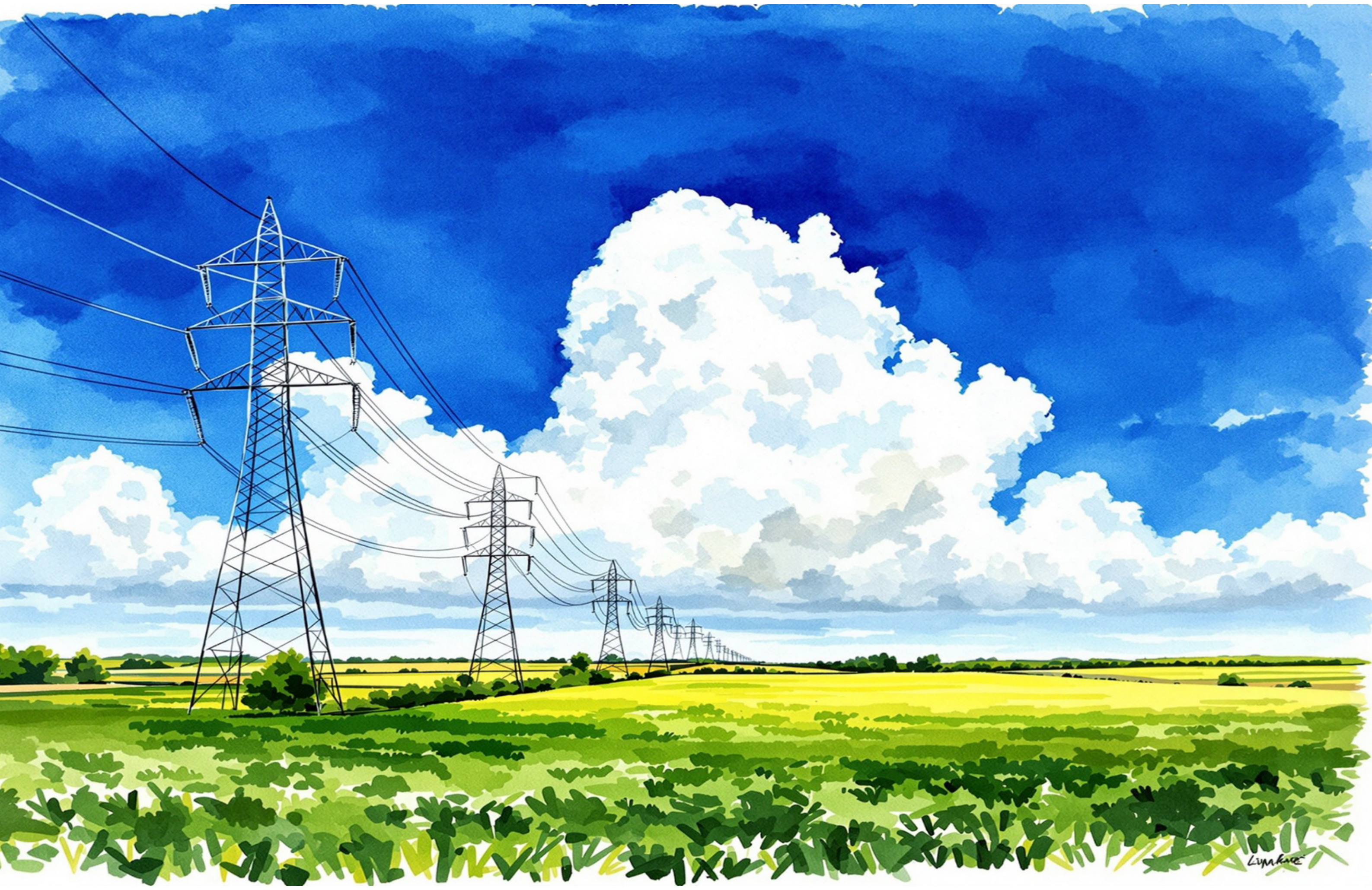
[160] Ibid.,



13. Sensitivity to electricity price and CO_2 intensity

13.1. Introduction

In this report the new technologies considered assumed a fully decarbonized power sector with CO_2 intensity of 0 kg/MWh. While this will likely be the case after 2040, currently power production still uses fossil fuels (mostly natural gas). Hence, a shift to full electrification or higher use of electricity on the short term will increase the indirect emissions of some industrial processes. The impact is dependent on the current CO_2 intensity of power production and the additional demand for electricity in the technologies applied. The examples below show the impact of indirect emissions and compare this with the direct CO_2 emissions of the technology that is being replaced by electrified processes. Moving from an almost decarbonized power sector to the current average Belgian CO_2 intensity of power production (e.g. 130 kg/MWh).

The electricity price has a major impact on the economic viability of electrification. The techno-economic assessments in this report assumed a power price of €70-80/MWh. To bring more insights in the power price sensitivity of electrification technologies, the examples below show the CO_2 avoidance cost for power prices between €20 and 120/MWh.

13.2. Steam cracking

Electrification of naphtha steam cracking (with mitigation of around 90-100% of emissions) will still lead to important overall emission reductions even at higher CO_2 grid intensity. At 130 kg/MWh emission reductions (including indirect emissions) will still be around 50% compared to conventional naphtha steam cracker (around 1.6 t CO_2/t ethylene).

The sensitivity to power prices is much stronger with power prices above €40/MWh already leading to €100/t CO_2 avoidance cost. At €100/MWh this cost goes up to more than €300/t CO_2, making the technology economically unattractive.

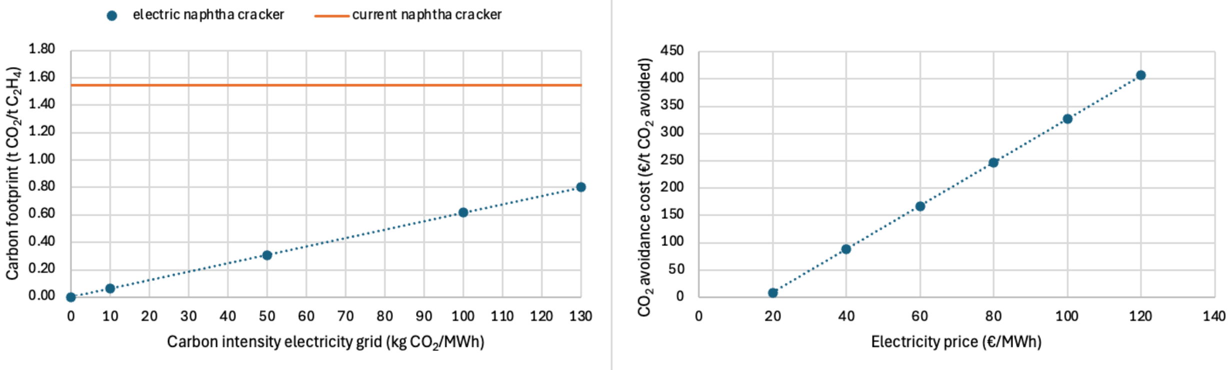


Figure 51: Impact on indirect emissions (left) and CO_2 avoidance cost (right) of electric naphtha steam cracking at different CO_2 intensity and price of electricity.

Ethane Steam Cracking, a less CO_2 intensive process to make ethylene is more sensitive to the grid CO_2 intensity when applying electrification. A grid intensity higher than 100 kg/MWh would lead to higher indirect emissions of an electric cracker compared to best performing incumbent ethane crackers.[161]

The power price also needs to be below €30/MWh to keep abatement costs below €100/t CO_2. A power price of €80/MWh would imply a CO_2 avoidance cost of almost €500/t.

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[161] The new and forthcoming INEOS project ONE ethane cracker has an expected CO_2 intensity of 0.31 t CO_2/t ethylene (source: INEOS, 2021).

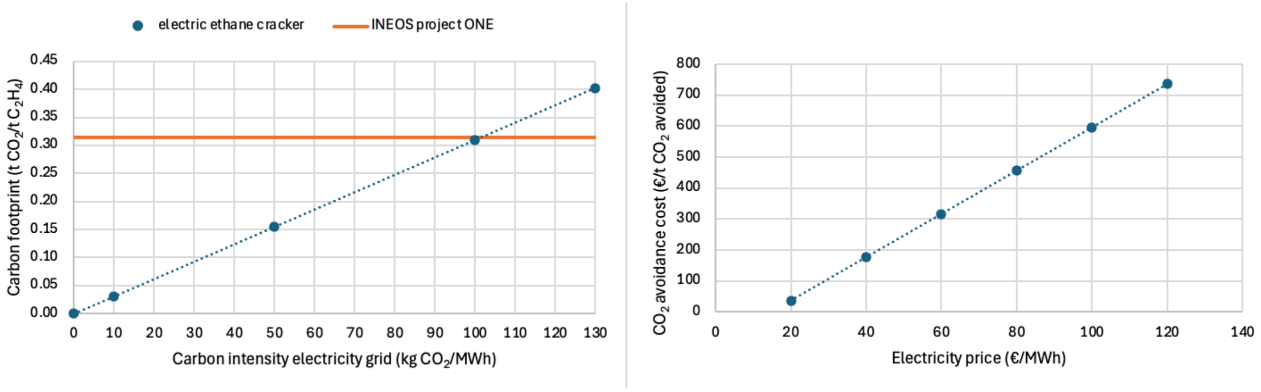

Figure 52: Impact on indirect emissions (left) and CO_2 avoidance cost (right) of electric ethane cracking at different CO_2 intensity and price of electricity.

13.3. Methanol production via CO_2 utilisation

The example of (electrified) methanol production via CO_2 utilisation shows the importance of CO_2 accounting. If the utilized CO_2 cannot be accounted as a reduction a grid intensity higher than 75 kg/MWh would imply higher emissions of the electrified process compared to the incumbent unabated process (via steam methane reforming). If on the other hand the utilised CO_2 can be accounted as a reduction, the current Belgian grid intensity (e.g. 130 kg CO_2/MWh) would still see (small) reductions in an electrified process versus the direct emissions of the incumbent process.

Similarly, the abatement cost and viability is dependent on the accounting rules. While CCU type processes that use hydrogen are in general more expensive, the utilization of CO_2 can depress the avoidance cost significantly. At €20/MWh the avoidance cost would be €200/t if the utilised CO_2 can be accounted as mitigation. If this is not the case the price would shoot up to €600/t at same power price. At €80/MWh the respective avoidance costs are €500 and 1300/t CO_2.

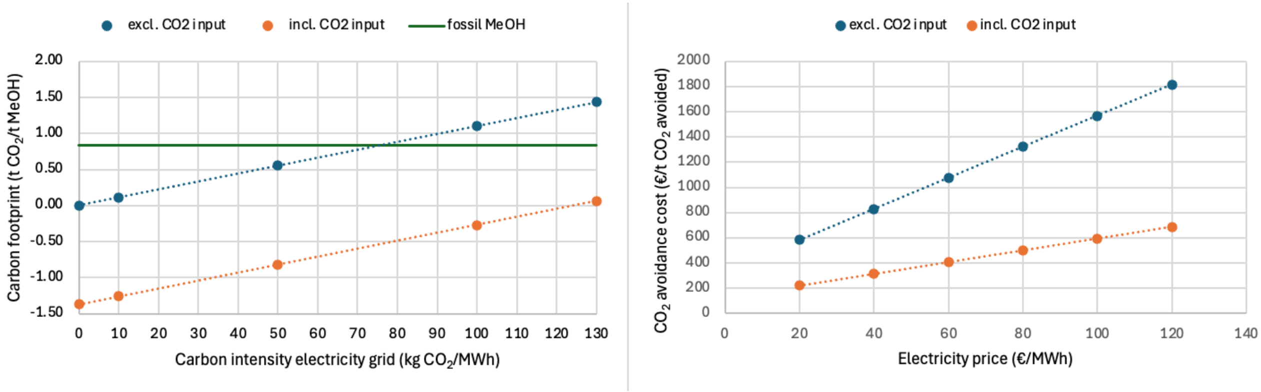

Figure 53: Impact on indirect emissions (left) and CO_2 avoidance cost (right) of (electric) CO_2 to methanol at different CO_2 intensity and price of electricity.

13.4. Steel H_2 DRI

The production of steel via DRI and 100% electrolytical hydrogen (65% electrolyser efficiency) has a relative low sensitivity to the CO_2 intensity of power production. At current CO_2 intensity for Belgium with locally produced hydrogen a DRI would still emit around 70% less GHG emissions compared to blast furnace steel using cokes (around 1.8 t CO_2/steel).

On the other hand, the electricity price will need to be lower than €40/MWh to keep the CO_2 avoidance cost below €100/t. At €100/MWh, the CO_2 avoidance cost is around €225/t CO_2. The latter would imply an increase in steel production costs of over €400/t steel.

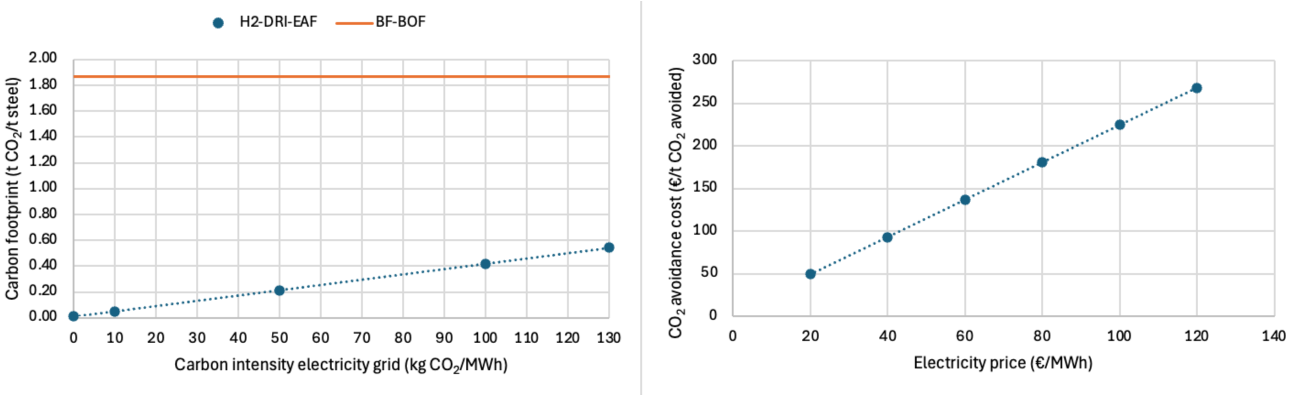

Figure 54: Impact on indirect emissions (left) and CO_2 avoidance cost (right) of H_2-DRI at different CO_2 intensity and price of electricity.

13.5. Cement kiln electrification with and without carbon capture

For cement the case of kiln electrification with and without CO_2 capture (from process emissions) is considered. Due to the high energy intensity kiln electrification on its own requires a low CO_2 grid intensity to make an important mitigation impact. At current Belgian power grid CO_2 intensity, electrification of a cement kiln would only reduce emissions by 10% when accounting for the indirect emissions. However, with CO_2 capture of the process emissions added even at grid intensity of 130 kg/MWh around 80% emission reductions (incl. indirect) are possible.

Counter-intuitively it is cheaper per tonne of CO_2 avoided to combine electrification with CO_2 capture because the cost of CO_2 capture is (much) lower versus electrification. A combined system would have a CO_2 avoidance cost of around €80/t at €20/MWh power price. While electrification alone would cost around €150/t CO_2 avoided at same power price. At a power price of €100/MWh the avoidance cost for electrification alone would be close to €500/t CO_2, while a system that is electrified and capture the process CO_2 would have an avoidance cost of a bit more than €200/t CO_2.

Hence for cement production carbon capture with or without electrification should be the most interesting option.

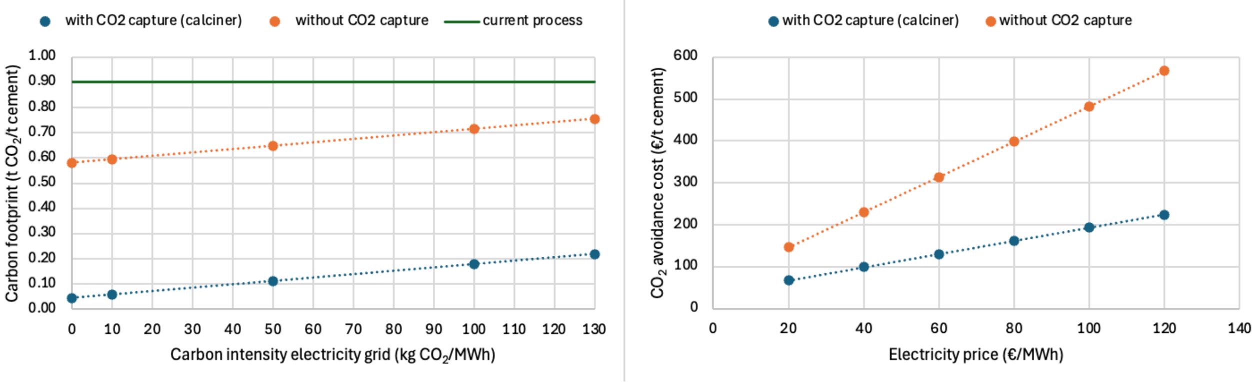

Figure 55: Impact on indirect emissions (left) and CO_2 avoidance cost (right) of cement electrification (and CC) at different CO_2 intensity and price of electricity.

13.6. Industrial heat pump

Industrial heat pumps offer due to their high efficiency always a mitigation benefit even at lower Coefficient of Performance (COP) and different power grid CO_2 intensities. Also economically heat pumps are interesting investments (for heating to 200°C).

A heat pump with COP 4.5 (delivering an output temperature of maximum 80°C) would even bring an economic benefit at power prices below €100/MWh. A heat pump with COP 4 (with max. output temperature of 150°C) would only have a mitigation cost of about €20/t CO_2 at a power price of €80/MWh. The practical benefits of these industrial heat pumps can be even bigger by re-using industrial waste heat and/or by implementing a hybrid heating system that activates the heat pump at lower power prices. When it comes to low-temperature heating, industrial heat pumps are close to a no-regret investment.

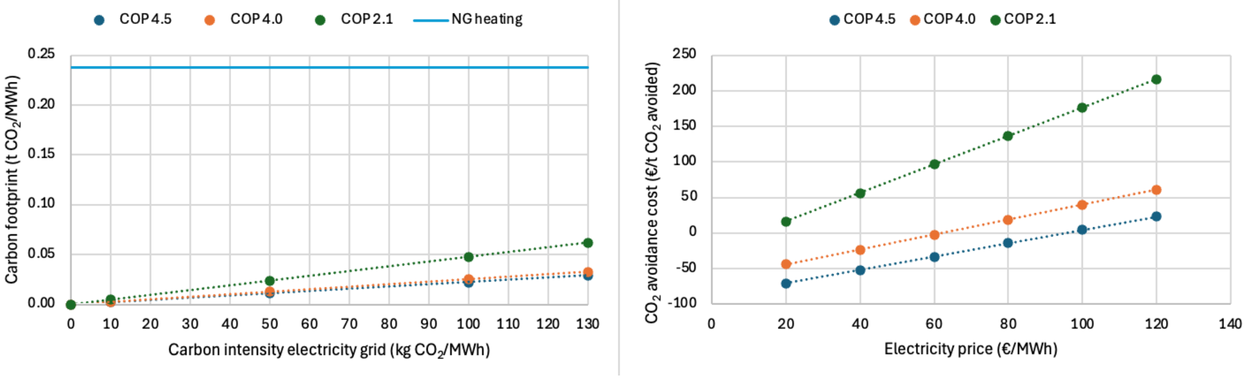

Figure 56: Impact on indirect emissions (left) and CO_2 avoidance cost (right) of industrial heat pumps (with different COPs) at different CO_2 intensity and price of electricity.

14. TRL 9 by 2040

14.1. Introduction

This study selected technologies that have a high chance to be at TRL 9 by 2040 at the latest. For large-scale industrial applications, the assumption is made that moving from TRL 6 to 9 would take around 15 years. This is based on examples of technology development and timing thereof in sectors such as steel, cement and chemicals. The long development time at higher TRLs is related to the expectation of high reliability and performance at industrial scale which requires extensive testing time for large-scale pilots, demonstration and first-of-a-kind processes. The 2040 cut-off point is chosen because of existing and (likely) forthcoming 2040 EU targets (or caps) under the EU Emissions Trading System (ETS) which are already have a high ambition level and will require deep emission reductions to happen even in the period 2030-2040.

14.2. Chemical industry

For the chemical industry out of the 76 technologies assessed there are 23 that are considered too early stage to make a meaningful contribution by 2040-2050. The technologies that are expected to be ready by 2040 are diverse and cover carbon capture (and storage), carbon capture and utilization, electrification, chemical recycling and biomass use. The technologies that likely will take more time to develop include innovative carbon capture solutions, aromatics production via biomass and advanced electrochemical and plasma processes for production of high value chemicals.

Carbon capture and storage, though technologically possible at the moment, has been set consistently at TRL 7 because a full value chain from capture to transport and storage of CO_2 has not been established yet at large scale (in the EU).

It is expected that a variety of technologies will be available by 2040 to achieve deep emission reductions in the chemicals industry.

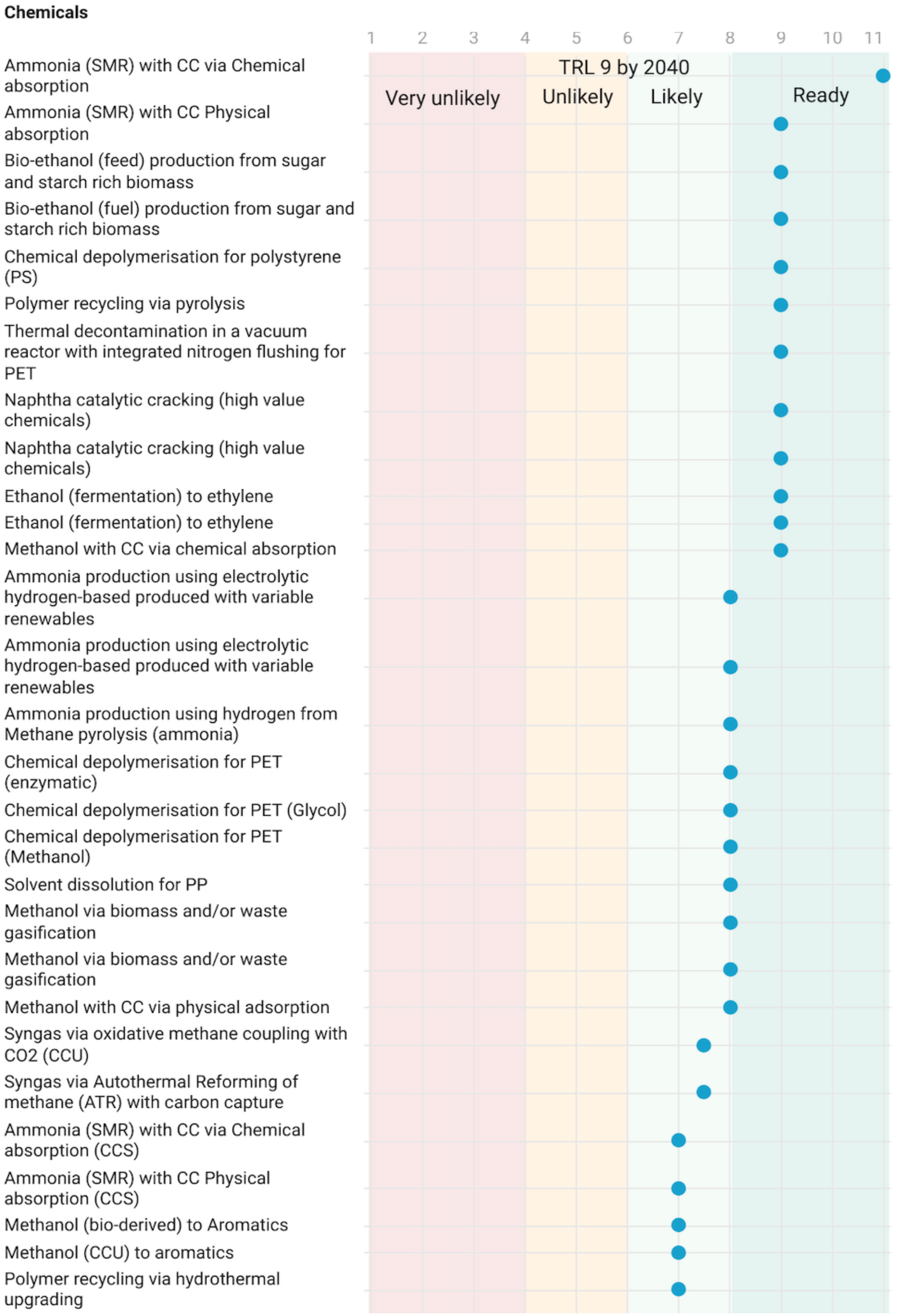

Figure 57: TRL assessment of climate friendly technologies for the Chemical industry (sources: IEA Clean Energy Technology Guide, diverse)

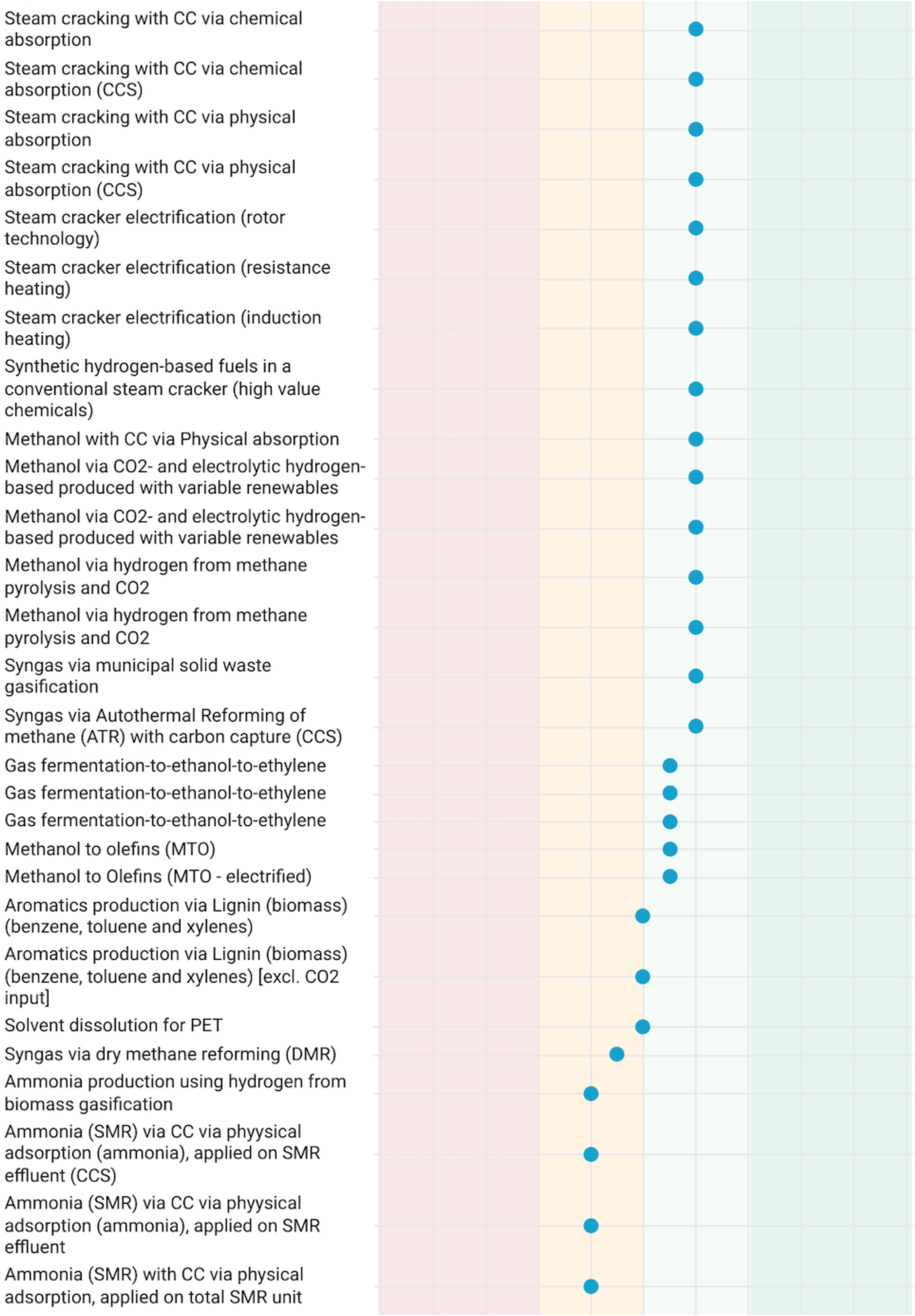

Figure 58: Continued - TRL assessment of climate friendly technologies for the Chemical industry (sources: IEA Clean Energy Technology Guide, diverse)

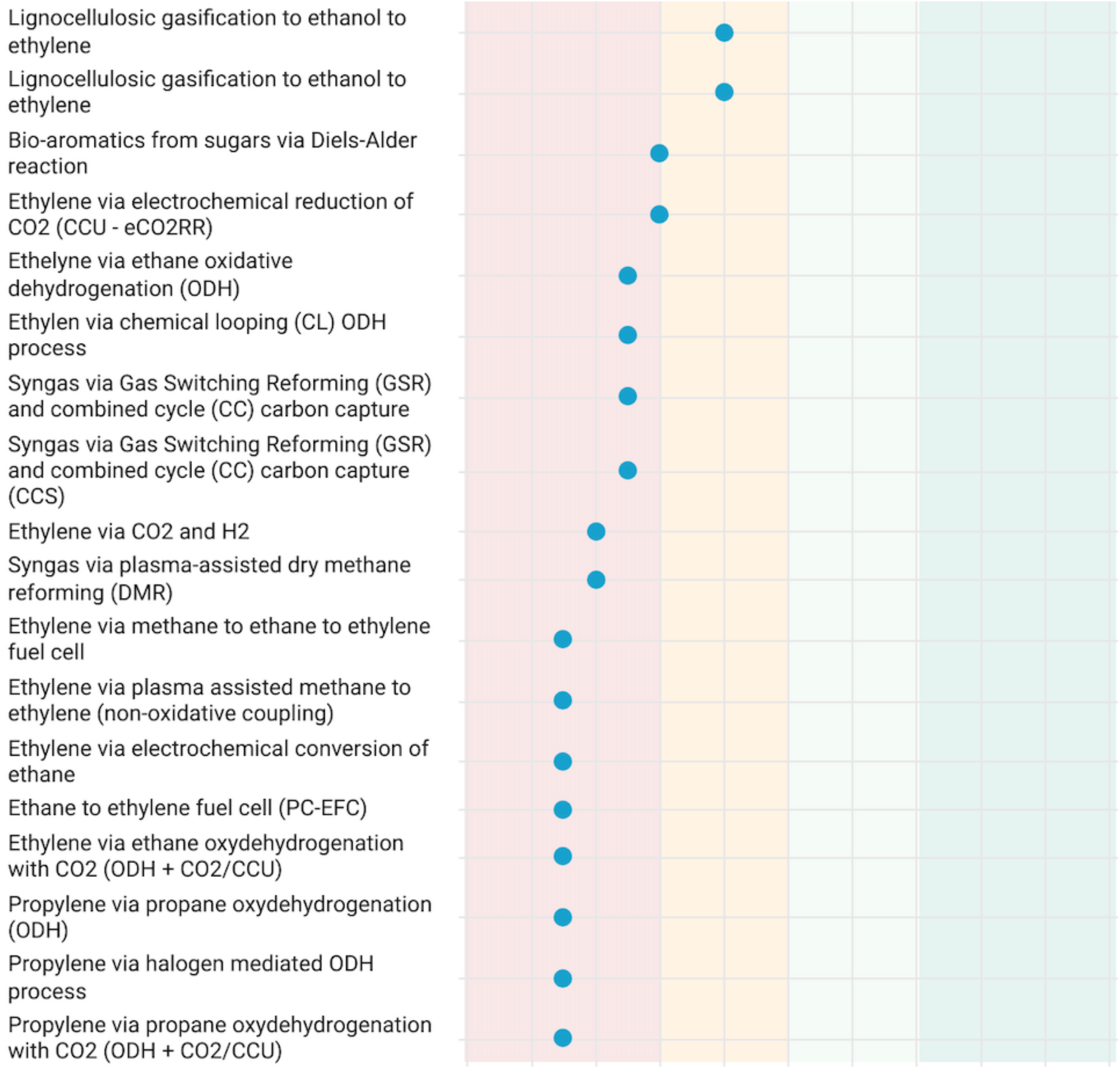

Figure 59: Continued - TRL assessment of climate friendly technologies for the Chemical industry (sources: IEA Clean Energy Technology Guide, diverse)

14.3. Cement, concrete and lime

For cement and concrete (and lime) 9 technologies out of the 35 considered here might not be market-ready by 2040. By 2040 the cement (and lime) industry will have a variety of mitigation options at its disposal to deploy. This includes options for carbon capture, bioenergy, cement and concrete recycling and alternative binders. To ensure high-temperature electrification reaches TRL 9 in time additional efforts for the development for large-scale pilots and demonstration plants will be required. More advanced carbon capture technologies (e.g. membrane separation) and electrochemical processes will likely require more time to reach TRL 9.

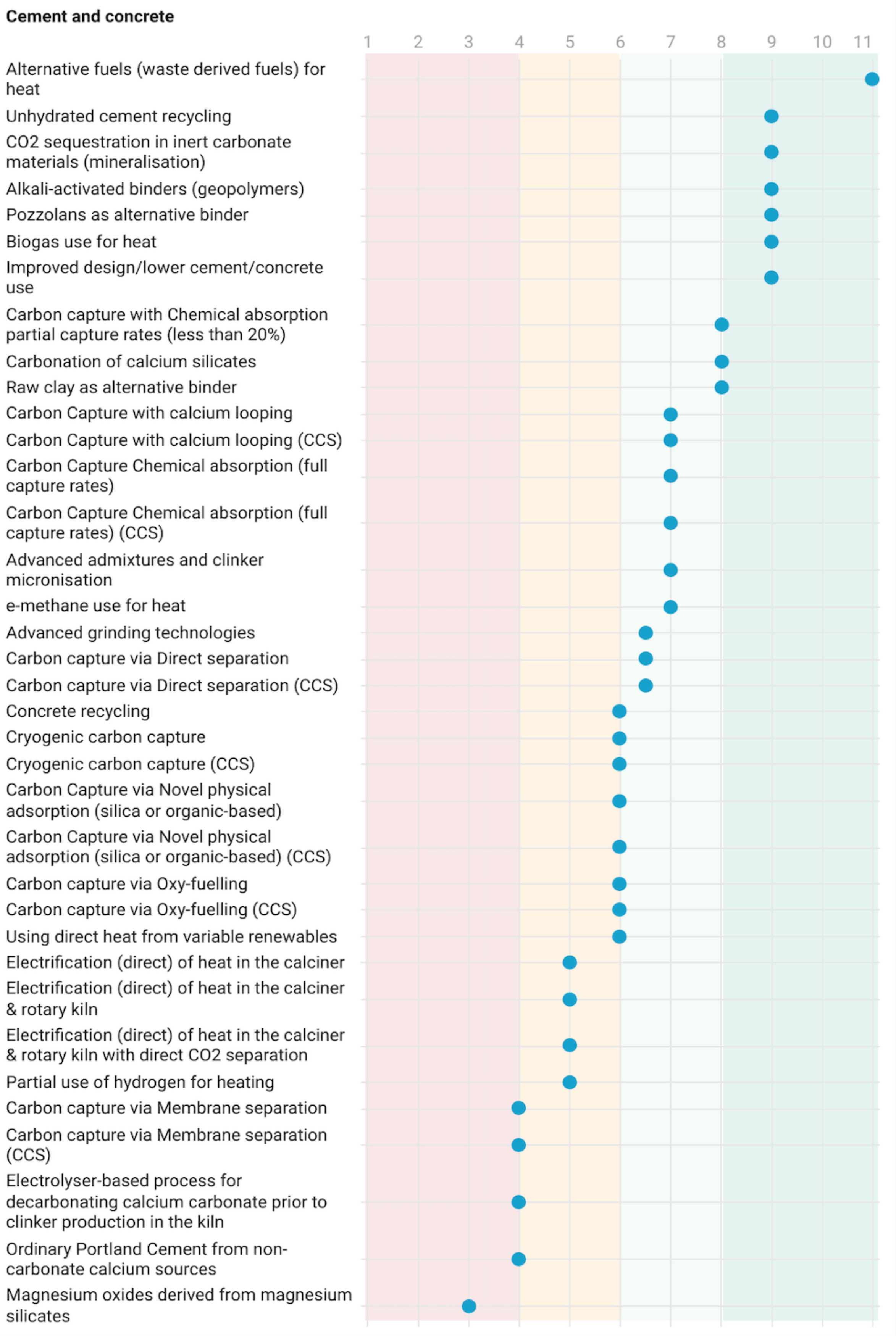

Figure 60: TRL assessment of climate friendly technologies for the cement and concrete industry (sources: IEA Clean Energy Technology Guide, diverse)

14.4. Iron and Steel

For iron and steel production there are still quite a few technologies under development that might not reach TRL 9 by 2040 (16 out of the 27 considered here). The most advanced technologies include partial substitution of coal in blast furnaces with biomass or hydrogen. The use of steel off-gases for fuels or chemicals production is also relatively advanced at this moment (with a large-scale demonstration at ArcelorMittal in Ghent). Large scale carbon capture (and storage) in blast furnaces is under development but still needs to be proven at scale. Direct reduction of iron ore with 100% clean hydrogen is also advancing well but deployment is being slowed down in the EU due to investment climate and cost issues. There are innovative processes in steel production in development (e.g. low- and high-temperature electrolysis) but these are expected to not be market-ready before 2040.

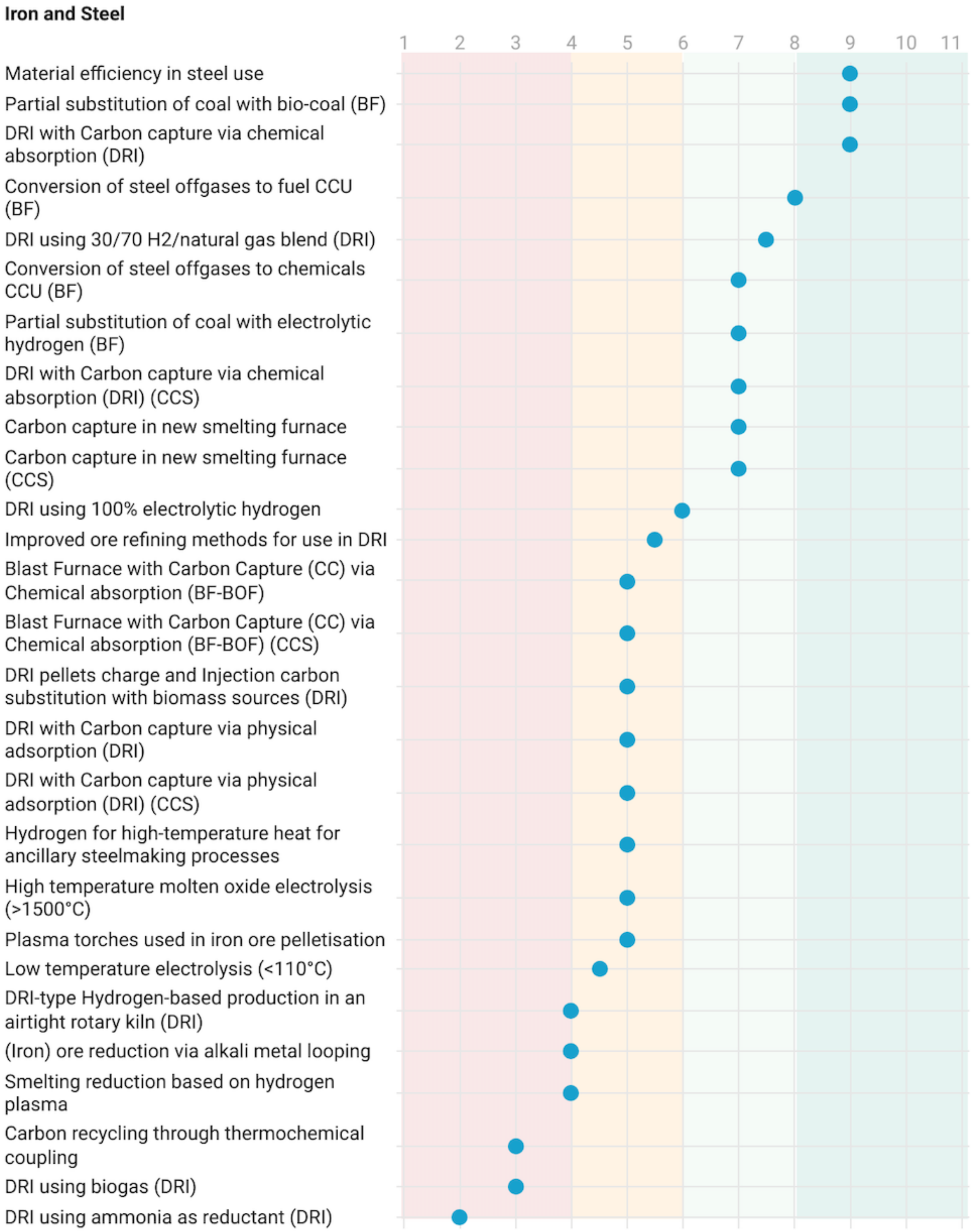

Figure 61: TRL assessment of climate friendly technologies for the Iron and Steel industry (sources: IEA Clean Energy Technology Guide, diverse)

14.5. Pulp and paper

In pulp and paper production there are still some technologies that require more R&D and will it hence have difficult to reach TRL 9 by 2040 (12 out 18 technologies considered). On the other hand, electrification of heat and the use of pulping by-products are already at higher TRL levels today. The more challenging technologies include carbon capture (due to low CO_2 concentration) and innovative techniques that dramatically reduce the use of water and/or energy required in pulping and paper production.

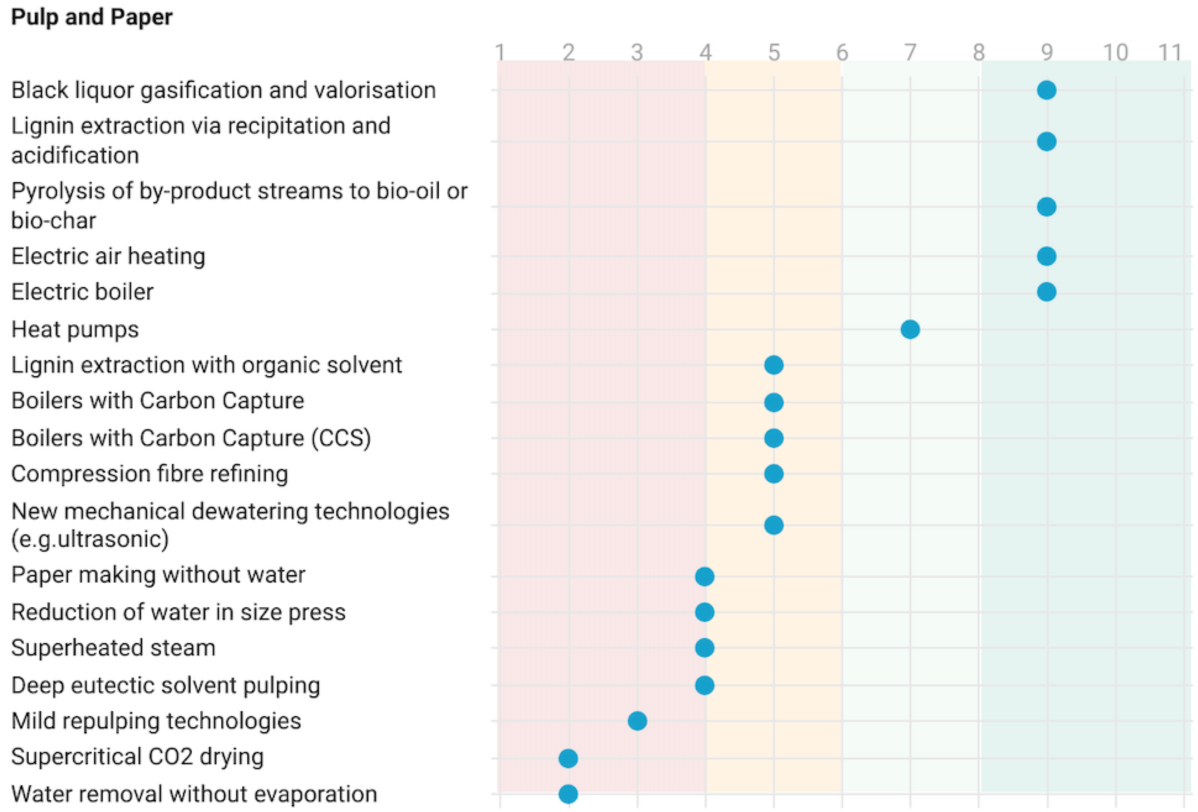

Figure 62: TRL assessment of climate friendly technologies for the pulp and paper industry (sources: IEA Clean Energy Technology Guide, diverse)

14.6. Industrial heat

Finally, for industrial heat only 9 of the 27 technologies considered will likely not be able to reach market readiness by 2040. The most advanced and market-ready technologies include the use of biomass for heating but also a wide variety of technologies for low-temperature heat (from heat pumps to e.g. infrared heating). For high-temperature heating challenges remain to apply new technologies next to the currently known induction and resistance heating. Furthermore, the TRL trajectory might be different for sectors given that the new technologies will have to be integrated into different processes (e.g. glass, ceramics, non-ferro, ...).

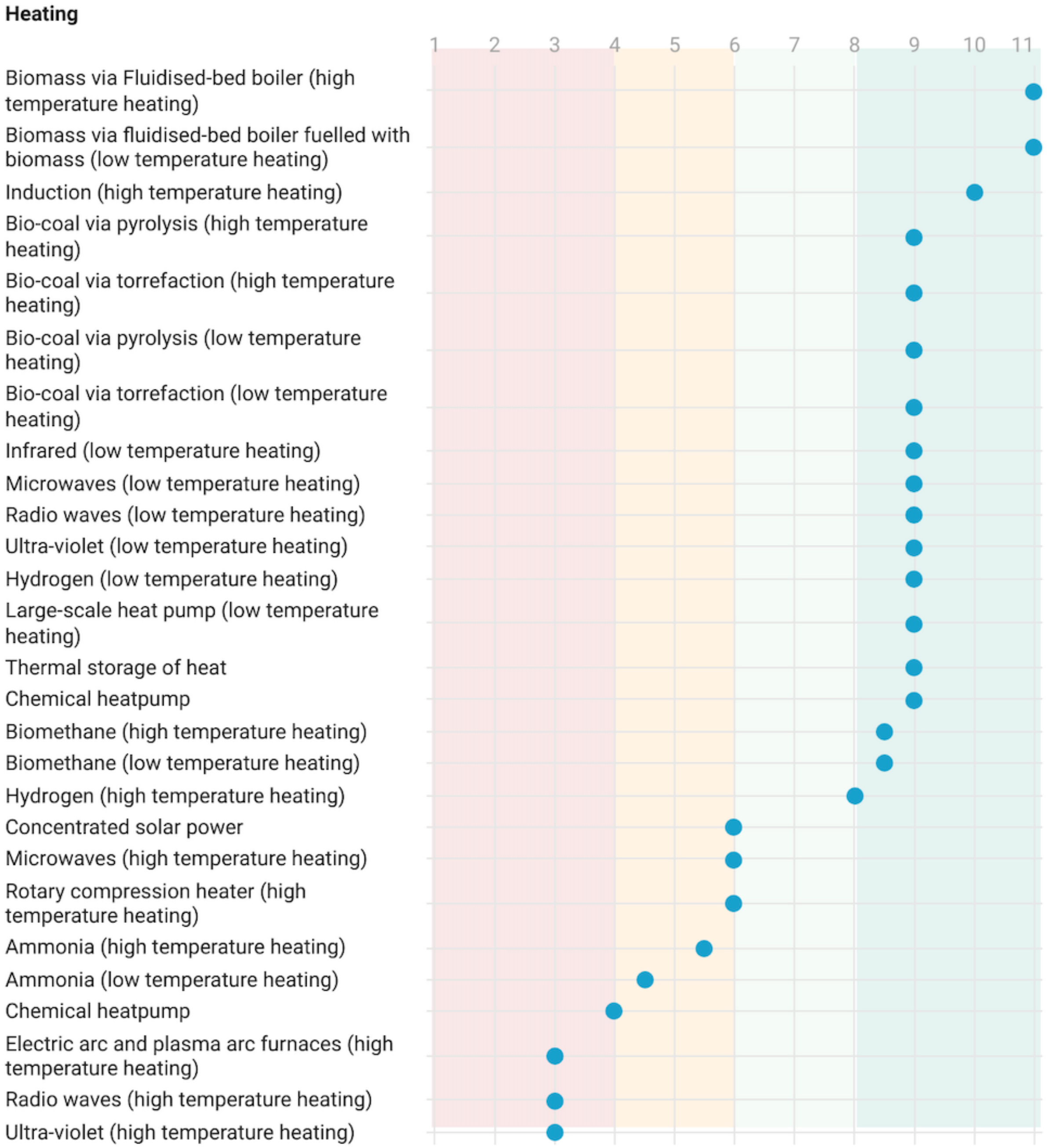

Figure 63: TRL assessment of climate friendly technologies for industrial heating (sources: IEA Clean Energy Technology Guide, diverse)

14.7. Conclusion

Out of the 183 technological options considered in this report 69 are considered to likely not be market ready by 2040. On the other hand, around 40 options are already at TRL 9. The 114 technologies that will likely reach market readiness by 2040 are diverse across different sectors forming a broad technology pool for companies to invest in or to support for further R&D towards TRL 9. The lower TRL options, while not likely to reach market readiness by 2040 cannot be discounted however, due to their highly innovative nature that might allow for more radical process changes and efficiency gains, likely at scale around or after 2050. Examples are industrial scale electrochemistry for high-value chemicals, steel and cement, innovative electrification of heat (e.g. plasma-based heating or processes) and advanced and more efficient carbon capture.

15. Technology options for Belgian industry

15.1. General assessment

With technology readiness cut-off and the techno-economic parameters in place the analysis for application in Belgian context next focuses on two angles. First, the evaluation of the technology types (e.g. CC(U)S, electrification, etc.) that can be applied in Belgium. This includes the boundary conditions but also uncertainties for their timely and wide-scale implementation in Belgium. Secondly, the sector specific context. This includes identifying which technology-groups are most promising for the sectors considered in this report.

Out of the 114 technologies that likely will reach market readiness by 2040, 92 technological options[162] have been techno-economically assessed in more detail. Some options were not further considered due to lack of techno-economic data or highly improbable application in Belgium at large scale (e.g. concentrated solar power cement or coal-based methanol with carbon capture).

The results are shown in figure 65 and table 6 below. Here the technologies are listed according to technology type (e.g. electrification, carbon capture (CC), carbon capture

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[162] This includes a small number of variations of similar or same technologies (e.g. CCU or biobased tech. with or without accounting for CO_2 utilisation and carbon capture with and without storage of CO_2.)

and storage (CCS), carbon capture and utilisation of CO_2 (CCU), biobased technologies, use of hydrogen (for heat or in process) and (chemical) recycling).

The technologies' mitigation potential and abatement cost are illustrated via colour coding with:

- For mitigation; red indicating a low mitigation impact (< 20%) and blue a technology with carbon negative potential (> 100%)
- For abatement costs (€/t CO_2 avoided); the dark green options have a (relative) low cost (< €40/t) and move to purple with the highest abatement costs (> €200/t).

Overall, most technologies listed achieves deep (direct) emission reductions (i.e. over 80% reduction versus incumbent technology). Also listed are options that can even bring about negative emission reductions via bio-based inputs and/or CO_2 utilisation. Most technologies considered sees a relatively high mitigation cost (e.g. > €100/t CO_2 avoided) well above the current average CO_2 price under the EU ETS (around €73/t)[163]. It is likely that the actual abatement cost for most of the technologies is higher at the moment due to recent inflation impacting basic materials and global trade barriers impacting some value chains.

The next sections give a more detailed evaluation per technology type and specific relevance for the Belgian context.

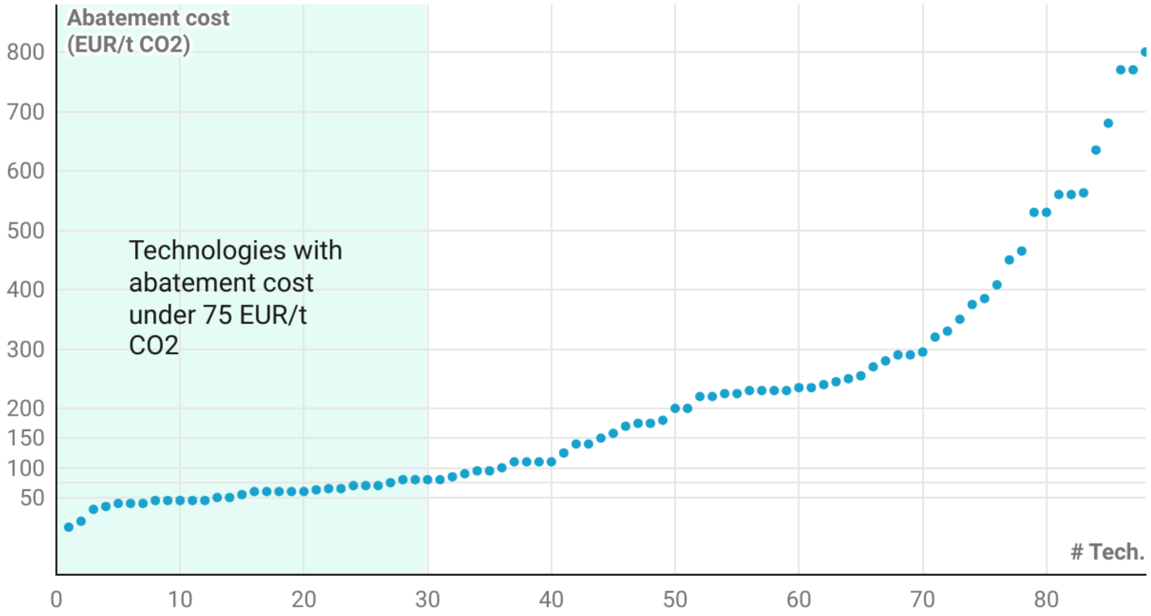

Figure 64: Ordering selected (>TRL 6) technologies by abatement cost €/t CO_2)

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[163] Trading Economics, 2025. Current average for last 12 months.

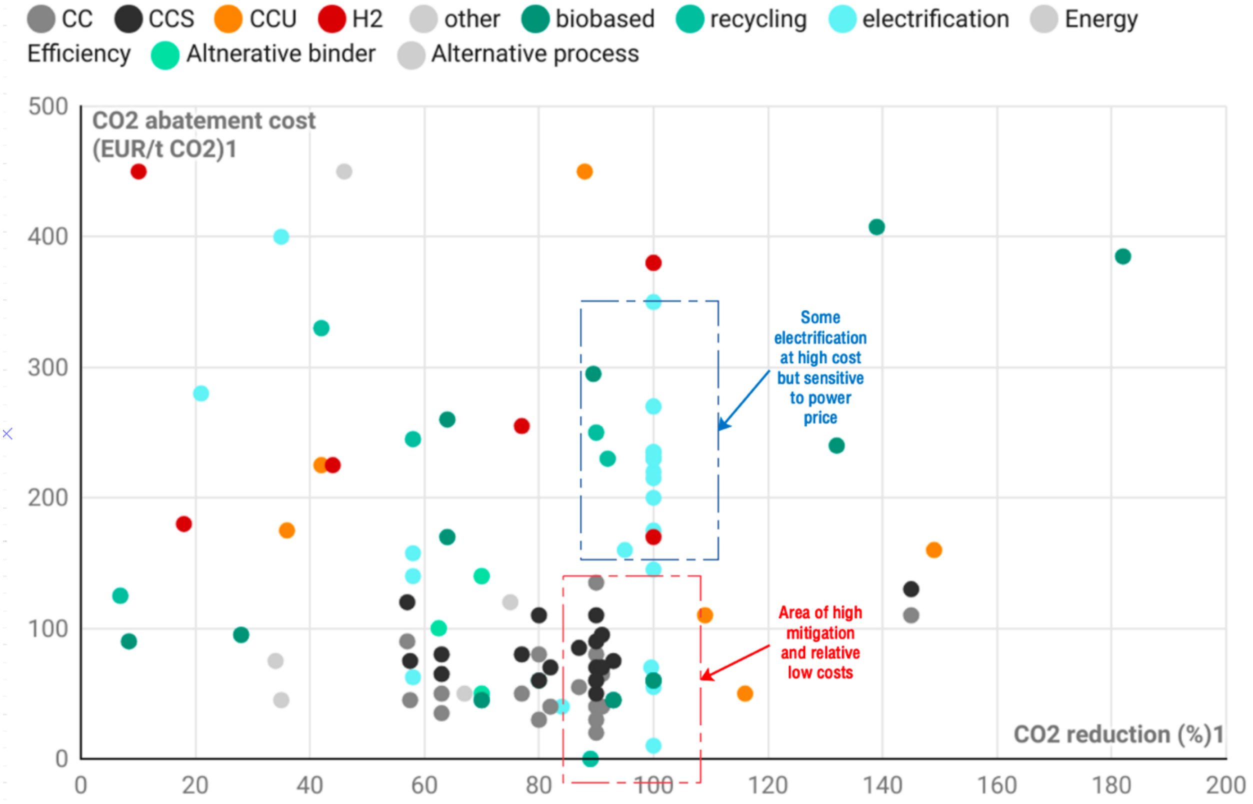

Figure 65: Overview of industrial mitigation technologies (% reduction (x-axis), Abatement cost (y-axis)) colored by technology type.

Table 5: Mitigation and cost assessment of >TRL6 technologies

TRL	Sector	Technology	Type	Avoided CO_2 (%)	CO_2 red. cost (EUR/t CO_2)	Evaluation
9	Cement and concrete	Alkali-activated binders (geopolymers)	Altnerative binder	70	50	Alternative binders are cost-effective mitigation. Availabilty can be issue
8	Cement and concrete	Carbonation of calcium silicates	Altnerative binder	70	140	
6	Chemicals	Aromatics production via Lignin (biomass) (benzene, toluene and xylenes) (*)	biobased	608	320	Biomass used to produce chemical products can have major reduction impact (negative emissions) depending on CO_2 accounting. Costs are in general very high esp, for second generation biofuel. Biomass for heating has some potential but bio-methane comes with high mitigation cost. For Belgium specifically biomass availability and supply chain can become issue.
6	Chemicals	Aromatics production via Lignin (biomass) (benzene, toluene and xylenes)	biobased	100	1935	
7	Chemicals	Methanol (bio-derived) to Aromatics	biobased	429	800	
9	Chemicals	Bio-ethanol (feed) production from sugar and starch rich biomass (*)	biobased	240	100	
9	Chemicals	Bio-ethanol (fuel) production from sugar and starch rich biomass	biobased	80	60	
9	Chemicals	Ethanol (fermentation) to ethylene	biobased	331	465	
8	Chemicals	Methanol via biomass and/or waste gasification (*)	biobased	216	150	
8	Chemicals	Methanol via biomass and/or waste gasification	biobased	132	240	
7	Chemicals	Syngas via municipal solid waste gasification	biobased	182	385	
9	Iron and Steel	Partial substitution of coal with bio-coal (BF)	biobased	28	95	
9	Pulp and Paper	Black liquor gasification and valorisation	biobased	89.5	295	
9	Pulp and Paper	Lignin extraction via recipitation and acidification	biobased	139	408	
9	Pulp and Paper	Pyrolysis of by-product streams to bio-oil or bio-char	biobased	67	563	
9	Heating	Bio-coal via pyrolysis (high temperature heating)	biobased	93	45	
9	Heating	Bio-coal via torrefaction (high temperature heating)	biobased	70	45	
8.5	Heating	Biomethane (high temperature heating)	biobased	58	530	
11	Heating	Biomass via Fluidised-bed boiler (high temperature heating)	biobased	100	60	
9	Heating	Bio-coal via pyrolysis (low temperature heating)	biobased	93	45	
9	Heating	Bio-coal via torrefaction (low temperature heating)	biobased	70	45	
8.5	Heating	Biomethane (low temperature heating)	biobased	58	530	
11	Heating	Biomass via fluidised-bed boiler fuelled with biomass (low T heating)	biobased	100	60	
11	Chemicals	Ammonia (SMR) with CC via Chemical absorption	CC	90	40	Carbon capture and storage overall offers the most cost-effective mitigation. However this technology is highly dependent on availabilty of infrastructure (e.g. liquefaction, transport and storage). It is only cost-effective for industries with large process emissions and at location (e.g. backbone) that allows the cost-effective transport of CO_2. Due to the presence of cement, lime, chemicals and steel in Belgium (often in industrial clusters) this option is seen as having a potential high impact.
9	Chemicals	Ammonia (SMR) with CC Physical absorption	CC	63	35	
7	Chemicals	Steam cracking with CC via chemical absorption	CC	90	80	
7	Chemicals	Steam cracking with CC via physical absorption	CC	90	80	
7.5	Chemicals	Syngas via Autothermal Reforming of methane (ATR) with carbon capture	CC	93	45	
7	Cement and concrete	Carbon Capture with calcium looping	CC	90	60	
7	Cement and concrete	Carbon Capture Chemical absorption (full capture rates)	CC	91	65	
6	Cement and concrete	Cryogenic carbon capture	CC	91	40	
6.5	Cement and concrete	Carbon capture via Direct separation	CC	63	50	
6	Cement and concrete	Carbon Capture via Novel physical adsorption (silica or organic-based)	CC	82	40	
6	Cement and concrete	Carbon capture via Oxy-fuelling	CC	87	55	
9	Iron and Steel	DRI with Carbon capture via chemical absorption (DRI)	CC	80	80	
7	Iron and Steel	Carbon capture in new smelting furnace	CC	90	30	
7	Chemicals	Ammonia (SMR) with CC via Chemical absorption (CCS)	CCS	90	70	
7	Chemicals	Ammonia (SMR) with CC Physical absorption (CCS)	CCS	63	65	
7	Chemicals	Steam cracking with CC via chemical absorption (CCS)	CCS	90	110	
7	Chemicals	Steam cracking with CC via physical absorption (CCS)	CCS	90	110	
7	Chemicals	Syngas via Autothermal Reforming of methane (ATR) with carbon capture (CCS)	CCS	93	75	
7	Cement and concrete	Carbon Capture with calcium looping (CCS)	CCS	90	90	
7	Cement and concrete	Carbon Capture Chemical absorption (full capture rates) (CCS)	CCS	91	95	
6	Cement and concrete	Cryogenic carbon capture (CCS)	CCS	91	70	
6.5	Cement and concrete	Carbon capture via Direct separation (CCS)	CCS	63	80	
6	Cement and concrete	Carbon Capture via Novel physical adsorption (silica or organic-based) (CCS)	CCS	82	70	
6	Cement and concrete	Carbon capture via Oxy-fuelling (CCS)	CCS	87	85	
7	Iron and Steel	DRI with Carbon capture via chemical absorption (DRI) (CCS)	CCS	80	110	
7	Iron and Steel	Carbon capture in new smelting furnace (CCS)	CCS	90	60	
7	Chemicals	Methanol (CCU) to aromatics	CCU	818	375	Carbon capture and utilisation has the potential to achieve (large) carbon negative emissions but this depends on the legal framework for CO_2 accounting (incl. e.g. DAC and permanence of captured CO2 in materials). It is however a very expensive technology and without full accounting of utilised CO_2 both the mitigation impact and cost-effectiveness will be dramatically reduced. Mineralisation of CO_2 is an exception here with cost effective long-term fixation of CO_2.
6.5	Chemicals	Gas fermentation-to-ethanol-to-ethylene (steel gas)	CCU	319	280	
6.5	Chemicals	Gas fermentation-to-ethanol-to-ethylene (H_2 and CO_2)	CCU	404	1180	
6.5	Chemicals	Gas fermentation-to-ethanol-to-ethylene (biogas)	CCU	179	2900	
6.5	Chemicals	Methanol to olefins (MTO)	CCU	320	220	
6.5	Chemicals	Methanol to Olefins (MTO - electrified)	CCU	361	200	
7	Chemicals	Methanol via CO2- and electrolytic hydrogen-based produced with variable renewables (*)	CCU	264	290	
7	Chemicals	Methanol via CO2- and electrolytic hydrogen-based produced with variable renewables	CCU	100	770	
7	Chemicals	Methanol via hydrogen from methane pyrolysis and CO_2 (*)	CCU	264	290	
7	Chemicals	Methanol via hydrogen from methane pyrolysis and CO_2	CCU	100	770	
7.5	Chemicals	Syngas via oxidative methane coupling with CO_2 (CCU)	CCU	88	450	
9	Cement and concrete	CO_2 sequestration in inert carbonate materials (mineralisation)	CCU	109	110	
7	Iron and Steel	Conversion of steel offgases to chemicals CCU (BF)	CCU	36	175	
8	Iron and Steel	Conversion of steel offgases to fuel CCU (BF)	CCU	42	225	
8	Chemicals	Ammonia production using electrolytic hydrogen-based produced with renewables (Alkaline)	electrification/H_2	100	235	Electrification has deep mitigation potential across different sectors, either in full or hybrid form. However, mitigation costs are high in general, but with high sensitivity to power prices. Current Belgian average power prices for industry will need to come down to make this an attractive mitigaiton option. Industrial heat pumps (low T) are exception and are currently already economically interesting. Furthermore, attention is required to provide necessary infrastructure (production and transport of electricity) and to reduce the CO_2 intensity of electricity produced.
8	Chemicals	Ammonia production using electrolytic hydrogen-based produced with renewables (PEM)	electrification/H_2	100	350	
8	Chemicals	Ammonia production using hydrogen from methane pyrolysis (ammonia)	electrification	100	270	
7	Chemicals	Steam cracker electrification (resistance heating)	electrification	100	220	
9	Pulp and Paper	Electric air heating	electrification	58	140	
9	Pulp and Paper	Electric boiler	electrification	58	158	
7	Pulp and Paper	Heat pumps	electrification	58	63	
10	Heating	Induction (high temperature heating)	electrification	100	230	
6	Heating	Microwaves (high temperature heating)	electrification	100	230	
6	Heating	Rotary compression heater (high temperature heating)	electrification	100	175	
9	Heating	Infrared (low temperature heating)	electrification	100	200	
9	Heating	Microwaves (low temperature heating)	electrification	100	230	
9	Heating	Radio waves (low temperature heating)	electrification	100	235	
9	Heating	Large-scale heat pump (COP 4) (low temperature heating)	electrification	100	10	
7	Chemicals	Synthetic hydrogen-based fuels in a conventional steam cracker (high value chemicals)	H_2/CCU	44	225	Hydrogen replacing (fossil) feedstock in industry can be relevant option (e.g. steel), but comes with relatively high mitigation cost (linked to power price). Use of hydrogen for (high/low-temp.) heating is too expensive, esp. when direct electrification is option.
7	Iron and Steel	Partial substitution of coal with electrolytic hydrogen (BF)	H_2	18	180	
6	Iron and Steel	DRI using 100% electrolytic hydrogen	H_2	100	170	
7.5	Iron and Steel	DRI using 30/70 hydrogen/natural gas blend (DRI)	H_2	77	255	
8	Heating	Hydrogen (high temperature heating)	H_2	100	560	
9	Heating	Hydrogen (low temperature heating)	H_2	100	560	
8	Chemicals	Chemical depolymerisation for PET (enzymatic)	recycling	56	635	Chemical recycling is an extremely valuable technology (e.g. redcution of waste and fossil fuel dependence) but currently in most cases too expensive compared to virgin plastics. Furthermore solid and reliable waste value chains need to be established. Here regulatory support wil be essential (e.g binding recycling targets)
8	Chemicals	Chemical depolymerisation for PET (glycol)	recycling	89	65	
8	Chemicals	Chemical depolymerisation for PET (methanol)	recycling	7	125	
9	Chemicals	Chemical depolymerisation for polystyrene (PS)	recycling	82	680	
7	Chemicals	Polymer recycling via hydrothermal upgrading	recycling	58	245	
9	Chemicals	Polymer recycling via pyrolysis	recycling	42	330	
6	Chemicals	Solvent dissolution for PET	recycling	92	230	
8	Chemicals	Solvent dissolution for PP	recycling	90	250	

	Very low	**low**	**medium**	**high**	**very high**	**extremely high**		
Abatement cost	0-40	41-80	81-120	121-160	161-200	201-400+		
	Very low	**low**	**medium**	**high**	**very high**	**negative**	**medium carbon negative**	**high carbon negative**
CO_2 reduction %	0-20	21-40	41-60	61-80	81-100	101-200	201-400	401-600+

(*) Variation of technology that includes full negative emission accounting

15.1.1. Electrification

The electrification of industrial processes forms an important mitigation option. For low-temperature heat (< 150°C) industrial heat pumps are now being deployed and growing in capacity and temperature range (up to 300°C, but with lower efficiency). When combination with low temperature heat recovery the efficiency of industrial heat pumps increases. These heat pumps are currently among the most cost-effective deep mitigation option for lower industrial heat applications. However, to be successful in Belgium the cost gap between gas and electricity will needs to be smaller than factor 3.

Around 30-40% figure 66 of industrial (low temperature) heat related emissions in Belgium could in theory be mitigated via these heat-pumps, today. This includes food and beverages, pulp and paper, lower temperature applications in the chemicals industry and more downstream industrial sectors (e.g. machine building, automotive, ...).

High(er) temperature electrification (e.g. in naphtha or ethane steam cracking, cement, lime, glass and ceramics) can deliver deep mitigation and, in theory, eliminate most of the high-temperature energy related emissions. By 2035-2040 more than 90% of industrial heat can be made electric if these technologies mature.[164]

However, as mentioned before, most of these technologies are still in (often later stage of) development. More importantly, at a €70-80/MWh electricity price most of these technologies have a high abatement cost (€150 to almost €300/t CO_2 avoided). For application in high-value chemicals production, power prices will have to be below €40/MWh to bring the abatement cost below €100/t CO_2.

Furthermore, the lower efficiency compared to heat pumps makes high-temperature electrification more sensitive to the CO_2 intensity of the electricity used, hence with important increase in the indirect emissions. Full electrification of industry and hence replacing fossil fuels for heat will lead to a dramatic overall increase in electricity demand in Belgium. An additional demand that will have to be met CO_2 free electricity production capacity.

Not only power production capacity will need to follow the additional demand, also the necessary (high-voltage) infrastructure to transport electricity to industrial end consumers will need to be provided and planned.

Finally, a retrofit of electrification technologies into existing processes will not always be possible or straightforward. This can increase the CAPEX of electrification if e.g. kilns or furnaces need to be fully replaced.

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[164] 90% potential claim in Rosenow et al., 2024; 99% claim in Madeddu, S. et al., 2020

15.1.2. CO_2 Capture and storage

Carbon capture and storage emerges as a technology that achieves deep emission reduction at a lower cost[165] compared to other most of the other technologies. For higher CO_2 concentration process emissions (e.g. in ammonia/blue hydrogen, cement and lime production and to lesser extent blast furnace steel) in incumbent installations carbon capture and storage is a viable option at this moment. For industrial processes with lower CO_2 concentration (such as steam cracking and high-temperature combustion) the mitigation costs will be higher but can become more affordable with further innovation and integration of use of (low-temperature) waste heat.

In theory most of the industrial process emissions in Belgium could be captured and stored, with exception of process emissions in glass and ceramics mostly due to high investments compared to mitigation potential and remote locations from possible CO_2 transport infrastructure. Some lime and cement producers might also face barriers to cost-effectively connect to CO_2 infrastructure. This would limit the potential of the technology to address all process emissions.

While carbon capture and storage could bring about important mitigation for industry, major elements need to be in place for this to materialise. First of all, the CO_2 transport and liquefaction infrastructure to ensure that locally captured CO_2 can be transported for storage. There are currently a handful of projects in Belgium that seek to deploy large-scale carbon capture (and storage) together with advanced studies and plans to develop a CO_2 backbone in Belgium. However, most have not yet reached a final investment decision due to cost increases and general economic uncertainty.

For steel production specifically, the introduction of DRI technology in Belgium would work well with carbon capture and storage, either via capturing at sponge iron production (with natural gas) or upstream in the production of blue hydrogen via autothermal reforming of methane (ATR).

CO_2 capture and storage is seen as an indispensable technology for sectors with large process emissions. Depending on the evolution of gas and power prices for industry carbon capture (and storage) can also be used for high-temperature heating especially if infrastructure for CO_2 transport would already be present (for process emissions).

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[165] The cost assessment in this report does not consider recent inflation due to higher energy and materials costs and disruption of value chains due to new global trade barriers. This inflationary pressure has had an impact on final investment decisions for first-of-a-kind large-scale integrated CO_2 capture, transport and storage projects (funded by the EU ETS innovation fund).

15.1.3. Carbon Capture and utilisation

Carbon capture and utilisation technologies belong among the most expensive mitigation options, with abatement costs in most cases well above €200/t. In the case that the utilised CO_2 that would not be accounted as a reduction (or negative CO_2 emission) the technology becomes in most cases unviable. The main reason for the higher mitigation costs is related to the energy use for reducing CO_2, often using hydrogen, to make other products. One exception is the sequestration in inert carbonate materials (mineralisation), being the least expensive CCU option and guarantees, in principle, long-term neutralisation of the carbon emissions.[166]

Methanol-to-olefins and the use of steel blast furnace gas to produce high-value chemicals are also less expensive compared to other CCU options considered. However, their economic viability depends, as mentioned before, if EU legislation will allow for negative accounting of the used (biologic or air captured) carbon. Even with legal clarity, additional support for the deployment of most CCU type technologies will be required given that the abatement cost will be in most cases well above the expected EU ETS CO_2 price in the short (and likely medium) term.

The use of (green) hydrogen (and derivatives) as fuel for high-temperature heating is a very expensive mitigation option. Direct electrification will have an important techno-economic advantage compared to the use of hydrogen as fuel, more so if the (electrolytic) hydrogen is locally produced in Belgium. It is possible that cheaper imported hydrogen (via pipeline) can reduce the cost gap between electrification. However, this will require major infrastructure developments across the EU from gigantic solar based hydrogen production in southern Europe to trans-European pipeline delivering this hydrogen to northwest Europe.

Hydrogen use as feedstock in industry (e.g. steel) is also relative expensive but can be made more economically interesting via production of steel close to e.g. cheap wind energy or via the use of blue hydrogen (natural gas derived with carbon capture and storage). For Belgium the latter will be the more likely route to take.

15.1.4. Bio-based energy and feedstock

For bio-based inputs both heating and biomass as feedstock were assessed in this report. For heating bio-coal (produced via torrefaction of wood) looks the most cost-

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[166] Another relative long-term CO_2 storage option via CCU is the copolymerisation of CO_2 with epoxides to polymers, such as polyurethane (PU) foams, which find applications in insulation panels (rigid PU) for housing or mattresses (flexible PU).

effective. For bio-coal the main bottleneck is the sustainable supply of (clean waste) wood, which is not guaranteed in the Belgian context.

Bio-methane can be a viable option for high heat processes that have difficulty electrifying but cost and availability can be an issue.

Ethanol from sugar and starch rich crops (1st generation biofuels) is a mature technology but competes heavily with land-use for food production. Second generation biofuel or -feedstock using (lignocellulosic) biomass waste is more sustainable but faces higher abatement costs. Biomass derived methanol (which can be imported) can become part of feedstock replacing naphtha via the methanol to olefins process. The gasification of biomass (and other waste) to syngas and next to methanol is another route towards high value chemicals for Belgium. The production of aromatics via lignin is promising but further R&D and cost reductions are required.

15.1.5. Recycling and material efficiency

Recycling and materials efficiency are essential options, not only from a climate mitigation perspective but also to reduce demand for raw materials and fossil fuel-based feedstock. Efficient use of materials, while not specifically elaborated in this report, is a low-cost option with CO_2 mitigation impacts along the value chain.

The integration of a large-scale and mature chemical recycling industry within existing petrochemical production facilities is highly beneficial, particularly for Belgium, which has extensive polymer value chains. Chemical recycling processes can directly supply monomers for repolymerization, produce high-value chemicals (HVCs) that traditionally come from naphtha or ethane steam cracking, or generate syngas to feed methanol-to-olefins (MTO) or methanol-to-aromatics (MTA) pathways. This approach effectively addresses plastics that are challenging to recycle mechanically, thereby mitigating a significant portion of the end-of-life emissions that would otherwise result from incineration. For economic viability, chemical recycling operations demand substantial scale and a consistent, reliable supply chain of plastic waste, which may involve importing large volumes of waste. Furthermore, these chemical recycling routes, especially pyrolysis, catalytic cracking, and gasification, are energy-intensive and produce CO_2 emissions. Therefore, to ensure a low-greenhouse gas footprint, the capture and subsequent utilization or storage of these CO_2 emissions is a critical consideration for the sustainable development of plastic recycling.

15.1.6. Hydrogen and derivatives

In general, using (electrolytic) hydrogen for industrial (high temperature) heat is expected to be an expensive option, with companies likely choosing (more efficient) direct electrification or carbon capture and storage. It is uncertain if relatively cheap carbon free hydrogen will become available on a large scale in Belgium, via imports via pipeline by 2040. For industrial feedstock it more likely that blue hydrogen (i.e. steam methane reforming (SMR) or autothermal reforming (ATR) with carbon capture and storage) is chosen in Belgium due to the presence of existing SMR installations and the relative low cost of natural gas.

15.2. Impact on Belgian industrial emissions

15.2.1. Sectoral assessment

With a set of technologies identified that can theoretically play a role in deep greenhouse gas mitigation of Belgian industry the next questions are:

- Which of these technologies will be applied in each sector and to what extent?
- By when is deployment expected?
- What is the estimated mitigation impact and
- what are the conditions that need to be in place for the deployment?

Table 7 below gives an overview of this sectoral assessment. The timeframe for achieving deep reductions in industry is set in the period 2040-2050. This relates to uncertainty about forthcoming EU 2040 targets and related policies. While the EU ETS cap currently is set to reach 0 by 2040, flexibility via banking of allowances and the use of external credits (via amendment to the EU ETS directive) can create more emission space after 2040.

Table 6: Overview of key sectoral mitigation technologies for Belgium, their mitigation impact and conditions for deployment

Sector	**Key technologies** **(++): very likely deployment, (+): likely deployment, (u): uncertain deployment by 2040**	**Mitigation impact est. (ref. 2005) - assuming same production capacities**	**Essential conditions for deployment**
Chemicals	• *Carbon Capture and Storage for process emissions and some high-T processes (++)* • *Electrification low-T: heat-pumps for low-T heat (++)* • *Electrification high-T: induction/resistance (u – cost)/rotor(+)* • *Methanol/ethanol production via waste/bio (+)* • *Methanol to olefins (CCU) (+)* • *Other CCU (u – cost and regulatory context)* • *Chemical recycling of plastics (++)*	• *If all technologies are deployed at scale in period 2040-2050, mitigation of 80-90% and more is possible.* • *If carbon capture and storage and electrification are delayed or downsized mitigation will be well below 30%. (limited fuel/feed switch e.g. bio-based and efficiency)* • *Impact of advanced recycling of plastics is difficult to estimate*	• *Full (scale) value chain infrastructure for carbon capture and storage must be in place by 2035* • *Supply for electrification via clean electricity must be guaranteed. Critical investments in additional (renewable) capacity essential by 2035* • *Average price of electricity below €40/MWh for high-temperature electrification* • *Development of reliable supply chain for (plastic) waste and biomass to scale up chemical recycling and CCU (2035 latest)* • *Clarity on accounting for CCU in chemicals production*
Cement and Lime	• *Carbon Capture and Storage (+)* • *Carbon Capture and Utilisation +* H_2 *(u – cost and regulatory context)* • *CCU mineralisation (+)* • *Alternative fuels (bio/waste derived) (++)* • *Kiln electrification (+ from 2035)*	• *With CCS and electrification mitigation will be over 90%.* • *With CCS and no electrification mitigation will be around 50%* • *Without CCS and electrification further mitigation will be minimal (<25%, via limited fuel switch)*	• *Full (scale) value chain infrastructure for carbon capture and storage must be in place by 2035. In particular transport of* CO_2 *to sea-harbours.* • *High voltage connections for electrification of heat and stable, clean and affordable electricity* • *Local demand for green cement and lime*
Iron and Steel	• *Replacement of coal in BF (biomass, hydrogen) (+)* • *Carbon capture with utilisation and storage (u)* • *CCU to ethanol (+)* • *(Blue) hydrogen based DRI (u – Investment context)* • *Additional recycled steel via EAF (+)*	• *Full deployment of all options will reduce emissions by 80% (DRI + BF) - >90% (DRI)* • *If DRI+CCS investments do not take place mitigation will be much lower, around 25% (efficiency and feed switch)*	• *Highly dependent on EU investment climate for steel (e.g. trade tensions, global capacity)* • *Similar as above: CCS infrastructure and/or access to affordable blue hydrogen* • *Clarity on accounting of CCU in steel production*
Ceramics/glass/non-ferro	• *Kiln electrification: full or hybrid (+)* • *Alternative fuels/feedstock (u – availability and cost)*	• *With kiln electrification mitigation can reach over 80% in plants that deploy the technology (e.g. larger ceramics)* • *Alternative fuels and feedstock highly dependent on availability* • *Process emissions in glass, ceramics will remain a challenge to address due to possible lack of access to CCS network.* • *Overall mitigation in these sectors expected to be not high than 80% in period 2040-2050*	• *Supply and price of clean electricity* • *Develop the possibility and support to retrofit electrification smaller kilns* • *Reliable supply of alternative fuels/gases at affordable price (e.g. bio- or* H_2 *based)*

Food	- *Heat pumps / e-boilers (++)* - *Bio-based energy (+)*	- *Widescale deployment of electrification has started* - *Use of biomass will depend on location and activity* - *Overall, 90% reductions or more are possible in by 2040*	- *Pro-active reinforcement of power grid (possible bottlenecks with connection to distribution grid in case of wide scale electrification)* - *Address challenges/opportunities for companies with variable heat requirements (heating/cooling)*
Pulp and paper	- *Electrification of heat (heat pumps and e-boilers) (++)* - *Bio-based energy (++)*	- *With deployment of electrification, replacement of fossil fuel with bio-based (waste) inputs mitigation of 90% or more should be possible.*	- *Similar as above*
Other industries	- *Heat pumps / e-boilers (++)* - *Alternative fuels/bio-based (u – availability and cost)*	- *Deployment of heat pumps and e-boilers will cover most of the low-T heat.* - *Some high temperature processes might not be mitigated.* - *Estimated mitigation impact of around 90%. (uncertain)*	- *Similar as above*

15.2.2. Overall evaluation

Context and disclaimer

The main goal of this report was to identify technologies that can help Belgian industry achieve deep greenhouse gas emission reductions and to present their techno-economic context.

To estimate the overall mitigation impact of these technologies detailed modelling is required such as via the EnergyVille VITO TIMES-BE equilibrium model[167] or the Climact Pathways explorer simulation model[168]. Both models have recently modelled options for 2050 net-0 emissions for Belgium, with sectoral resolution.

Below a theoretical "what if type", expert judgement based, simulation is given to demonstrate the maximum potential of a selection of promising technologies in Belgium. It considers the sectoral evaluation mentioned before and pushes these technologies towards a highly optimistic (and hence likely not realistic) implementation.

From a practical perspective the boundary conditions that can enable industry to maximise deep emission reduction are more relevant. These inform the policy context and recommendations that can leverage the industry's potential for deep greenhouse gas mitigation.

Theoretical mitigation potential simulation

It is **theoretically** possible for Belgian industry (with similar production volumes as today) to reduce its **direct** GHG emissions by around 90% (compared to 2005 levels) within the period 2040-2050, using technologies that are currently well advanced, or technologies expected be market ready by 2035-2040. Reaching this level of abatement can happen under the following (again theoretical) conditions, given here *as an example*:

- Carbon capture and storage: full deployment for all process emissions in cement, lime, chemicals and steel and assuming capture rate of 90%. Process emissions represent around 1/3 of industrial greenhouse gas emissions. Depending on cost of electricity and available infrastructure, some high- temperature processes could also apply carbon capture (see figure 66).
- Electrification of almost all (over 90% of) industrial heat: All low- to medium-temperature heat (30-40% of industrial energy related GHG in industry) will be electrified in first phase (e.g. via heat pumps and e-boilers). Almost all high temperature heat will gradually be electrified following the technology developments (2035-2050).

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[167] See: https://perspective2050.energyville.be

[168] https://becalc.netzero2050.be

- Blue hydrogen as feedstock: All methane-based hydrogen production (e.g. for ammonia) in Belgium applies carbon capture and storage (i.e. blue hydrogen). In steel production, by 2040, the current blast furnaces in Belgium are replaced by the DRI (+CCS) + EAF route.
- Biomass: In sectors with close ties to biomass supply or waste chains (e.g. paper and food) the enhanced use of biomass is maximised.
- Waste valorisation: Avoiding combustion of (municipal, bio-based and plastic) waste and valorising it towards naphtha feed replacement and syngas to molecules such as methanol.
- Recycling: Closing the plastics value chains via chemical recycling and reducing dependence on raw materials and fossil feedstock.

Moving beyond the mitigation mentioned above will require extended use of technologies that use CO_2 (via biomass and/or CCU) to generate negative emissions. The latter options are however among the most expensive currently, with further R&D needed. There is also the need for regulatory clarity (e.g. via carbon accounting rules) to know to what extent and where CO_2 utilisation can contribute to negative emissions.

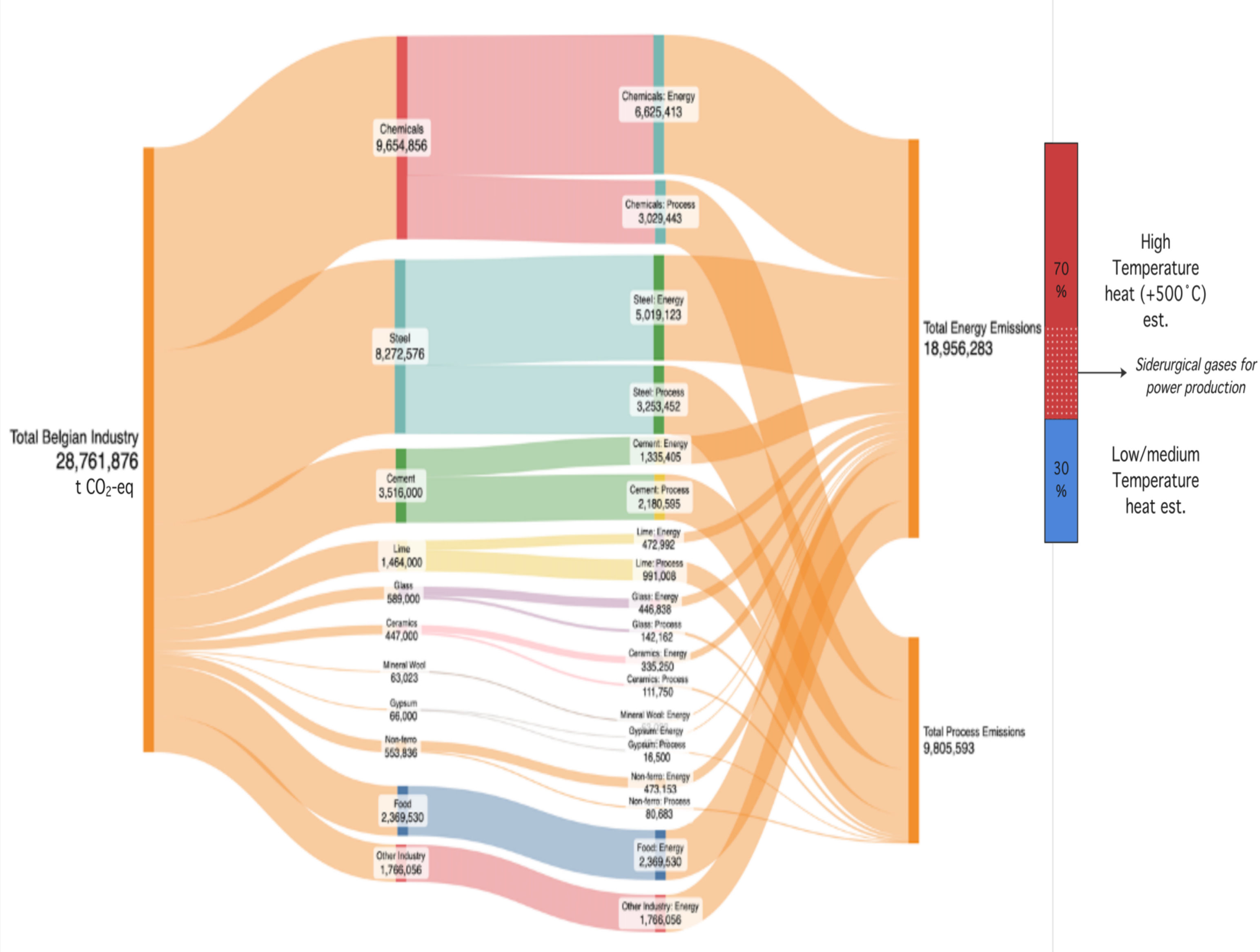

Figure 66: Industrial CO_2 emissions per sector with an estimate of process emissions and emissions related to high and low/medium heat in Belgian industry. Based on Belgium, 2024, CRT and expert guesstimates[169].

Enabling conditions to reach deep emission reductions

However, achieving deep emission reductions in industry over the next decades is by no means straightforward. There are essential enabling conditions that need to be in place for timely and full-scale deployment of mitigation technologies and options. This includes:

- Electricity price: for high-temperature electrification, reducing electricity costs for industry will be an important enabling condition. This includes not only reducing the absolute price of electricity but also reducing the relative cost difference between electricity and natural gas use for heating.

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[169] Uncertainty about chemical process emissions. Some of the petrochemical emissions are under UNFCCC classified as process emissions, while it are emissions from the combustion of gases from naphtha steam cracking. These have been allocated in this figure to energy emissions (high temp).

- Electricity production: Electrification in industry will dramatically increase electricity demand in Belgium. At the same time other parts of the economy are also moving in direction of electrification (e.g. transport and buildings). Currently industrial demand (35 TWh) represents around 45% of Belgium's total power consumption (78 TWh).[170] According to Paths2050 scenario's by Vito-Energyville it is estimated that electricity demand by industry will almost double (to 68-70 TWh) by 2050.[171] Ensuring that adequate capacity will be ready in the next 15 years via additional domestic production and import capacity is not only an essential condition for deep industrial mitigation but also the overall climate transition of Belgium. As shown in the sensitivity analysis in this report, the CO_2 intensity of electricity production must become very low as to avoid increasing indirect emissions with high levels of electrification, in particular for high-temperature industrial heat.
- Electricity prices: For high temperature electrification of heat the electricity price will make or break this technology deployment in Belgium (e.g. power prices above €40-60/MWh will lead to (very) high abatement cost for electrifying naphtha steam cracking).
- Electricity networks: With additional electricity demand in industry, power grids (transmission and distribution) will have to be reinforced to ensure stable supply and avoidance of bottlenecks that delay industrial investments.
- CO_2 infrastructure: Carbon capture and storage for industry in Belgium, requires the development of an extensive pipeline network that connects major industrial emitters (with large process emissions) across the country to hubs and shipping terminals. These are major infrastructure investments requiring extensive planning, permitting and budgets. To maximise the potential of carbon capture in Belgium, this network will need to be in place over the next 10-15 years.

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[170] 2024 data, Source: Enerdata, 2025.

[171] Vito-Energyville, 2025

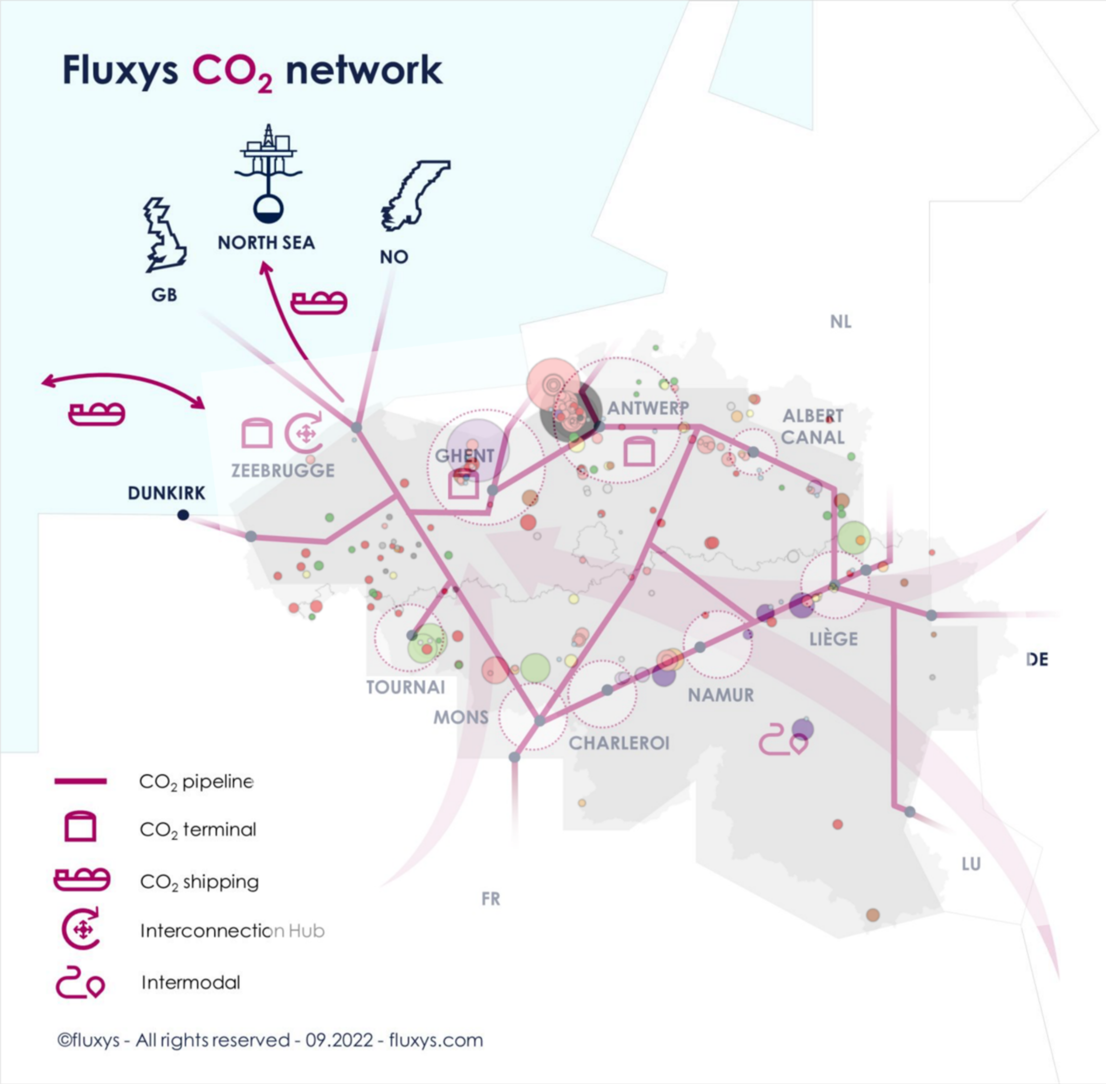


Figure 67: Planned Fluxys CO_2 network (source: Fluxys) and major industrial emitters (Source: VUB)

- CO_2 accounting: For CCUS the way the utilised CO_2 is accounted is an essential factor in the viability and deployment of these technologies. Important conditions for full accounting (including negative emissions' accounting) include biological or air-captured CO_2 sourcing and long-term storage in materials.
- Availability of sustainable biomass: Biomass can play an important role, either in high-temperature heating (e.g. biogas, bio-coal) or as feedstock for chemicals and steel production. From a sustainability perspective priority should go to biomass waste that does not compete with food production. Further research would be required to establish how much of this biomass can be available for the transition of industry.
- Availability and cost of alternative fuels: In some cases, electrification and carbon capture might not be possible. Alternative (e.g. hydrogen derived) fuels can be used

as option. This will require the development of a reliable supply chain of these fuels (e.g. via import).

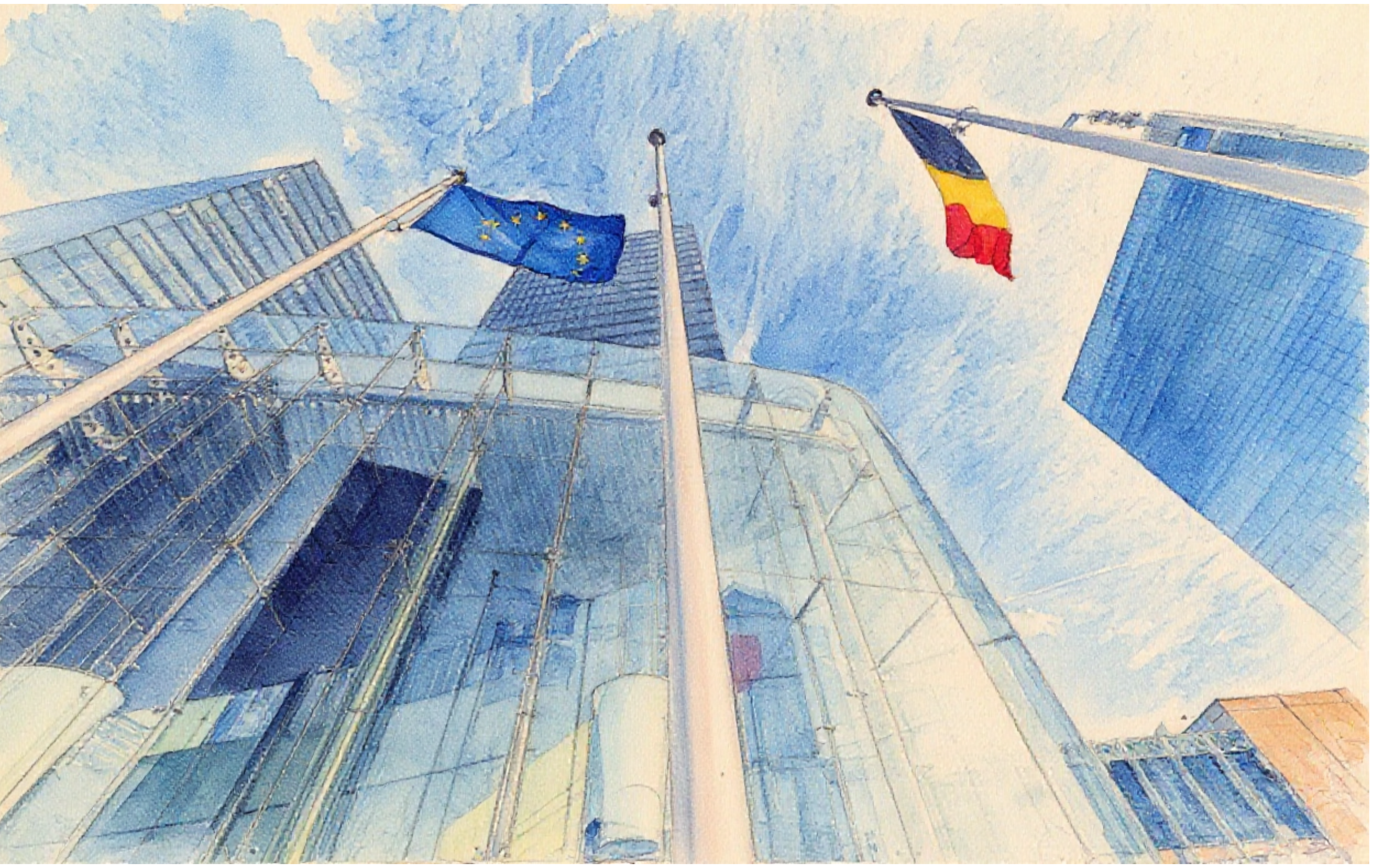
- Technology cost: As shown before, most technologies will have a mitigation cost well above the current EU ETS price. Technology costs have, in general, gone up recently due to inflation. This forms an important barrier for the deployment of large-scale demonstration and first-of-a-kind plants. Therefore, additional support will be required to kick-start some of the technological options in Belgium.

In chapter 16.1 boundary conditions will be revisited and placed in a policy context.

15.2.3. No regret options

Given the wide range of technological options, are there with what is currently known, no-regret options for the industrial transition in Belgium? The following technologies and options should be a no-regret priority.

- Industrial heat-pumps: due to their high efficiency a technology that can contribute to cost effective electrification of part of industrial heat
- Hybrid e-boilers: less efficient compared to heat pumps but can be used flexible (e.g. at times of negative or low power prices)
- Carbon capture infrastructure: For most process emissions there is no large-scale alternative to achieve deep emission reductions
- Investment in additional clean power: there is no doubt that the expected electrification of society incl. industry will require additional power capacity.
- Investment in transmission and distribution networks: essential for deployment of electrification
- Prioritise circular economy and materials efficiency: Because it generates benefits beyond GHG mitigation such as lower dependence on imported raw materials, waste etc.



16. Policy recommendations[172]

16.1. Defining the challenges

According to a four-pillar framework consisting of Infrastructure, Investment, Innovation, and Integration, the industry sector faces several key challenges in achieving net-zero emissions:

Infrastructure

- Absence of reliable, affordable, and clean power risks significant delays in the electrification of industry.
- Lack of robust national infrastructure for CO_2 liquefaction and transport is a precondition for industries like chemicals, steel, and cement to invest in new process technologies for CO_2 capture and utilisation.
- Major investments by industrial actors are unlikely to materialise if key infrastructure (e.g., for hydrogen, CO_2, and upgraded power grid) is not available, reliable, and future-proof.

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[172] The policy challenges and options are derived from a policy paper developed for the ETF financed Procura project and used the outputs from the most recent TIMES-BE model. Ref. Wyns, T. and Khandekar, G., 2025.

- The current "first come, first served" approach to infrastructure access is likely unsustainable and may hinder or delay the transition to a net-zero energy system, impacting industrial electrification projects.
- Upfront financing of infrastructure often results in high costs for early end-users, as network operators seek to recover capital expenditure, which can deter initial industrial investments.
- The regulatory context, such as permitting procedures, may not adequately support fast deployment of necessary infrastructure.

Investment

- Mobilising private capital at scale for industrial process upgrades is one of the greatest challenges to achieving climate neutrality.
- Current EU ETS carbon pricing (currently €60–80/t CO_2) is often insufficient to support key technologies like CCS, which typically requires a sustained CO_2 price well above €150/t CO_2 to become viable until 2040.
- The competitiveness of decarbonisation pathways, such as electrification and the use of green hydrogen as industrial feedstock, depends heavily on electricity pricing and the cost gap between natural gas and electric power.
- Higher investment and operational costs of new clean technologies, compared to conventional systems, pose a barrier for the private sector, which is often more risk-averse.
- Complex and time-consuming permitting procedures, regulatory uncertainty, and inadequate strategies for engaging local communities can hinder necessary investments in the industrial sector.
- In Belgium, electricity prices are often more than four times higher than natural gas prices for end-consumers, making the electrification of industrial processes economically unattractive.
- The lack of a mature consumer market for green products and services (e.g., green steel, fertilisers, cement, and plastics) is a barrier, as these measures may come with higher upfront costs.
- The lack of global carbon pricing impacts EU industrial competitiveness, though the Carbon Border Adjustment Mechanism (CBAM) is intended to mitigate this. However, the latter needs to be improved for higher effectiveness.

Innovation

- Abatement remains technologically or economically challenging in hard-to-abate sectors, requiring innovation breakthroughs.
- The deployment of higher Technology Readiness Level (TRL) solutions needs to be accelerated and commercialised, specifically targeting areas like high-temperature electrification and CCU pathways for industrial processes.
- Limited budgets available mean that federal and regional innovation funding streams must be tightly aligned with EU priorities and co-funding opportunities to maximise impact.

Integration

- The net-zero transition is a complex, interconnected system encompassing energy, heat, molecules, and recycled materials, requiring systemic coordination across these elements.
- There is a risk of fragmented or inefficient investments if systems thinking, sector coupling, digitalisation, and collaborative governance are not prioritised.
- Strengthening the effectiveness of governance structures in Belgium and enhancing coordination with neighbouring countries is crucial, as climate and energy transition responsibilities are shared between federal and regional levels.
- Ensuring interoperability across borders and aligning the development of CCS and hydrogen backbones with EU-level corridors is necessary to reduce capital costs and improve efficiency.
- Improved policy coordination and strategic alignment between different levels of government and stakeholders are essential given the scale and urgency of required investments.

16.2. Policy recommendations

Possible policy options for the industry sector to meet the challenges in the areas of investment, innovation, infrastructure and integration are as follows:

Infrastructure

- Develop shared infrastructure for CO_2, steam, and hydrogen to reduce costs through economies of scale and ensure timely access for major emitters to transport and storage facilities.

- Provide public support where needed for the development of Carbon Capture and Storage (CCS) hubs and to enable electrification use as feedstock in existing or new industrial sites.
- Ensure that the regulatory context, such as permitting procedures and specifications for CO_2 transport by pipeline, supports fast deployment of infrastructure.
- Pursue integrated spatial planning to align new infrastructure with land use priorities, which can also streamline environmental impact assessments and accelerate permitting.
- Consider fast-track procedures for infrastructure projects of national strategic importance.
- Develop mechanisms to mobilize patient capital, possibly through a national Infrastructure Development Bank, to support large-scale investments in areas like electrification, clean molecule logistics and CCS, helping to lower financing costs and enable public-private risk sharing.

Investment

- Utilize well-designed public co-financing tools such as the EU ETS Innovation Fund and Contracts for Difference (CfDs) to address higher investment and operational costs of new clean technologies and provide revenue stability.
- Remove regulatory barriers, including complex and time-consuming permitting procedures and regulatory uncertainty, by prioritising regulatory simplification for clean investments and political commitment to key enabling infrastructure projects.
- Reform energy pricing and taxation by shifting the burden away from electricity and increasing the relative cost of natural gas to improve the economic case for industrial electrification, as electricity prices can be significantly higher than natural gas prices.
- Use green public procurement and introduce clean product standards to create lead markets for low-carbon materials such as green steel, fertilizers, cement, and plastics, despite potential higher upfront costs.

Innovation

- Prioritize the rapid deployment of high Technology Readiness Level (TRL) solutions, supported by well-designed demonstration-to-commercialization pipelines, backed by national programs and EU-level instruments like the EU ETS Innovation Fund.

- Develop dedicated innovation clusters focused on high-temperature electrification, Carbon Capture, Utilization, and Storage (CCUS) integration into production value chains (e.g., methanol and aromatics), and next-generation circularity solutions like high-yield mechanical and chemical recycling platforms and industrial symbiosis networks.
- Align federal and regional innovation funding streams tightly with EU priorities and co-funding opportunities (e.g., Horizon Europe, Innovation Fund, IPCEIs) to leverage larger funding pools and foster cross-border cooperation.
- Between 2030 and 2040, focus on R&D for high reward technologies for industrial innovation, specifically targeting the electrification of high-temperature processes (e.g., electric kilns) and electrochemical processes.
- By 2050, consider deployment of negative emissions technologies like bioenergy with carbon capture and storage (BECCS) or direct air capture (DAC) to offset hard to abate residual emissions.

Integration

- Approach the net-zero transition as a complex, interconnected system, encompassing energy, heat, molecules, and recycled materials.
- Enable greater sector coupling to unlock synergies and improve overall system efficiency, making it a mainstream component of industrial development. This includes integrating power-to-X technologies, industrial waste heat recovery, and multi-vector energy hubs.
- Strengthen the effectiveness of governance structures in Belgium and enhance coordination with neighbouring countries.
- Align the development of CCS and hydrogen backbones with EU-level corridors to reduce capital costs and ensure interoperability across borders.
- Explore shared pipelines, storage, and processing facilities at the industrial cluster level to cut duplication, reduce system costs, and enhance resilience.
- Establish a national transition council with representatives from all levels of government, industry, and civil society to provide a unified platform for strategic direction and implementation.
- By 2040, ensure Belgium's industrial clusters and ports host multi-vector energy hubs that integrate power, heat, and hydrogen management.

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