Decarbonisation routes for the Dutch industry towards 2040

Report prepared for Gasunie

PwC
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Subject: Report – Decarbonisation routes of the Dutch industry towards 2040

Dear Maarten,

We are pleased to contribute, through this study, to the further development of the Dutch industrial energy transition. Please find enclosed our report dated June 2026 (hereinafter: the Report), which presents the outcome of the work we agreed to carry out in accordance with the contract concluded following the procurement procedure for Verduurzamingsroutes van de Nederlandse Industrie (reference WS2871962540).

The Report addresses the agreed scope of work, including an analysis of current emissions, energy and feedstock use in the Dutch industry, and a techno-economic assessment of decarbonisation routes such as electrification, CCS, biomethane and (low-carbon) hydrogen towards 2040.

Should you have any questions regarding the Report, please do not hesitate to contact me.

Kind regards,

On behalf of PricewaterhouseCoopers Advisory N.V.,

Prof. Dr. Gülbahar Tezel

Partner PwC

About this document

Scope

▨ 🟧 ▨

Limited Extensive

This document presents insights from the work conducted under the engagement letter dated 06 February 2026 (reference WS2871962540). This document presents a cross-sector fact base on energy use, emissions, and techno-economic abatement pathways for Dutch industry (specifically the large EU ETS industry including waste processing) towards 2040, built up from a process-level view for each sector. Our analysis covers approximately 62% of industrial and waste-related emissions (i.e., ca. 45 $MtCO_2$-eq per year). This includes refineries, basic chemicals, fertilisers, industrial gases, steel, waste processing, ceramics, glass, food, paper, and other industry. The results are synthesised into an industry-wide techno-economic abatement cost curve, with abatement costs reflecting up-front capital expenditures and ongoing fixed and variable operating costs (includes commodity prices, network costs, and taxes). Throughout this document, CO_2 refers to total greenhouse-gas emissions expressed in CO_2-equivalent terms.

Our analysis assumes that industrial production levels in NL remain at current levels i.e., there is no scaling down/up in industrial activity compared to the 2020-’24 average. In reality, sectors facing competitive pressures either due to market forces or policy choices could scale down or choose a specific investment pathway which does not align with the most techno-economically efficient abatement pathway if one were to assume that they continue to operate with their current plant configurations. For example, the RFNBO obligation on transport can cause refineries to substitute current grey hydrogen usage with green hydrogen, automatically reducing reliance on existing SMR output.

Access and clarity of information

▨ 🟧 ▨

Limited Extensive

Our analysis was conducted using publicly available information, validated with insights from internal experts. Where data gaps or outdated information were identified, clearly documented assumptions were applied to ensure transparency and internal consistency. We assume that the information used is reliable, accurate, and comprehensive in all significant aspects. It is important to note that unless explicitly mentioned in our report, we did not independently verify or validate the accuracy or completeness of the information in accordance with international audit and review standards.

Access to our report

This document is specifically prepared for Gasunie (the client) with whom we have agreed on the purpose and scope of our work, or to whom we have explained the nature and extent of our work and the limitations therein. We do not accept any responsibility, duty of care, or liability - contractually, in tort (including negligence), or otherwise - for the use of the report by parties other than the client.

Other comments

This document as well as any dispute arising from or related to (the contents of) the report are governed exclusively by Dutch law.

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Executive summary

Key take-aways

Ca. **86%** of industrial emissions come from **six sectors** and **less than 10%** from the ‘**cluster 6’ industry**, all facing **tightening incentives** under EU and Dutch climate policy (EU ETS, Fit for 55, etc.) toward full decarbonisation by 2050

Decarbonisation options differ strongly by sector. Top six emitting sectors rely **primarily on CCS** to abate a large portion of their GHG emissions; ‘Cluster 6’ industries are better suited for **electrification** and **fuel substitution with biomethane**

Achieving net zero requires a reduction of **~44 Mt CO_2/year**, with **CCS expected to drive most reduction** (~21 Mt CO_2 of year, of which **83% through blue hydrogen**), followed by **direct iron reduction & electric furnaces in the steel sector** (~9 Mt CO_2/year), **partial electrification via hybrid boilers** (~6 Mt CO_2/year) and fuel substitution by **biomethane** (~4 Mt CO_2/year). The **required supporting infrastructure** is found to be **sufficient,** if development goes according to plan

Policies can cause shifts in the abatement curve, e.g., RFNBO obligations (under REDIII) can potentially **increase green hydrogen demand**, replacing lower-cost abatement options (like CCS and biomethane)

Executive summary

Decarbonising Dutch industry: a pragmatic pathway to net zero

- Dutch industry **emits roughly 72 Mt of CO_2 annually** (2020–2024 average), of which about **44 Mt originates from large emitters covered by the EU ETS and waste processors** – the focus of this analysis. Over the period 2021-23, the industry accounted for **ca. 12% of Dutch** GDP, employed roughly **385K FTEs** and generated about **€5bn in tax revenues**
- **Emissions are highly concentrated. Six sectors** (refineries, basic chemicals, fertilisers, industrial gases, steel and food) account for around **86% of emissions** and roughly **half of industrial energy use**. In contrast, so-called **"cluster 6" industries** (including glass, ceramics, food and paper) consume a **sizeable share of natural gas** (around 30%) but contribute **less than 10% of total emissions**, reflecting lower process emissions and temperature requirements
- The policy direction is unambiguous. The **EU's legally binding target** of climate neutrality by 2050, embedded in both European and Dutch law, implies **full decarbonisation** of these sectors. While obligations fall largely on **the industry rather** than **individual companies**, a dense web of instruments, most notably the EU ETS, the Carbon Border Adjustment Mechanism (CBAM) and the Fit for 55 package, will tighten incentives and raise the cost of unabated emissions over time

Technology pathways: constrained by physics, refined by economics

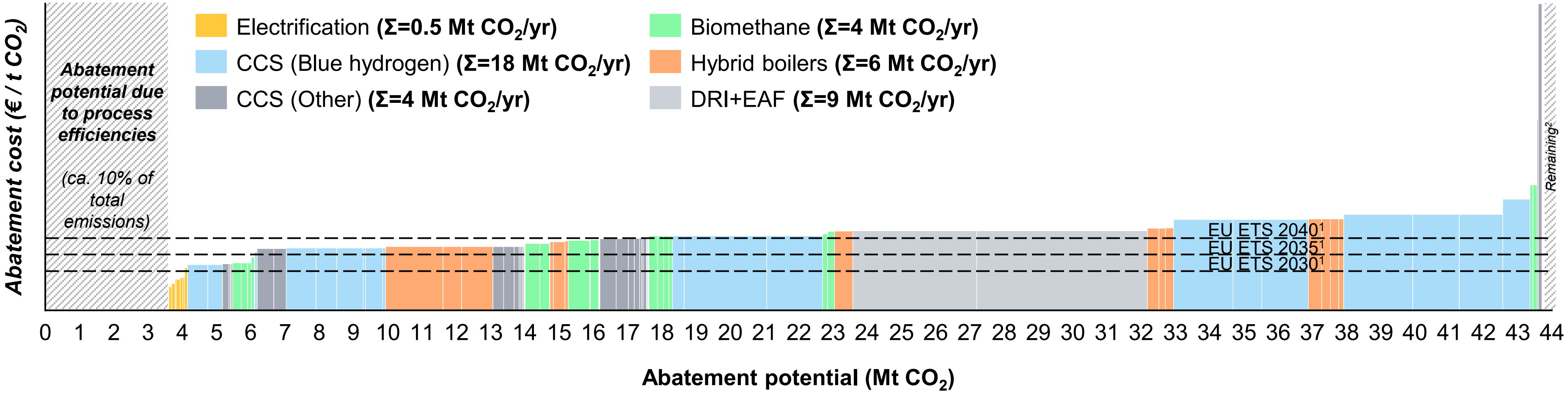
- From a technical standpoint, abatement options **vary markedly by sector**. The **top six emitting sectors** rely on high-temperature processes and often generate concentrated CO_2 streams, making **carbon capture and storage (CCS), fuel substitution with hydrogen & biomethane, and electrification of high-temperature processes** (assuming TRL levels improve towards 2040) as technically feasible abatement options **in the long-run**. In 'cluster 6' sectors, where heat demand is lower and more dispersed, **low- to medium-temperature electrification** (through heat pumps and hybrid e-boilers) and **fuel-substitution with biomethane** are generally more suitable
- Once costs are considered, the menu narrows. Across sectors, three options are most viable: **CCS**, **low- to medium-temperature electrification** (mostly hybrid boilers) and **biomethane**. For hydrogen production, a large source of emissions, **new autothermal reformers (ATRs)** with integrated CO_2 capture **outperform retrofitting legacy steam methane reformers (SMRs),** which are structurally ill-suited for deep capture. **Electrification is attractive** where process **temperatures are low to medium**, while **biomethane** offers a **flexible**, **near-term substitute** for natural gas

Note: All sector deep-dives can be found in the appendix

Executive summary

GHG abatement cost curve for Dutch Industry

(In €/t CO_2 & Mt CO_2/year, *2040P)*



CCS, including blue hydrogen, dominates the transition

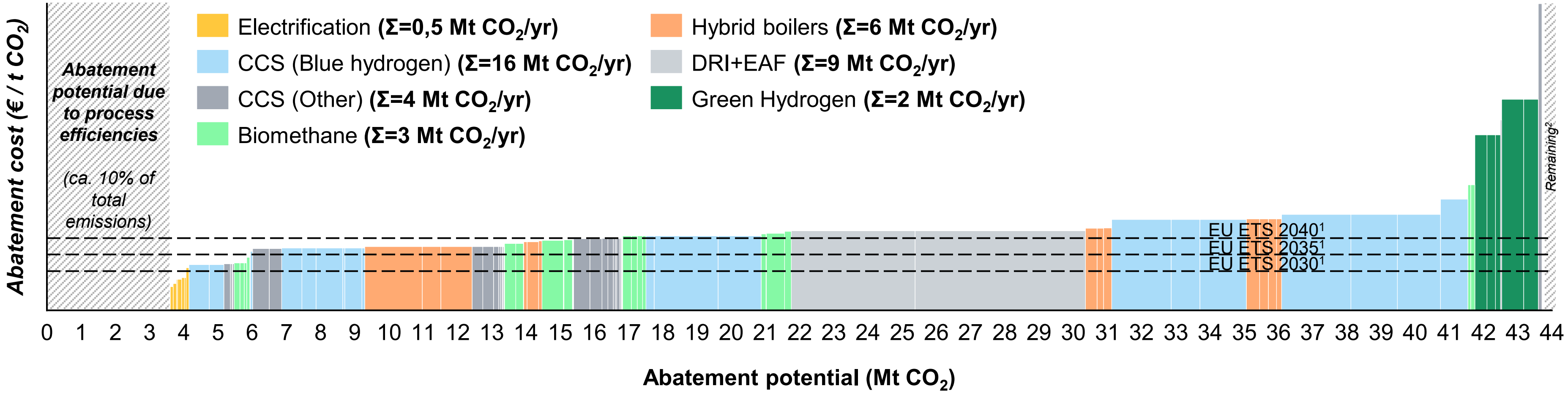
- Assuming industrial output remains broadly stable, achieving net zero across the sectors in scope requires emissions reductions of roughly **44 Mt CO_2 annually**. A bottom-up techno-economic assessment shows that carbon capture and storage (CCS), especially through the production of blue hydrogen, is the main decarbonisation option toward 2040,[3] delivering **~21 Mt CO_2 per year of reductions**
- **Ca. 11 Mt CO_2 per year** is expected to come from **CCS on SMRs** in **refineries** and **industrial gas sectors**, on **DRI** in **steel**, and in **waste/sludge incineration**. **Ca. 9 Mt CO_2 per year** is abated via **Auto Thermal Reforming (ATR)** to process fuel-/off-gases in refineries and basic chem. sectors
- Electrification plays a **secondary** but **still material role**. Replacing combined heat and power units (CHPs) and conventional steam boilers with **hybrid e-boilers** is expected to abate around **6 Mt CO_2 annually**. These changes, together with CCS deployment, would require **2 GW of additional electricity network capacity** – manageable, but not trivial
- **Biomethane** serves as both a **bridging and residual solution**. It is particularly relevant for ‘cluster 6’ industries and for **closing remaining emissions** gaps from CCS in top six emitting sectors, contributing a further **4 Mt of annual abatement**. Electrification, blue hydrogen and biomethane **compete as substitute fuels**, so their use **depends strongly on price projections**. This **does not hold for CCS (including blue hydrogen from off gases) and direct iron reduction & electric furnaces in the steel sector**, as they are **often the only viable option**
- Encouragingly, infrastructure availability does not appear to **constrain cost-effective abatement** by 2040. Planned expansions of electricity grids, CO_2 transport and storage infrastructure, hydrogen supply, and biomethane production are **expected to be sufficient** and **delivered on time**

1) EU ETS forecasts are based on EU ETS Impact assessment report (EC, 2024); 2) Remaining ca. 1 Mt CO_2 per year is excluded because emissions in some sectors are highly fragmented, meaning these sectors are not fully abated within the scope of this study; 3) Techno-economically optimised for abating all industry emissions until 2040

Executive summary

GHG abatement cost curve for Dutch Industry

(In €/t CO_2 & Mt CO_2/year, *2040P)*



Policy overlays shift the curve and raise costs

- Policy **mandates**, however, **can alter the optimal pathway**. Under the Renewable Energy Directive (RED III), obligations for renewable fuels of non-biological origin (RFNBOs) could drive **demand for green hydrogen** in the order of **4.4 TWh by 2030[3]**, rising to **5.7 TWh by 2035** and stabilising thereafter
- Relative to the most cost-efficient curve, these obligations **substitute** some **lower-cost abatement options**. Roughly **0.3 Mt of CO_2 reductions** via **biomethane** and **1.5 Mt through CCS** on SMRs would be replaced by direct **use of green hydrogen from the grid –** amounting to ca. 5.7 TWh of hydrogen consumption. The emissions outcome remains similar, but the end-user cost increases, illustrating the **tension** between **technology-neutral efficiency** and **policy-driven technology choices**

Driving coordinated decarbonisation in a large and geographically concentrated industry

- Dutch industrial activities are **physically concentrated in five industrial clusters**, characterised by dense interconnections, which **enhance efficiency** but also increase systemic vulnerability
- This clustering has **two implications**. First, **decarbonisation strategies** must be **coordinated** at **cluster level** to preserve synergies and avoid suboptimal fragmentation. Second, any **erosion of competitiveness risks cascading effects** across value chains

1) EU ETS forecasts are based on EU ETS Impact assessment report (EC, 2024); 2) Remaining ca. 1 Mt CO_2 per year is excluded because emissions in some sectors are highly fragmented, meaning these sectors are not fully abated within the scope of this study; 3) The analysis assumes full cost pass-through of the RFNBO obligation for non-ammonia-related hydrogen consumption (around 40% of total volumes) within the fertiliser sector. However, competitive pressure from non-EU producers not subject to the RFNBO requirement is likely to limit effective pass-through in practice, as highlighted in the *Speelveldtoets 2024*

2

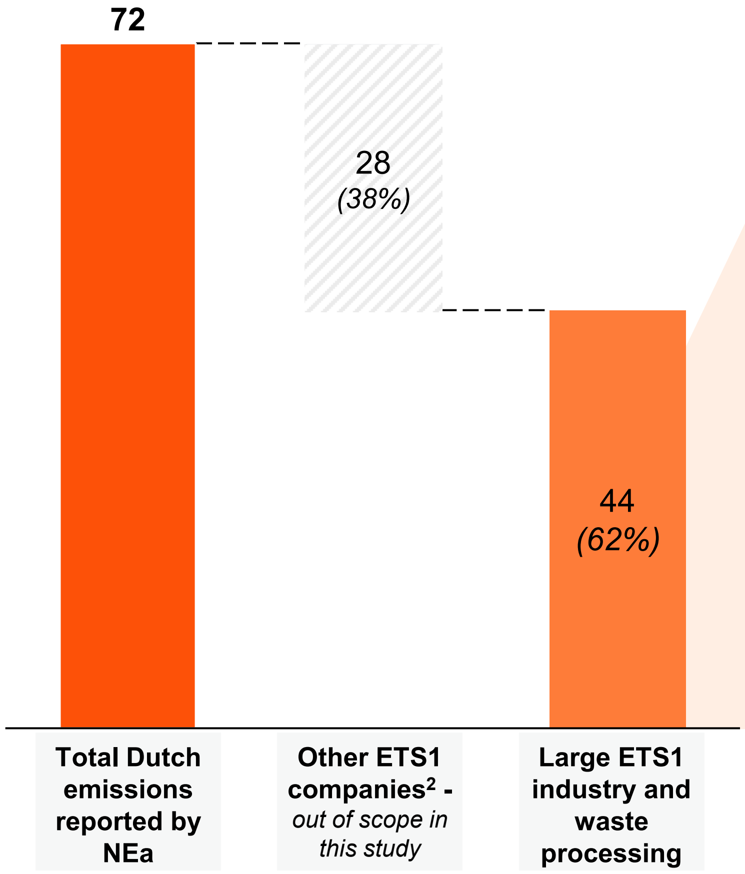
Introduction Dutch industry

The industry incl. waste processors in scope emits ca. 44 Mt CO_2/yr (avg. 2020-2024), with the top 6 emitting sectors responsible for ca. 86% of total emissions

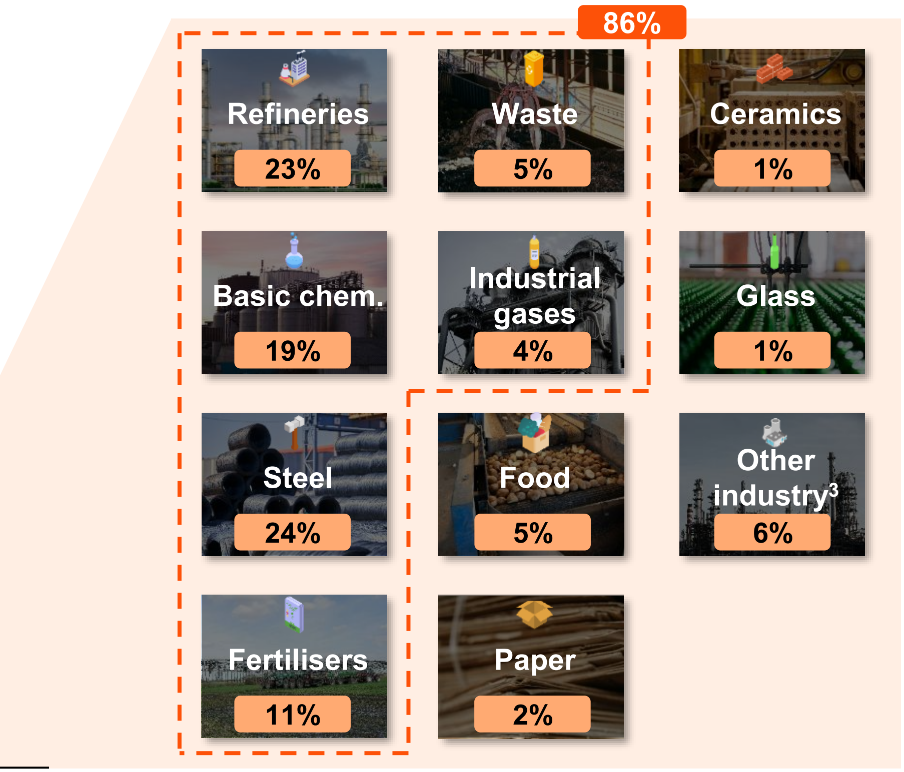
Dutch ETS & waste sector emissions

Total GHG emissions from Dutch ETS1 sectors

(in Mt CO_2, 2020-2024 avg.[1])



Zoom-in: sector emission contribution



Key insights

- Total Dutch emissions covered under the EU ETS1 scheme are **72 Mt CO_2** (based on the 2020-2024 average), and is defined by all the companies which are **available under NEa**
- In this report, **in-scope industry** are the following selected ETS sectors**: refineries, basic chemicals, fertilisers, steel, industrial gases, food, waste processing, paper, ceramics, glass, and other industry**, which are responsible for **44 Mt CO_2 (61%)** emissions (based on 2020-2024 average)[1]
- **Largest sectors** within this study are refineries, basic chemicals, steel, fertiliser and food, responsible for **ca. 86%** of the **total emissions in scope**
- Sectors which are **excluded** are **energy providers (except refineries)**, **data centres**, **greenhouse horticulture**, **hospitals/ university** and **airport/ aviation**, which are responsible for **28 Mt CO_2 (39%)** of the total Dutch industry emissions (based on 2020-2024 average)

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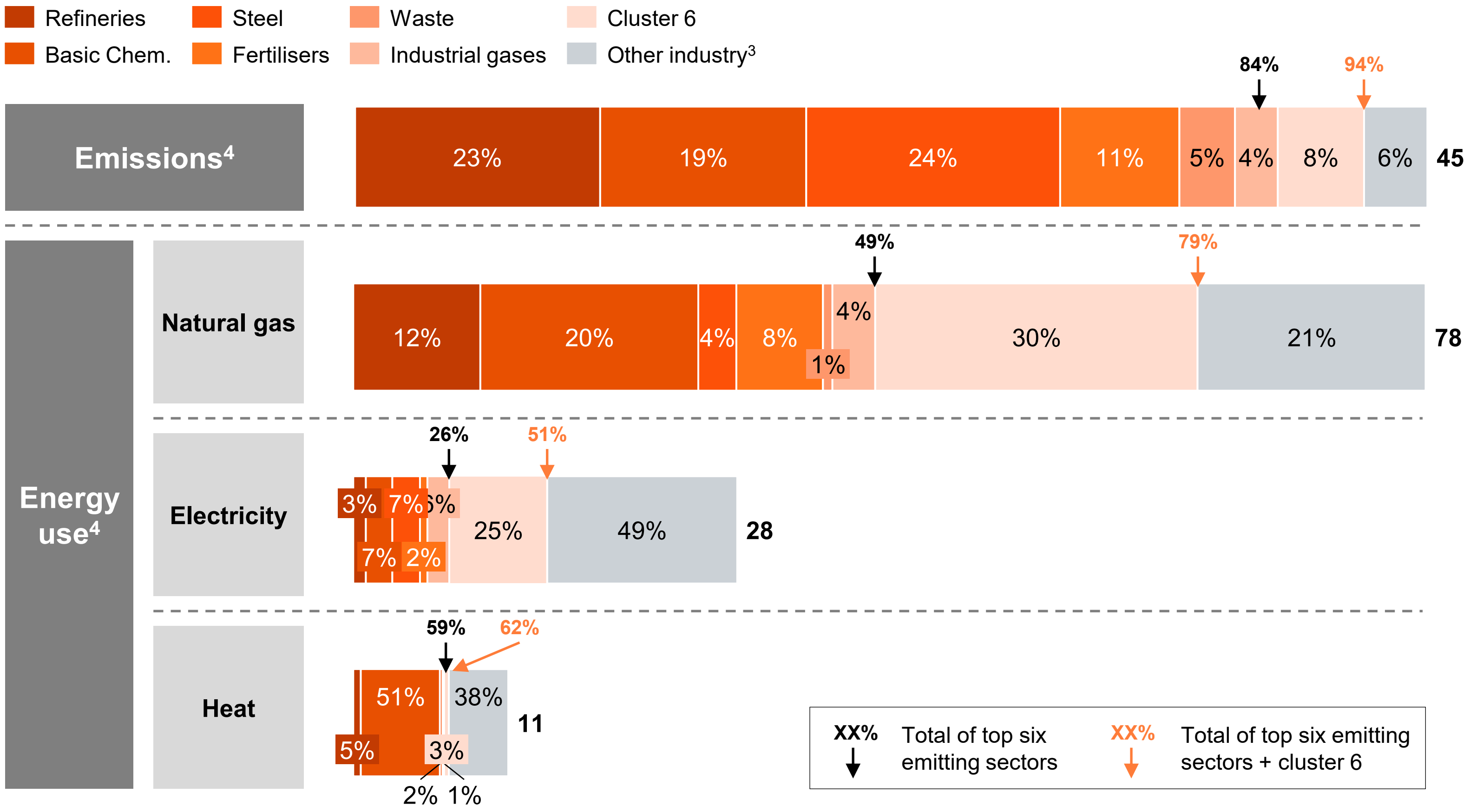
1) Most waste processing plants have only been included in NEa emissions numbers since 2024, so this is used as the baseline (rather than the 5-year average), and the 5-year average for steel excludes 2023 as an outlier due to prolonged maintenance; 2) Includes emissions by stationary installations such as data centres, greenhouse horticulture, energy providers, hospitals/universities and airports/aviation; 3) Other industry includes, amongst others, plastics, other chemicals, non-ferrous metal, machine industry, transport equipment and printing; Sources: NEa

Beyond the top-emitting sectors, cluster 6 industries use a significant share of natural gas (30%) and contribute around 10% of industrial emissions

Emissions and energy use of large ETS industry (incl. waste)

Emissions and energy use of large ETS industry[1] and waste sector in The Netherlands

(In Mt CO_2, 2024 and in TWh, average of 2020 – 2024[2])



Key insights

- **Top 6 sectors** (refineries, basic chemicals, fertilisers, steel, waste and industrial gases) are **responsible for 86%** of the in-scope Dutch industry emissions, much of which coming from crude oil and petroleum products
- **Basic chemicals** consumes **~20% of industry natural gas**, driven by **heavy natural-gas** use in **CHPs and boilers** for heat generation; **refineries** (12%) and **fertilisers** (8%) use (mainly) natural gas to produce onsite hydrogen
- **Cluster 6** takes up **~30%** of **total natural gas usage** due to extensive use of **natural gas fired CHPs and boilers** in the **food processing** and **paper production** sectors
- Top sectors use **little electricity**, and main consumption is driven by **cluster 6** (mainly by food through **cooling**, freezing and pumping and machine industry through welding) and **other industry** (mainly by machine industry through CNC-machining and automation)
- Top 6 sectors consume **59% of industrial heat**, with **basic chemicals** alone **using ~50%**, largely due to the high heat demand for steam cracking

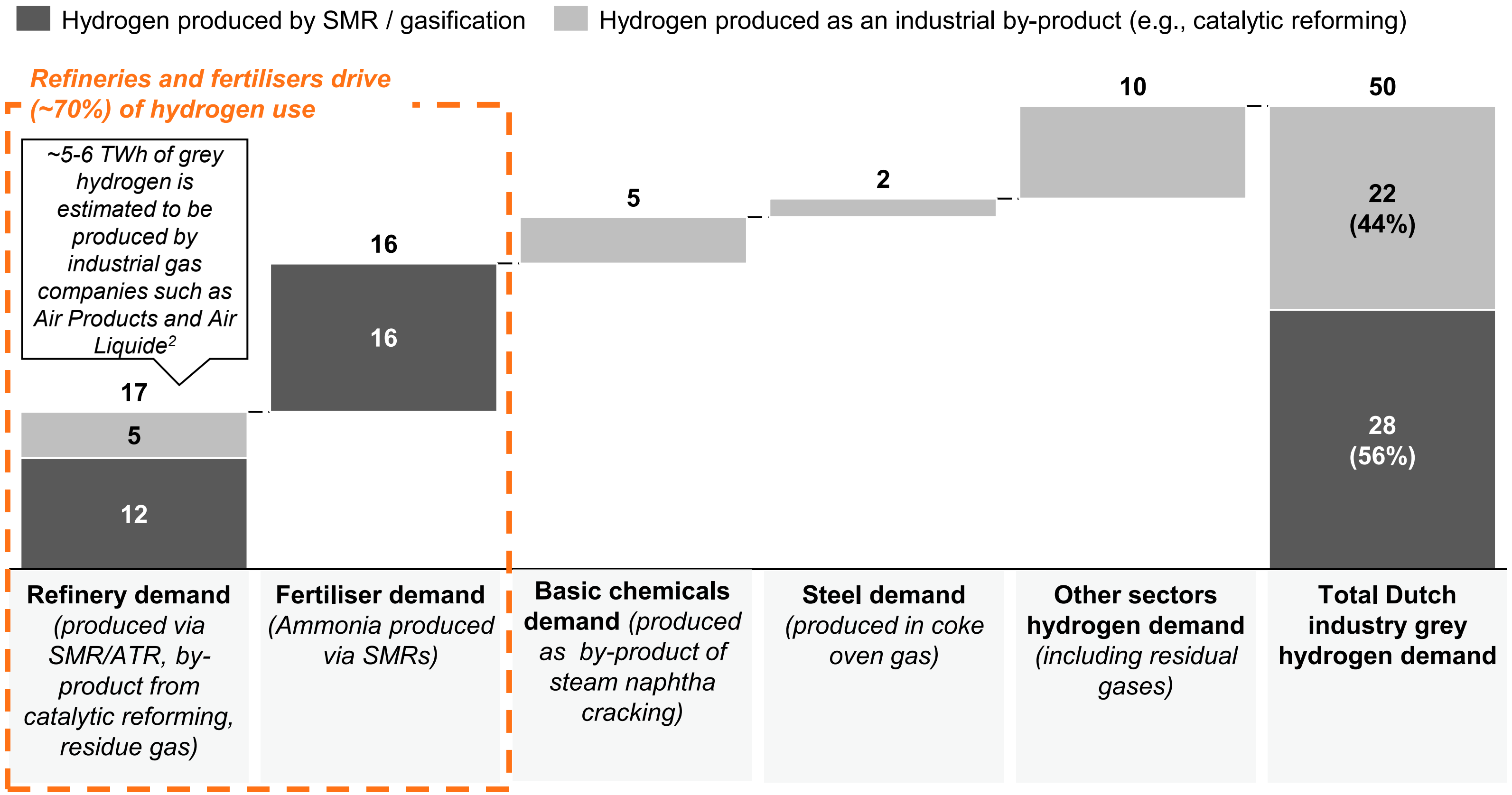
1) Industry is defined by companies under NEa excluding data centres, energy provider, greenhouse horticulture, hospital/ university and airport/ aviation; 2) Most waste processing plants have only been included in NEa emissions numbers since 2024, so we use it as the baseline (rather than the 5-year average); 3) Other industry contains, amongst others, plastics, other chemicals, non-ferrous metal, machine industry, transport equipment and printing; 4) Emissions reflect total GHG emissions across all energy carriers; however, only energy usage of natural gas, electricity, and heat consumption are shown, as these are the focus of the study | Sources: CBS, NEa

Currently, the Dutch industry demands ~50 TWh/yr grey hydrogen; refineries and fertilisers account for ~70% of the demand, primarily supplied via SMRs

Grey H_2 demand from large ETS industry (incl. waste)

Grey hydrogen demand in The Netherlands by sector and production route [1,2]

(In TWh/yr, 5-year average 2020-2024)



Key insights

- **Current hydrogen production (~50 TWh/yr) is dominated by SMR and gasification,** accounting for 28 TWh/yr (56%) of current total grey H_2 use; the remainder (44%) is produced as products of industrial processes the rest are by-products
  - **Refineries (~17 TWh/yr – ~34%): largest hydrogen-consuming** sector, with production primarily via SMR and gasification (including ~6 TWh from industrial gas producers) as well as by-products from catalytic reforming
  - **Fertiliser** (**~16 TWh/yr – ~32%): second largest consumer,** relying exclusively on SMR for ammonia synthesis
  - **All other sectors (~17 TWh/yr – ~34%):** Hydrogen primarily supplied as by-products of existing processes, including basic chemicals (steam cracking), steel (coke oven gas, mainly used as fuel), and a range of smaller industrial uses

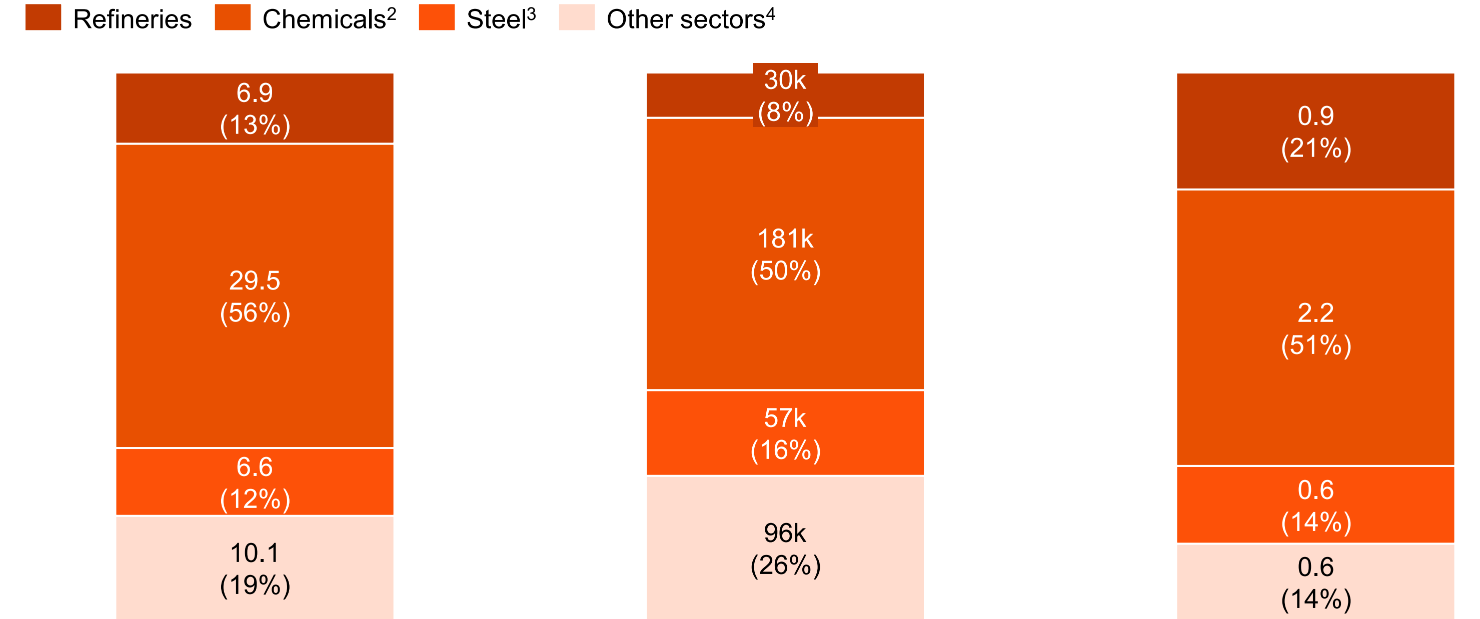
1) Sector split from the Statistics Netherlands / TNO hydrogen balance: refineries ~65 PJ, ammonia ~58 PJ, and other uses (incl. basic chemicals and smaller industry) ~17 PJ; steel hydrogen mainly appears in coke-oven gas (~5PJ); 2) No explicit percentage split between on-site and off-site hydrogen is provided. Off-site hydrogen, supplied by industrial gas players such as Air Products and Air Liquide, is therefore estimated by deriving hydrogen volumes using hydrogen-to-CO_2 production ratio for a typical SMR production

Sources: TNO, CBS

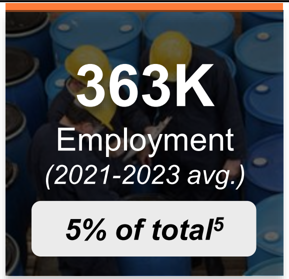
The industry accounts for ca. 12% of Dutch GDP, with refineries, chemicals, steel, ceramics, glass, and paper generating ca. €53 bn per year (ca. 5% of GDP)

Socio-economic impact – contribution to economy

Socio-economic impact of Dutch industry in GVA, jobs and taxes[1]
(based on 2021-2023 average)



€ 53.1 B
GVA
(2021-2023 avg.)
5% of GDP



363K
Employment
(2021-2023 avg.)
5% of total[5]

€ 4.3B
Taxes
(2021-2023 avg.)

Key insights

- The total Dutch industry contributed **ca. 12%** of the Netherlands' GDP between 2021-2023. The contribution from refineries, chemicals, steel, ceramics, glass & paper sectors was ca. **5% of Dutch GDP, employed 5% of total domestic labour force** (excl. jobs from public administration)
- **The combined chemical industry** (including basic chemicals, fertilisers, industrial gases) contributed €29.5 B to the Dutch GDP (2021-2023). The **Steel** sector had a large **economic impact**, driven by one firm in NL (€6.6 B contribution to the Dutch GDP)
- Sectoral **tax contributions** are **broadly proportional** to the GVA of each sector

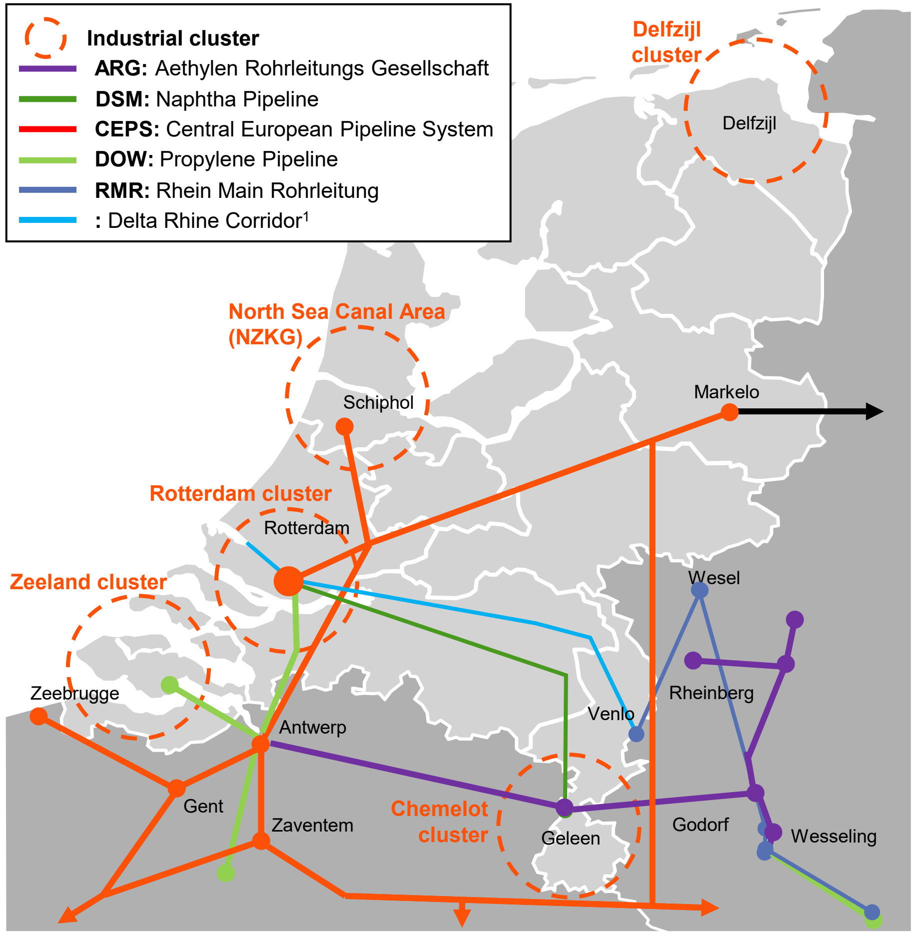
1) The numbers shown are a sum of direct, indirect and induced effects in terms of GVA, jobs added and taxes paid; 2) Includes basic chemicals, fertilisers & industrial gases; 3) Includes both ferrous- and non-ferrous metals; 4) Includes ceramics, glass and paper; 5) Excluding public administration

Sources: De Sociaaleconomische Impact van 6 Sectoren binnen de Basisindustrie (Strategy&, 2021), CBS

Dutch industry has interconnected clusters, where shared infrastructure and energy flows create strong cross-sector dependencies and system-level efficiencies

Industrial clusters & interdependencies

Regional connectedness



Interconnectedness

Industrial clusters

The Dutch industry has **interconnected clusters through pipelines** and **shared infrastructure**, with material and energy flows creating strong cross-sector interdependencies and system-level efficiencies. **Interconnectedness across sectors** is evident as companies rely on each other's products for feedstock/ inputs and infrastructure - **two prominent examples** include:

Chemelot cluster	Industrial hub consisting of **>60 production facilities** in the chemical sector, where refinery-derived feedstocks are transformed into **chemical intermediates** and **end-products**
Rotterdam Cluster	Regional **industrial cluster** centred on **chemical products** (such as chlorine and chlorinated products), connecting **refineries with chemical manufacturers** with downstream users within the **Rotterdam port region**

Interdependencies *(between clusters)*

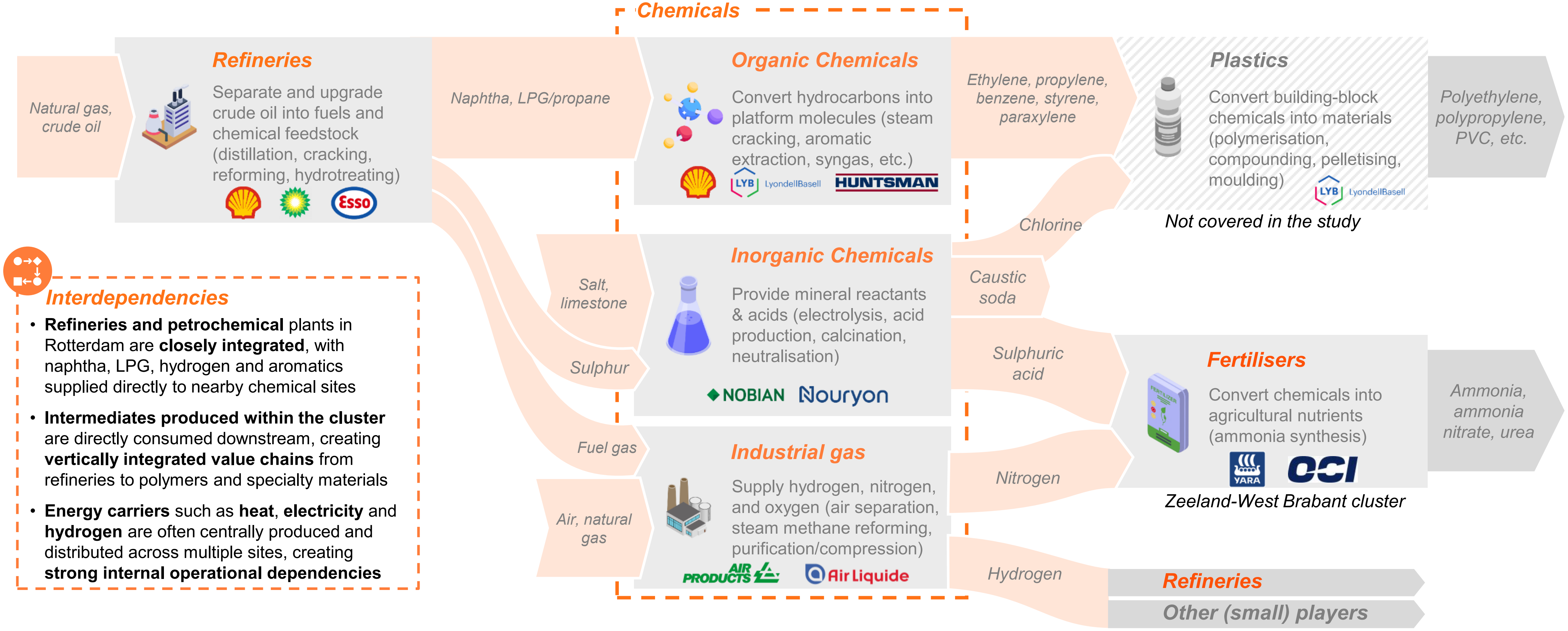
- Extensive pipeline networks connect **refineries**, **steam crackers** and **chemical plants**, **enabling** the **transport** of crude oil, naphtha, LPG, hydrogen, fuel gases and CO_2; shared port, storage and tank infrastructure supports flexible, high-volume exchanges
- **Rotterdam** functions as a major Dutch and Northwest European (NWE) hub, **supplying intermediates** such as **naphtha**, **aromatics** and **polymers** to other **chemical** and **plastics clusters in NWE**, with strong pipeline connections to **Belgium** and **Germany** for crude oil, products, hydrogen and CO_2
- **Chemelot** depends on **refineries and petrochemical** hubs, incl. Rotterdam and Antwerp, for key feedstocks delivered via **pipelines and logistics networks**, while supplying **intermediates and polymers** to manufacturers across the Netherlands, Europe, and the Chemelot cluster

1) Not yet operational. Sources: Sociaaleconomische Impact van 6 Sectoren binnen de Basisindustrie (Strategy&, 2021)

For example, Rotterdam cluster shows strong interdependencies between refineries and chemical industry, characterised by multiple product flows between them

Deep dive: Interdependencies within the Rotterdam cluster

ILLUSTRATIVE



Chemicals

Natural gas, crude oil

Refineries

Separate and upgrade crude oil into fuels and chemical feedstock (distillation, cracking, reforming, hydrotreating)

Naphtha, LPG/propane

Organic Chemicals

Convert hydrocarbons into platform molecules (steam cracking, aromatic extraction, syngas, etc.)

Ethylene, propylene, benzene, styrene, paraxylene

Plastics

Convert building-block chemicals into materials (polymerisation, compounding, pelletising, moulding)

Polyethylene, polypropylene, PVC, etc.

Not covered in the study

Chlorine

Salt, limestone

Sulphur

Inorganic Chemicals

Provide mineral reactants & acids (electrolysis, acid production, calcination, neutralisation)

Caustic soda

Sulphuric acid

Fertilisers

Convert chemicals into agricultural nutrients (ammonia synthesis)

Ammonia, ammonia nitrate, urea

Zeeland-West Brabant cluster

Fuel gas

Air, natural gas

Industrial gas

Supply hydrogen, nitrogen, and oxygen (air separation, steam methane reforming, purification/compression)

Nitrogen

Hydrogen

Refineries

Other (small) players

Interdependencies

- **Refineries and petrochemical** plants in Rotterdam are **closely integrated**, with naphtha, LPG, hydrogen and aromatics supplied directly to nearby chemical sites
- **Intermediates produced within the cluster** are directly consumed downstream, creating **vertically integrated value chains** from refineries to polymers and specialty materials
- **Energy carriers** such as **heat**, **electricity** and **hydrogen** are often centrally produced and distributed across multiple sites, creating **strong internal operational dependencies**

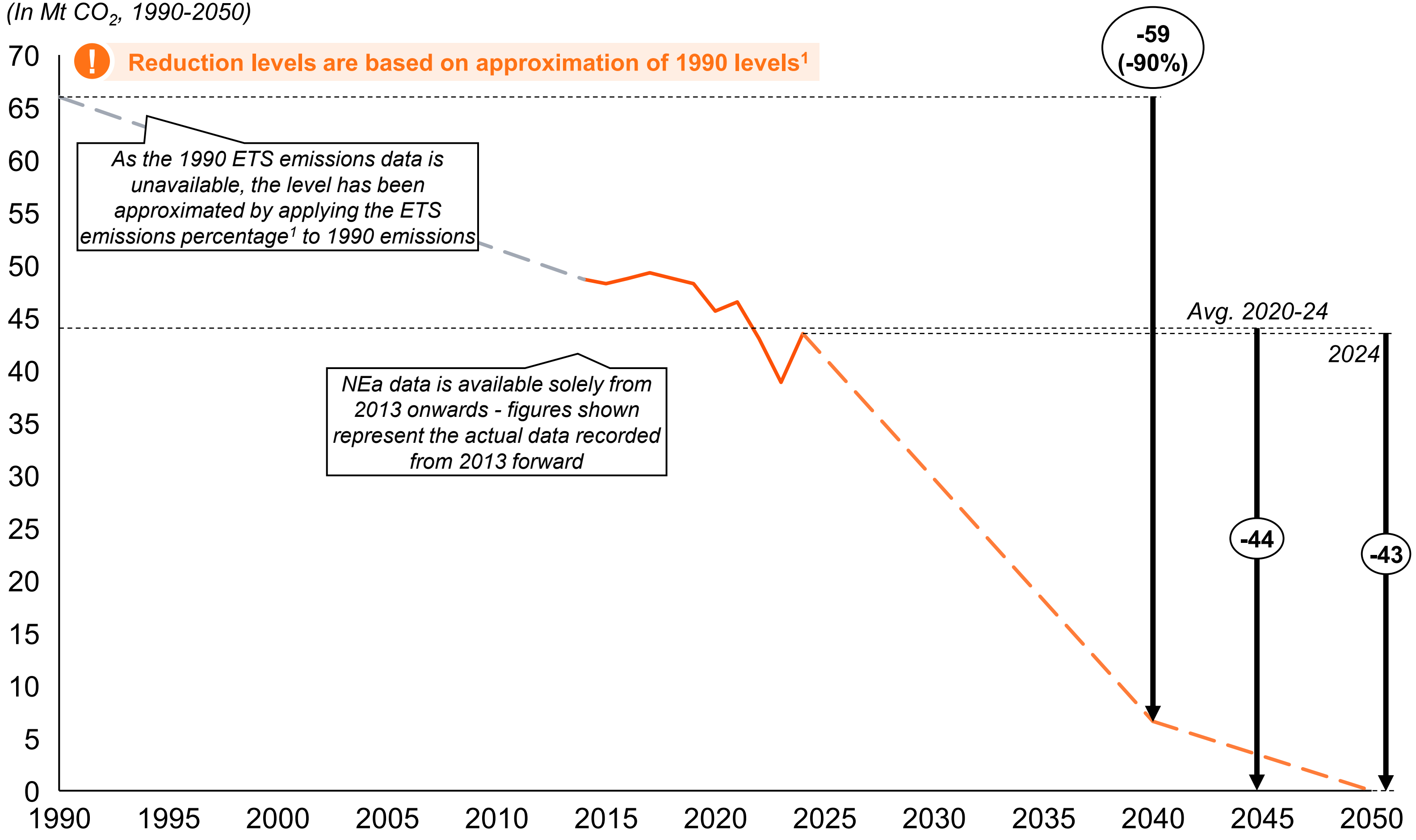
Sources: MIDDEN, Sociaaleconomische Impact van 6 Sectoren binnen de Basisindustrie (Strategy&, 2021)

In the lead-up to achieving net zero by 2050, the large EU ETS industry, incl. waste mgmt., will need to reduce emissions by ca. 43 Mt CO2/ yr compared to 2024 levels

Dutch industry ambition

Total Dutch ETS industry and waste emissions

(In Mt CO_2, 1990-2050)



! **Reduction levels are based on approximation of 1990 levels[1]**

As the 1990 ETS emissions data is unavailable, the level has been approximated by applying the ETS emissions percentage[1] to 1990 emissions

NEa data is available solely from 2013 onwards - figures shown represent the actual data recorded from 2013 forward

Key insights

- The Dutch industry **does not face a single legally binding, economy-wide 2040 decarbonisation target** under the EU Climate Law or the Dutch Klimaatwet; rather, it is steered through binding EU- and national instruments aligned with the **legally binding objective of climate neutrality (net-zero GHG) by 2050**. If one illustrates a scenario in which an economy-wide reduction of ~90% by 2040 were applied proportionally to industry, this would imply an indicative reduction of ~59 $MtCO_2$/yr by 2040 relative to 1990, and **a trajectory to net-zero by 2050 (~43 Mt CO_2/yr reduction versus 2024 levels)**
- While climate neutrality is **targeted for 2050**, **2040** is also a **key delivery horizon** for **industrial decarbonisation**, with an EU-wide ambition of driving 90% emission reduction by this year
- Achieving the 2050 target **will require a fundamental transformation**, moving beyond efficiency gains to widespread **implementation of abatement technologies** such as carbon capture and storage (CCS), fuel substitution and electrification
- Note: Post-2020, **industrial activity declined** sharply due to **COVID-19**, causing a major drop in production, trade and energy demand, **translating into lower emissions**, industrial output, and port throughput

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1) Between 2020 and 2024, ETS emissions in scope accounted for ca. 76% of total emissions; this percentage is used as an estimate for ETS emissions in scope in 1990, based on the reported total of ca. 87 Mt industry emissions in 1990

Sources: Emissieregistratie, NEa; Port of Rotterdam

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GHG abatement for Dutch industry towards 2050

Abatement methods vary across sectors: CCS is the best technology for the six high emission sectors due to high-temp. processes & higher CO_2 conc. in flue gases

Sector characteristics and possible abatement options

■ High emission sectors

□ Cluster 6 industry

Sector	Key process characteristics: Process temperature	Key process characteristics: CO_2 concentration	Abatement options: CCS – Pre- comb	CCS – Post-comb	(Partial) fuel substitution – Hydrogen	(Partial) fuel substitution – Bio-methane	Electrification – Low-mid temp.[1]	Electrification – High temp.[2]	Green ammonia (import)	Other
■ **Refineries**	**High** (500-1000 °C) in furnaces, SMR and FCC	• ~5-10% in flue gas • ~20-25% in process gas	🟩 ✓	🟩 ✓	🟩 ✓	🟩 ✓	🟩 ✓	🟩 ✓		
■ **Basic chemicals**	**Medium to high** (150-850 °C) in boilers and cracking furnaces	• ~4-15% in flue gas	🟩 ✓	🟩 ✓	🟨 ✓	🟩 ✓	🟨 ✓	🟩 ✓		
■ **Fertilisers**	**High** (500-1000 °C) in SMR	• ~5-10% in flue gas • ~55-65% in syngas	🟩 ✓	🟩 ✓	🟩 ✓	🟩 ✓	✓	🟩 ✓	🟩 ✓	
■ **Steel**	**Very high** (1100-1700 °C) in blast furn., basic oxygen furn.	• ~20-25% in BFG • ~10-20% in BOG	🟩 ✓	🟩 ✓	🟩 ✓	🟩 ✓				🟩 ✓[3]
■ **Waste**	**Low-High** (850-1100, 25-900 °C) in waste incineration and thermal soil remediation	• ~6-12% in flue gas		🟩 ✓	🟩 ✓	🟩 ✓				🟩 ✓[4]
■ **Industrial gases**	**High** (500-1150 °C) in SMR and ATR	• ~4-15% in flue gas	🟩 ✓	🟩 ✓		🟩 ✓				
□ **Food**	**Low** (5-100 °C) In steam/natural gas boilers and CHP units	• ~4-15% in flue gas		🟩 ✓	🟩 ✓	🟩 ✓	🟨 ✓[5]			
□ **Paper**	**Low** (5-100 °C) in natural gas boilers and CHP units	• ~4-15% in flue gas		🟩 ✓	🟩 ✓	🟩 ✓	🟨 ✓[5]			
□ **Ceramics**	**Both low and high** (70-90 °C, 1000-1300°C) in drying and firing of material, respectively	• ~8-10% in flue gas		🟩 ✓	🟨 ✓	🟩 ✓	🟩 ✓	🟩 ✓		
□ **Glass**	**Both low and very high** (1450-1600°C, 25-580 °C) in melting, refining and annealing	• ~8-10% in flue gas		🟩 ✓	🟨 ✓	🟩 ✓		🟩 ✓		

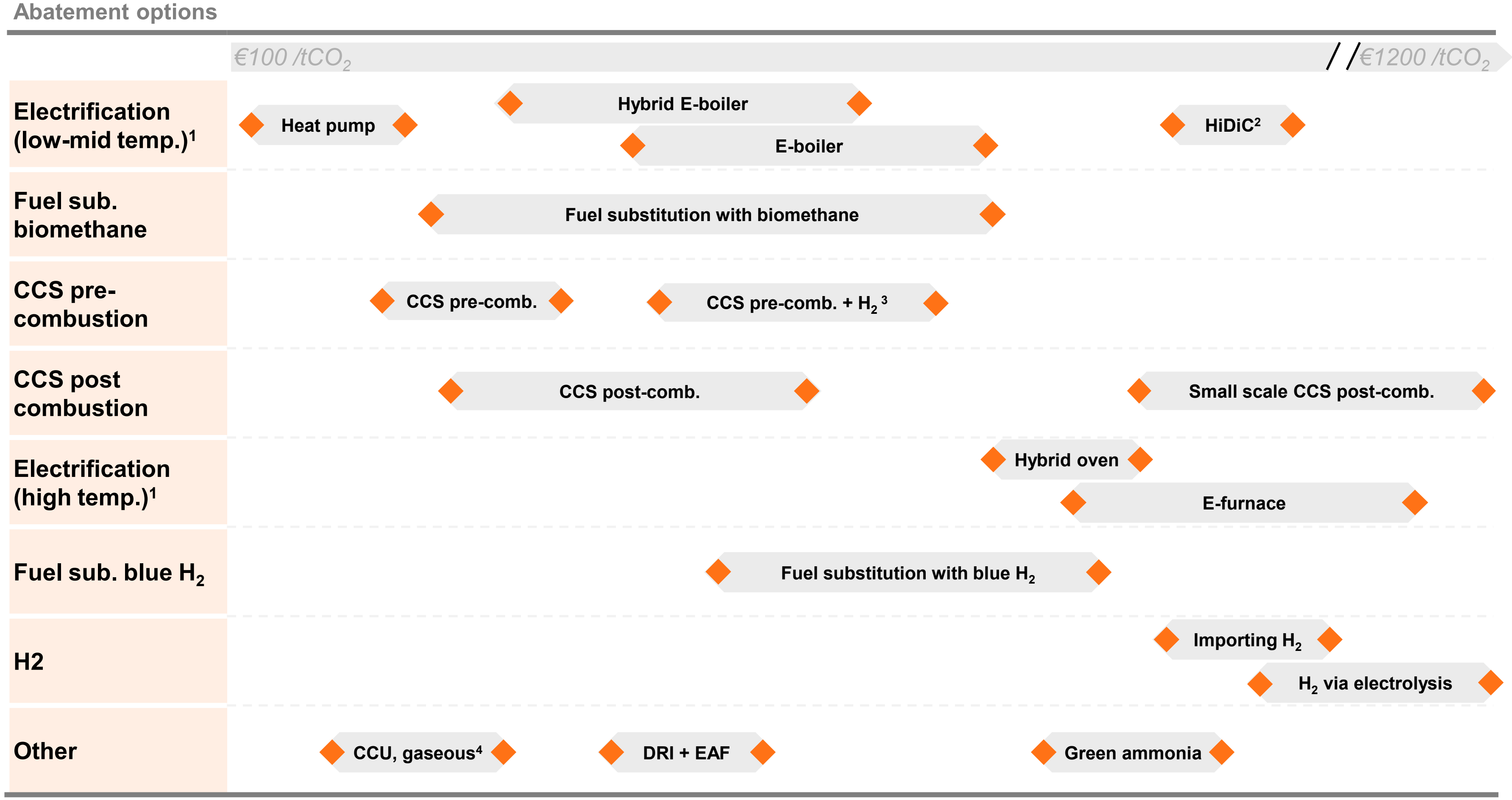
The choice of replacing ammonia production with green ammonia import will be driven by several factors – *see deep-dive on slide 31*

1) E.g., heat pumps, e-boilers; 2) E.g., (hybrid) e-furnaces; 3) DRI+EAF on natural gas (high TRL 9), DRI+EAF on hydrogen (imported or on-site production, low TLR of 6; 4) CCU; 5) Heat pumps in food and paper sectors currently have a medium TRL (5-7), expected to increase to 9 before 2040;
Sources: MIDDEN, PBL, CBS, Speelveldtoets 2025, Agora, FCW, IEAGHG

Current TRL: 🟩 High TRL (>7) 🟨 Medium TRL (5-7) 🟧 Low TRL (<5)
✓ Technical abatement option

Across industries, CCS, biomethane, and small-scale hybrid electrification are generally the cheapest abatement options to reduce emissions

Unit cost of abatement options



Key considerations

- **Abatement costs shown reflect ranges** driven by differences **in CO_2 concentration**, **scale**, operating **hours**, and **sector-specific** differences
- Both **pre- and post-combustion CCS** consistently appear among the lowest-cost options for large emission sources, particularly where high-purity CO_2 streams are available
- **Low- and mid-temperature electrification** (e.g., heat pumps, hybrid e-boilers) on existing assets deliver cost-efficient abatement but **may not enable full decarbonisation** on their own. Combined with fuel substitution, these technologies offer 100% abatement pathways
- **Small-scale CCS is a high-cost abatement option,** driven by substantial upfront CAPEX and high transportation costs, resulting in **low economic attractiveness**
- While biomethane shows **competitive abatement costs**, large-scale deployment across sectors is **limited by sustainable feedstock availability** and **competing demand**

1) Low-temperature electrification consist of e.g. heat pumps and e-boilers instead of e.g. e-furnaces; 2) Heat Integration Distillation in Columns; 3) Cost of transforming fuel gases or natural gas into blue hydrogen (using ATR + CCS) and using this as a fuel. Scale used from SDE++ model (29 kt/y H_2); economies of scale may reduce cost, see next slide 4) It is assumed that the captured carbon is permanently bound in the chosen use case, required for EU ETS. Sources: MIDDEN, PBL, CBS, KEV 2025; NEa; CE Delft; Rijksoverheid; Belastingdienst

Most emission reductions are expected to come from CCS, with biomethane as the next most important option; electrification contributes less to overall abatement

Techno-economic abatement potential across sectors

🟧 High emission sectors

▨ Cluster 6 industry

Sector	Total emission abated *(Mt CO_2)*	Abatement options: CCS		Fuel substitution			Electrification		Other
		Pre- comb	Post-comb	Hybrid[1]	Blue H_2[2]	Bio-methane	Low-mid temp.[3]	High temp.[4]	
Refineries	**10.1** *(100%)*	-	**8%** *(FCC unit)*	***10%*** *(CHP)*	**70%** *(Furnace, H_2 production)*	**12%** *(Furnace, H_2 production)*	-	-	-
Basic chemicals	**7.1** *(94%)*	-	**52%** *(Steam cracking)*	**42%** *(CHP)*	-	-	-	-	-
Fertilisers[5]	**4.8** *(95%)*	-	-	-	**81%** *(SMR)*	**14%** *(SMR)*	-	-	-
Steel	**11.3** *(100%)*	-	**7%** *(Coke, Sinter, Pellet, BF & BOF)*	-	**9%** *(Coke, Sinter, Pellet, BF & BOF)*	**7%** *(Coke, Sinter, Pellet, BF & BOF, downstream steelmaking)*	-	-	**76%** *DRI+EAF* *(Coke, Sinter, Pellet, BF & BOF)*
Waste[6]	**1.9** *(91%)*	-	**90%** *(Incineration, soil remediation)*	-	-	**1%** *(Soil remediation)*	-	-	-
Industrial gases	**1.8** *(100%)*	-	-	-	**86%** *(ATR, SMR)*	**14%** *(SMR)*	-	-	-
Food	**1.6** *(100%)*	-	-	**77%** *(Natural gas boiler, CHP, steam boiler)*	-	-	**23%** *(Natural gas boiler, CHP, steam boiler)*	-	-
Paper	**0.7** *(100%)*	-	-	**88%** *(Natural gas boiler, CHP)*	-	-	**12%** *(Natural gas boiler, CHP)*	-	-
Ceramics	**0.4** *(91%)*	-	**23%** *(Preparation, shaping, drying, firing)*	-	-	**44%** *(Preparation, shaping, drying, firing)*	**23%** *(Preparation, shaping, drying)*	-	-
Glass	**0.4** *(78%)*	-	**9%** *(Melting & fining)*	-	-	**69%** *(Annealing, refining & conditioning, melting)*	-	-	-

Key considerations

- **Fuel substation with biomethane** excluded for top-emitting sectors[7]; however, it remains a viable option for **smaller required volumes**, such as in smaller sectors (cluster 6)
- However, **fuel substitution with biomethane** can serve to **close residual emission gaps** when technologies like CCS are insufficient, particularly in top emitting sectors
- Given the **higher capture rates of post-combustion CCS** compared to pre-combustion, post-combustion CCS is **preferred** to address emissions and due to **smaller required volumes of biomethane** to abate the remaining emissions
- **Low- to medium-temperature electrification methods**, including **hybrid electric boilers** and **heat pump systems**, provide contributions in certain sectors, though widespread electrification is **limited by technical challenges**; combining **electrification** with **fuel substitution** presents **full abatement potential**

Detailed overview of options and selection of techno-economic pathways detailed in the appendix

1) Hybrid use of e-boiler (43%), blue hydrogen (29%) or biomethane (28%) depending on lowest price; 2) Blue hydrogen covers pre-combustion CCS on fuel gases & post-combustion CCS on SMRs on hydrogen processes; 3) E.g., heat pumps, e-boilers; 4) E.g., e-furnaces; 5) Abatement is based on 95% of sector emissions as last 5% is realised with process efficiencies; 6) Full abatement of sector emissions is not possible due to capture rates of post CCS and biomethane fuel substitution not being possible for the sector; 7) See deep-dive on biomethane. Sources: MIDDEN, PBL, CBS, KEV 2025; NEa

Infrastructure availability/supply capacity of electricity, CCS, biomethane and H_2 towards 2040 is not expected to be constraint for the cost-efficient options

Assessment of infrastructure constraints – summary

Category	Expected demand	Infrastructure/supply capacity status	Potential impact on abatement curve
Electricity	• Electricity **demand increases** across multiple abatement options (e.g., pre- and post-combustion CCS, electrification, and hybrid solution) • Electrification-driven abatement translates into an **extra grid requirement of ~2 GW**	• Currently, all industrial clusters **face grid congestion** and **extensive** connection **waiting lists** • Grid congestions are expected to be **resolved by 2036 in most regions as per the published expectation by grid operators** (e.g., Moerdijk cluster requires large additional capacity and is projected to be relieved by 2036)	• Grid limitations are **not expected to cap abatement deployment** by 2040, as announced network reinforcements are assumed to **largely resolve congestion before 2040**
CCS	• CCS is the most **cost-effective abatement option** for top-emitting sectors • Total CCS volumes are expected to be **~21 Mt CO_2/yr by 2040** requiring significant transport capacity	• CO_2 transport and storage infrastructure is **assumed to be available** at **large scale by 2040 (60.5 Mt CO_2/yr)** due to all the announced projects and based on the intention of Gasunie to build Aramis capacity towards the max. volumes of 22 Mt CO2/yr as soon as FID is taken	• CCS is **not expected to constrain** the **abatement curve**; key risk of **execution delays** remains, with several projects still **awaiting realisation**
Biomethane	• Biomethane can be a **primary abatement route** for Cluster 6 sectors, while playing a **supplementary role** for top emitters • Total biomethane demand from industry is assumed to reach **~3.0 bcm per year by 2040** • **Demand from other sectors** could reach **2.0 bcm** (driven by REDIII target)	• Biomethane is currently **predominantly consumed** by the **transport** and **built environment sectors** • Current supply forecasts at a European level[1] indicate that **101 bcm of biomethane could potentially be produced annually by 2040 in EU-27** countries	• Biomethane use is constrained by **supply** and **price uncertainty**, which are internalised through **pricing assumptions** in the abatement curve rather than **explicit capacity caps** • Following principle is used: Biomethane is **excluded for large-scale substitution in top-emitting sectors**; largely used to close residual emissions to reach full abatement
(Blue & Green) Hydrogen	• Hydrogen (incl. blue and green) is a **major pillar** of the techno-economic abatement curve, **contributing largely** to **abatement across key sectors** (SMR units in refineries, fertilisers, and industrial gases or in hybrid solutions) • Total hydrogen demand is assumed to reach **~89 TWh per year by 2040**	• Hydrogen infrastructure is expected to **develop broadly in line with long-term demand expectations** • **Last-mile connections to the hydrogen backbone can be expensive (€1m per km)**, making it more expensive for smaller cluster 6 firms to implement hydrogen-based abatement	• Infrastructure **availability is not expected to be a constraint** on the abatement curve • **Last-mile delivery** and on-site integration are **considered while comparing cost-efficiency** of options for cluster 6 companies

[1] Theoretically it is possible to either physically or administratively procure biomethane if there is a European-level scheme post-2030 (which is the current intention from EU)

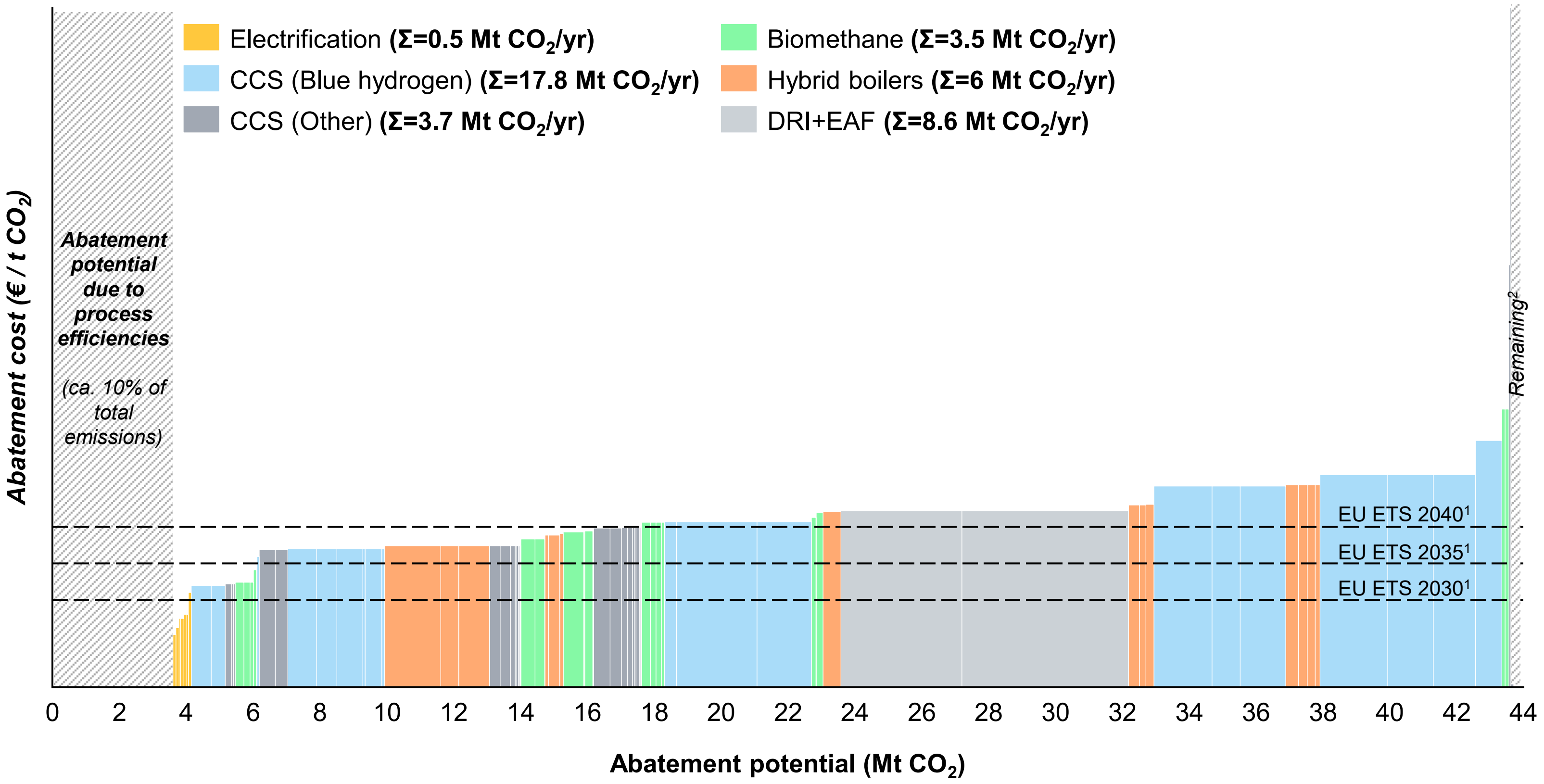
Sources: Netbeheer Nederland; KEV, II3050, NPE, European Biogas Association, Ministry of Economic Affairs and Climate; Forest Research; Waga Energy;

Assuming current industrial output, the most techno-economically efficient GHG red. pathway excl. policies will be dominated by CCS, biomethane & electrification

Most techno-economically efficient: Abatement cost curve

GHG abatement cost curve for Dutch Industry
(In €/t CO_2 & Mt CO_2/year, *2040P)*

! Assumes industry will stay at current levels



Underlying assumptions

- **Blue hydrogen** covers **pre-combustion CCS on fuel gases & post-combustion CCS** on **SMRs** in **hydrogen processes**
- **Key assumptions** underlying the most techno-economically efficient abatement cost curve:
  - **Industrial activity:** Current industrial base is assumed to remain broadly stable to 2040
  - **Inclusion of policy:** Policies are not reflected in the abatement curve; incorporating subsidies, mandates, or penalties could materially shift the curve
  - **Infrastructure constraints:** Based on public sources, we assess that there will be no infrastructure constraints by 2040; reality could be different
  - **Biomethane:** Excluded for large-scale substitution in top-emitting sectors[1], primarily used to close residual emissions; Applied to enable full fuel substitution or close residual emissions to reach full abatement
  - **CHPs:** Decarbonisation assumed via a hybrid solution[2] rather than CCS due to the technical challenges of capturing CO_2 from dilute CHP flue gases
  - **Steel sector:** DRI + EAF (natural gas) with CCS and biomethane substitution is assumed to be the most cost-effective near-term abatement option. Hydrogen-based DRI + EAF (although announced currently) is less cost-efficient, hence not included here
  - **Small scale post-comb CCS**: Post-comb. CCS at small scale within cluster 6 is constrained by high CAPEX

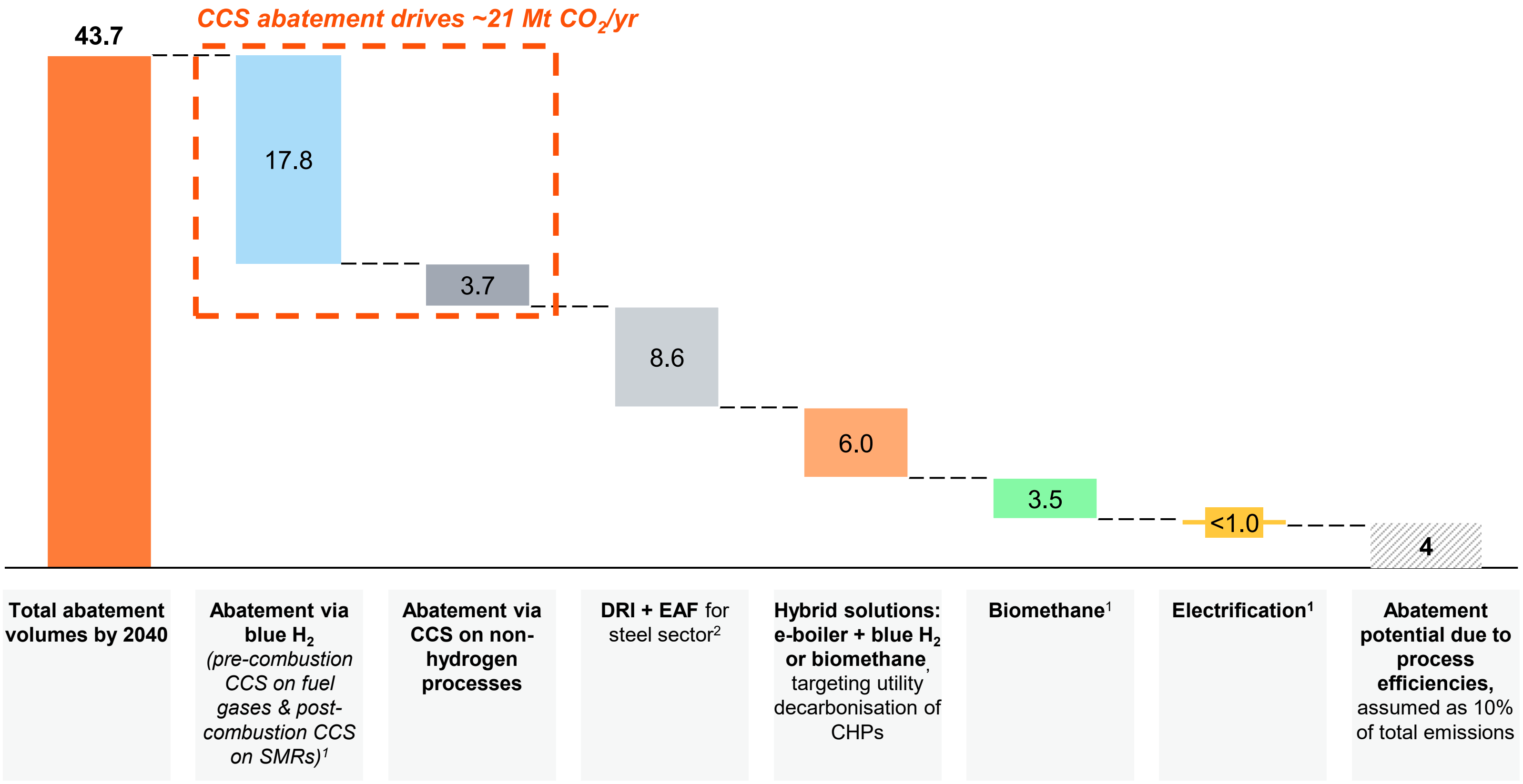
1) See methodology slide on biomethane (i.e., transport and built env. due to penalties in the range of 300-400 €/t CO2); 2) Electric boilers during low price hours combined with biomethane or blue H_2 fired CHP;
3) Remaining ca. 1 Mt CO_2 per year is excluded because emissions in some sectors are highly fragmented, meaning these sectors are not fully abated within the scope of this study
Sources: KEV, CBS, NEa, MIDDEN; PBL; CE Delft, EU ETS Impact assessment report (EC, 2024)

Ca. 21 Mt CO_2/yr is expected to be abated via CCS followed by DRI+EAF (8.6 Mt CO_2/yr) & hybrid E-boilers (6.0 Mt CO_2/yr)

Most techno-economically efficient: Abated CO_2 per option by 2040

CO_2 abatement volumes for Dutch industry
(In Mt CO_2/year, *2040P)*

! Assumes industry will stay at current levels



Key insights

- CCS is the **dominant driver of decarbonisation towards 2040**, followed by **electrification and biomethane:**
  - **Blue hydrogen** drives **the most abatement towards 2040**, accounting for **ca. 18 Mt CO_2/yr emission** reduction; This is mainly driven by the **largest emitting sectors** (i.e., processing fuel gasses from refinery and basic chemicals furnaces, as well as processing natural gas in SMRs serving refineries, industrial gasses, and fertilisers sectors)
  - **(Post-combustion) CCS on non-hydrogen processes contributes ~4 Mt CO_2/yr across sectors**, including on FCCs, waste incinerators, and DRI production for steel
  - **Utility decarbonisation contributes ~6 Mt CO_2/yr in the form of hybrid e-boilers,** driven by CHP and gas boiler replacements across sectors. This option would use electricity at low-price hours (43%) or substitute fossil fuels by blue hydrogen (29%) or biomethane (28%)
  - **Biomethane** emerges as a **complementary abatement option towards 2040** (ca. ~4 Mt CO_2/yr emission reduction), primarily used to close residual emissions for full abatement in the largest sectors and as a pragmatic solution for cluster 6 sectors
  - **Steel contributes ~9 Mt CO_2/yr through DRI + EAF**, reflecting a structural transition in steelmaking rather than incremental abatement
  - **Operational improvements deliver ~4 Mt CO_2/yr** through ~5-10% process efficiency gains across sectors

1) Excluding hybrid boilers; 2) Does not include the CCS inherent to DRI + EAF; Sources: KEV, CBS, NEa, MIDDEN; PBL

RFNBO obligations from RED III could mandate green H_2 usage in the order of 4.4 TWh in 2030, rising to 5.7 TWh in 2035 (uncertainty towards 2040)

Inclusion of relevant policies in the abatement curve

Approach

- **Policy-adjusted abatement curves** can diverge from **the most techno-economic cost-efficient curve**, as regulations and norms may steer technology deployment toward options that are not cost-optimal
- **Understanding the full policy impact** requires a **comprehensive view** of all relevant instruments –subsidies, targets/ambitions, and norms/obligations – **not only within the industry** but also **upstream** e.g., electricity and hydrogen production
- Due to the **difficulty of modelling the likelihood of receiving subsidies** for each abatement option, and the **non-binding nature of targets/ambitions** (which could be subject to change), we focus our analysis on **norms & obligations** to develop the policy-driven abatement curve
- In terms of **obligations** and **norms**, only **RED III** is found to have relevant norms that will directly impact the Dutch industry i.e., **RFNBO obligation,** and indirectly the bio-methane blending obligation for non-ETS sectors (as this will impact the price of biomethane in the market)
- The analysis assumes full cost pass-through of the RFNBO obligation for non-ammonia-related hydrogen consumption (around 40% of total volumes) within the fertiliser sector. However, competitive pressure from non-EU producers not subject to the RFNBO requirement is highly likely to limit effective pass-through in practice, as highlighted in the Speelveldtoets 2024. In this case, the extra volumes from the fertiliser sector will not be realised

Deep-dive on the RFNBO obligation (from RED III)

RED III – RFNBO norm

RED III introduces **renewable fuels of non-biological origin** (RFNBO) as a key decarbonisation lever, with **binding targets for industrial hydrogen use** and an **emissions-based framework for transport fuels:**

- RED III (Art. 22a) introduces **RFNBO targets** for **industrial hydrogen use**, requiring **at least 42% compliance by 2030, rising to 60% by 2035.** Effective obligations will depend on **national implementation design**, including scope definitions and exemptions. The **Dutch draft proposal** indicates a **gradual compliance ramp-up**, with effective company-level requirements **increasing from ~4% in 2030** to **~9.9% in 2035.** Given Dutch proposal is currently still a draft**, current RFNBO EU targets** are taken as basis for projected H_2 volumes in 2030, 2035, and 2040
- RED III (Art. 25) introduces an **emissions-based RFNBO sub-target for transport**, requiring **at least 1% of energy supplied to the transport sector** to be RFNBO-compliant by 2030. For the Netherlands, this corresponds to ~1.5 TWh, allocated across road transport, inland shipping, maritime, and aviation, with aviation volumes aligned with ReFuelEU Aviation.[2] As compliance is measured via GHG reduction rather than hydrogen usage volumes, **EU-level targets** are used as **the basis for indicative RFNBO volumes** rather than binding hydrogen demand

Sector[1]		Current H_2 volumes	Exempted H_2 volumes	In-scope H_2 volumes	Required 2030 H_2 volumes	Required 2035-2040 H_2 volumes	*Scope rationale*
Fertilisers[2]		16 TWh	10 TWh	6 TWh	**2.5 TWh**	**3.6 TWh**	*Largest H_2 industrial user; 60% exempted nationally with remaining volumes in scope*
Refineries[1]	**RFNBO industry**	1 TWh	n/a	1 TWh	**0.4 TWh**	**0.6 TWh**	*Limited H_2 industrial use, with main H_2 an intermediate for transport fuels*
	RFNBO Transport	17 TWh	n/a	17 TWh	**1.5 TWh[2]**		*H_2 contributes under the emissions-based transport RFNBO framework*
Other industry		2 TWh	- n/a	2 TWh	**n/a**	**n/a**	*RFNBO-relevant, but excluded from analysis due to fragmented sectoral use*

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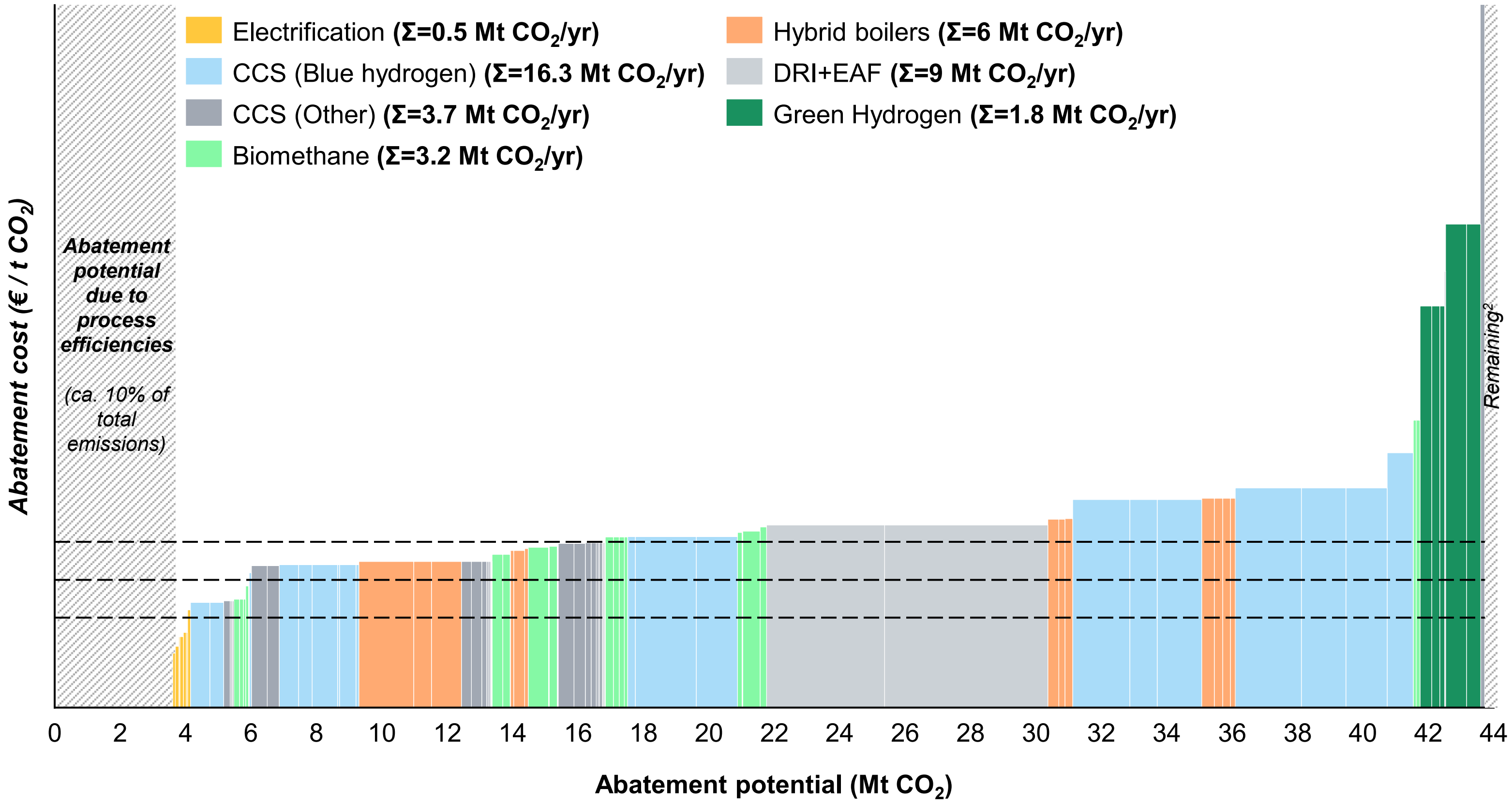
1) Excludes emissions related to outsourced activities such as with industrial gases; 2) based on TNO (2022, https://publications.tno.nl/publication/34640734/IAgClX/TNO-2022-P10989.pdf) with 2030 estimates; value beyond 2030 may be higher, up to a maximum of 17 TWh (full in-scope H_2 volume) Sources: Directive (EU) 2023/2413 (RED III), Article 22a – RFNBO targets in industry; European Commission – Renewable Energy Directive revision; Advies Raad van State – wetsvoorstel jaarverplichting RFNBO's (2025)

RFNBO obligated volumes could cause[4] ca. 0.3 Mt/yr reduction by biomethane and ca. 1.5 Mt/yr reduction by CCS on SMR units to be substituted by direct green H_2 use

RFNBO adjusted: Abatement cost curve

GHG abatement cost curve for Dutch Industry
(In €/t CO_2 & Mt CO_2/year, *2040P)*

! Assumes industry will stay at current levels



Comments

- RFNBO obligations displaces part of **post-combustion CCS and biomethane**, which are replaced by **green hydrogen** (only affected refineries and fertilisers)
- Remainder of the **abatement cost curve** is unchanged, as it is unaffected by RFNBO norms and continues to be driven by **blue hydrogen**, **biomethane fuel substitution**, **post-combustion CCS,** and **hybrid solutions**
- **Key assumptions** underlying the RFNBO adjusted abatement cost curve:
  - **Industrial activity:** Current industrial base is assumed to remain broadly stable to 2040
  - **Policy reflection:** RFNBO (part of REDIII) is considered in the curve
  - **Infrastructure constraints:** No infrastructure constraints are applied to this abatement curve
  - **Biomethane:** Excluded for large-scale substitution in top-emitting sectors[1], primarily used to close residual emissions; Applied to enable full fuel substitution or close residual emissions to reach full abatement
  - **CHPs:** Decarbonisation assumed via a hybrid solution[2] rather than CCS due to the technical challenges of capturing CO_2 from dilute CHP flue gases
  - **Steel sector:** DRI + EAF (natural gas) with CCS and biomethane substitution is assumed to be the most cost-effective near-term abatement option. Hydrogen-based DRI + EAF (although announced currently) is less cost-efficient, hence not included here

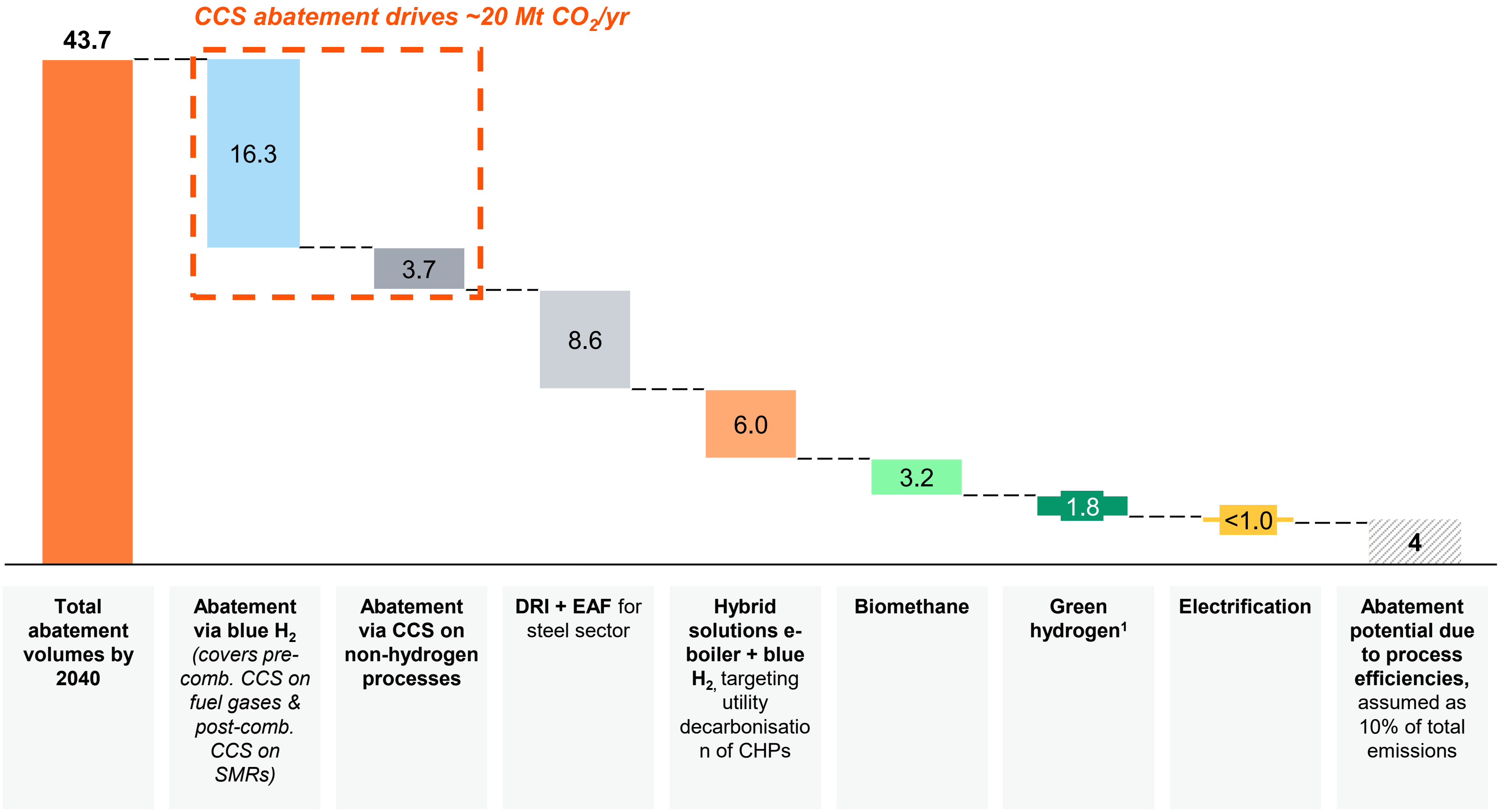
1) Given anticipated price increases as industrial demand enters the mix, i.e., limited supply, overall high level of demand & higher willingness to pay level from other sectors (i.e., transport and built env. due to penalties in the range of 300-400 €/t CO_2); 2) Electric boilers during low price hours combined with biomethane- or blue H_2 fired CHP; 3) Remaining ca. 1 Mt CO_2 per year is excluded because emissions in some sectors are highly fragmented, meaning these sectors are not fully abated within the scope of this study; 4) The analysis assumes full cost pass-through of the RFNBO obligation for non-ammonia-related hydrogen consumption (around 40% of total volumes) within the fertiliser sector. However, competitive pressure from non-EU producers not subject to the RFNBO requirement is highly likely to limit effective pass-through in practice, as highlighted in the Speelveldtoets 2024; Sources: KEV, CBS, NEa, MIDDEN; PBL; CE Delft; REDIII, EU ETS Impact assessment report (EC, 2024)

Resulting abatement from blue H_2 (ca. 16.3 Mt/yr) and biomethane (3.2 Mt/yr) lowers with respect to the policy agnostic abatement

RFNBO adjusted: Abated CO_2 per option by 2040

CO_2 abatement volumes for Dutch industry
(In Mt CO_2/year, *2040P*)

! Assumes industry will stay at current levels



Key insights

- **Several differences emerge** between **the most techno-economically efficient** and **RFNBO-adjusted case,** as other components remain the same:
  - **CCS continues to be the dominant driver of decarbonisation towards 2040 in the RFNBO-adjusted case,** despite reductions in abatement volumes: blue H_2 drives the largest share of abatement with 16.3 Mt CO_2/yr, down 1.5 Mt CO_2/yr from the techno-economic curve
  - **Biomethane still contributes a substantial share of abatement (~3 Mt CO_2/yr).** However, biomethane – used to close residual emissions in largest emitting sectors – is partially replaced by green hydrogen in SMR processes for refineries and fertilisers, resulting in **a reduction of total abatement volumes of 0.3 Mt CO_2/yr** compared to the techno-economic abatement curve
  - **Limited green hydrogen volumes (~2 Mt CO_2/yr)** are added to the **RFNBO-adjusted abatement cost curve,** partially replacing **biomethane** for residual emissions abatement and **post-combustion CCS on SMR processes** in refineries and fertilisers

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[1] The analysis assumes full cost pass-through of the RFNBO obligation for non-ammonia-related hydrogen consumption (around 40% of total volumes) within the fertiliser sector. However, competitive pressure from non-EU producers not subject to the RFNBO requirement is highly likely to limit effective pass-through in practice, as highlighted in the *Speelveldtoets 2024*

Sources: KEV, CBS, NEa, MIDDEN; PBL

A1

Methodology & assumptions

Abatement unit costs reflect the NPV of incremental cost of transitioning from a conventional technology to green alternative, divided by the NPV of CO_2 abated

Abatement cost calculation methodology

Definition Average cost of reducing one ton of CO_2 emissions, calculated as the **additional cost** of an abatement measure **divided by the emissions abated** (€/t CO_2)

$$\textit{Abatement unit costs} = \frac{NPV(\textit{cost of green option} - \textit{costs of grey alternative})}{NPV(CO_2\ \textit{abated})}$$

$$= \frac{NPV(CAPEX) + NPV(OPEX\ \textit{fixed}) + NPV(OPEX\ \textit{variable})}{NPV(CO_2\ \textit{abated})}$$

			Key sources
CAPEX		**Upfront investment** required to build and install abatement options	• MIDDEN • PBL
OPEX	**Fixed**	**Recurring annual costs** which are not depending on production levels (e.g., maintenance, etc.)	• MIDDEN • PBL
	Variable	**Energy costs** and **carbon storage costs** of abatement options, reflecting only the **difference in costs** between the **“green” option** and the **conventional** (“grey”) alternative	• PBL • KEV • EU ETS 1 & 2

Additional assumptions:

- WACC assumed for **NPV calculation** is **7.3% (nominal)** for most technologies, with 6.0% (nominal) only for E-boilers and heat pumps (PBL)
- Abatement costs values in this study are **nominally constant,**[1] expressed in **€ / t CO_2.** Energy prices are presented as **real (inflation of 2% assumed)**
- **Construction time** for all technologies is assumed to be **1 year**
- **Operational time** for a technology to run is **15 years** for all technologies except for the hybrid e-furnace (10 years)
- Energy prices consists of **commodity**, **network costs** and **tax** – *see deep-dive on price assumptions on the next page*
- **Lower heating values** (LHV) are used for energy calculations underpinning abatement unit costs.

Comments

- All **CAPEX**, **fixed OPEX**, and **variable OPEX** assumptions are derived from **publicly available sources** to ensure transparency and consistency across abatement options
- For the **variable OPEX** (i.e., energy prices), covering historical levels and future projections, **sensitivities** to **future market developments** and **price volatilities** are **not considered**
- **Abated volumes** and **energy use** are derived from **publicly available emissions data** and **allocated across sector-specific processes** using public sources – *see deep-dive for volume determination*

Nominally constant implies that a fixed amount holds over the entire operational period.

All price projections (commodities, network costs, and taxes) are collected from publicly available sources and are used for calculating abatement unit costs

Price assumptions[1]

		2030 *(in €/MWh LHV)*				2035 *(in €/MWh LHV)*				2040 *(in €/MWh LHV)*				Key source(s)
		Commodity	Network	Tax	Total cost	Commodity	Network	Tax	Total cost	Commodity	Network	Tax	Total cost	
Electricity	**Avg. price**	69	23	<1	**92**	65	34	<1	**99**	65	41	<1	**106**	Fraunhofer, KEV 2025, EMBER
	Low price[2]	25	23	<1	**48**	10	34	<1	**44**	4	41	<1	**46**	Fraunhofer, KEV 2025, EMBER
Natural gas		35	1	6	**42**	32	1	5	**38**	28	1	5	**34**	KEV 2025
Bio-methane		88	1	6	**90**	122	1	5	**93**	126	1	5	**66**	KEV 2025 & EU ETS 2
Green hydrogen[3]		290	6	<1	**297**	196	6	<1	**203**	164	6	<1	**171**	PBL
Blue hydrogen[3]		106	6	<1	**113**	95	6	<1	**102**	84	6	<1	**91**	PBL
Grey hydrogen[3]		75	6	<1	**82**	71	6	<1	**78**	67	6	<1	**74**	PBL
Green ammonia[3] *(in €/ t NH_3)*		1,271	–	–	**1,271**	1,081	–	–	**1,081**	891	–	–	**891**	PBL
Heat		32	–	–	**32**	29	–	–	**29**	25	–	–	**25**	PBL & KEV 2025
Coking coal		22	–	–	**22**	21	–	–	**21**	20	–	–	**20**	Wood Mackenzie
Coal		12	–	–	**12**	12	–	–	**12**	13	–	–	**13**	Coking coal/coal price ratio
CO_2 transport and storage *(in €/ t CO2)*	**Pipeline**	–	100	–	**100**	–	100	–	**100**	–	100	–	**100**	PBL
	Ship/ truck	–	124	–	**124**	–	124	–	**124**	–	124	–	**124**	
EU ETS 1 *(in €/ t CO_2)*		126	–	–	**126**	**183**	–	–	**183**	240	–	–	**240**	EU ETS Impact assessment report

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1) The assumptions are primarily based on publicly available data, then actively tested and refined through analyses and consultations with industry experts. Any adjustments made are transparently documented e.g., see slide 37 for details; 2) Average price in hours where an e-boiler is cheapest (43%) as opposed to a boiler fueled with biomethane (28%) or hydrogen (29%); 3) Commodity price, which may differ from the price of production at a given site

Note: Prices in $€_{2024}$ | Sources: KEV 2024, KEV 2025, PBL, CE Delft, Rijksoverheid, Bloomberg, SDE++, EU ETS Impact assessment report (EC, 2024)

For each sector, abatement options are defined at the process level and translated into sector-wide abatement potential based on key technical constraints

Technical abatement potential

① Total emission per sector

Total CO_2 emissions are defined per sector

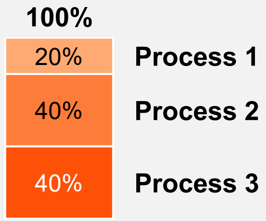
Total sector emissions

Source: NEa

② Sector split by process type

Total emissions per sector are allocated to the **various processes**

Emissions per process

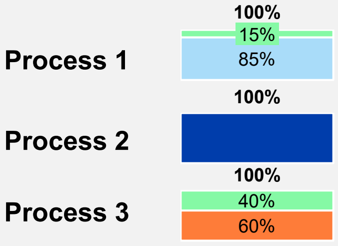


Sources: MIDDEN, other literature

③ Abatement potential per option (defined at process level)

GHG abatement potential is assessed per process incl. all abatement options possible to abate 100%

Technical abatement potential per process



Technical considerations:

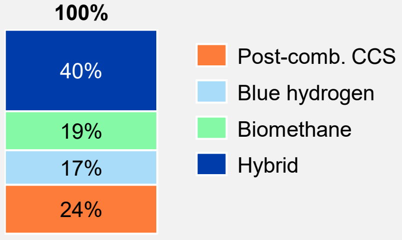
- Abatement options with **low TRL's** (currently and by 2040) are not considered
- Aim is always to **abate 100%** per process (e.g., last mile with biomethane), and should be technically possible

Sources: MIDDEN, other literature

④ Abatement potential per sector

Abatable emissions per sector

Abatement potential per sector

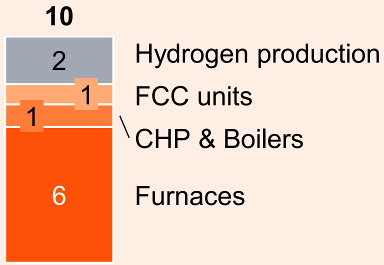


Sources: NEa, MIDDEN, other literature

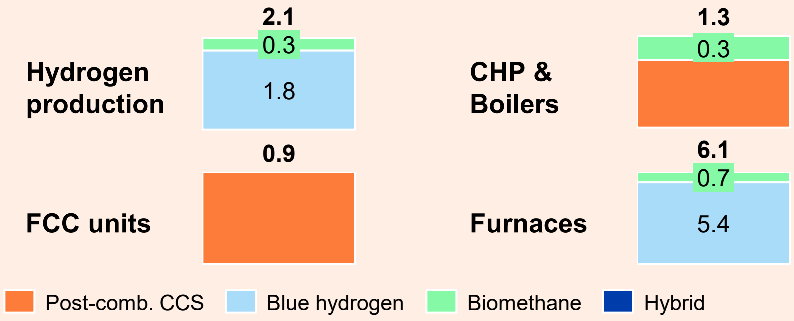
Example: Refineries

Total emissions refineries (Mt CO_2)

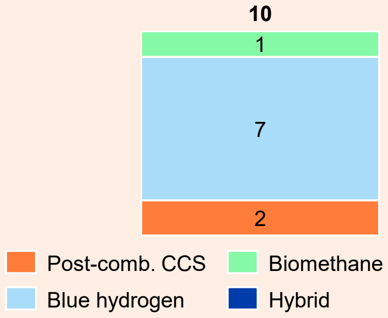
GHG emissions per process (Mt CO_2)



Technical abatement potential per process (Mt CO_2)



Abatement potential refineries (Mt CO_2)



Sources: NEa; MIDDEN, NEa, Assessing the potential of decarbonisation options for industrial sectors (Gailani et al., 2024), EIGA best practices

A2

Analysis of infrastructure constraints

Achieving industrial decarbonisation through electrification will require around 2 GW of additional capacity; expected to become available towards 2040

Assessment of constraints on the electricity grid

		Additional grid capacity required (MW)		Capacity TSO[1] (MW)				Capacity DSO[2] (MW)				Implementation feasibility of abatement (indicative)	
Cluster[3]	Location	CCS / CCU	Electrification (incl. hybrid options)	Current	Required	Waiting list	Grid avail. (year)	Current	Required	Waiting list	Grid avail. (year)	2035	2040
Rotterdam-Moerdijk	Shell Pernis	100	128	518	879	1419	2030	–	–	46	–	Low	Medium
	Esso	61	86					–	–	24	2036	Low	Medium
	BP Rotterdam	52	80					–	–	200	2032	Low	Medium
	Air Liquide	20	–					–	–	91	–	Medium	High
	Air Products	14	–					–	–	5	–	Medium	High
	Shell Moerdijk	47	219	2282	4260	2317	2036	345	183	150	2027	Low	Medium
Chemelot	SABIC Geleen	29	130	1200	2208	1670	2034	89	98	14	2027	Low	Medium
	OCI	43	–					89	98	14	2027	Medium	High
Zeeland-West-Brabant	Yara Sluiskil	64	–	1200	2244	1440	2035	–	–	0	–	Medium	High
	Zeeland Refinery	37	50					–	–	72	–	Low	Medium
	Dow Terneuzen	60	402					–	–	37	2028	Low	Medium
NZKG[4]	Tata Steel	43	252	4140	6992	4390	2036	*Only TSO connection*				Low	Medium
Other	AVR Rozenburg	<10	–	518	879	1419	2030	–	–	91	–	Medium	High
	AEB Amsterdam	<10	–	4140	6992	4390	2036	–	–	–	–	Medium	High
	Attero Wijster	<10	–	–	–	–	–	173	56	17	2025	High	High
	HVC Alkmaar	<10	–	4140	6992	4390	2036	19	21	4	2033	Low	Medium
	AVI Twence	<10	–	1375	1949	1305	2035	38	41	14	2027	Medium	High
		∑ ~2,000 MW											

Key insights

- Approximately **2 GW of extra grid capacity** is required for top emitters to accommodate CCS/CCU and electrification projects
- Industrial connections/ expansions require **capacity at both TSO and DSO level**; only sites with **direct TSO access** are exempted (e.g., TATA Steel IJmuiden), resulting in predominantly **low-to-medium connection feasibility** up to ~2035
- **Electrification** and **CCS/CCU projects are delayed beyond 2035**, irrespective of project readiness or cost-effectiveness, due to the expected waiting lists
- Hower, based on announced TSO and DSO expansions, grid congestion is assumed to be **largely resolved by 2040**, enabling **scale-up of electrification** and **CCS/CCU** after 2035, and resulting into **no electricity grid constraints** towards 2040
- *This analysis is based on the assumption that the Netbeheer Nederland Capaciteitskaart is entirely representative of grid developments per location, and that companies have not already applied and received additional connection capacity to implement decarbonisation projects*
- *Furthermore, it is expected that the 2 GW additional capacity can materialise before 2040. A part of these required expansions are already part of the TSO/DSO investment agenda; for the required expansions that are not part of the agenda, it is assumed that infrastructure can be made available before 2040, taking into account lead times of 5 to 10 years.*[5]

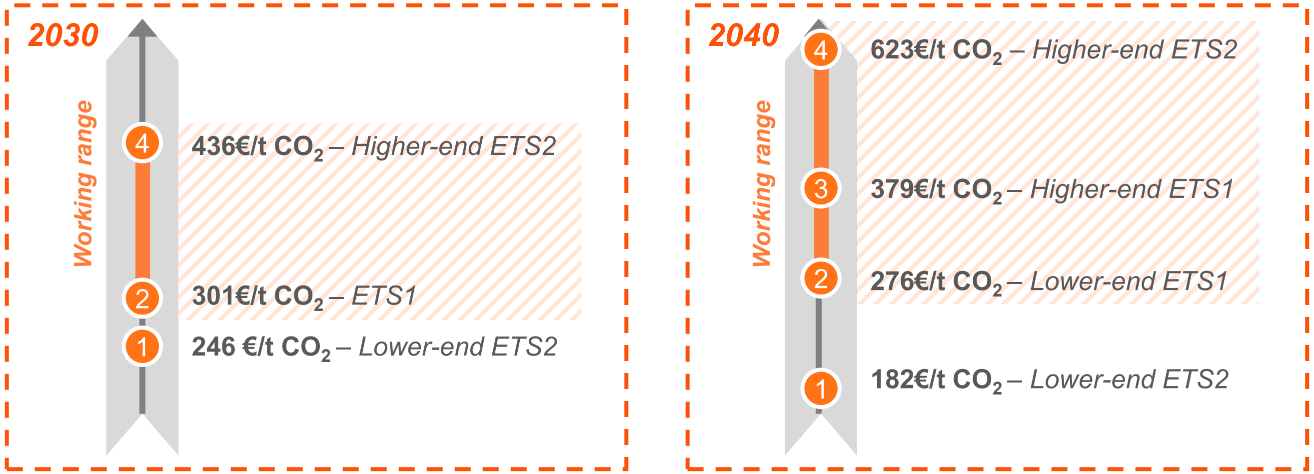
1) Transmission system operator, high voltage; 2) Distribution system operator, medium voltage; 3) Clusters based on geographical location and ZIP code; other entails AVIs throughout the country 4) Noordzeekanaalgebied 5) Lead times of 4-5 years in industrial regions, up to 10 years if new cables are required. (Speelveldtoets 2025, Strategy&). Note: Not all data is available, unavailable data is noted down as a dash
Sources: Netbeheer NL Capaciteitskaart, Tata Steel

Biomethane demand from industry may push prices higher; projections likely underestimate this, so we use the upper end of EU ETS2

Assumptions underlying biomethane pricing

Approach confirmed in discussion with industry stakeholders

Biomethane value drivers and price assumptions



2030

Working range

④ **436€/t CO_2** – *Higher-end ETS2*

② **301€/t CO_2** – *ETS1*

① **246 €/t CO_2** – *Lower-end ETS2*

2040

Working range

④ **623€/t CO_2** – *Higher-end ETS2*

③ **379€/t CO_2** – *Higher-end ETS1*

② **276€/t CO_2** – *Lower-end ETS1*

① **182€/t CO_2** – *Lower-end ETS2*

*For the analysis, in the base case, **we use the upper end of EU ETS 2 price level.** Sensitivity analysis is conducted on this towards the end to show the impact of +/-20% on the results*

As biomethane is considered as **a viable decarbonisation option for industry (fuel substitution)**, **additional demand emerges** limiting supply and increases willingness to pay. As **current biomethane pricing does not fully capture this additional industrial demand,** the following approach defines the pricing range for biomethane:

① **Lower-end EU ETS2:** Valued at natural gas parity plus avoided ETS2 carbon cost in industrial use, assuming lowest estimate for EU ETS2 carbon cost

② & ③ **EU ETS1:** Under scarcity, supply shifts towards industry from sectors with lower willingness to pay (e.g., buildings and transport), raising the market-clearing price to EU ETS1 (under assumption ETS2 is lower)

④ **Higher-end EU ETS2:** If other abatement options than biomethane are limited for ETS2 sectors, ETS2 prices and biomethane demand rise. The biomethane clearing price then reaches this higher ETS2 level

Guiding principles

Guiding principles to allocate biomethane as a fuel substitution **abatement option** across sectors:

Largest emitting sectors

- Applied **selectively where substitution does not displace critical use of internal fuel gases** (valuable intermediate energy carriers in refinery or basic chemicals otherwise lost / under-utilised)
- Volumes capped by the **realistically accessible share of available biomethane supply**
- Used **primarily to close residual emissions** to reach full abatement after structural abatement options are deployed

Cluster 6 sectors

- Applied **selectively limited process integration** allows **direct replacement of fossil fuels as energy carrier**
- Volumes capped by **realistically accessible share of available biomethane supply**
- Used **either to enable full fuel substitution** or **to close residual emissions** to reach full abatement

PwC

Sources: KEV, II3050, NPE, European Gas Association, Ministry of Economic Affairs and Climate; Forest Research; Waga Energy; SDE++ (PBL)

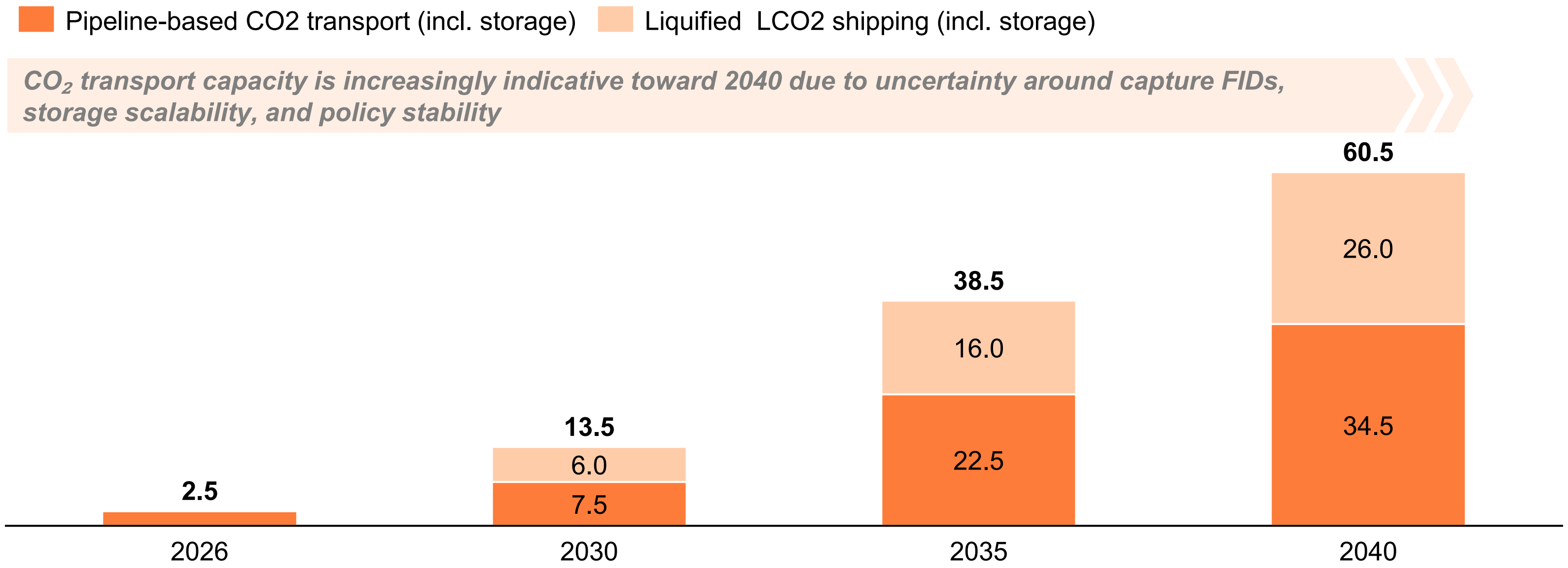
Dutch CO_2 transport and storage capacity could scale to ~60 Mt by 2040; realisation remains uncertain

NL CO_2 transport and storage capacity

See deep-dive on next page

Projected maximum available CCS transport and storage capacity (pipeline-based and liquified CO_2 transport) *in Mt CO_2/year, 2030P -2040P*

CO_2 transport capacity is increasingly indicative toward 2040 due to uncertainty around capture FIDs, storage scalability, and policy stability



Towards 2030	Porthos operates at full capacity (~2.5 $MtCO_2/yr^1$); Aramis Phase 1 starts operations around 2030, with limited initial utilisation as industrial capture projects ramp — resulting in total pipeline transport of ~7–8 $MtCO_2$/yr; CO_2next terminal is commissioned around 2030, enabling ~4–6 $MtCO_2$/yr of liquid CO_2 handling capacity, including early shipping-based volumes from regional emitters
Towards 2035	Aramis scales progressively towards ~20 $MtCO_2$/yr transport capacity, supported by additional storage providers and new capture connections; Cross-border pipeline developments (e.g. Delta Rhine Corridor) begin contributing to realising these volumes; Shipping-based CO_2 transport expands towards ~12–16 $MtCO_2$/yr, driven by scaling utilisation of CO_2next and growth of regional shipping chains
Towards 2040	Aramis reaches its long-term design capacity (~20–22 $MtCO_2$/yr), forming the backbone of the Dutch CCS transport system; Additional pipeline corridors and system optimisation increase total pipeline transport capacity towards ~30–35 $MtCO_2$/yr; Liquid CO_2 transport scales further towards ~20–25 $MtCO_2$/yr, assuming full development of terminal throughput and maritime logistics networks

Key insights

- **CCS transport capacity scales rapidly after 2030** as Aramis ramps alongside Porthos (~2.5 Mt/yr), increasing total system capacity from ~15 Mt in 2030 to ~40 Mt by 2035 and ~60 Mt by 2040
- **Pipeline infrastructure remains the structural backbone of the CCS system**, accounting for most transport capacity as backbone expansion and cross-border corridors increase pipeline volumes to ~35 Mt by 2040
- **Liquefied CO_2 shipping develops as a complementary route**, growing from ~7 Mt in 2030 to ~26 Mt by 2040, enabling access for emitters outside pipeline-connected clusters
- **Realised transport volumes remain uncertain**, as utilisation will depend on **capture project FIDs**, **storage availability**, **infrastructure sequencing** and **policy support**

1) Porthos Phase 1 provides 2.5 Mt CO_2/yr of transport and storage capacity, fully contracted by Shell, Esso, Air Liquide and Air Products, with operations expected to start around 2026.
Source: announcements from Porthos and Aramis; input from Gasunie CCS working group

Porthos and Aramis are the main options for CO$_2$ storage through pipeline, while other projects focus on CO$_2$ shipping

Deep dive: NL CO$_2$ transport capacity projects

CO$_2$ transport	Project	Description	Status	Operation start	Capacity	Storage
Pipeline-based CO$_2$ transport (incl. storage)	**Porthos**	Integrated onshore and offshore pipeline transporting captured CO$_2$ from Rotterdam industry to depleted North Sea gas fields (P18 cluster)	• **Under construction nearing completeness** (FID taken Oct 2023: onshore & offshore pipelines installed; wells are ready for injection) • Fully contracted to Shell, Esso, Air Liquide, Air Products	• **2026** (first injection)	• **Storage 2.5 Mt CO$_2$/yr** • No formal announcement for further expansion	✓
	Aramis	Open-access offshore CO$_2$ transport backbone in the Rotterdam area (Maasvlakte), connecting multiple industrial clusters to Dutch North Sea storage (e.g. Porthos onshore pipeline, LCO$_2$ terminal etc.), as well as offshore storage capacity (e.g. Total, Shell)	• **Pre-FEED and FEED completed,** and recognised as EU PCI • Final Investment Decision (FID) expected in 2027-2028, once permitting appeal is granted	• **2030** (up to 5-year construction post FID, 2033) • **Full completion towards 2040**	• **Phase 1:** 5 – 7.5 Mt/yr • **Expansion** up to 22 Mt/yr (unclear timeline)	✓
	Delta Rhine Corridor (CO$_2$)	Planned cross-border CO$_2$ pipeline corridor linking Rotterdam with Chemelot and the German industry (Rhine-Ruhr)	• **Route development** and **ongoing coordination**	• **Early 2030s,** phased developments	• Multi Mt CO2/yr strategic backbone capacity	✗
Liquified CO$_2$ shipping (incl. storage), imports	**CO$_2$NEXT (CO$_2$NECT)**	LCO$_2$ terminal in Rotterdam (Maasvlakte), receiving LCO$_2$ by ship and connected directly to Aramis infrastructure	• **FEED progressing / development phase (2025)** • **FID** aimed for **2026-2027**	• **2030 (targeted)** • Expansion timeline unclear	• **5 Mt/yr** at launch • **15 Mt/yr** (scalable terminal throughput towards)	✗
Liquified CO$_2$ shipping (excl. storage), exports	**HES International**	Terminals in Rotterdam for liquid CO$_2$ storage	• Currently in **expression of interest phase**	• **2029 (targeted)**	• **~20 Mt CO$_2$/yr** transport	✗
	Carbon Connect Delta	Regional initiative transporting captured CO$_2$ by ship from the Schelde-Delta region to dispose of their captured CO$_2$	• **FEED and concept selected,** remaining in feasibility & coordination phase • **FID** taken in **2023 (Yara)**	• **~2026 (first volumes, indicative)**	• **0.8 Mt/yr** (15 yrs, transport to Norway) • Potential capacity unclear	✗
	Carbon Collectors	CO$_2$ maritime transport and logistics developed supporting ship-based CCS value chains	• **Early FEED contract announced (2026)**	• **2029-2030 (initial vessels)**	• **0.5-1.5 Mt/Yr** (2029-2030) • Up to **6 Mt/yr**	✗
Storage only	**Neptune Energy (L10CCS)**	Operator of offshore gas fields, foreseeing supply of storage capacity and potentially offshore pipeline	• **FEED phase finalised (2025)** • **FID pending, aimed at 2026-2027**	• **2030** (indicative, aligned with Aramis start-up)	• **~5 Mt CO$_2$/yr** Initial expansion	✓

Notes: Relevant cancelled projects include Athos (similar project as Porthos for the Amsterdam/IJmuiden area, fell through when Tata opted for CO$_2$ reduction instead of storage) and Petrogas (research was done into the possibility of storing CO$_2$ in Petrogas' empty oilfields, however no significant progress has been made since 2021)

A3

Industry deep-dives

The Netherlands has 5 refineries, strategically positioned in proximity to major harbours and closely connected to clients in neighbouring countries

Refineries – Sector overview

Sector overview

Sector definition

- The refining sector includes **capital-intensive** and **highly integrated facilities** that **convert crude oil** and **other hydrocarbon feedstocks into marketable fuels** and **chemical (intermediate) products**

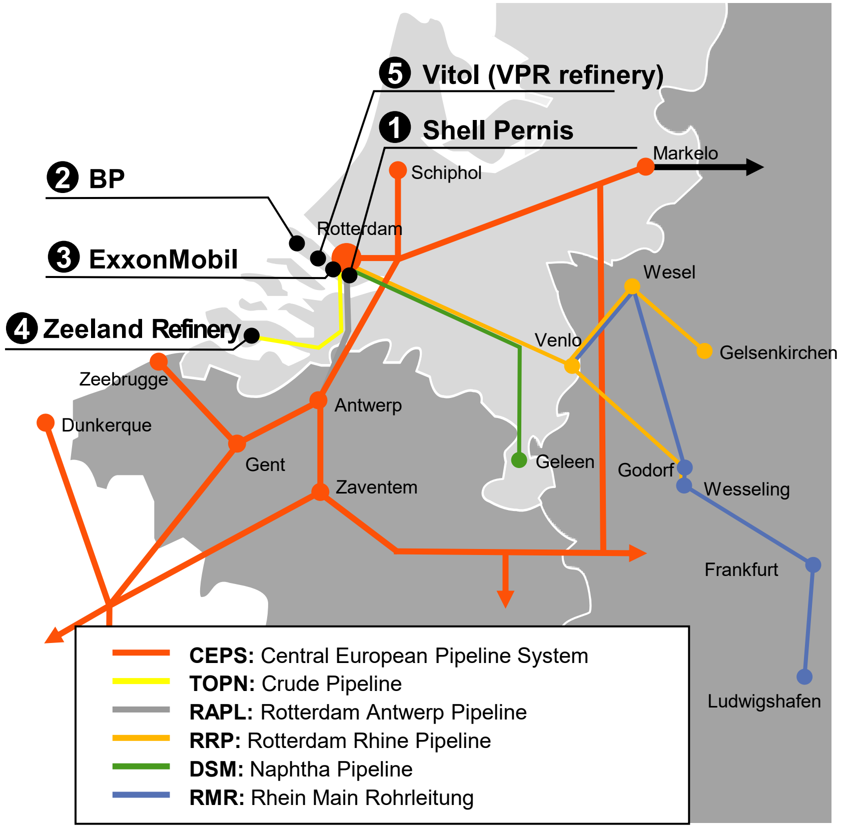
System integration & strategic positioning

- The Dutch refineries hold a **strategically important position**, underpinned by **deep-seaport access**, **robust pipeline infrastructure**, and **close integration with industrial clusters**
- The sector is **highly clustered and integrated**, with **extensive cross-border pipeline connections** to Germany and Belgium as **operates within maintenance cycle** (e.g. five-year turnarounds)

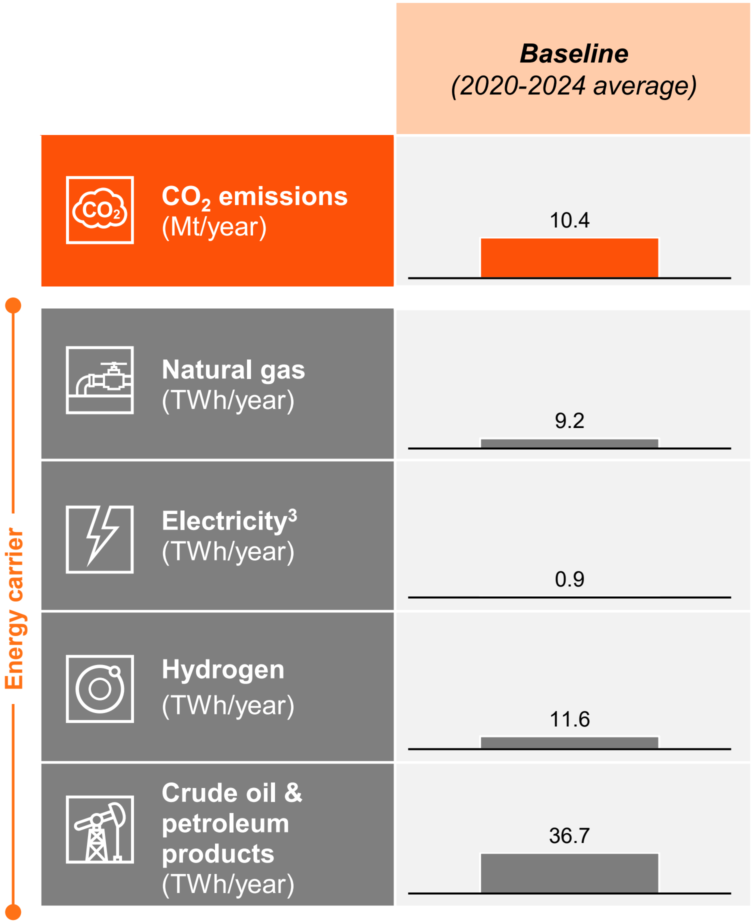
Products & end-use markets

- The refining sector produces (largely) **homogeneous products** – such as gasoline, diesel, jet fuel, LPG, naphtha, and fuel oil[2] – that serve **the chemical manufacturing sectors**, **transport**, **aviation**, **shipping**, **residential and commercial energy**, and **power generation**

Physical connectedness of NL refineries with ARRRA[1] cluster



Energy profile



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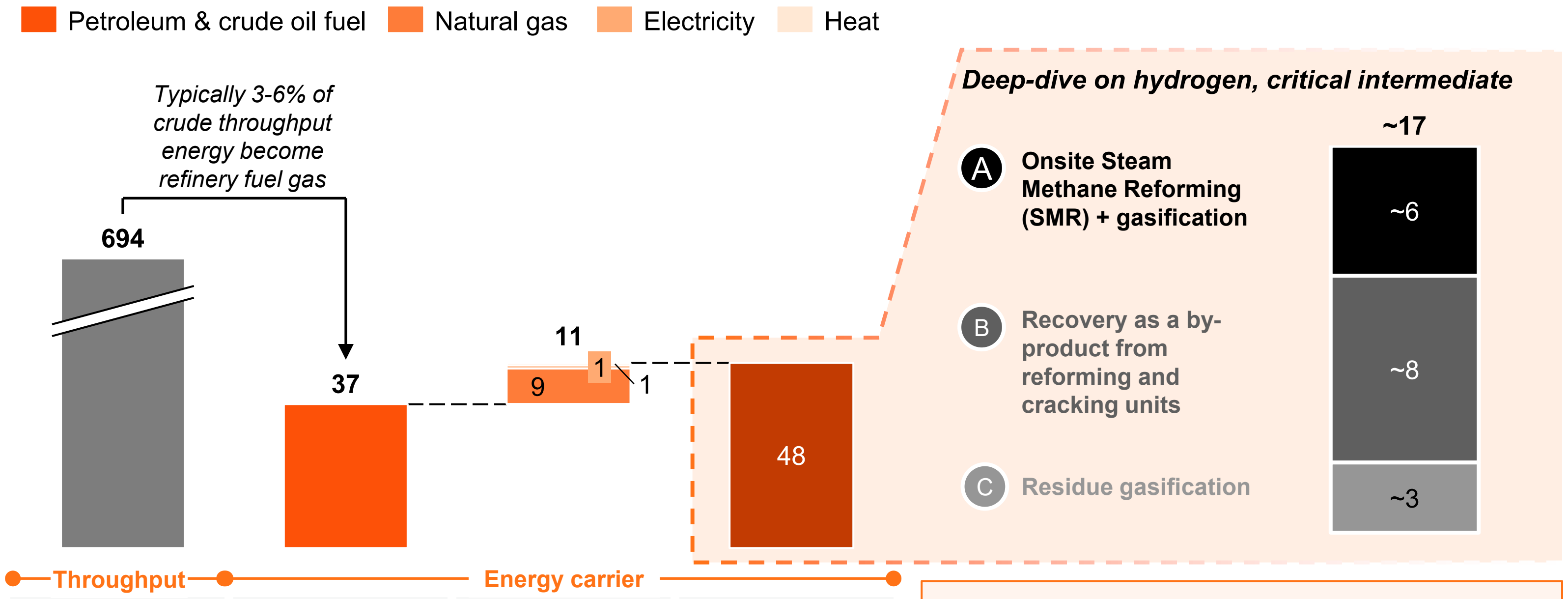
1) Antwerp, Rotterdam & Rhine-Ruhr Area; 2) Current EU-level demand distribution for these end products is – 48% diesel,15% gasoline,11% LPG, 8% naphtha, 3% jet fuel, 3% biofuels, 1% fuel oil and 11% other products (such as cokes, lubricants and asphalt) 3) only net imports into the sector (as part of the electricity demand is self-produced in CHP plants). Sources: Concawe Refineries Map, CBS, Port of Rotterdam

Refineries upgrade ~700 TWh of crude oil (inputs) into fuels, operating largely on internally recovered gases - 17 TWh of H_2 production at the core of the process

Refineries – Energy profile

Refinery input and energy use by carrier
(In TWh, *5-year average 2020-2024)*



Crude oil & petroleum throughput, process material flow, not operational energy use	**Internally generated refinery fuels & residues** (refinery off-gas, PSA tail gas, etc.), produced during crude processing	**External energy supply,** including electricity, heat, and natural gas	**Total operational energy demand**

Note: All **hydrogen currently consumed by refineries** is **either self-produced** or **via captive on-site generation**, typically through SMR units operated by industrial gas suppliers (e.g. Air Products, Air Liquide) located **on or adjacent to refinery sites** or connected through (short-distance) pipelines

Key insights

- **Refineries separate** and **upgrade crude oil** (and other petroleum products) into **fuel products;** outputs are primarily used as fuels rather than chemical feedstocks
- Most process heat is supplied by **internally recovered refinery fuel gases (~37 TWh)**
- **External energy carriers** are **limited (~11 TWh)**: natural gas mainly supports hydrogen production, while electricity and heat cover mechanical loads
- **Hydrogen is central to refining (17 TWh)**, for sulphur removal and upgrading of heavy fractions (hydrotreating and hydrocracking). Hydrogen (as an intermediate product) is supplied via :
  - Ⓐ **Steam Methane Reforming (SMR)**[1]: ~6 TWh
  - Ⓑ **Recovery as a by-product**[2] from reforming and cracking units:~8 TWh
  - Ⓒ **Residue gasification**[3] (site specific): ~3 TWh

Deep-dive on process on next page

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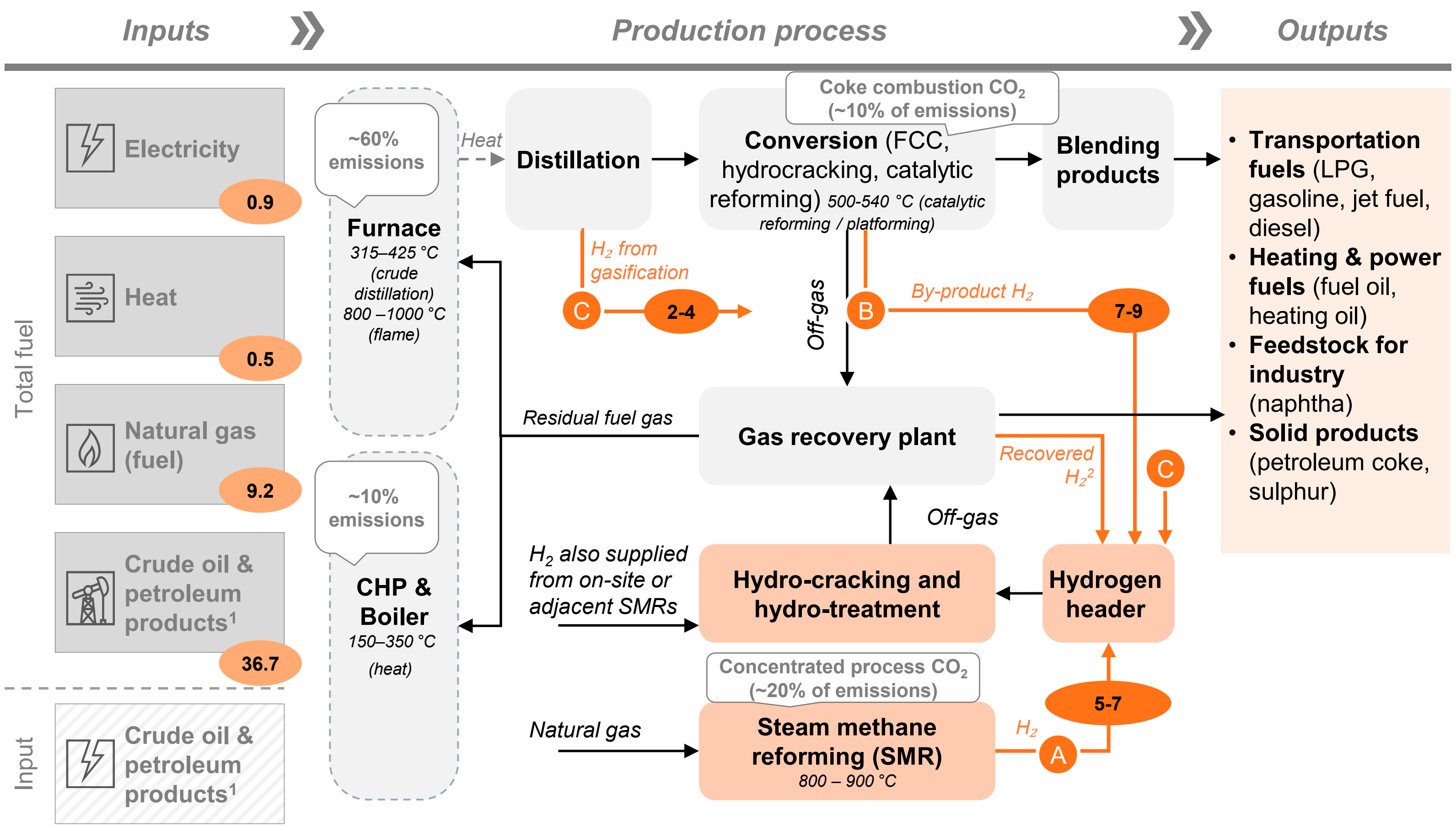
1) Natural gas reacts with heat at high temperature to produce hydrogen; 2) Hydrogen formed in catalytic reforming and cracking units is separated from off-gases (e.g., PSA/membranes) and recycled to hydrotreating and hydrocracking units; 3) Heavy residues or coke are gasified to syngas (H_2 + CO), shifted and purified to supply additional hydrogen where installed
Sources: CBS, PBL MIDDEN

In refineries, the bulk of emissions originates from furnaces, as high-temperature process requirements necessitate the use of natural gas and refinery fuel gases

Refineries – Process overview



Inputs » *Production process* » *Outputs*

Total fuel

Electricity 0.9

Heat 0.5

Natural gas (fuel) 9.2

Crude oil & petroleum products[1] 36.7

Input

Crude oil & petroleum products[1]

~60% emissions

Furnace
315–425 °C (crude distillation)
800 –1000 °C (flame)

~10% emissions

CHP & Boiler
150–350 °C (heat)

Heat

Distillation

Coke combustion CO_2 (~10% of emissions)

Conversion (FCC, hydrocracking, catalytic reforming) *500-540 °C (catalytic reforming / platforming)*

Blending products

H_2 from gasification

C 2-4

Off-gas

B *By-product H_2* 7-9

Residual fuel gas

Gas recovery plant

Recovered H_2[2]

C

Off-gas

H_2 also supplied from on-site or adjacent SMRs

Hydro-cracking and hydro-treatment

Hydrogen header

Concentrated process CO_2 (~20% of emissions)

Natural gas

Steam methane reforming (SMR)
800 – 900 °C

H_2 A 5-7

- **Transportation fuels** (LPG, gasoline, jet fuel, diesel)
- **Heating & power fuels** (fuel oil, heating oil)
- **Feedstock for industry** (naphtha)
- **Solid products** (petroleum coke, sulphur)

Key insights

- **Refineries emissions are mainly driven** by 4 systems[2]:
  1. **Dilute flue-gas emissions from furnaces (~60%),** which provide high-temperature process heat across the refinery
  2. **Concentrated CO_2 at the SMR unit (~20%),** arising from hydrogen production for hydrocracking and hydrotreating
  3. **Coke combustion at the FCC regenerator (~10%),** where coke deposited on the catalyst is burned to supply conversion heat.
  4. **Boilers and CHP units (~10%)**, providing heat and electricity to refinery processes and utilities
- **Abatement pathways will therefore** be defined across these systems

CO_2 Largest amount of CO_2 emissions ▨ Hydrogen production or consumption ● XX Total usage in TWh ● XX Hydrogen usage in TWh

1) The stated 36.7 TWh fuel is used for energy, while the remaining crude oil & petroleum product input is transformed into other energy carriers (e.g. crude oil into crude oil fractions); 2) Recovered hydrogen is separated from reactor off-gas and recycled to the hydrogen header. Because it remains within the refineries' internal loop, it does not create new hydrogen supply/ demand
Sources: CBS, MIDDEN, NEa

Refinery emissions are primarily caused by furnaces (~60%), hydrogen prod. via SMR (~20%), FCC coke combustion (~10%), and boilers/CHP (~10%)

Refineries – Key characteristics

Sub-processes	Key role	CO_2 emission mechanism	Typical CO_2 concentration	Operating temperature	Hydrogen involvement	Fuel dependence	Abatement options
Furnaces	• Provides **high-temperature heat** for **separation and conversion** • Maintains **heat-recovery** and **fuel-gas network operation**	• **~60% of refinery emissions** • Hydrocarbons fuel combustion generates heat transferred to process streams for separation and reaction, releasing CO_2	• **~7-8%**	• **Very high operating temperature** (radiant heat ~800–1000 °C)	• **Indirect role** (supporting conversion units)	• **Largest consumer of refinery fuel gas**	• **CCS (post-combustion)** • **Electrification** • **H_2 fuel substitution**
SMR	• **Produces hydrogen for hydro-treating** and **hydrocracking** • **Requires continuous operations** to meet product specifications	• **~20% of refinery emissions** • Hydrocarbons react with heat to form syngas (CO+ H_2), and the water-gas shift reaction converts CO to CO_2 while producing H_2	• **~20-25%** in process gas • **~8-10%** in reformer furnace flue gas	• **Very high operating temperatures** (reformer tubes at ~800–900°C)	• **Hydrogen is a required product,** core chemical reactant	• **Uses natural gas and refinery off-gas** as feed and fuel	• **CCS (Pre-combustion)** • **Green hydrogen (electrolysis)**
CHP & Boilers	• **Provides heat integration**, and **on-site electricity** • **Maintains utility pressure** and **heat balance** across units	• **~10% of refinery emissions** • Fuel gas combustion supplies heat generation and power for plant utilities, releasing CO_2	• **~5-10%**	• **Medium operating temperatures** (~150–350 °C)	• n/a	• **Major consumer of refinery fuel gas**	• **CCS (post-combustion)** • **E-boilers** • **Hybrid boilers**
FCC	• **Regenerates catalyst** in the cracking unit • **Requires continuous catalyst** circulation and regeneration	• **~10% of refinery emissions** • Coke formed from the feedstock deposits on the catalyst and is oxidised during regeneration, releasing CO_2	• **>15%**	• **High operating temperatures** (~700–750°C)	• n/a	• **Carbon originates from crude oil molecules,** not the chosen fuel	• **CCS (post-combustion)**

Sources: CBS, PBL MIDDEN

~60% of emissions comes from furnaces, e-furnaces could technically enable full abatement; technology maturity currently insufficient for large-scale deployment

Refineries – Abatement options (1/4)

					Change in total fuel use (TWh/year)					
Sub-process	**Abatement option**	**Description**	**Abated CO_2[1]**	**Unit costs**	**Natural gas**	**Biomethane**	**H_2**	**Electricity**	**Heat**	**Key considerations** (incl. TRL, challenges, etc.)
Furnaces *~60% of total emissions* **6.2 Mt CO_2/year**	**E-furnace**	Electrifying furnaces replaces fossil fuels with electricity, eliminating direct combustion emissions from this process (subject to electricity carbon intensity)	▼**6.2 Mt CO_2/year** *(-100%)*	**>500 €/t CO_2**	▼3.6	-	-	▲30.7	-	• TRL for high temperature electric furnaces remains moderate, technology is in use on a smaller scale; sufficient commercial maturity is expected for broader deployment towards 2040 • Abatement option is constrained, as high-value refinery fuel gases must be utilised rather than displaced
	H_2 + CCS (pre-combustion)	Producing hydrogen from process off-gas using reforming combined with CO_2 capture before combustion, reducing CO_2 emissions with ~90%	▼**5.6 Mt CO_2/year** *(-90%)*	***Gaseous transport***						• Pre-combustion options depend on hydrogen integration and CO_2 transport and storage availability • Hydrogen production is assumed to provide ~80% power the furnace (requiring additional natural gas in the ATR to meet the same total heat demand)
				300-500 €/t CO_2	▲7.7	-	-	▲1.5	▼2.0	
				Liquid transport						
				300-500 €/t CO_2	▲7.7	-	-	▲1.5	▼2.0	
	CCS (post-combustion)	Capturing CO_2 from furnace exhaust gases and storing it permanently can reduce furnace-related emissions by up to ~90%	▼**5.6 Mt CO_2/year** *(-90%)*	***Gaseous transport***						• Post-combustion CCS costs are highly sensitive to CO_2 concentration, with flue-gas concentration assumed to be 7.5% CO_2 for furnaces • Costs might be significantly higher due to the spread of furnace stacks across industrial sites, complicating implementation
				300-500 €/t CO_2	-	-	-	▲ 1.2	▲ 4.5	
				Liquid transport						
				300-500 €/t CO_2	-	-	-	▲1.4	▲4.5	

1) Abatement as percentage of total process emissions
Sources: MIDDEN, CBS, NEa, Assessing the potential of decarbonisation options for industrial sectors (Gailani et al., 2024), EIGA best practices

Due to the reliance on on-site fuel-gas firing, fuel substitution options for furnaces are limited, resulting in an abatement potential of only around 11% of emissions

Refineries – Abatement options (2/4)

					Change in total fuel use (TWh/year)					
Sub-process	**Abatement option**	**Description**	**Abated CO_2[1]**	**Unit costs**	**Natural gas**	**Biomethane**	**H_2**	**Electricity**	**Heat**	**Key considerations** (incl. TRL, challenges, etc.)
Furnaces *~60% of total emissions* **6.2 Mt CO_2/year**	**Blue H_2 fuel substitution**	Replacing natural gas and fuel gas with low-carbon hydrogen as furnace fuel can fully eliminate direct CO_2 emissions from fuel combustion	▼**0.7 Mt CO_2/year** *(-11%)*	**>500 €/t CO_2**	▼3.6	-	▲3.8	-	-	• TRL for high temperature hydrogen-powered furnaces remains moderate. First hydrogen fired furnace planned to be operational in 2028, full deployment towards 2040 assumed • Blue hydrogen only replaces natural gas uses in the furnaces, as to not displace high-value refinery fuel gases • Residual furnace emissions remain, requiring additional abatement options
	Biomethane fuel substitution	Replacing natural gas with biomethane as furnace fuel can fully eliminate direct CO_2 emissions from fuel combustion	▼**0.7 Mt CO_2/year** *(-11%)*	**<300 €/t CO_2**	▼3.6	▲3.6	-	-	-	• Biomethane substitution deployment is highly dependent on limited supply and long-term price uncertainty • Can be combined with CCS to close the gap towards 100% emissions reduction

1) Abatement as percentage of total process emissions

Sources: MIDDEN, CBS, NEa, Assessing the potential of decarbonisation options for industrial sectors (Gailani et al., 2024), EIGA best practices

For SMR, accounting for 21% of total emissions, post-combustion CCS is the preferred technical option to abate 85% of the process emissions

Refineries – Abatement options (3/4)

					Change in total fuel use (TWh/year)					
Sub-process	**Abatement option**	**Description**	**Abated CO_2[1]**	**Unit costs**	**Natural gas**	**Biomethane**	**H_2**	**Electricity**	**Heat**	**Key considerations** (incl. TRL, challenges, etc.)
SMR (H_2 prod.) *~21% of total CO_2 emissions* **2.2 Mt CO_2/year**	**Electrolysis (Green hydrogen)**	Replacing SMR-based hydrogen with hydrogen produced via water electrolysis using renewable electricity eliminates all direct CO_2 emissions from hydrogen production	**▼2.2 Mt CO_2/year** *(-100%)*	>500 €/t CO_2	▼3.0	-	-	▲10.5	-	• High electricity requirements imply large dependence on access to grid capacity • Importing green hydrogen could be cheaper, albeit still substantially more expensive than blue hydrogen options
	CCS (pre- & post-combustion)	Capturing both high-purity process CO_2 and dilute furnace flue gas CO_2, enabling overall capture rates ~90-95%	**▼2.1 Mt CO_2/year** *(-94%)*	***Gaseous transport***						• Maximum abatement potential, capturing CO_2 both from syngas and furnace combustion • Technically enables near-complete (~90-95%) SMR emission abatement – however, industry players have indicated that full chain CCS retrofits on SMRs are unlikely to see large-scale adoption
				<300 €/t CO_2	-	-	-	▲0.4	▲0.9	
				Liquid transport						
				<300 €/t CO_2	-	-	-	▲0.4	▲0.9	
	CCS (Post-combustion)	Capturing dilute CO_2 from the reformer furnace flue gas after fuel combustion, with capture rates up to ~85% of flue gas emissions	**▼1.9 Mt CO_2/year** *(-85%)*	***Gaseous transport***						• Captures from flue gas; suitable for retrofits but has higher energy penalty due to lower CO_2 concentration • Requires large absorber/stripper units, heat extraction, and space - often a significant site constraint • Best suited for clusters with pipeline connections and stable waste-heat availability
				<300 €/t CO_2	-	-	-	▲0.3	▲1.2	
				Liquid transport						
				<300 €/t CO_2	-	-	-	▲0.4	▲1.2	
	CCS (Pre-combustion)	Capturing high-purity CO_2 from reforming process gas, typically addressing ~60% of total SMR emissions at lower cast	**▼1.3 Mt CO_2/year** *(-60%)*	***Gaseous transport***						• Captures reformer syngas before combustion, delivering large emission reductions at relatively low transport cost • Residual furnace emissions remain (~40%), requiring additional abatement (e.g., post-combustion CCS, fuel substitution, electrification, etc.)
				<300 €/t CO_2	-	-	-	▲0.2	▲0.4	
				Liquid transport						
				<300 €/t CO_2	-	-	-	▲0.3	▲0.4	

1) Abatement as percentage of total process emissions

Sources: MIDDEN, CBS, NEa, Assessing the potential of decarbonisation options for industrial sectors (Gailani et al., 2024), EIGA best practices

For CHP & boilers (10% of emissions), hybrid e-boilers with hydrogen may be the most techno-economically viable; for FCC units, only post-combustion CCS as a pathway

Refineries – Abatement options (4/4)

Sub-process	Abatement option	Description	Abated CO_2[1]	Unit costs	*Change in total fuel use (TWh/year)*					Key considerations (incl. TRL, challenges, etc.)
					Natural gas	Biomethane	H_2	Electricity	Heat	
CHP & Boilers *~10% of total CO_2 emissions* ***1.1* Mt CO_2/year**	**E-boilers**	Electrifying heat generation by replacing fossil-fired boilers with high-efficiency electricity unit	▼**1.1 Mt CO_2/year** *(-100%)*	300-500 €/t CO_2	▼2.8	-	-	▲6.6	-	• E-boilers have high energy efficiency (>99%), and are considered highly efficient • E-boilers deployment is contingent on grid capacity expansion and power price competitiveness • Fuel gases currently used in boilers must be valorised for this option to be valid
	Hybrid e-boiler + blue H_2 or biomethane	Optimising heat supply by combining electrified boilers during low-power price periods, while using biomethane or blue hydrogen during peak demand	▼**1.1 Mt CO_2/year** *(-100%)*	300-500 €/t CO_2	▼8.4	-	▲4.9	▲1.0	-	• Hybrid e-boilers reduces peak electricity demand through dual-fuel flexibility – however, it increases operational complexity due to fuel switching
	CCS (post-combustion)	Capturing dilute CO_2 from CHP and boiler flue gases for transport and permanent storage	▼**0.9 Mt CO_2/year** *(-90%)*	***Gaseous transport*** 300-500 €/t CO_2	-	-	-	▲0.2	▲0.9	• Post-combustion CCS costs are highly sensitive to CO_2 concentration, with flue-gas concentration is assumed to be 5% CO_2 for CHP / boilers
				Liquid transport 300-500 €/t CO_2	-	-	-	▲0.2	▲0.9	
	Biomethane fuel substitution	Substituting natural gas with biomethane as CHP/boiler fuel can fully eliminate direct CO_2 emissions from fuel combustion	▼**0.3 Mt CO_2/year** *(-32%)*	300-500 €/t CO_2	▼2.7	▲2.7	-	-	-	• Biomethane substitution deployment is highly dependent on limited supply and long-term price uncertainty • Abatement option is constrained, as high-value refinery fuel gases must be utilised rather than displaced
FCC *~9% of total CO_2 emissions* ***1.0* Mt CO_2/year**	**CCS (Post-combustion)**	Capturing CO_2 from FCC generator can reduce emissions by 90%	▼**0.9 Mt CO_2/year** *(-90%)*	***Gaseous transport*** <300 €/t CO_2	-	-	-	▲0.2	▲0.3	• Post-combustion CCS costs are highly sensitive to CO_2 concentration, with flue-gas concentration assumed to be 17% CO_2 for FCC
				Liquid transport <300 €/t CO_2	-	-	-	▲0.2	▲0.3	

1) Abatement as percentage of total process emissions

Sources: MIDDEN, CBS, NEa, Assessing the potential of decarbonisation options for industrial sectors (Gailani et al., 2024), EIGA best practices.

In the refinery sector, full abatement for the furnaces can be achieved through a combination of CCS (post or pre-comb. + H_2) and biomethane fuel substitution

Refineries – Abatement pathways (1/3)

Sector: Refineries

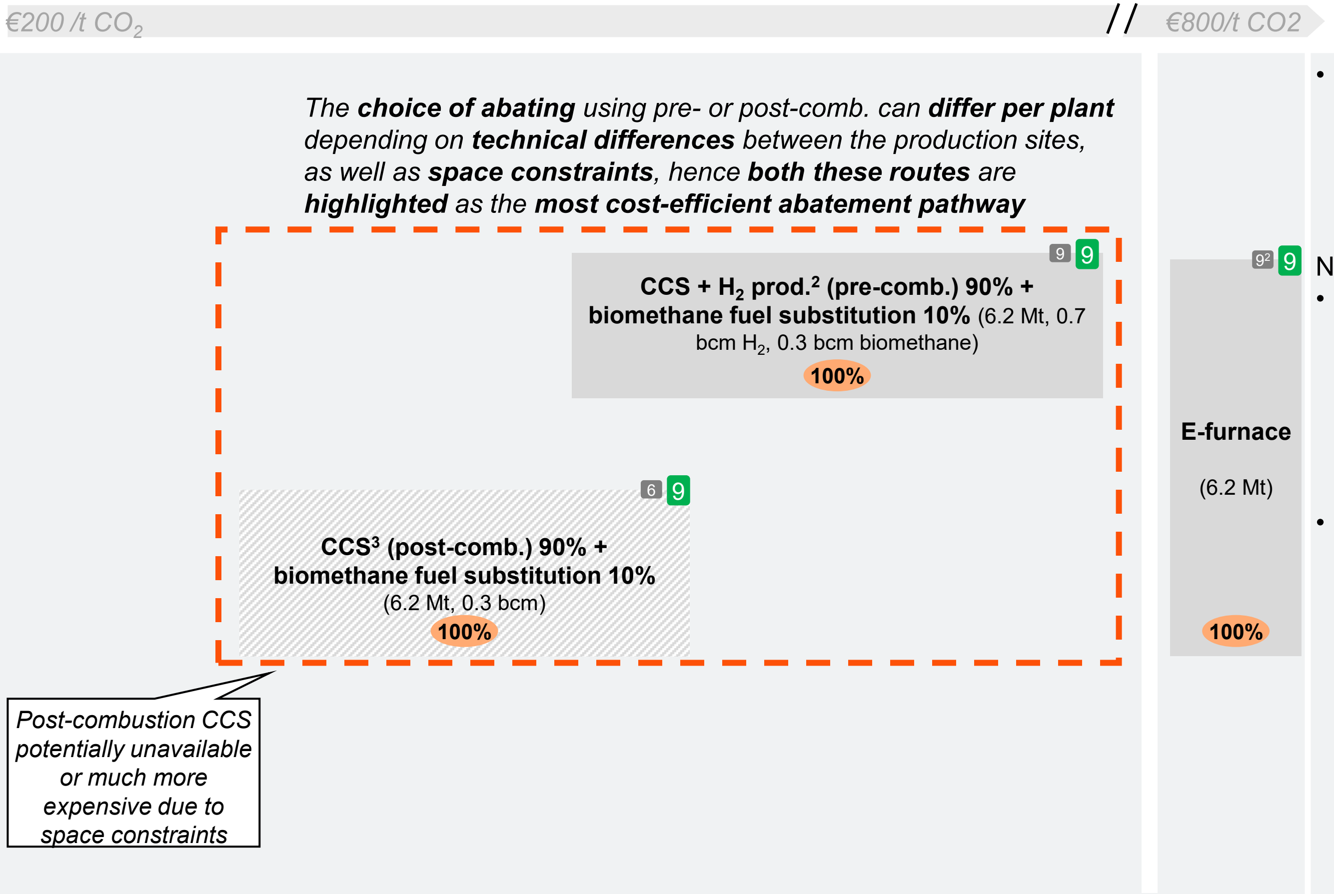
Process: **Furnaces**

Provides high-temperature heat for separation and conversion

Med. temp. ~290 – 510°C

CO_2 emissions: **6.2 Mt** *(60%)*

Abatement pathways



*The **choice of abating** using pre- or post-comb. can **differ per plant** depending on **technical differences** between the production sites, as well as **space constraints**, hence **both these routes** are **highlighted** as the **most cost-efficient abatement pathway***

CCS + H_2 prod.[2] (pre-comb.) 90% + biomethane fuel substitution 10% (6.2 Mt, 0.7 bcm H_2, 0.3 bcm biomethane)

CCS[3] (post-comb.) 90% + biomethane fuel substitution 10% (6.2 Mt, 0.3 bcm)

Post-combustion CCS potentially unavailable or much more expensive due to space constraints

E-furnace (6.2 Mt)

Key considerations

- **Full process decarbonisation is assumed: CCS** abates only **90%** of fuel-gas emissions, with the residual **10% abated** via fuel substitution with biomethane

Note (applicable for all pathway slides):

- The range within **unit costs of abatement** for the CCS routes shown here, is driven by the expected **range of biomethane costs** and **price difference** between **gaseous and liquid transport routes** for the CCS part of the pathway
- Unit costs of abatement for CCS options are **point estimates** are **derived from PBL's OT model (2026)**. CAPEX and fixed OPEX figures are taken form OT model, while the **variable OPEX estimates** for each option are calculated bottom-up using **commodity prices**, **network costs and energy taxes** as per the assumption section of this report

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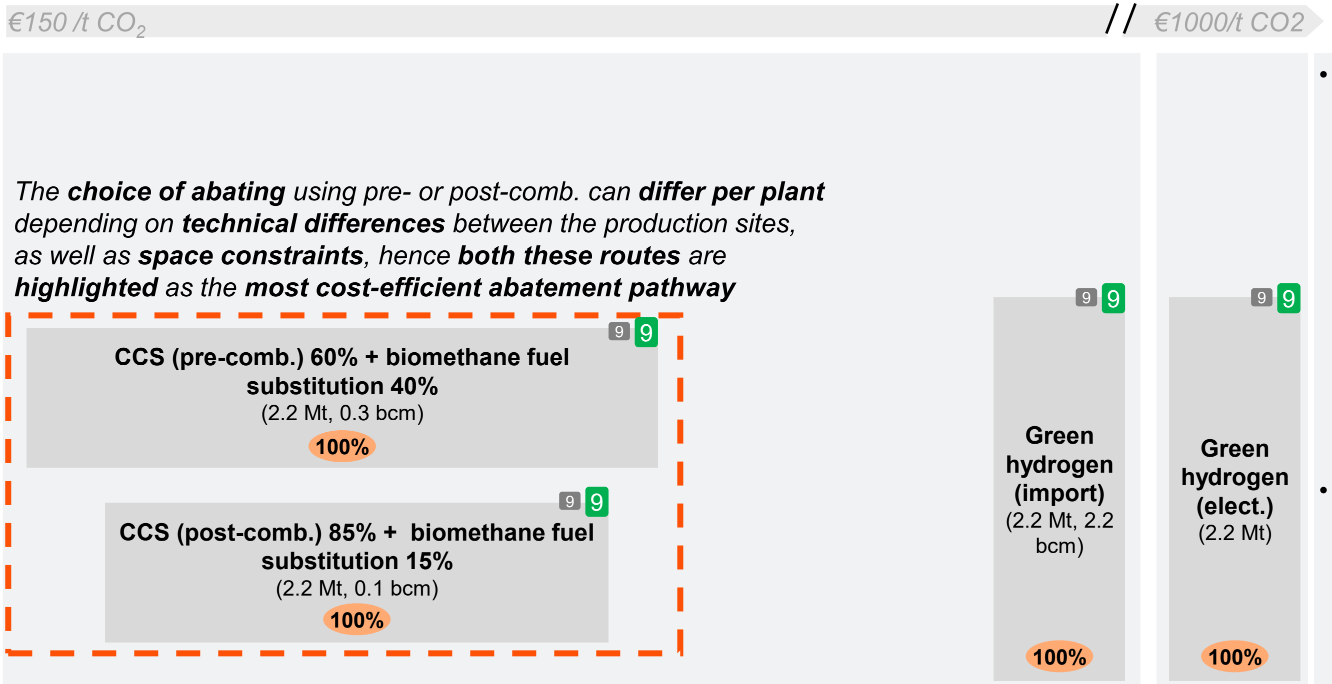
1) ATR hydrogen production is assumed to operate in a closed loop, providing sufficient hydrogen to power the furnace; 2) Technology in use on smaller scale in different industries; 3) Post-combustion CCS costs are highly sensitive to CO_2 concentration – flue-gas concentration is assumed to be 7.5% CO_2 for furnaces | Sources: CBS, PBL MIDDEN, Agora, FCW, hydrogen insight

■ Current TRL	**2040 TRL:** 🟩 High TRL (>7) 🟧 Medium TRL (5-7) 🟥 Low TRL (<5)
XX% Share of abated system emissions	⬚ Techno-economic option(s)

Full abatement for the SMRs can be achieved through a combination of CCS (post or pre-comb.) and biomethane fuel substitution

Refineries – Abatement pathways (2/3)

Sector	Process	CO_2 emissions	Abatement pathways	Key considerations
Refineries	**SMR** Produces hydrogen for hydro-treating and hydrocracking *High temp. ~700 – 1000°C*	**2.2 Mt** *(21%)*	see below	• **For SMRs, pre-combustion CCS with biomethane fuel substitution may be the lowest-cost option** for full abatement (only 65-80% possible with CCS, rest needs to be abated by biomethane for 100% abatement), large dependency on **biomethane availability** (due to large amount of required biomethane) and **biomethane price** – thus, **post-combustion CCS with biomethane** is considered most techno-economically viable • Emissions from the **gasification unit** is considered under SMR and it is assumed that this unit has the **same decarbonisation pathways** as the SMR



€150 /t CO_2 // €1000/t CO2

*The **choice of abating** using pre- or post-comb. can **differ per plant** depending on **technical differences** between the production sites, as well as **space constraints**, hence **both these routes** are **highlighted** as the **most cost-efficient abatement pathway***

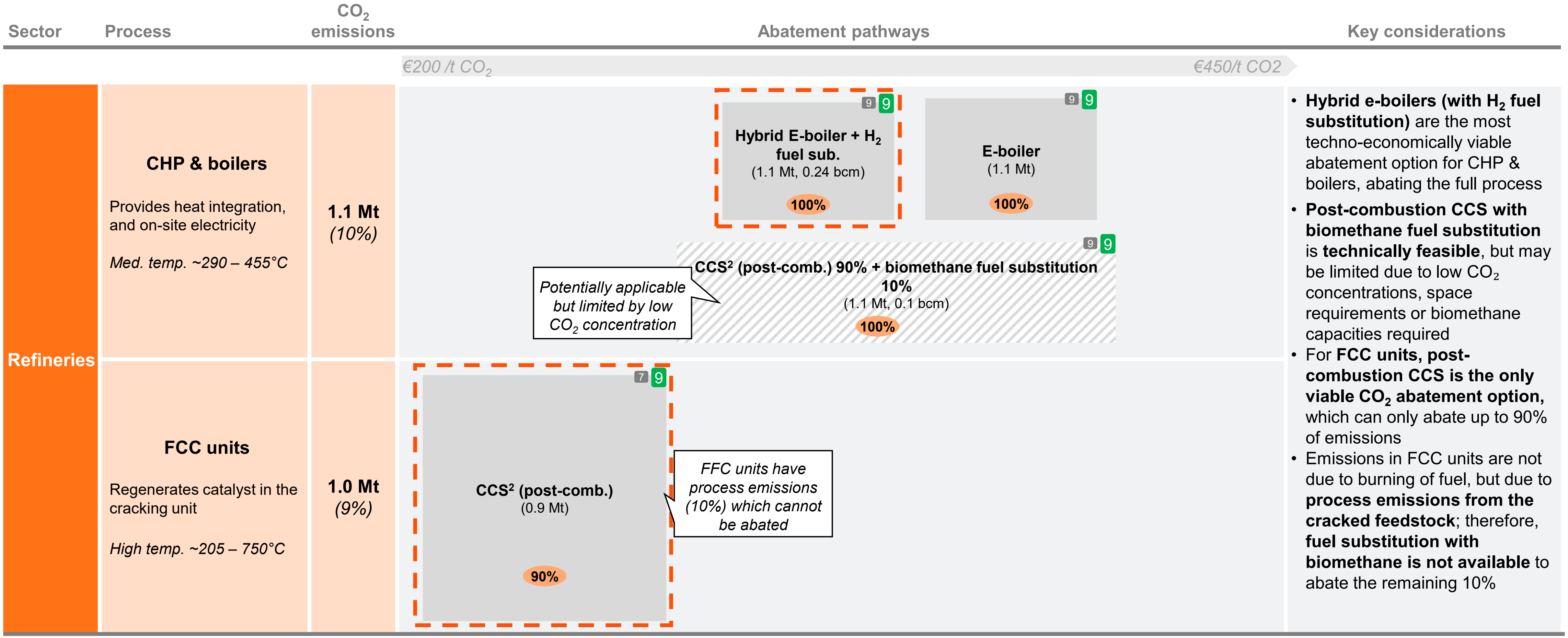
- 9 🟩9 **CCS (pre-comb.) 60% + biomethane fuel substitution 40%** (2.2 Mt, 0.3 bcm) **100%**
- 9 🟩9 **CCS (post-comb.) 85% + biomethane fuel substitution 15%** (2.2 Mt, 0.1 bcm) **100%**
- 9 🟩9 **Green hydrogen (import)** (2.2 Mt, 2.2 bcm) **100%**
- 9 🟩9 **Green hydrogen (elect.)** (2.2 Mt) **100%**

1) Excl. last-mile delivery costs (e.g., CAPEX of last mile delivery) | Sources: CBS, PBL MIDDEN, Agora, FCW, hydrogen insight

⬜ Current TRL | **2040 TRL:** 🟩 High TRL (>7) 🟧 Medium TRL (5-7) 🟥 Low TRL (<5)
XX% Share of abated system emissions ⬚ Techno-economic option(s)

For CHP, hybrid e-boilers (with H_2) are more attractive than pure e-boilers assuming CCS is technically constrained; FCC can only be abated through CCS

Refineries – Abatement pathways (3/3)



CHP & boilers

Provides heat integration, and on-site electricity

Med. temp. ~290 – 455°C

1.1 Mt *(10%)*

Hybrid E-boiler + H_2 fuel sub. (1.1 Mt, 0.24 bcm) **100%**

E-boiler (1.1 Mt) **100%**

CCS² (post-comb.) 90% + biomethane fuel substitution 10% (1.1 Mt, 0.1 bcm) **100%**

Potentially applicable but limited by low CO_2 concentration

FCC units

Regenerates catalyst in the cracking unit

High temp. ~205 – 750°C

1.0 Mt *(9%)*

CCS² (post-comb.) (0.9 Mt) **90%**

FFC units have process emissions (10%) which cannot be abated

- **Hybrid e-boilers (with H_2 fuel substitution)** are the most techno-economically viable abatement option for CHP & boilers, abating the full process
- **Post-combustion CCS with biomethane fuel substitution** is **technically feasible**, but may be limited due to low CO_2 concentrations, space requirements or biomethane capacities required
- For **FCC units, post-combustion CCS is the only viable CO_2 abatement option,** which can only abate up to 90% of emissions
- Emissions in FCC units are not due to burning of fuel, but due to **process emissions from the cracked feedstock**; therefore, **fuel substitution with biomethane is not available** to abate the remaining 10%

PwC

1) Excl. last-mile delivery costs (e.g., CAPEX of last mile delivery); 2) Post-combustion CCS costs are highly sensitive to CO_2 concentration – flue-gas concentration is assumed to be 5% CO_2 for CHP/boilers and ~17% for FCC units | Sources: CBS, PBL MIDDEN, Science direct

■ Current TRL	**2040 TRL:**	🟩 High TRL (>7)	🟧 Medium TRL (5-7)	🟥 Low TRL (<5)
XX% Share of abated system emissions		⬚ Techno-economic option(s)		

The Dutch organic basic chemicals (LVOC) sector anchored by steam crackers located in 3 main industrial clusters: Rotterdam, Zeeland, and Chemelot

Basic chemicals – Sector overview

Sector overview

Sector definition

- The Netherlands' **large volume organic chemicals (LVOC) sector** is centred on steam cracking, with 6 units operating nationally across **3 major clusters** (Rotterdam, Zeeland, and Chemelot)
- The LVOC sector converts hydrocarbon feedstocks (primarily naphtha, LPG) into **core organic building blocks**

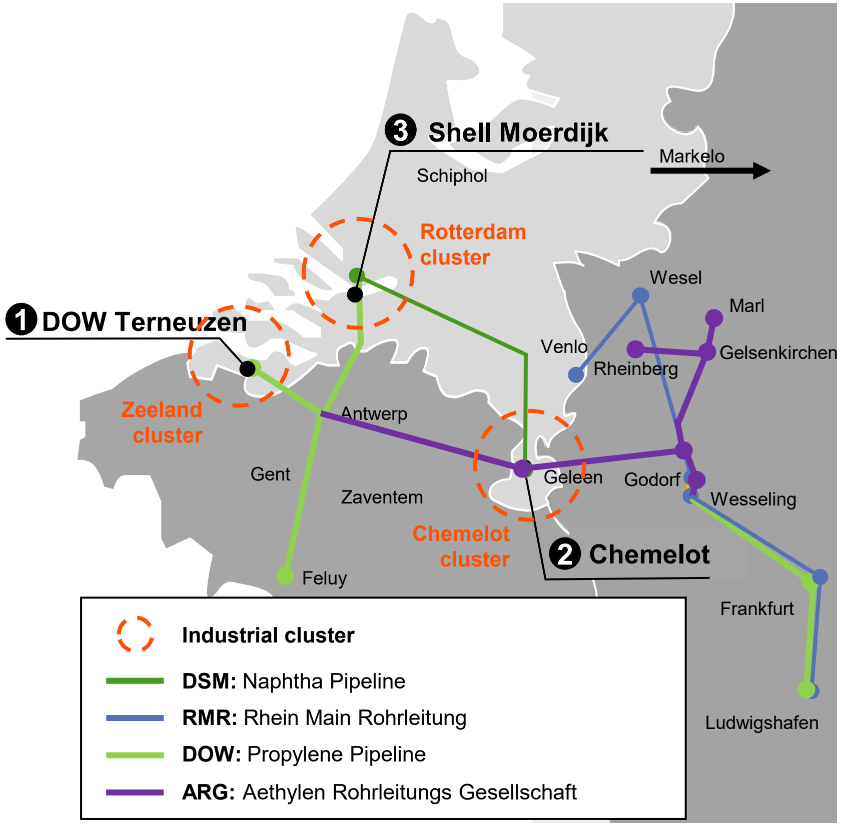
System integration & strategic positioning

- LVOC sites are **highly integrated with upstream refineries**, which supply naphtha/LPG via **dedicated pipeline networks** (notably SABIC-linked and Dow-linked systems)
- The sector is **deeply embedded in the energy system**, relying on large volumes of **natural gas, electricity, and heat**, often supported by **on-site or cluster-level CHP installations**.

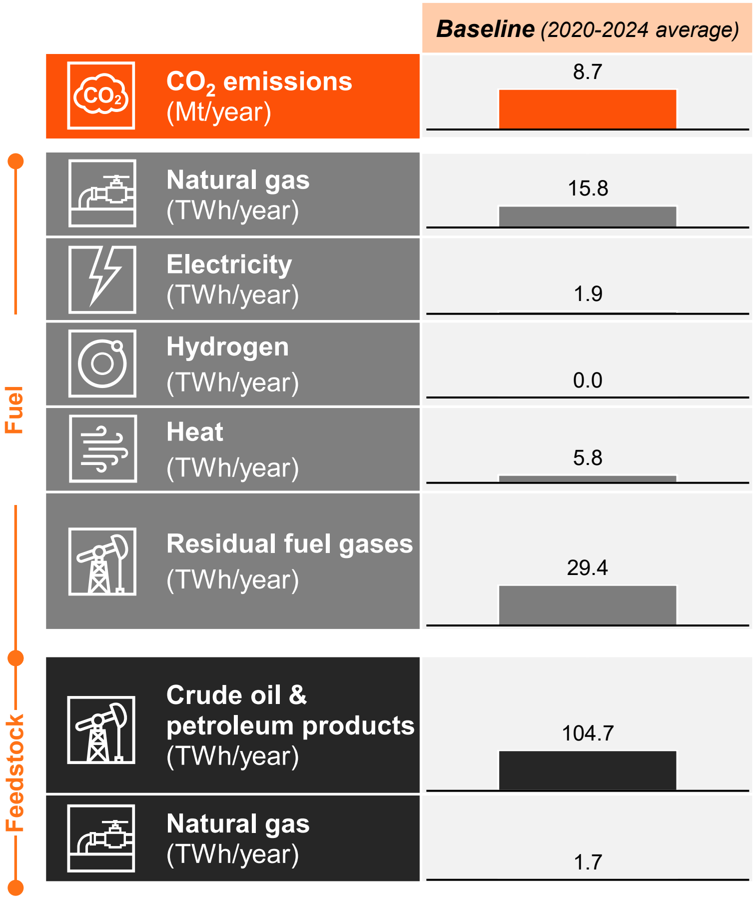
Products & end-use markets

- The LVOC sector produces **high-volume base chemicals**, including ethylene, propylene, benzene, toluene, and xylenes
- These products support downstream value chains: **plastics & packaging, automotive, construction materials, consumer goods, electronics, resins,** and **broader specialty chemicals manufacturing**

Physical connectedness of NL steam cracking units



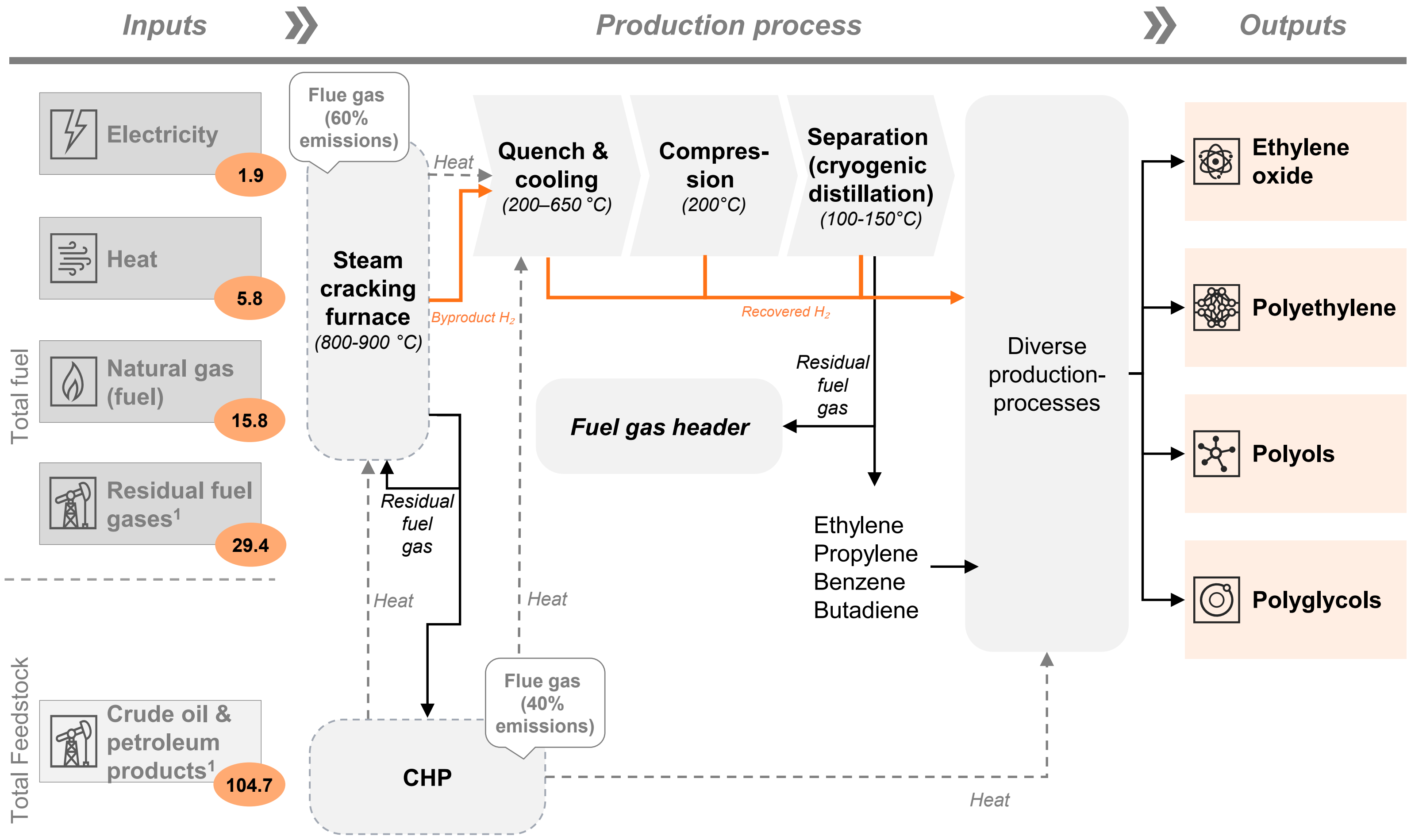
Energy profile



Sources: CBS, PBL MIDDEN

Steam cracking is the primary source of CO_2 emissions accounting for ~60% of total emissions; heat and electricity supply by CHP contribute remaining ~40%

Basic chemicals – Process overview



Inputs » *Production process* » *Outputs*

Total fuel

Electricity 1.9

Heat 5.8

Natural gas (fuel) 15.8

Residual fuel gases[1] 29.4

Total Feedstock

Crude oil & petroleum products[1] 104.7

Flue gas (60% emissions)

Heat

Steam cracking furnace *(800-900 °C)*

Byproduct H_2

Quench & cooling *(200–650 °C)*

Compression *(200°C)*

Separation (cryogenic distillation) *(100-150°C)*

Recovered H_2

Residual fuel gas

Fuel gas header

Residual fuel gas

Heat

Heat

Ethylene
Propylene
Benzene
Butadiene

Diverse production-processes

Flue gas (40% emissions)

CHP

Heat

Ethylene oxide

Polyethylene

Polyols

Polyglycols

Key insights

- **LVOC site emissions** are mainly driven by **3 systems**:
  1. **Steam-cracking furnaces (~60%)[1],** which deliver the ultra-high-temperature heat (~800–850 °C) required for ethylene cracking
  2. **CHP and steam-boiler utilities (~40%),** supplying heat and electricity to compressors, quench systems, refrigeration units and derivative plants
  3. **Quenching & cooling systems(<5%),** which rapidly cool cracked gas via transfer-line exchangers and indirect heat recovery, **running on heat and electricity** and therefore do not directly contribute to combustion emissions, they **contribute indirectly** via power and heat demand
- **Abatement pathways therefore align with these systems:** priority lies with **furnace decarbonisation**, followed by **site utilities** (CHP/boilers)

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1) Values are derived from the emission distributions of the large emitters in the sector
Sources: CBS, NEa, PBL MIDDEN, Speelveldtoets 2025

CO_2 Largest amount of CO_2 emissions ▨ Hydrogen production or consumption ● XX Total usage in TWh ● XX Hydrogen usage in TWh

PwC

Steam cracking is dominated by high temperature operations within furnaces (~800-900°C), where natural and fuel gas play a significant role as fuel

Basic chemicals – Key characteristics

Sub-processes	Key role	CO_2 emission mechanism	Typical CO_2 concentration	Operating temperature	Hydrogen involvement	Fuel dependence	Abatement options
Steam cracking furnaces	• Provides **high-temperature heat** (~850 °C) for steam cracking, the core LVOC step for producing ethylene, propylene, butadiene, aromatics • Maintains **heat-recovery** and **fuel-gas network operation** • **Largest single point source in steam-cracker-based basic-chemical sites**	• **~60% of LVOC industry emissions** • **Act as the largest single emitter at LVOC sites,** due to the high heat demand of steam cracking • **Release CO_2 from hydrocarbon fuel combustion**, which **generates** the **heat** transferred to process streams for separation and reaction	• **~8-10%**	• **Very high operating temperature** (~700-850 °C)	• **Indirect role** (H_2 is a component of fuel gas generated in cracking, used in hydrogenation of downstream products)	• **Major consumer of cracker fuel gas** and **supplementary natural gas**	• **Electrification of furnaces (e-crackers)** • **H_2 fuel substitution** • **CCS (post-combustion)** • **Electrification**
CHP & Boilers	• Provides **heat integration,** and **on-site electricity** • **Supplies high-pressure steam** to power rotating equipment, such as the cracked-gas compressor and hydrogenation reactors • **Generates electricity via CHP,** while **simultaneously** producing **heat** to maximise energy efficiency	• **~40% of LVOC industry emissions** • Act as the **second-largest emitter at LVOC sites,** reflecting their central role in utility supply • **Release CO_2** from **fuel-gas combustion**, which produces heat and power for downstream units and plant utilities	• **~4-15%**	• **Medium operating temperatures** (~150–525 °C)	• Currently limited	• **Mix of natural gas and cracker fuel gas**	• **CCS (post-combustion)** • **E-boilers** • **H_2 fuel substitution** • **Biomethane fuel substitution** • **Hybrid e-boiler**

Sources: CBS, NEa, PBL MIDDEN, Speelveldtoets 2025, Carbon capture storage and use technical, economic and societal perspectives (Markewitz & Bongartz, 2015)

All process emission in cracking furnaces could be cut by electrifying furnaces, though technology and infrastructure still need large improvements

Basic chemicals – Abatement options (1/4)

					Change in total fuel use (TWh/year)					
Sub-process	**Abatement option**	**Description**	**Abated CO_2[1]**	**Unit costs**	**Natural gas**	**Biomethane**	**H_2**	**Electricity**	**Heat**	**Key considerations** (incl. TRL, challenges, etc.)
Steam cracking furnaces *61% of total CO_2 emissions* **5.4 Mt CO_2/year**	**Blue H_2 fuel substitution**	Replacing fuel gas with low-carbon hydrogen as furnace fuel can fully eliminate direct CO_2 emissions from fuel combustion	▼**5.4 Mt CO_2/year** *(-100%)*	**300-500 €/t CO_2**	-	-	▲22.6	-	-	• TRL for high temperature hydrogen-powered furnaces remains moderate, limiting near-term large-scale deployment; however, sufficient commercial maturity is expected for broader deployment towards 2040 • Abatement option is constrained, as high-value refinery fuel gases must be utilised rather than displaced
	E-furnace	Electrifying furnaces replaces fossil fuels with electricity, eliminating direct combustion emissions from this process (subject to electricity carbon intensity)	▼**5.4 Mt CO_2/year** *(-100%)*	**>500 €/t CO_2**	-	-	-	▲28.0	-	• TRL for high temperature electric furnaces remains moderate, technology is in use on a smaller scale; sufficient commercial maturity is expected for broader deployment towards 2040 • Abatement option is constrained, as high-value refinery fuel gases must be utilised rather than displaced

[1] CO_2 abatement as percentage of total process emissions
Sources: CBS, NEa, PBL MIDDEN, Speelveldtoets 2025

Both pre- and post-combustion CCS are technically viable options capable of abating up to 90% of emissions from steam-cracker furnaces

Basic chemicals – Abatement options (2/4)

					Change in total fuel use (TWh/year)					
Sub-process	**Abatement option**	**Description**	**Abated CO_2**[1]	**Unit costs**	**Natural gas**	**Biomethane**	**H_2**	**Electricity**	**Heat**	**Key considerations** (incl. TRL, challenges, etc.)
Steam cracking furnaces *61% of total CO_2 emissions* **5.4 Mt CO_2/year**	**H_2 + CCS (pre-combustion)**	Producing hydrogen from process off-gas using reforming combined with CO_2 capture before combustion, reducing CO_2 emissions with ~90%	▼**4.8 Mt CO_2/year** *(-90%)*	***Gaseous transport***						• Pre-combustion options depend on hydrogen integration and CO_2 transport and storage availability • Hydrogen production is assumed to provide sufficient hydrogen to power the furnace (avoiding the need to supplement energy consumption of the furnace)
				300-500 €/t CO_2	▲4.6	-	-	▲1.3	▼1.7	
				Liquid transport						
				300-500 €/t CO_2	▲4.6	-	-	▲1.5	▼1.7	
	CCS (post-combustion)	Capturing CO_2 from furnace exhaust gases and storing it permanently can reduce furnace-related emissions by up to ~90%	▼**4.8 Mt CO_2/year** *(-90%)*	***Gaseous transport***						• Post-combustion CCS costs are highly sensitive to CO_2 concentration, with flue-gas concentration is assumed to be 5% CO_2 for furnaces
				300-500 €/t CO_2	-	-	-	▲1.6	▲5.8	
				Liquid transport						
				300-500 €/t CO_2	-	-	-	▲1.8	▲5.8	

1) Abatement as percentage of total process emissions

Sources: CBS, NEa, PBL MIDDEN, Speelveldtoets 2025

CHP & boilers can be fully abated by (hybrid) e-boilers, with hybrid e-boilers combined with hydrogen fuel substitution representing the lowest-cost option

Basic chemicals – Abatement options (3/4)

					Change in total fuel use (TWh/year)					
Sub-process	**Abatement option**	**Description**	**Abated CO_2[1]**	**Unit costs**	**Natural gas**	**Biomethane**	**H_2**	**Electricity**	**Heat**	**Key considerations** (incl. TRL, challenges, etc.)
CHP & Boilers *39% of total CO_2 emissions* **3.4 Mt CO_2/year**	**Hybrid e-boiler + blue H_2 or biomethane**	Optimising heat supply by combining electrified boilers during low-power price periods, while using biomethane or blue hydrogen during peak demand	▼**3.4 Mt CO_2/year** *(-100%)*	300-500 €/t CO_2	▼15.8	-	▲9.9	▲6.5	-	• Hybrid e-boilers reduces peak electricity demand through dual-fuel flexibility – however, it increases operational complexity due to fuel switching
	E-boilers	Electrifying heat generation by replacing fossil-fired boilers with high-efficiency electricity unit	▼**3.4 Mt CO_2/year** *(-100%)*	300-500 €/t CO_2	▼15.8	-	-	▲15.1	-	• Electrifying boilers significantly increases site-wide electricity demand, already noted as a bottleneck in chemical clusters • May conflict with electrification of crackers, competing for limited grid expansion potential • SHP heat (500+°C) is not yet achievable with current electrical boiler technology
	Post-combustion CCS	Capturing CO_2 from flue gases of CHP and boilers; reducing emissions (by ~90%) where fuel combustion remains	▼**3.0 Mt CO_2/year** *(-90%)*	***Gaseous transport*** <300 €/t CO_2	-	-	-	▲0.8	▲2.9	• Post-combustion CCS costs are highly sensitive to CO_2 concentration, with flue-gas concentration is assumed to be 5% CO_2 for CHP / boilers
				Liquid transport 300-500 €/t CO_2	-	-	-	▲0.9	▲2.9	

1) Abatement as percentage of total process emissions
Sources: CBS, NEa, PBL MIDDEN, Speelveldtoets 2025

In addition, fuel substitution with biomethane or blue hydrogen can abate emissions from CHPs and boilers, but only delivers partial abatement (~64%)

Basic chemicals – Abatement options (4/4)

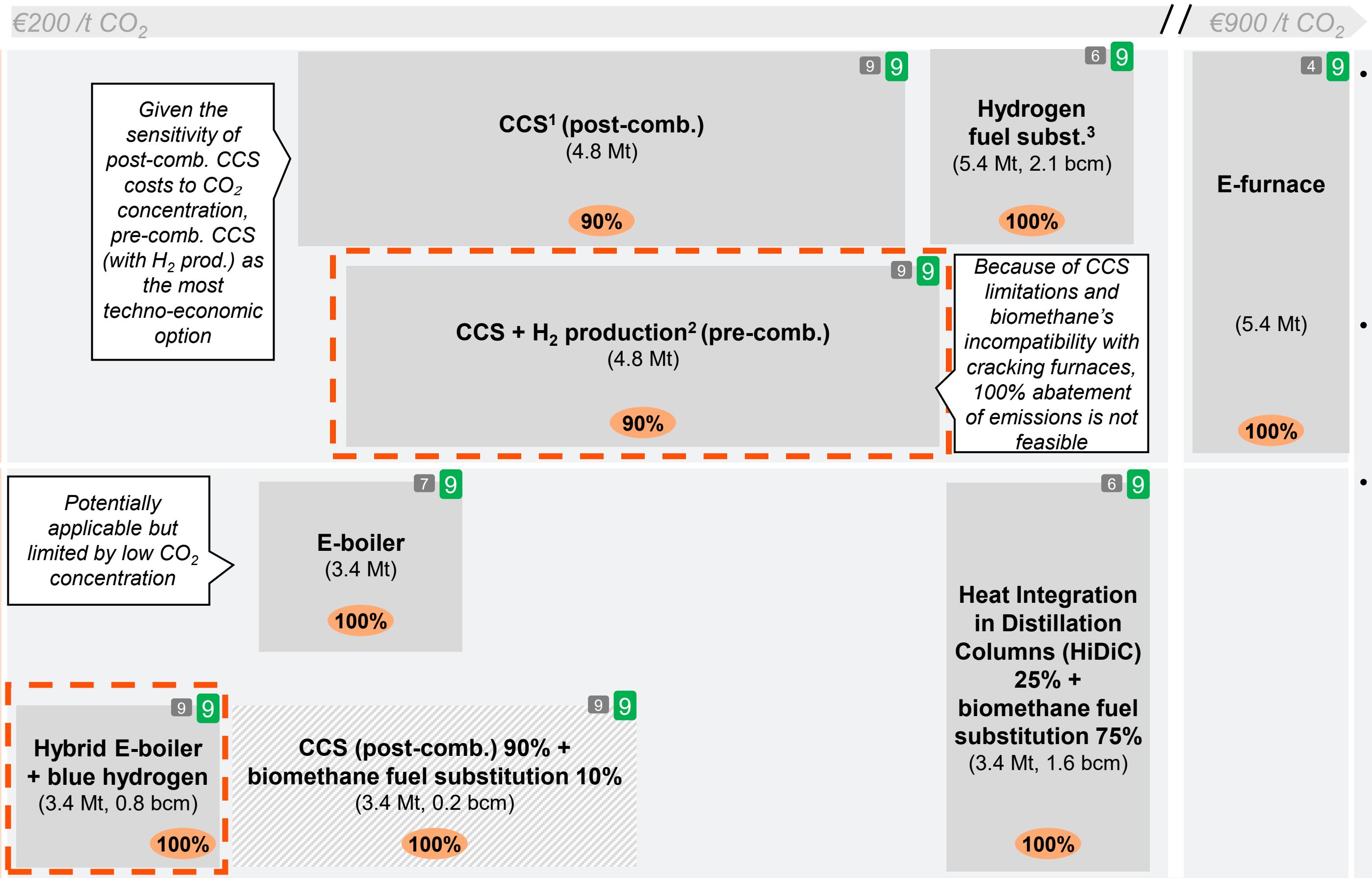
					Change in total fuel use (TWh/year)					
Sub-process	**Abatement option**	**Description**	**Abated CO_2[1]**	**Unit costs**	**Natural gas**	**Biomethane**	**H_2**	**Electricity**	**Heat**	**Key considerations** (incl. TRL, challenges, etc.)
CHP & Boilers *39% of total CO_2 emissions* **3.4 Mt CO_2/year**	**Biomethane fuel substitution**	Substituting natural gas (not fuel gas) with biomethane as CHP/boiler fuel can eliminate 64% of CO_2 emissions	**▼2.2 Mt CO_2/year** *(-64%)*	**300-500 €/t CO_2**	▼15.8	▲15.8	-	-	-	• Biomethane substitution deployment is highly dependent on limited supply and long-term price uncertainty • Biomethane only replaces natural gas uses in the furnaces as to not displace refinery high-value refinery fuel gases
	Blue H_2 fuel substitution	Substituting natural gas (not fuel gas) with blue hydrogen as CHP/boiler fuel can eliminate 64% of CO_2 emissions	**▼2.2 Mt CO_2/year** *(-64%)*	**300-500 €/t CO_2**	▲4.3	-	▲7.0	-	-	• Sites include CHP plants, tied into site power/heat balances; switching to H_2 requires modifying turbines and ensuring stable H_2 supply • Feasibility depends on regional hydrogen infrastructure, with expected commercial deployment after 2030
	Heat Integration Distillation in Columns (HiDiC)	Using integrated heat exchange in distillation columns to reduce energy consumption, reducing CO_2 emissions with ~90%	**▼0.8 Mt CO_2/year** *(-25%)*	**>500 €/t CO_2**	-	-	-	▲2.3	-	• The TRL is approximately 5-6, indicating that extensive commercial use is expected to be restricted • Implementation necessitates new reforming units and modifications to furnace or boiler feed systems

[1] Abatement as percentage of total process emissions

Sources: CBS, NEa, PBL MIDDEN, Speelveldtoets 2025

For basic chemicals, CCS + H_2 production is the most-techno-economic option for cracking furnaces; hybrid e-boilers (with H_2) is the abatement path for CHP’s

Basic chemicals – Abatement pathways



Sector	Process	CO_2 emissions	Abatement pathways		Key considerations
			€200 /t CO_2	*€900 /t CO_2*	
Basic chemicals	**Cracking furnaces** Provides heat for steam cracking *High. temp. 800 – 900°C*	**5.4 Mt** *(61%)*	*Given the sensitivity of post-comb. CCS costs to CO_2 concentration, pre-comb. CCS (with H_2 prod.) as the most techno-economic option* **CCS[1] (post-comb.)** (4.8 Mt) – 90% – TRL 9 / 9 **Hydrogen fuel subst.[3]** (5.4 Mt, 2.1 bcm) – 100% – TRL 6 / 9 **CCS + H_2 production[2] (pre-comb.)** (4.8 Mt) – 90% – TRL 9 / 9 (techno-economic option) *Because of CCS limitations and biomethane’s incompatibility with cracking furnaces, 100% abatement of emissions is not feasible*	**E-furnace** (5.4 Mt) – 100% – TRL 4 / 9	• For **cracking furnaces, pre-combustion CCS via hydrogen production[2]** is the **most techno-economic option; post-combustion CCS[1]** becomes **more cost-effective** only at **high CO_2 concentrations** • **Hybrid e-boilers (with H_2 fuel substitution)** is the most techno-economic abatement option for CHP & boilers for full process abatement • **Electrification** is the sector’s most actively explored pathway, offering **full CO_2 abatement**, with **demonstration projects** underway even though costs remain high
	CHP & boilers Provides heat integration, and on-site electricity *Med. to high. temp. 150 – 525 °C*	**3.4 Mt** *(39%)*	*Potentially applicable but limited by low CO_2 concentration* **E-boiler** (3.4 Mt) – 100% – TRL 7 / 9 **Hybrid E-boiler + blue hydrogen** (3.4 Mt, 0.8 bcm) – 100% – TRL 9 / 9 (techno-economic option) **CCS (post-comb.) 90% + biomethane fuel substitution 10%** (3.4 Mt, 0.2 bcm) – 100% – TRL 9 / 9 **Heat Integration in Distillation Columns (HiDiC) 25% + biomethane fuel substitution 75%** (3.4 Mt, 1.6 bcm) – 100% – TRL 6 / 9		

Note: Abatement costs are inflation-adjusted (2% p.a.) and reported in nominal terms

[1] Post-combustion CCS costs are highly sensitive to CO_2 concentration – flue-gas concentration is assumed to be 5% CO_2 for furnaces; [2] ATR hydrogen production is assumed to operate in a closed loop, providing sufficient hydrogen to power the furnace; [3] Excl. last-mile delivery costs (e.g., CAPEX of last mile delivery) | Sources: CBS, PBL MIDDEN

■ Current TRL | **2040 TRL:** 🟩 High TRL (>7) 🟧 Medium TRL (5-7) 🟥 Low TRL (<5)

XX% Share of abated system emissions ⬚ Techno-economic option(s)

Dutch fertiliser plants are located strategically due to access to deep-sea ports and strong connections to chemical industry hubs (e.g., Chemelot)

Fertiliser – Sector overview

Sector overview

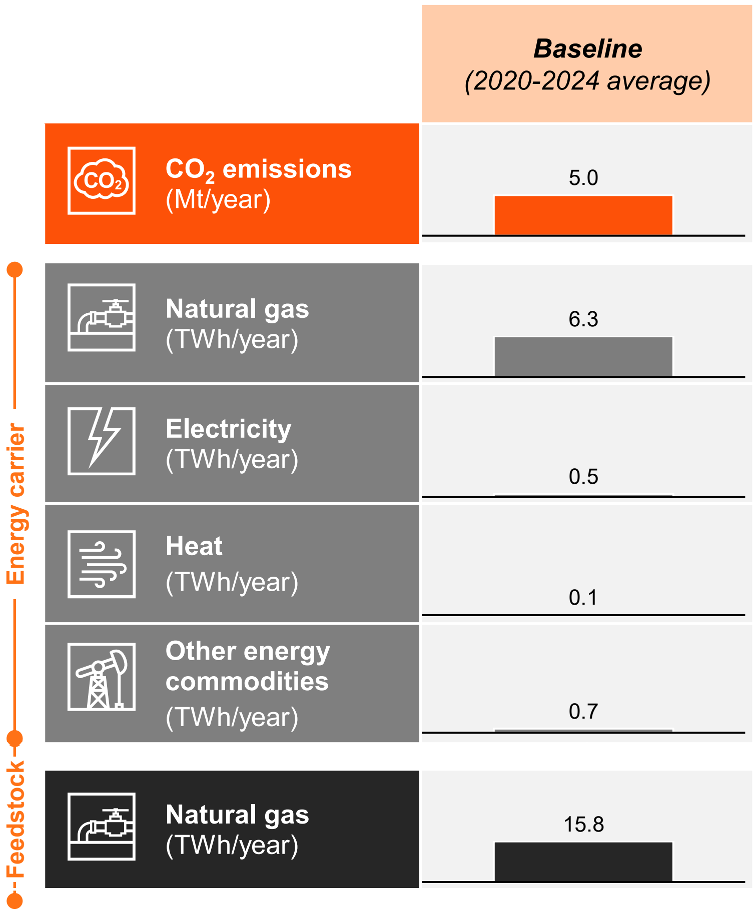
Sector definition	• Fertiliser sector consists of **chemical production plants** that currently heavily rely on natural gas for hydrogen conversion to produce **ammonia** and **ammonia-based fertiliser** (e.g., urea, and ammonium nitrate)
System integration & strategic positioning	• All fertiliser plants within NL are strategically located near **deep-sea harbours** (Amsterdam, Zeeland, Antwerpen) and/ or in a **heavy industry cluster** (Chemelot) • Companies across **different sectors** collaborate closely to **secure hydrogen supply** (e.g., Yara Sluiskil is directly linked with DOW Terneuzen with a hydrogen pipeline)
Products & end-use markets	• End products of the fertiliser sector are (largely) **homogeneous bulk fertilisers** (e.g., ammonia, urea, ammonium nitrate, etc.) as well as **specialty** products mainly used in agriculture

Locations of largest fertiliser plants, incl. market share

Market share¹

①	YARA	~55%	③	ICL	~10%
②	OCI	~30%	④	ROSIER	~5%

Energy profile



	Baseline (2020-2024 average)
CO₂ emissions (Mt/year)	5.0
Natural gas (TWh/year)	6.3
Electricity (TWh/year)	0.5
Heat (TWh/year)	0.1
Other energy commodities (TWh/year)	0.7
Natural gas (TWh/year)	15.8

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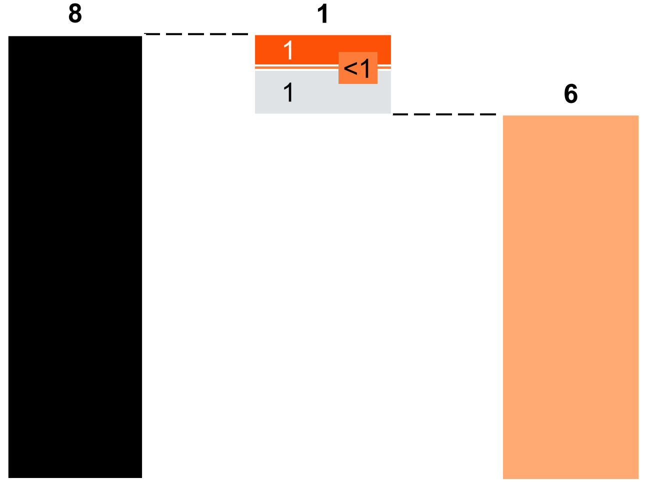
1) Market share is determined based on the production capacity of the companies;
Sources: CBS, PBL MIDDEN, Company websites

Large amounts of natural gas are used in fertiliser production, both as fuel (~6 TWh) and as feedstock (~16 TWh) for hydrogen production

Fertiliser – Energy profile

Fuel use

Fertiliser fuel use by carrier
(In TWh, *5-year average 2020-2024)*



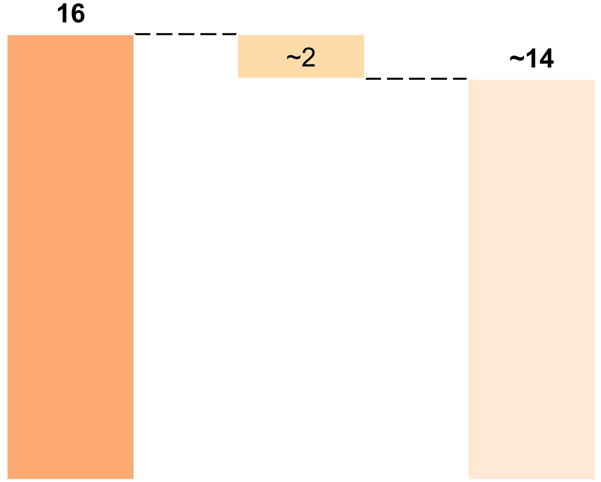
Total fuel used in the Dutch fertiliser sector

Total energy provided by **electricity, heat sources and other energy commodities**

Total natural gas used as fuel for furnaces and boilers

Feedstock use

Natural gas feedstock use for hydrogen prod.
(In TWh, *5-year average 2020-2024)*



Total natural gas used as feedstock for hydrogen production using steam methane reforming (SMR)

Efficiency losses in energy (~10%[1]) **for hydrogen** production

Internal hydrogen production to be used for ammonia production

🟥 Electricity 🟧 Heat 🟧 Natural gas ⬜ Hydrogen ⬛ Total coal and coal products ⬜ Total crudes/ petroleum products ⬜ Total other energy commodities

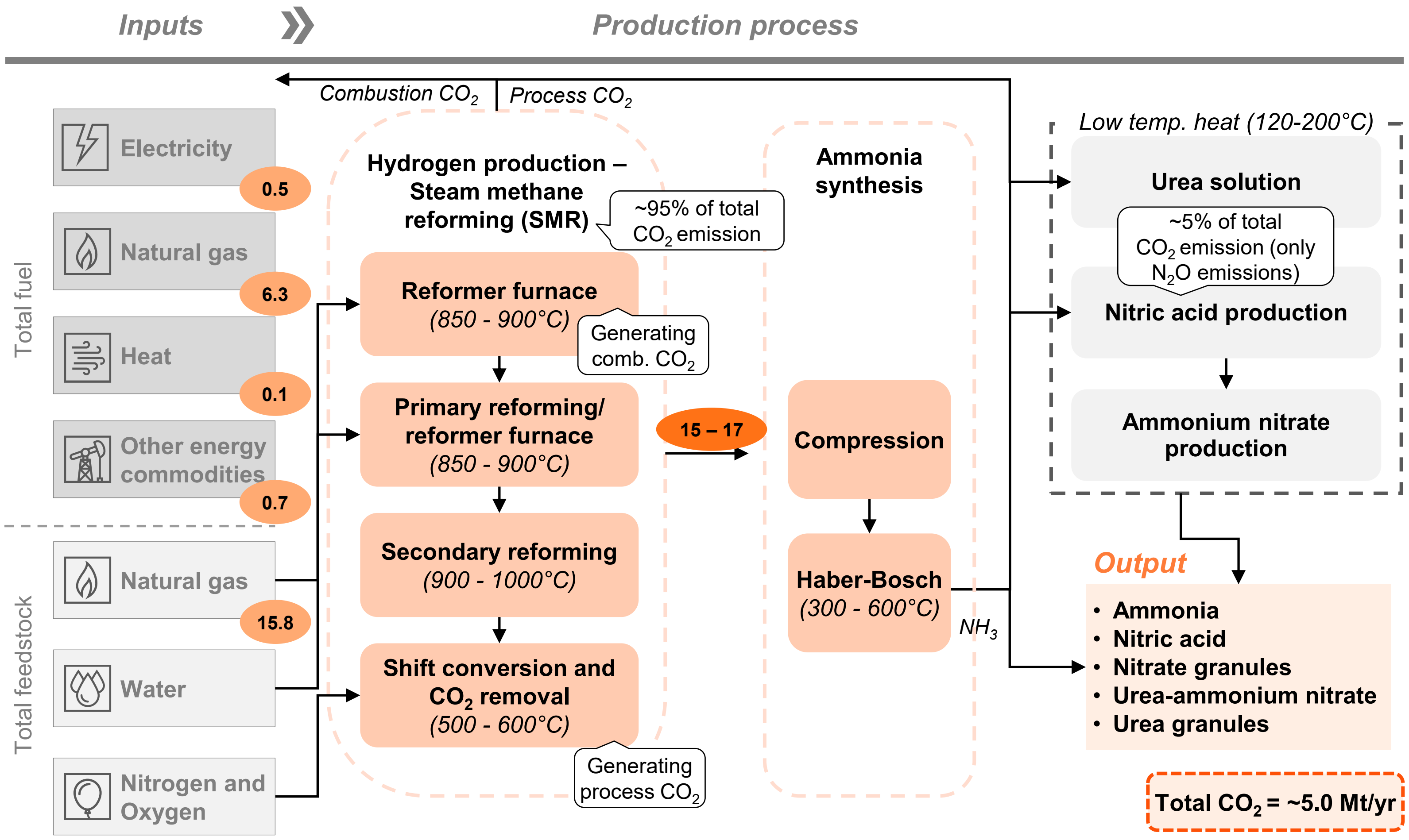
Key insights

- **Fertiliser production** converts on-site produced (grey) hydrogen into **ammonia** and **ammonia-based fertiliser products**
- **Nearly all** energy used in the production process is provided by **natural gas (~6 TWh)** the bulk of which is used in providing energy in the SMR process (producing hydrogen)
- Next to being an important fuel, **feedstock natural gas** is key in the hydrogen production, **~16 TWh of natural gas** is used and is converted into **~14 TWh** of hydrogen (~90% efficiency)
- **All hydrogen** produced via SMR is **routed directly into ammonia production**, serving as the sole **hydrogen feedstock** for the **Haber–Bosch synthesis** loop where it is combined with nitrogen to produce ammonia

[1] Assumed ~10% of natural gas is dedicated to efficiency losses
Sources: CBS, MIDDEN, Review of steam methane reforming as a method of hydrogen production (Szablowski et al. 2025)

Fuel consumption is primarily driven by reformer furnaces while feedstock use is driven by the reforming step required to produce hydrogen for ammonia synthesis

Fertiliser – Process overview



Key insights

- Fuel and feedstock use is **primarily driven** by the steam methane reforming (SMR), which burns **natural gas** to **heat the furnaces** and uses natural gas **feedstock** for **hydrogen production**
- **Large hydrogen** volumes (15 – 17 TWh) are **essential for the ammonia production** (due to ammonia synthesis in Haber-Bosch process), as hydrogen is an **irreplaceable feedstock** for ammonia synthesis
- **Hydrogen production (SMR)** is the **dominant emission** source, is responsible for **~95% of total sector emissions**, of which **~40% of the total emissions** coming from combustion and **~60% of the total emissions** coming from process emissions
- High-purity CO_2 is currently captured on-site and utilised as **input for urea production**, reducing vented emissions
- After producing ammonia, the ammonia serves as the **feedstock for urea and ammonium nitrate**, which are further processed into the final fertiliser products

Sources: CBS, MIDDEN, NEa, energy.nl, Best Available Techniques (BAT), Process implications of electrifying ammonia production (Dechany, 2023)

CO_2 Largest amount of CO_2 emissions ▨ Hydrogen production or consumption ● XX Total usage in TWh ● XX Hydrogen usage in TWh

Fertiliser emissions are dominated by hydrogen production (~95%), and can be abated via electrolysis, CCS, fuel substitution or imported ammonia

Fertiliser – Key characteristics

System unit	Key role	CO_2 emission mechanism	Typical CO_2 concentration	Operating temperature	Hydrogen involvement	Fuel dependence	Abatement options
SMR	- Provides high-temperature heat steam reforming of methane - Produces hydrogen which will be used in the ammonia production process	- **~95% of fertiliser emissions** - **Hydrocarbons react with heat to form syngas (CO + H_2)**, and the water-gas shift reaction converts CO to CO_2 while producing H_2	- **~55-65%** in shifted syngas - **~5-10%** in flue gas	- **Very high operating temperature** (~500–1000 °C)	- **Hydrogen is the product produced,** core chemical reactant	- **Largest consumer of natural gas** as **fuel** and **feedstock**	- **Green hydrogen (electrolysis)** - **CCS (pre-combustion)** - **Biomethane fuel substitution** - **H_2 fuel substitution** - **Imported ammonia**
Ammonia synthesis	- Transforms hydrogen into ammonia through the Haber-Bosch process - Requires continuous high-pressure operation for equilibrium conversion	- **Limited emissions** due to no inherent carbon in process - Nitrogen reacts with hydrogen to obtain ammonia, where CO_2 emissions originate from process gas heater	- n/a	- **High operating temperatures** (~300–600°C)	- **Hydrogen is a required product,** core chemical reactant	- **Uses natural gas** as fuel	- **CCS (Post-combustion)**
Nitric acid production	- Oxidises ammonia to nitric oxide and ultimately nitric acid - Requires continuous catalyst operation for oxidation	- **<5% of fertiliser emissions** - Process emissions are mainly N_2O and not CO_2 - Emissions in NL >70% less than European benchmark	- **~12–18%** N_2O (not CO_2) in tail gas	- **Low operating temperatures** (~120–200°C)	- n/a	- Mainly **uses electricity** as **fuel**	

Focus on hydrogen production, which drives most fertiliser emissions; while ammonia synthesis offers energy-efficiency potential and nitric acid production can further reduce emissions by removing N_2O before the absorption tower

Sources: MIDDEN (2019, 2024), Best Available Technique, Axens, Process implications of electrifying ammonia production (Dechany, 2023)

Fully abating SMR emissions via electrolysis or green hydrogen is costly - CO_2 for urea production to be supplied separately

Fertiliser – Abatement options (1/3)

					Change in total fuel use (TWh/year)					*Change in total feedstock use (TWh/year)*		
Sub-process	**Abatement option**	**Description**	**Abated CO_2[1]**	**Unit costs**	**Natural gas**	**Biomethane**	**H_2**	**Electricity**	**Heat**	**Natural gas**	**Biomethane**	**Key considerations** (incl. TRL, challenges, etc.)
SMR *95% of total emissions* **4.8 Mt CO_2/year**	**Electrolysis (green hydrogen)**	Replacing SMR with renewable-powered electrolysis, eliminating SMR emissions	▼**4.8 Mt CO_2/year** *(-100%)*	**>500 €/t CO_2**	▼6.3	-	-	▲30.7	-	▼15.8	-	• Requires investing in new production unit and high CAPEX • Limitations due to electricity grid capacity constraints • CO_2 required for urea synthesis must be supplied from alternative sources, this option will eliminate process CO_2 currently used for urea
	Green H_2 fuel substitution	Replacing the on-site hydrogen production by obtaining imported green hydrogen, eliminating SMR emissions	▼**4.8 Mt CO_2/year** *(-100%)*	**>500 €/t CO_2**	▼6.3	-	▲16.2	-	-	▼15.8	-	• Relatively easy implementation and high immediately on-site emission reduction • High dependence on hydrogen production from market and might be challenging • CO_2 required for urea synthesis must be supplied from alternative sources, this option will eliminate process CO_2 currently used for urea

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1) Abatement as percentage of total process emissions

Sources: MIDDEN, CBS, NEa, Dincer et al. (2018), Assessing the potential of decarbonisation options for industrial sectors (Gailani et al., 2024), EIGA best practices, Valor International; YARA

Fully abating SMR emissions via imported green ammonia is costly, fuel substitution with biomethane is possible, and does fully abate the sector

Fertiliser – Abatement options (2/3)

					Change in total fuel use (TWh/year)					*Change in total feedstock use (TWh/year)*		
Sub-process	**Abatement option**	**Description**	**Abated CO_2[1]**	**Unit costs**	**Natural gas**	**Biomethane**	**H_2**	**Electricity**	**Heat**	**Natural gas**	**Biomethane**	**Key considerations** (incl. TRL, challenges, etc.)
SMR *95% of total emissions* **4.8 Mt CO_2/year**	**Imported green ammonia from the market**	Replacing the on-site hydrogen production by obtaining imported green ammonia, eliminating all SMR emissions	▼**4.8 Mt CO_2/year** *(-100%)*	**>500 €/t CO_2**	▼6.3	-	-	-	-	▼15.8	-	• Importing green ammonia eliminates onsite process CO_2 for urea production for key players (under constant output assumptions caps the domestic CO_2 emissions that imports can avoid) • CO_2 required for urea synthesis must be supplied from alternative sources, replacing currently available process CO_2 • High dependency on imported ammonia volumes is introduced.
	Biomethane fuel and feedstock substitution	Substituting natural gas in the existing SMR with biomethane to eliminating lifecycle emissions of the total sector emissions	▼**4.8 Mt CO_2/year** *(-100%)*	**<300 €/t CO_2**	▼6.3	▲6.3	-	-	-	▼15.8	▲15.8	• Biomethane substitution deployment is highly dependent on limited supply and long-term price uncertainty • Biomethane will be used primarily to close residual emissions to reach full abatement after structural abatement options are deployed • Application feasibility depends on availability of required volumes

1) Abatement as percentage of total process emissions
Sources: MIDDEN, CBS, NEa, Assessing the potential of decarbonisation options for industrial sectors (Gailani et al., 2024), EIGA best practices, Valor International; YARA

Combining pre- and post-combustion CCS can enable significant abatement of the fertiliser sector to abate; however, a full CCS retrofit on existing SMRs is unlikely

Fertiliser – Abatement options (3/3)

					Change in total fuel use (TWh/year)					*Change in total feedstock use (TWh/year)*		
Sub-process	**Abatement option**	**Description**	**Abated CO_2[1]**	**Unit costs**	**Natural gas**	**Biomethane**	**H_2**	**Electricity**	**Heat**	**Natural gas**	**Biomethane**	**Key considerations** (incl. TRL, challenges, etc.)
SMR *95% of total emissions* **4.8 Mt CO_2/year**	**CCS (pre- & post-combustion)**	Implementing a combination of pre- and post-combustion CCS on all CO_2 released from hydrogen production	▼**4.5 Mt CO_2/year** *(-94%)*	***Gaseous transport***								• Technically enables near-complete (~90-95%) SMR emission abatement – however, industry players have indicated that full chain CCS retrofits on SMRs are unlikely to see large-scale adoption
				<300 €/t CO_2	-	-	-	▲0.8	▲2.0	-	-	
				Liquid transport								
				<300 €/t CO_2	-	-	-	▲1.0	▲2.0	-	-	
	CCS (post-combustion)	Capturing low-purity CO_2 generated from natural gas used as fuel during hydrogen production	▼**4.0 Mt CO_2/year** *(-85%)*	***Gaseous transport***								• Higher capture cost per ton due to low CO_2 concentration and large gas volumes • Attractive as a retrofit option, but insufficient alone for net-zero pathways
				<300 €/t CO_2	-	-	-	▲0.8	▲2.7	-	-	
				Liquid transport								
				<300 €/t CO_2	-	-	-	▲0.9	▲2.7	-	-	
	CCS (Pre-combustion)	Capturing high-purity CO_2 from reforming process gas, typically addressing ~60% of total SMR emissions at lower cast	▼**2.9 Mt CO_2/year** *(-60%)*	***Liquid transport***								• CCS CAPEX and fixed OPEX investment in fertiliser plants is lower[2] as process CO_2 capture and part of the CCS utilities are already embedded in ammonia prod. • ~70% of high-purity process CO_2 used for urea prod.
				<300 €/t CO_2	-	-	-	▲0.5	▲0.9	-	-	
				Gaseous transport								
				<300 €/t CO_2	-	-	-	▲0.6	▲0.9	-	-	

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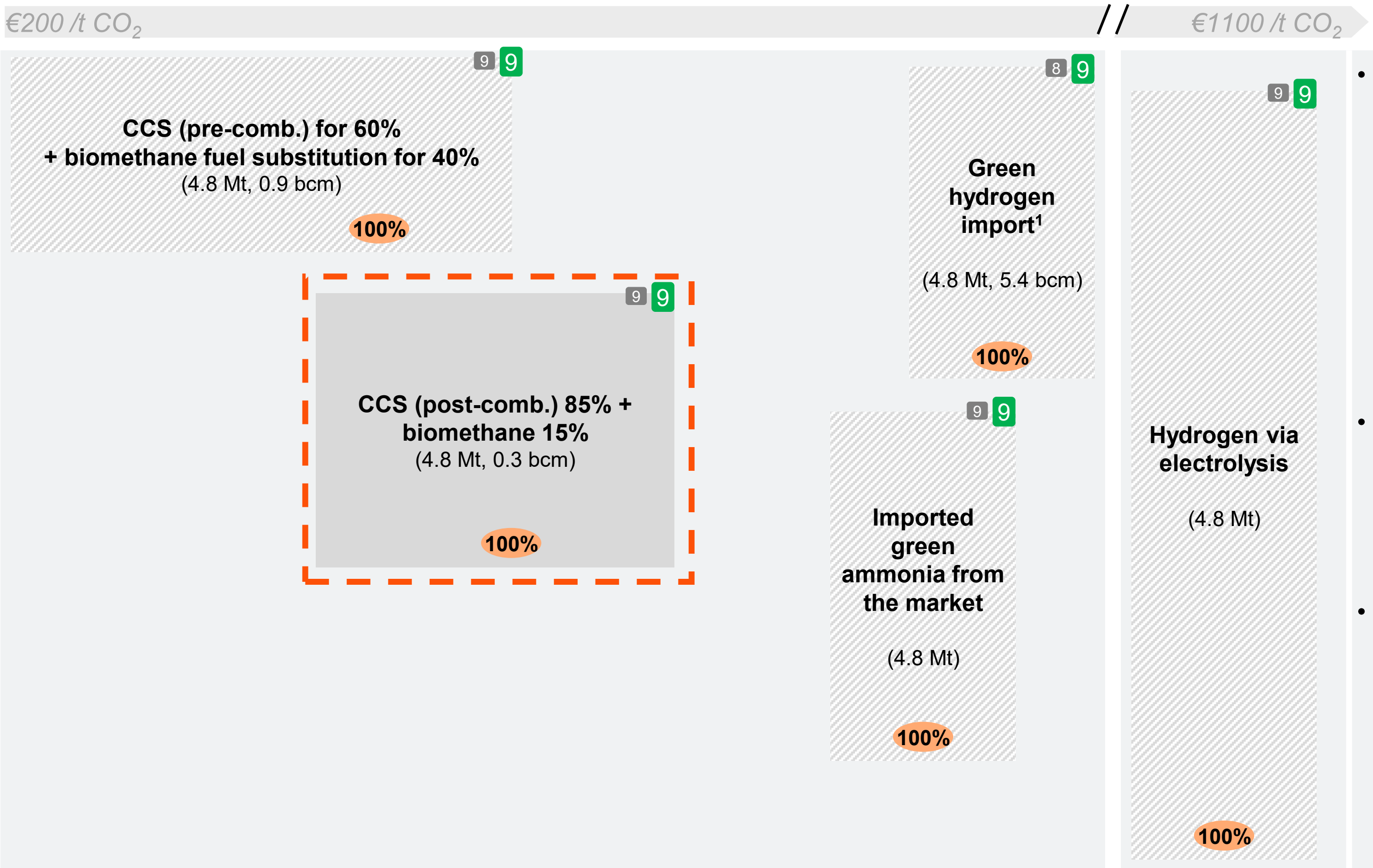
1) Abatement as percentage of total process emissions; CCS capture costs are assumed to represent ~75% of total CCS CAPEX, with the majority related to CO_2 capture and the remainder to compression units and retrofit/integration costs. For fertiliser plants applying pre-combustion CCS, a cost reduction of ~60% is applied to CAPEX and fixed OPEX, reflecting the presence of existing process CO_2 capture and partial compression/utilities | Sources: MIDDEN, CBS, NEa, Dincer et al. (2018), Assessing the potential of decarbonisation options for industrial sectors (Gailani et al., 2024), EIGA best practices, Zero Emissions Platform (Costs of CO_2 Capture, Transport and Storage), IEAGHG (2017)

Most techno-economically efficient options for SMR will be post-comb. CCS (85%) combined with biomethane (15%) for deep abatement

Fertiliser – Abatement pathways

Sector	Process	CO_2 emissions
Fertiliser	**SMR** Natural gas used as feedstock and furnace fuel in reforming process to generate hydrogen (core feedstock for ammonia synthesis) *Very high temp. ~800 – 900 °C*	**4.8 Mt** *(95%)*[2]

Abatement pathways



Key considerations

- For SMRs, **pre-combustion CCS for 60% with biomethane usage for the remaining 40%** is potentially the **lowest-cost option**, however due to the high dependency on **biomethane** (0.9 bcm) firms are not expected to choose this route as the last 40% abatement requirement can drive biomethane prices to the higher end
- **Post-combustion CCS for 85% with biomethane for the last 15%** turns out to be the most techno-economically efficient option due to the certainty around abatement costs
- Importing **green ammonia/ hydrogen** or producing **green hydrogen via electrolysis** would **eliminate process CO_2** that is currently used for urea production; hence these are not considered techno-economically possible to implement

Note: Abatement costs are inflation-adjusted (2% p.a.) and reported in nominal terms

1) Green hydrogen imported by ship as green ammonia, so this would always be more expensive than importing green ammonia directly; 2) We focus on abating hydrogen production, as only process efficiency options are available for other processes within fertiliser | Sources: CBS, PBL MIDDEN, Science direct

⬛ Current TRL | **2040 TRL:** 🟩 High TRL (>7) 🟧 Medium TRL (5-7) 🟥 Low TRL (<5)

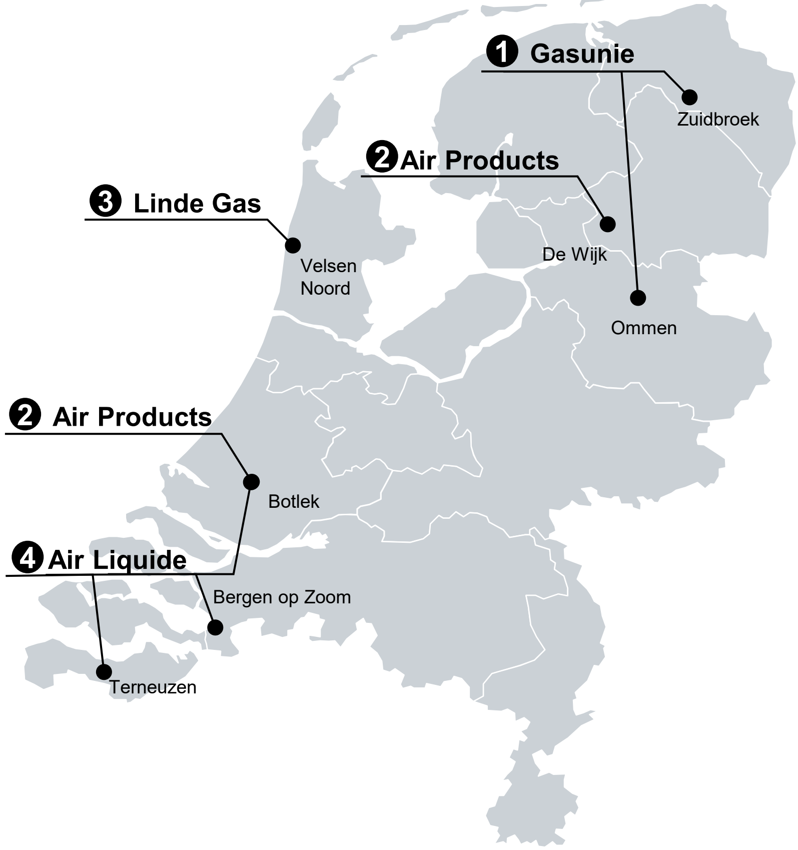
XX% Share of abated system emissions ⬚ Techno-economic option(s)

The Dutch industrial gases sector is spanned by four large players and is highly dependent on natural gas, alongside significant heat and electricity use

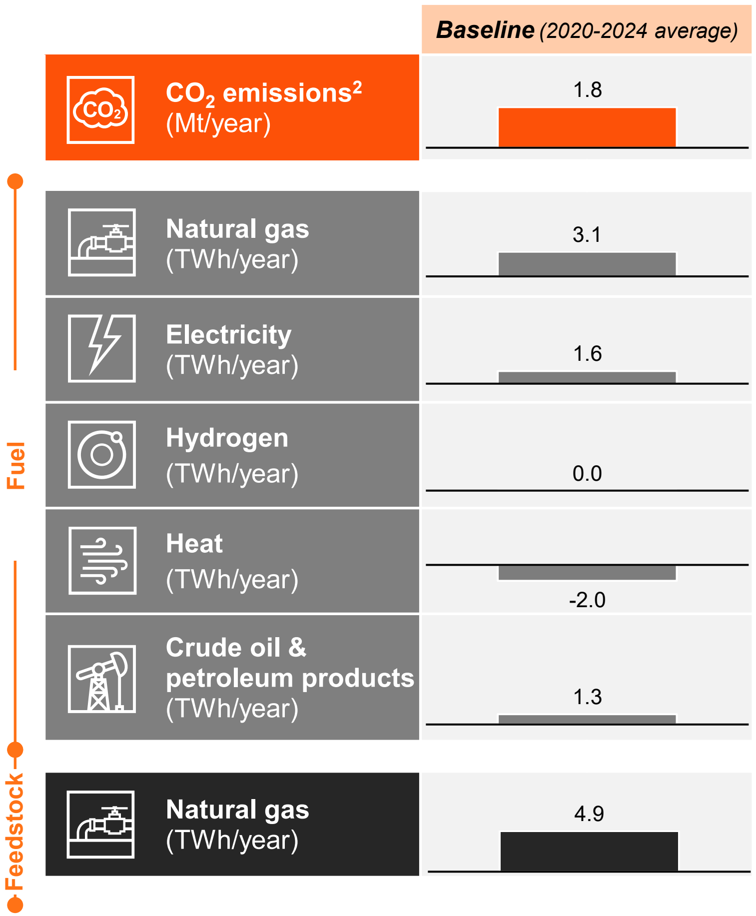
Industrial gases – Sector overview

Sector overview

Sector definition	• The Dutch industrial gases sector **produces hydrogen, carbon monoxide, syngas**, and **atmospheric gases** like oxygen, nitrogen, and argon for various industries • Hydrogen and CO are primarily produced via **steam methane reforming (SMR)** and **autothermal reforming**, using **natural gas** and **emitting significant CO_2**
System integration & strategic positioning	• Four main companies **operate multiple ASUs** and hydrogen/CO plants in industrial areas • **Hydrogen production** is closely integrated with the energy and chemical industries, with **merchant hydrogen** sold to **refineries and chemical plants**, benefiting from synergies with refinery gas and downstream processes • The sector **relies heavily on natural gas**, **heat**, and **electricity**, with some sites using on-site CHP systems to provide heat and power
Products & end-use markets	• The industrial gases sector provide a small set of fundamental gases that act as universal building blocks across the Dutch industry • These gases are **essential enablers of chemical reactions, material processing,** and **energy conversion**



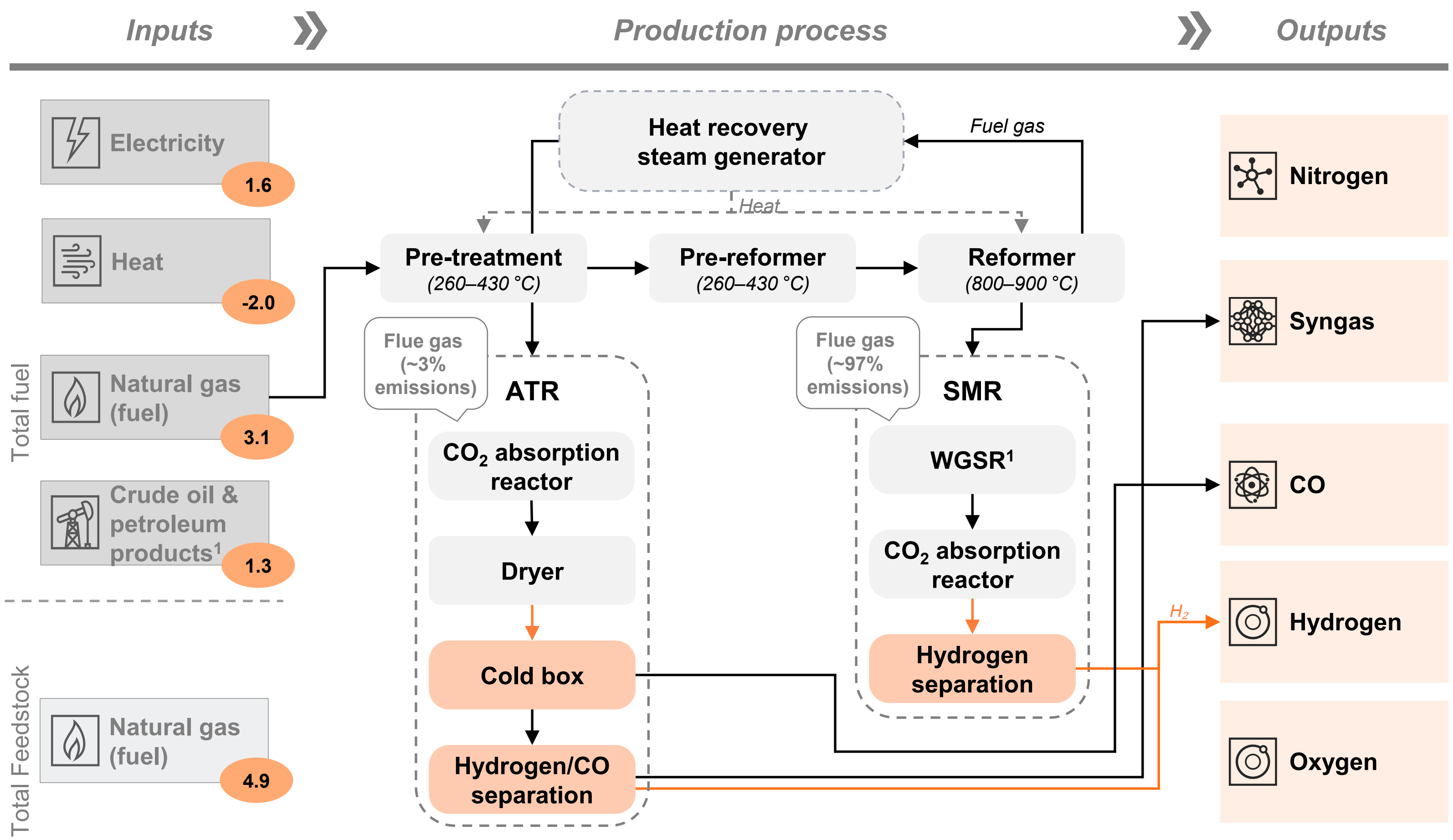
Energy profile



Sources: CBS, PBL MIDDEN

For industrial gases, SMR is the dominant production process and the primary source of CO_2 emissions, accounting over ~97% of total emissions

Industrial gases – Process overview



Inputs » *Production process* » *Outputs*

Total fuel

- Electricity 1.6
- Heat -2.0
- Natural gas (fuel) 3.1
- Crude oil & petroleum products[1] 1.3

Total Feedstock

- Natural gas (fuel) 4.9

Heat recovery steam generator

Fuel gas

Heat

Pre-treatment (*260–430 °C*) → Pre-reformer (*260–430 °C*) → Reformer (*800–900 °C*)

Flue gas (~3% emissions)

ATR

CO_2 absorption reactor → Dryer → Cold box → Hydrogen/CO separation

Flue gas (~97% emissions)

SMR

WGSR[1] → CO_2 absorption reactor → Hydrogen separation

H_2

Outputs:

- Nitrogen
- Syngas
- CO
- Hydrogen
- Oxygen

Key insights

- **Industrial hydrogen, carbon monoxide, and syngas** are primarily produced via **natural gas reforming**, a process that requires significant energy and results in direct CO_2 **emissions:**
  1. **Steam Methane Reforming (SMR) (~97%)**: In this method, natural gas reacts with heat at 800–950 °C to produce syngas (H_2 + CO), followed by water-gas shift and pressure swing adsorption (PSA) purification steps to produce pure hydrogen
  2. **Autothermal Reforming (ATR) (~3%)**: This technique involves a single reactor where natural gas reacts with oxygen and heat, combining partial oxidation and catalytic reforming to produce syngas at high pressure with integrated heat recovery
- These processes account for the majority of direct CO_2 emissions, stemming from both fuel combustion and the reforming reactions themselves

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1) Water Gas Shift Reaction

Sources: CBS, NEa, PBL MIDDEN, Speelveldtoets 2025

CO_2 Largest amount of CO_2 emissions ▨ Hydrogen production or consumption ● XX Total usage in TWh ● XX Hydrogen usage in TWh

Industrial gas production is dominated by high temperature operations within SMR (~800-900°C), and has a dependence on natural gas as fuel and feedstock

Industrial gases – Key characteristics

Sub-processes	Key role	CO_2 emission mechanism	Typical CO_2 concentration	Operating temperature	Hydrogen involvement	Fuel dependence	Abatement options
SMR	• Produces **high-purity hydrogen** for downstream processes (e.g., syngas conditioning, ammonia synthesis) • Provides **heat recovery** and **supports site utilities**	• **~97% of industrial gases industry emissions** (of total, ~52% H2 + CO SMR and ~45% pure H2 SMR) • Act as the **largest single emitter** at **production sites** • **CO_2 released** from **reforming reaction** and **fuel combustion** required to achieve high reformer temperatures	• **~8-10%**	• **Very high operating temperature** (~800-900 °C)	• **Primary hydrogen production route;** hydrogen is the core product	• Major consumer **of natural gas** as both **feedstock and fuel**	• **Biomethane fuel substitution** • **CCS (pre-combustion)** • **CCS (post-combustion)** • **Green hydrogen (electrolysis)**
ATR	• Produces **syngas by partially oxidising** natural gas with oxygen and heat and then reforming it catalytically • Supports **downstream hydrogen** and **CO-rich synthesis** routes (e.g., methanol, Fischer–Tropsch)	• **~3% of industrial gases industry emissions** • CO_2 released from **fuel-gas combustion** and **syngas conditioning** steps	• **~4-15%**	• **Very high operating temperature** (~950-1150 °C)	• **Limited direct hydrogen output**; product is **syngas** with tuneable **H_2/CO ratio**	• **Mix of natural gas and fuel gas**	• **CCS (pre-combustion)** • **Biomethane fuel substitution**

PwC

Sources: CBS, NEa, PBL MIDDEN, Speelveldtoets 2025, Carbon capture storage and use technical, economic and societal perspectives (Markewitz & Bongartz, 2015)

SMRs can co-produce H_2 and CO, making up 51% of emissions - some carbon ends up in the final product, rather than being emitted

Industrial gases – Abatement options (1/4)

Sub-process	Abatement option	Description	Abated CO_2[1]	Unit costs	Change in total fuel + feedstock use (TWh/year)					Key considerations (incl. TRL, challenges, etc.)
					Natural gas	Biomethane	H_2	Electricity	Heat	
SMR (H_2 + CO) *~51% of total CO_2 emissions* **0.9 Mt CO_2/year**	**Biomethane fuel & feedstock substitution**	Replacing natural gas with biomethane as fuel and feedstock in the SMR can fully eliminate direct CO_2 emissions	▼**0.9 Mt CO_2/year** *(-100%)*	<300 €/t CO_2	▼4.8	▲4.8	-	-	-	• Drop-in replacement for natural gas with minimal CAPEX, but large volumes needed to substitute SMR feedstock and fuel • Biomethane availability and price volatility are major constraints; sector-scale uptake unlikely without long-term contracting mechanisms • Part of the carbon ends up in the final product (CO), meaning that biomethane reduces both scope 1 and 2 emissions. The unit cost per t CO_2 in scope 1 is therefore higher than in other processes.
	Pre & post-combustion CCS	Performing both pre-combustion CCS on the product stream and post-combustion CCS on the flue gas from burners, capturing ~95% of the CO_2	▼**0.8 Mt CO_2/year** *(-94%)*	***Gaseous transport***						• Maximum abatement potential, capturing CO_2 both from syngas and furnace combustion • Technically enables near-complete (~90-95%) SMR emission abatement – however, industry players have indicated that full chain CCS retrofits on SMRs are unlikely to see large-scale adoption
				<300 €/t CO_2	-	-	-	▲0.2	▲0.4	
				Liquid transport						
				<300 €/t CO_2	-	-	-	▲0.2	▲0.4	
	Post-combustion CCS	Capturing ~85% of the CO_2 emissions from the flue gases in burners of the SMR	▼**0.8 Mt CO_2/year** *(-85%)*	***Gaseous transport***						• Captures from flue gas; suitable for retrofits but has higher energy penalty due to lower CO_2 concentration • Requires large absorber/stripper units, heat extraction, and space - often a significant site constraint • Best suited for clusters with pipeline connections and stable waste-heat availability
				<300 €/t CO_2	-	-	-	▲0.1	▲0.5	
				Liquid transport						
				<300 €/t CO_2	-	-	-	▲0.2	▲0.5	

1) Abatement as percentage of total process emissions

Sources: CBS, NEa, PBL MIDDEN, Speelveldtoets 2025

For an SMR with pure hydrogen, these process emission could be fully abated by either biomethane fuel substitution or green H_2 via electrolysis; CCS abates 94%

Industrial gases – Abatement options (2/4)

Sub-process	Abatement option	Description	Abated CO_2[1]	Unit costs	*Change in total fuel + feedstock use (TWh/year)*					Key considerations (incl. TRL, challenges, etc.)
					Natural gas	Biomethane	H_2	Electricity	Heat	
SMR (H_2) *45% of total CO_2 emissions* **0.8 Mt CO_2/year**	**Biomethane fuel & feedstock substitution**	Replacing natural gas with biomethane as fuel and feedstock in the SMR can fully eliminate direct CO_2 emissions	**▼0.8 Mt CO_2/year** *(-100%)*	**<300 €/t CO_2**	▼2.9	▲2.9	-	-	-	• Drop-in replacement for natural gas with minimal CAPEX, but large volumes needed to substitute SMR feedstock and fuel • Biomethane availability and price volatility are major constraints; sector-scale uptake unlikely without long-term contracting mechanisms • Does not eliminate process-related CO_2 from reforming reactions; only abates combustion emissions • Application feasibility depends on availability of required volumes
	Electrolysis (Green H_2)	Producing green hydrogen through electrolysis instead of current grey hydrogen production abates all CO_2 emissions	**▼0.8 Mt CO_2/year** *(-100%)*	**>500 €/t CO_2**	▼2.9	-	-	▲2.6	-	• Fully eliminates SMR-related emissions for hydrogen production but requires complete process replacement, new utilities, and large-scale electrical infrastructure • High OPEX risk due to electricity price volatility; dependent on cheap renewable power • TRL high for electrolysis, but industrial integration at required scale is still developing
	Pre & post-combustion CCS	Performing both pre-combustion CCS on the product stream and post-combustion CCS on the flue gas from burners allows for capturing ~95% of the CO_2	**▼0.8 Mt CO_2/year** *(-94%)*	***Gaseous transport***						• Maximum abatement potential, capturing CO_2 both from syngas and furnace combustion • Technically enables near-complete (~90-95%) SMR emission abatement – however, industry players have indicated that full chain CCS retrofits on SMRs are unlikely to see large-scale adoption
				<300 €/t CO_2	-	-	-	▲0.1	▲0.3	
				Liquid transport						
				<300 €/t CO_2	-	-	-	▲0.2	▲0.3	

[1] Abatement as percentage of total process emissions

Sources: CBS, NEa, PBL MIDDEN, Speelveldtoets 2025

Post-combustion CCS allows for higher reduction of CO_2 emissions (85%) than pre-combustion CCS (60%) at the pure H_2 SMR

Industrial gases – Abatement options (3/4)

Sub-process	Abatement option	Description	Abated CO_2[1]	Unit costs	Change in total fuel use (TWh/year)					Key considerations (incl. TRL, challenges, etc.)
					Natural gas	Biomethane	H_2	Electricity	Heat	
SMR (H_2) *45% of total CO_2 emissions* **0.8 Mt CO_2/year**	**Post-combustion CCS**	Capturing ~85% of the CO_2 emissions from the flue gases in burners of the SMR	▼**0.7 Mt CO_2/year** *(-85%)*	***Gaseous transport***						• Captures from flue gas; suitable for retrofits but has higher energy penalty due to lower CO_2 concentration • Requires large absorber/stripper units, heat extraction, and space - often a significant site constraint • Best suited for clusters with pipeline connections and stable waste-heat availability
				<300 €/t CO_2	-	-	-	▲0.1	▲0.5	
				Liquid transport						
				<300 €/t CO_2	-	-	-	▲0.1	▲0.5	
	Pre-combustion CCS	Performing pre-combustion CCS on the (high-purity) CO_2 in the product stream of the SMR	▼**0.5 Mt CO_2/year** *(-60%)*	***Gaseous transport***						• Captures reformer syngas before combustion, delivering large emission reductions at relatively low transport cost • Residual furnace emissions remain (~40%), requiring additional abatement. • Gaseous transportation requires integration of CO_2 compression and pipeline connections; suitable for clusters with pipeline access • Liquid transport CCS is technically similar to gaseous transport but oriented toward sites without pipeline access, offering deployment flexibility for dispersed assets, requiring CO_2 liquefaction capacity and off-site storage arrangements
				<300 €/t CO_2	-	-	-	▲0.1	▲0.2	
				Liquid transport						
				<300 €/t CO_2	-	-	-	▲0.1	▲0.2	

1) Abatement as percentage of total process emissions
Sources: CBS, NEa, PBL MIDDEN, Speelveldtoets 2025

For ATR units (3% of emissions), post combustion CCS and biomethane as fuel can fully abate the ATR; unit prices are comparable for both options

Industrial gases – Abatement options (4/4)

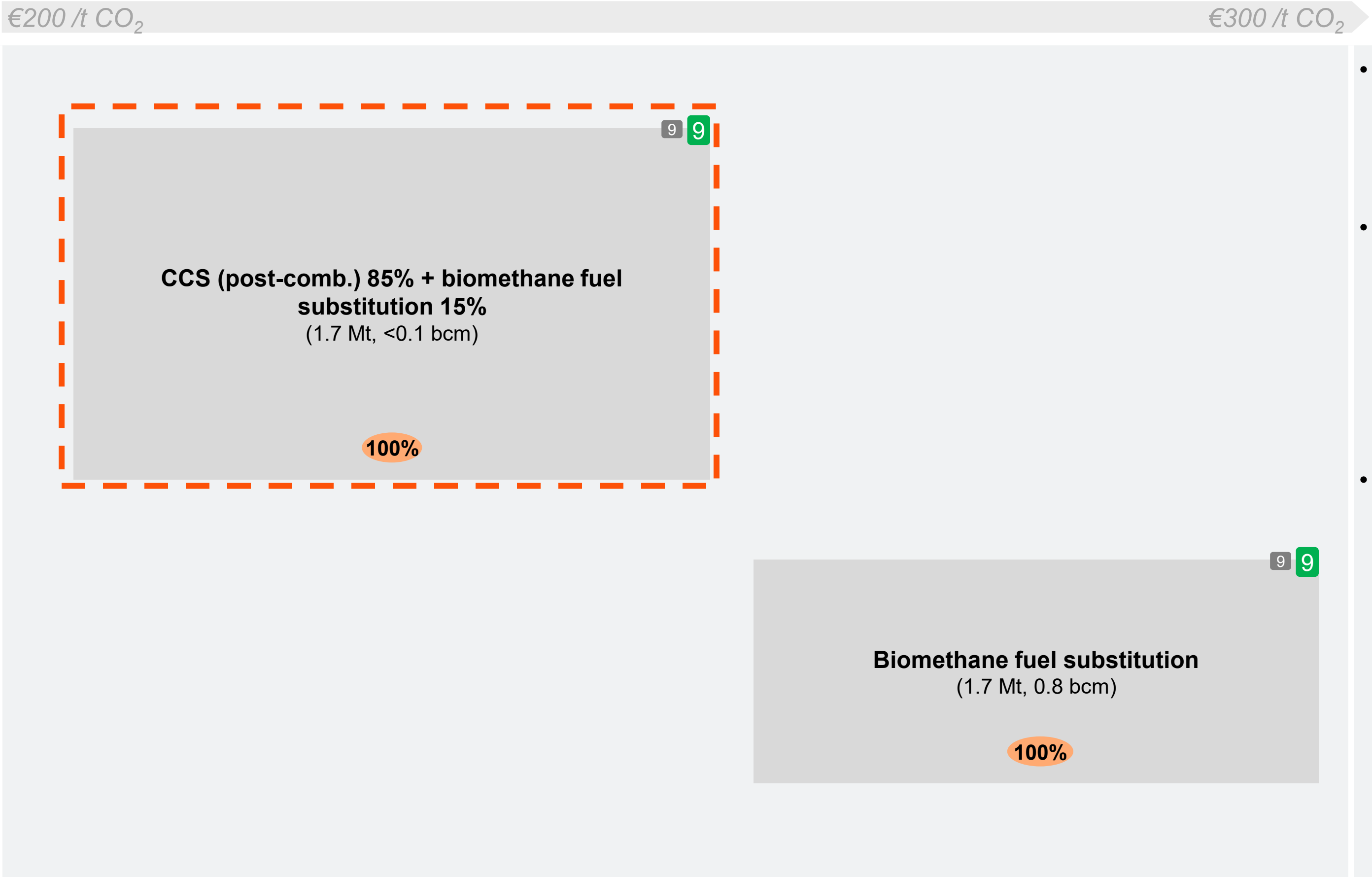
Sub-process	Abatement option	Description	Abated CO_2[1]	Unit costs	*Change in total fuel use (TWh/year)*					Key considerations (incl. TRL, challenges, etc.)
					Natural gas	Biomethane	H_2	Electricity	Heat	
ATR (syngas) *~3% of total CO_2 emissions* **<0.1 Mt CO_2/year**	**Post-combustion CCS**	Performing post-combustion CCS on the combined product + flue gas stream of the ATR	▼**<0.1Mt CO_2/year** *(-100%)*	*Gaseous transport*						• TRL of post-combustion CCS is 8, making deployment by 2040 likely • Spatial constraints at industrial sites often limit feasibility • In ATR, the full flue-gas stream is captured without dilution by air, maintaining a higher CO_2 concentration, which improves capture efficiency and lowers energy consumption per tonne of CO_2 removed
				<300 €/t CO_2	-	-	-	▲<1	▲<1	
				Liquid transport						
				<300 €/t CO_2	-	-	-	▲<1	▲<1	
	Biomethane fuel substitution	Replacing natural gas with biomethane as fuel and feedstock in the ATR can fully eliminate direct CO_2 emissions	▼**<0.1 Mt CO_2/year** *(-100%)*	300-500 €/t CO_2	▼0.2	▲0.2	-	-	-	• Full deployment will depend on biomethane availability (and corresponding price) • As syngas also contains carbon, emissions per methane input are relatively low, and costs per abated emission are high (as is the case for H_2/CO co-production). It produces 'green syngas'. • Supply is constrained, with strong competition from other industries; application feasibility depends on availability of required volumes

[1] Abatement as percentage of total process emissions

Sources: CBS, NEa, PBL MIDDEN, Speelveldtoets 2025

Combining post-combustion CCS with biomethane fuel substitution is the most techno-economical abatement option for hydrogen/CO production

Industrial gases – Abatement pathways (1/2)

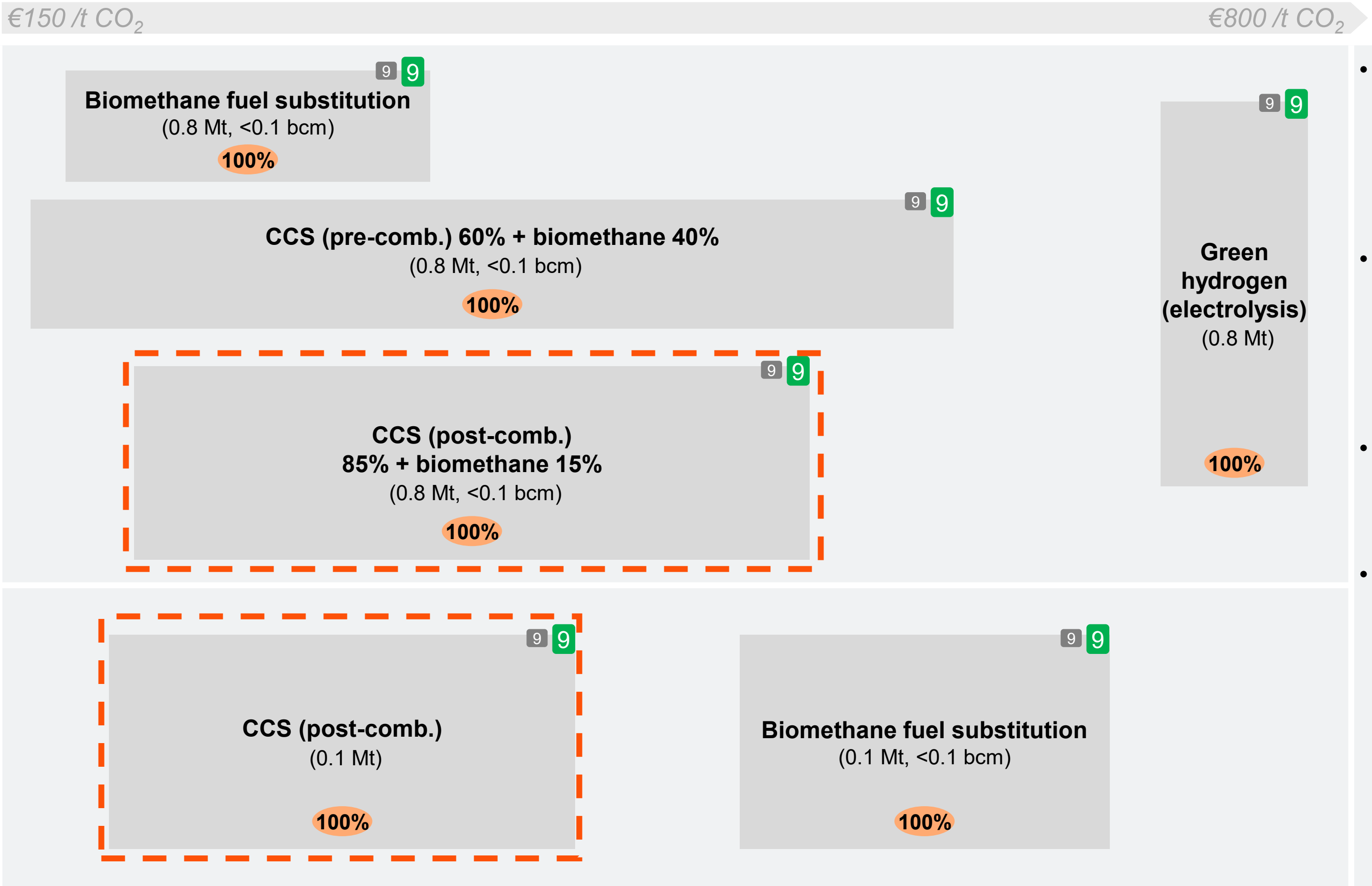
Sector	Process	CO_2 emissions	Abatement pathways	Key considerations
Industrial gases	**H_2 / CO co-production (SMR)** Converting natural gas into hydrogen and carbon monoxide through steam reforming *Very high temp.* ~800-1150 °C	**1.7 Mt** *(51%)*	*€200 /t CO_2* → *€300 /t CO_2* **CCS (post-comb.) 85% + biomethane fuel substitution 15%** (1.7 Mt, <0.1 bcm) 100% **Biomethane fuel substitution** (1.7 Mt, 0.8 bcm) 100%	• **Post-combustion CCS in combination with biomethane** is the most techno-economical option for abating all hydrogen/ CO production-based emissions • While **pre-combustion CCS** has the **lowest unit cost; post-combustion CCS** has a **lower range** due to a smaller dependence of biomethane to reach 100% abatement and is therefore considered the **most techno-economical option** • **Using biomethane fuel substitution,** part of the carbon **ends up in the final product** (as CO), rather than being emitted; consequently, **not all biomethane reduces scope 1 emissions** and the resulting **unit cost is relatively high**

Note: Abatement costs are inflation-adjusted (2% p.a.) and reported in nominal terms; 1) CAPEX of last mile delivery of hydrogen is around €1M per km pipeline
Sources: CBS, PBL MIDDEN

■ Current TRL | **2040 TRL:** 🟩 High TRL (>7) 🟧 Medium TRL (5-7) 🟥 Low TRL (<5)
XX% Share of abated system emissions ⬚ Techno-economic option(s)

H_2 production can be abated by post-comb CCS combined with biomethane and syngas production can be abated fully with only post-combustion CCS

Industrial gases – Abatement pathways (2/2)



Sector	Process	CO_2 emissions	Abatement pathways (€150 /t CO_2 → €800 /t CO_2)	Key considerations
Industrial gases	**H2 production (SMR)** Producing pure hydrogen through steam reforming, followed by a water shift *Very high temp.* ~950-1150 °C	**0.8 Mt** *(45%)*	9 9 **Biomethane fuel substitution** (0.8 Mt, <0.1 bcm) 100% 9 9 **CCS (pre-comb.) 60% + biomethane 40%** (0.8 Mt, <0.1 bcm) 100% 9 9 **CCS (post-comb.) 85% + biomethane 15%** (0.8 Mt, <0.1 bcm) 100% ⬚ 9 9 **Green hydrogen (electrolysis)** (0.8 Mt) 100%	- Both complete **biomethane fuel substitution** and **pre-combustion with biomethane fuel substitution** are **highly dependent on biomethane price and availability** - **Post-combustion CCS** only requires 15% biomethane for **full abatement**, leading to a **narrower price range;** hence the **most techno-economic option** - **Post-combustion CCS on ATRs** can abate up to **100% of emissions related to syngas production** - **Biomethane fuel substitution unit costs are high for syngas production**, for the same reason as in H_2/CO co-production
	Syngas production (ATR) Producing syngas by combining oxidation and steam reforming *Very high temp.* ~950-1150 °C	**0.1 Mt** *(3%)*	9 9 **CCS (post-comb.)** (0.1 Mt) 100% ⬚ 9 9 **Biomethane fuel substitution** (0.1 Mt, <0.1 bcm) 100%	

▩ Current TRL | **2040 TRL:** 🟩 High TRL (>7) 🟧 Medium TRL (5-7) 🟥 Low TRL (<5)

XX% Share of abated system emissions ⬚ Techno-economic option(s)

Note: Abatement costs are inflation-adjusted (2% p.a.) and reported in nominal terms
Sources: CBS, PBL MIDDEN

Steel production in the Netherlands is highly concentrated, only at Tata Steel IJmuiden, and emits approximately 11.3 Mt CO_2 per year

Steel – Sector overview

Sector overview

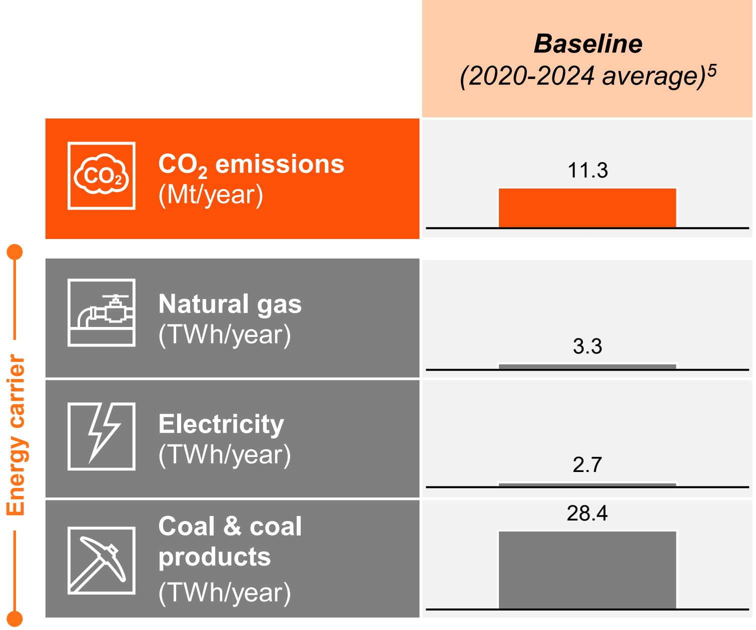
Sector definition	• Steel production is an **emission heavy** process that convert iron ore into **bulk steel** by mainly using **blast furnaces (BF)** and **basic oxygen furnaces (BOF)**
System integration & strategic positioning	• Dutch steelmaking production is represented by a single plant strategically located near a **deep-seaport and extensive rail infrastructure** which is vital for steel export to the rest of Europe • The steel facility is linked to an **on-site power plant** that generates electricity **primarily for steel production.** The **total emissions** of 11.3 Mt CO_2 shown on the right **include emissions** from the **on-site power generators** • Primary served markets are **automotive, manufacturing and construction**
Products & end-use markets	• The virgin steel sector produces **homogenous bulk steel** such as **slabs, hot-rolled coil (HRC)** and **galvanised steel**

Location of steel plants, incl. sectors served

Sectors served[1]

Manufactured goods[2]	~40%	Construction	~20%
Automotive	~25%	Others[3]	~15%

Energy profile



Inputs[4]

- Coal
- Iron ore
- Scrap steel

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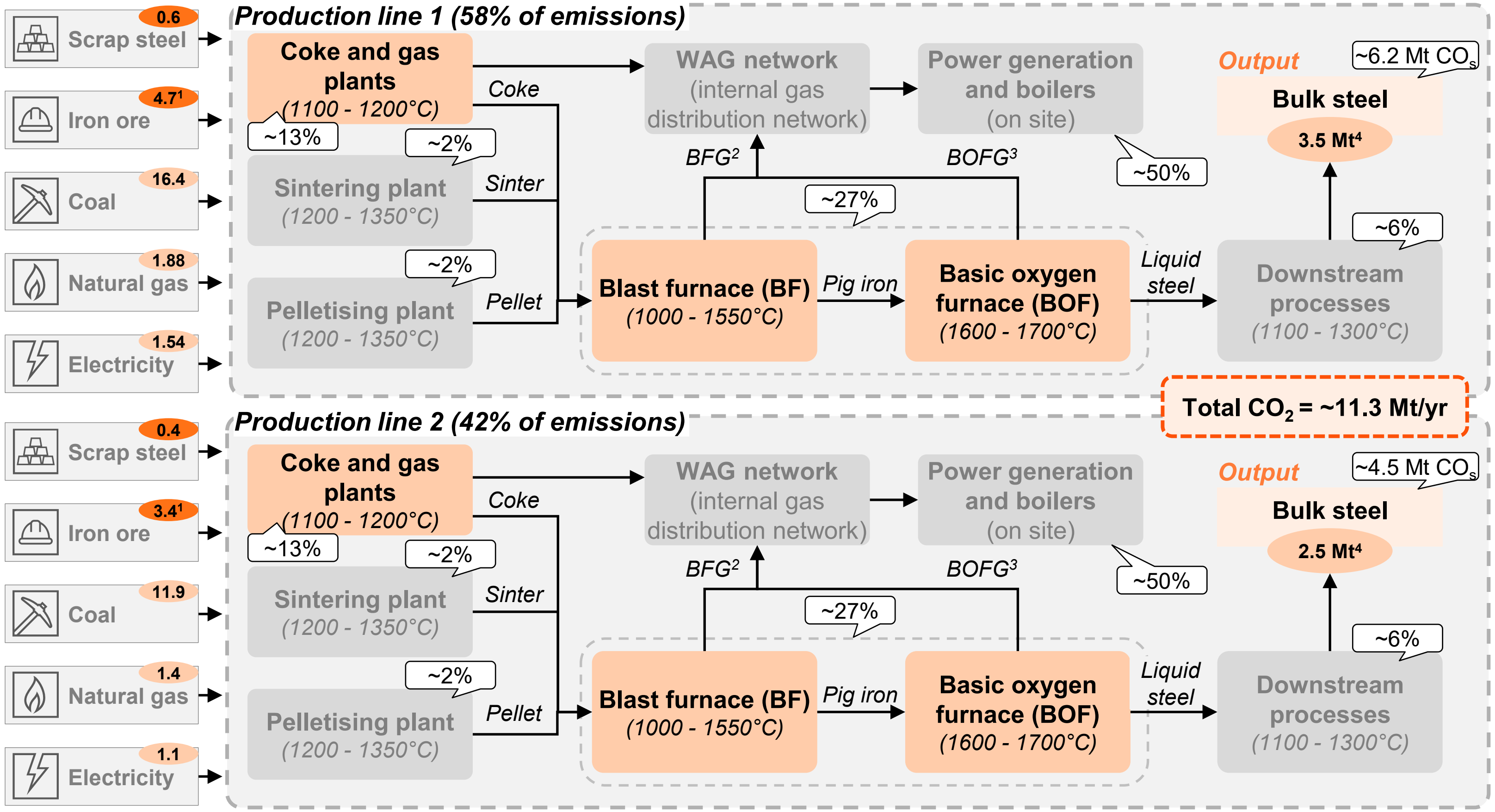
1) Percentages are based on European sales towards different sectors; 2) Manufactured goods include sales to general industry producing appliances, independent service centres and semi-finished products; 3) Others include packaging, energy & power, lifting & excavating and other transport such as aerospace and shipping; 4) Inputs are addressed by the inputs and abatement measures affecting those inputs will be reflected in reduced fuel use; 5) Excluding 2023 – outlier due to extended maintenance. Sources: Eurometal, PBL MIDDEN, Annual report TATA Steel, CBS, MER

The current prod. process uses coal as fuel and feedstock to produce bulk steel; ~50% of CO_2 emissions come from power generation and boilers

Steel – Process overview

Inputs » *Production process*



Key insights

- Steel production relies heavily on **high- temperature chemical reduction.** This process is inherently **energy-** and **carbon-intensive**
- Most CO_2 emissions originate from the two **blast furnaces** and **basic oxygen furnaces, which are used to produce liquid steel**, accounting for **ca. 27% of the total site emissions** (or 64% when including emissions from power generation using the off-gases from these two furnaces**).** These processes currently use coal and coke in large quantities to maintain high temperatures
- **COG (coke oven gas)** and **BFG (blast furnace gas)** are high-caloric gases, mainly due to their high hydrogen content. They are **cleaned** (e.g. removal of trace metals) and then **recycled/reused** across the site via the **WAG network** or diverted to the **power generators to produce electricity**

1) Based on the average t/tonnes of bulk steel from 2019/2020 until 2023/2024; 2) Blast furnace gas, which consists mainly of nitrogen, CO and CO_2; 3) Basic oxygen furnace gas, which consists mainly of CO and CO_2; 4) Based on the average bulk steel production from 2020 until 2024.

Sources: CBS, MIDDEN, NEa, energy.nl

% of total CO_2 emissions CO_2 emissions

🟧 Unique

⬜ Shared with other production line

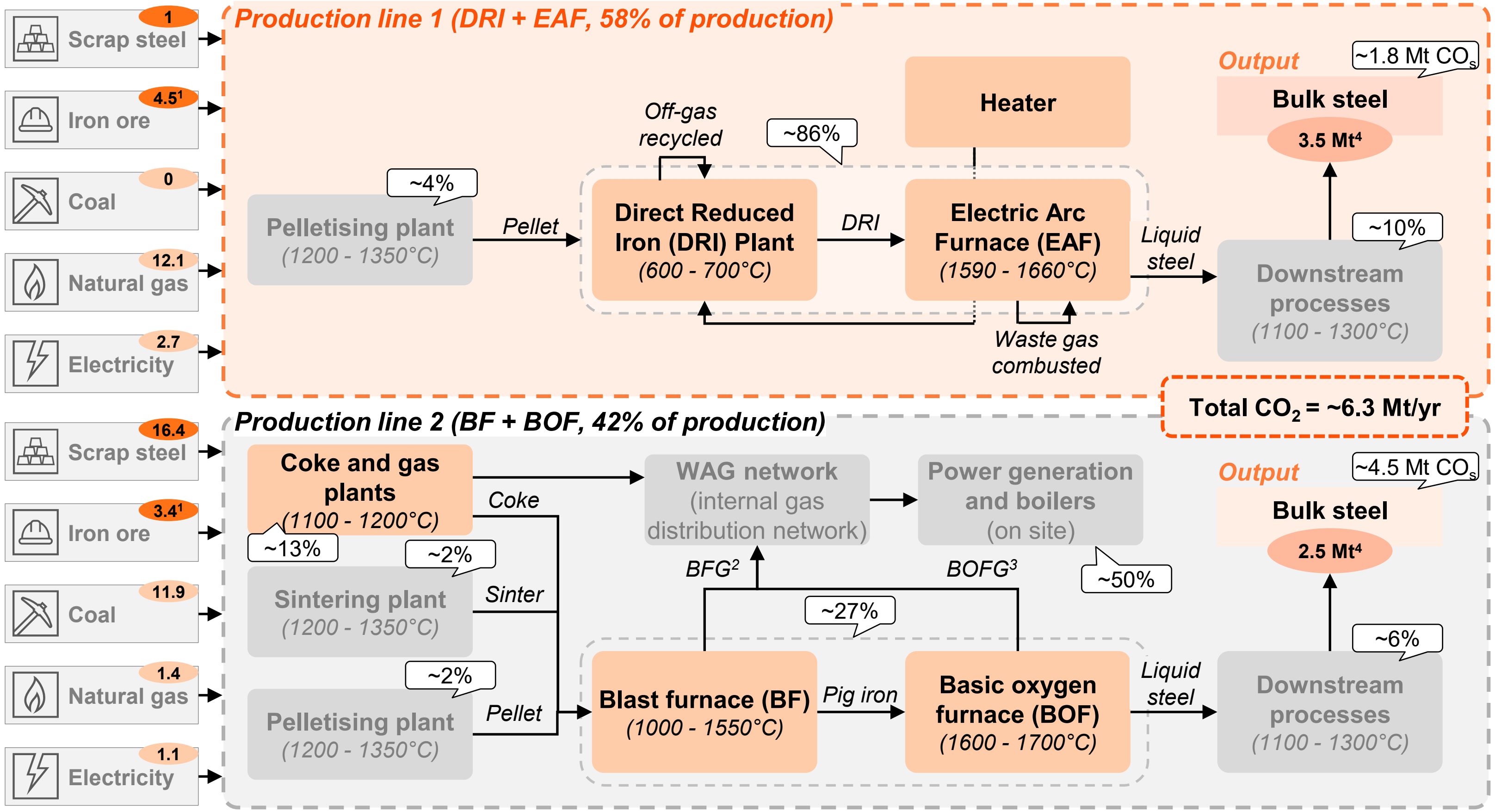
XX Total usage in TWh

XX Total usage in Mt

By replacing the blast furnace and basic oxygen furnace with a direct reduction step & an electric furnace, most emissions can be abated

Steel – Process overview with partial decarbonisation (one of the blast furnaces is replaced)

Inputs *Production process*



Production line 1 (DRI + EAF, 58% of production)

Scrap steel 1

Iron ore 4.5[1]

Coal 0

Natural gas 12.1

Electricity 2.7

Pelletising plant (1200 - 1350°C) ~4%

Pellet

Off-gas recycled ~86%

Direct Reduced Iron (DRI) Plant (600 - 700°C)

DRI

Heater

Electric Arc Furnace (EAF) (1590 - 1660°C)

Waste gas combusted

Liquid steel

Downstream processes (1100 - 1300°C) ~10%

Output ~1.8 Mt CO_2

Bulk steel 3.5 Mt[4]

Total CO_2 = ~6.3 Mt/yr

Production line 2 (BF + BOF, 42% of production)

Scrap steel 16.4

Iron ore 3.4[1]

Coal 11.9

Natural gas 1.4

Electricity 1.1

Coke and gas plants (1100 - 1200°C) ~13%

Coke

WAG network (internal gas distribution network)

Power generation and boilers (on site) ~50%

Sintering plant (1200 - 1350°C) ~2%

Sinter

Pelletising plant (1200 - 1350°C) ~2%

Pellet

BFG[2]

BOFG[3]

~27%

Blast furnace (BF) (1000 - 1550°C)

Pig iron

Basic oxygen furnace (BOF) (1600 - 1700°C)

Liquid steel

Downstream processes (1100 - 1300°C) ~6%

Output ~4.5 Mt CO_2

Bulk steel 2.5 Mt[4]

Key insights

- The **DRI + EAF** process **fundamentally shifts** part of the steel production capacity **towards gas-based direct reduction of iron ore (DRI) combined with an electricity-driven melting step**
- **After DRI + EAF replaces the first blast furnace (as per phase 1 plan of Tata Steel)**, direct **CO_2 emissions** from primary steel **drop sharply** as coal is eliminated as fuel and reductant. **Substitution of coal with natural gas** leads to **1.8 Mtpa** of residual CO_2 (see figure, left). Abating this remainder **requires CCS, biomethane** or **H_2**
- Unlike the traditional method, the DRI process also offers the possibility to integrate **hydrogen as a primary reducing agent**, which, compared to the current auxiliary role of recycled hydrogen, can lead **to near-zero direct CO_2 emissions** in steel production
- The DRI and EAF processes inherently generate **drastically reduced volumes of process gases**. Remaining off gas is recycled or burned within the reactors, and after Phase 1, additional electricity will be procured on the electricity market to make up for lower power generation output
- While **constant liquid steel output is assumed here** for abatement cost calculations, **Tata Steel's actual commercial plan** for the DRI + EAF transition has the new DRI + EAF plants at a different ratio of production capacity than the current blast furnaces

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1) Based on the average t/tonnes of bulk steel from 2019/2020 until 2023/2024; 2) Blast furnace gas, which consists mainly of nitrogen, CO and CO_2; 3) Basic oxygen furnace gas, which consists mainly of CO and CO_2; 4) Based on the average bulk steel production from 2020 until 2024.

Sources: CBS, MIDDEN, NEa, energy.nl

% of total CO_2 emissions CO_2 emissions

▨ Unique

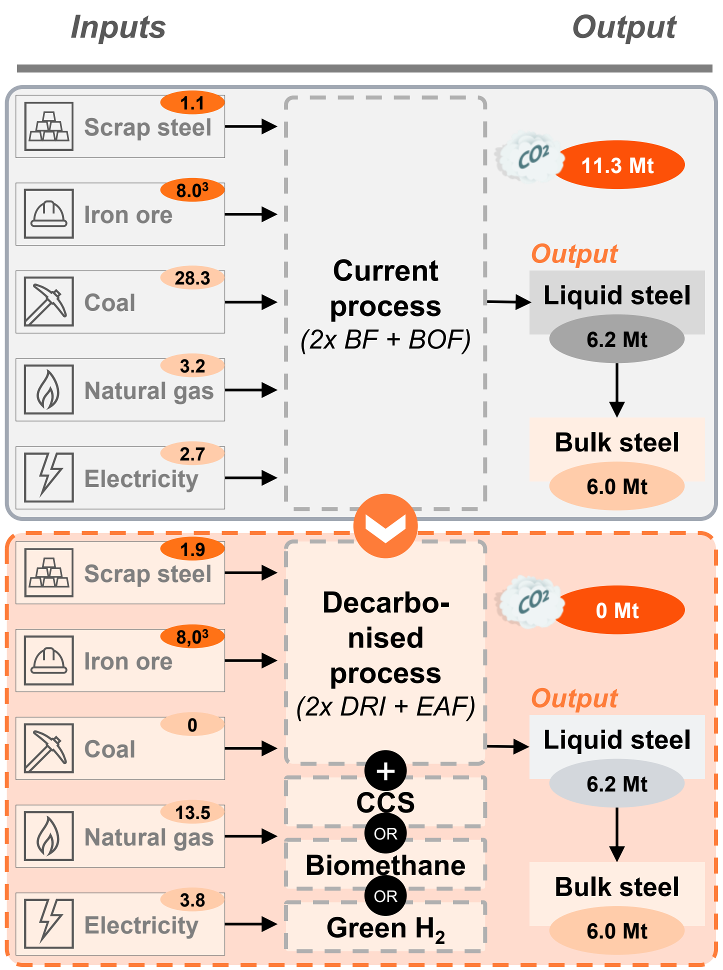
▨ Shared with other production line

XX Total usage in TWh

XX Total usage in Mt

The transition to DRI and EAF requires significant capital investments; CCS-related CAPEX will be low because a capture unit will be part of the DRI process

Steel – Costs of decarbonisation



	Overview of abatement costs under Phase 1 – for illustration	*Cost €mln[1]*
CAPEX	DRI + EAF related investments	3,162
	CCS related investments[2]	410 - 467
OPEX	DRI + EAF fixed OPEX	2,772
	Increased natural gas use	2,025
	Higher electricity use *(incl. savings in existing processes)*	563
	Elimination of coal consumption	-1,778
	CCS transport & storage costs (gaseous – liquid)	310 - 405
	Biomethane use (*replacing some natural gas to get to 100% abatement*)	201
	Increased scrap steel consumption and decrease of iron ore consumption	*N/a[3]*

Key insights

- The visual on the left illustrates the **current steel production process for both blast furnace** lines including their required inputs, and contrasts this with the **decarbonized DRI + EAF processes after the completion of Phase 1 and 2**
- The raw material and energy input mix is significantly different after decarbonization – there is **complete elimination of coking coal** and **an increase in scrap steel use** combined with a **decline in iron ore consumption**
- A significant temporary **reduction in internal liquid steel production capacity** is expected due to the replacement of the larger blast furnace with a smaller DRI + EAF in phase 1, which temporarily necessitates **external procurement of semi-finished steel products** (e.g., steel slabs) to maintain the overall final product volume
- Implementing a decarbonized **DRI + EAF** process requires **substantial upfront capital investments (in the order of 3.2 €bn for the DRI and EAF units in Phase 1 i.e., to abate up to 55% of total emissions)**
- Operational expenditures will undergo a fundamental rebalancing, with significant **savings from eliminating coal consumption** largely offset by **substantially higher costs for natural gas and electricity**

PwC

XX Total usage in TWh XX Total usage in Mt

1) NPV, €$_{2024}$ post-tax; 2) CAPEX mainly for additional (post-combustion) equipment for 45% of the captured CO_2, as the other 55% is already produced as a pure stream inherent to the DRI process; 3) Not included in the scope of this report, nor are any consequences on steel quality and corresponding prices; Sources: MIDDEN and MER

Most production process steps in the steel sector are operated at very high temperatures (>1000°C) and off-gases with high CO_2 conc. are emitted from them

Steel – Key characteristics

System unit	Key role	CO_2 emission mechanism[1]	Typical CO_2 conc.	Operating temperature	Hydrogen involvement	Fuel dependence	Abatement options
Coke oven	• Converts coal into coke for blast furnace by the coke oven, which creates COG	• **~13%[1] of steel emissions** • CO_2 emissions by devolatilisation of coal and combustion	• ~5-10% of CO_2 in COG	• **Very high op. temperature** (~1100–1200°C)	• Hydrogen is a byproduct and re-used at heating	• **Coking coal** to be transformed into coke	• **DRI + EAF (natural gas)** • **Post-combustion CCS on DRI + EAF (natural gas)** • **DRI + EAF (biomethane)** • **DRI + EAF (with hydrogen)**
Sinter plant	• Transforms iron ore and coke breeze into sinter by combustion/ oxidation process	• **~2% of steel emissions** • CO_2 emissions by combustion	• ~5-15% of CO_2 in off-gas	• **Very high op. temperatures** (~1200–1350°C)	• n/a	• **Natural gas** and **coke breeze** used as main fuels	
Pellet plant	• Ball and indurate to harden iron-ore pellets for blast furnace	• **~2% of steel emissions** • CO_2 emissions by combustion	• ~5-15% of CO_2 in off-gas	• **Very high op. temperatures** (~1200–1350°C)	• n/a	• **Natural gas** as main fuel	
Blast furnace	• Reduces iron ore to hot metal using coke and fuels	• **~27%[1] of steel emissions** • CO_2 from direct/ indirect reduction and fuel use	• ~20-25% of CO_2 in BFG	• **Very high op. temperatures** (~1000–1550°C)	• n/a	• Large consumer of **coke**	
Basic oxygen furnace	• Refines hot metal into steel by oxygen blowing	• **~0%[1] of steel emissions** • CO_2 emissions mainly from fuel firing	• ~10-20% of CO_2 in BOFG	• **Very high op. temperatures** (~1600–1700°C)	• n/a	• Consumes mainly **heat**	
Down-stream process	*Notable downstream process:* ***Reheating*** • Reheats slabs/coils ahead of rolling and coating steel	• **~5% of steel emissions** • CO_2 emissions mainly from fuel firing	• ~5-10% of CO_2 in flue gas	• **Very high op. temperatures** (~1100–1300°C)	• n/a	• **Natural gas** and **electricity**	• **Fuel substitution with biomethane** • **Electrification** • **Fuel substitution with hydrogen**

Sources: MIDDEN, Combustion-institute, Best Available Technique (BAT); 1) Excludes 50% emissions from energy generation (power generation and boilers). When allocating these emissions based on the origin of the off gases used for energy generation, these numbers come up to 26% (coke oven), 58% (blast furnace) and 6% (basic oxygen furnace).

DRI + EAF (all types) is the most suitable solution for abating most emissions of steel production; CCS can abate the remaining emissions from use of natural gas

Steel – Abatement options Phase 1

Sub-process	Abatement option	Description	Abated CO_2[1]	Unit costs	*Change in total fuel use (TWh/year)*						Key considerations (incl. TRL, challenges, etc.)
					Natural gas	Biomethane	H_2	Electricity	Heat	Coal	
Coke oven, pellet, sinter plant, blast furnace, basic oxygen furnace and energy generation *~55% of total emissions in phase 1* **6.2 Mt CO_2/year**	① **DRI + EAF (natural gas)**	Replacing BF and BOF with DRI & EAF, using natural gas and electricity	**▼5.0 Mt CO_2/year** *(-44.2%)*	300-500 €/t CO_2	▲10.26	-	-	▲1.17	-	▼16.44	• Well developed technology (TRL of 9), but requires building a new steel production line • DRI uses natural gas as a feedstock, but can use hydrogen in the future
	+ **CCS – pre- and post-combustion**	Collecting pure CO_2 streams from DRI (0.6 Mt) and additional CO_2 from exhaust gases (0.5 Mt) for permanent storage	**▼1.1 Mt CO_2/year** *(-9.5%)*	*Gaseous transport* <300 €/t CO_2	-	-	-	▲0.19	▲0.69	-	• CCS is for abating remainder of emissions emitted by DRI + EAF (natural gas) • CO_2 capture inherent to the DRI process for 55% of the emissions, so only requires an additional capture installation for the other 45%
				Liquid transport <300 €/t CO_2	-	-	-	▲0.22	▲0.69	-	
	② **DRI + EAF (biomethane)**	Replacing BF and BOF with DRI & EAF, using biomethane and electricity	**▼6.2 Mt CO_2/year** *(-54.8%)*	300-500 €/t CO_2	▼0.13	▲10.39	-	▲1.17	-	▼16.44	• Biomethane substitution is highly dependent on limited supply and long-term price uncertainty • Does not make use of the CCS-potential inherent in DRI + EAF. CCS combined with lower amounts of biomethane could reach full abatement; CCS combined with higher amounts of biomethane is also possible to achieve net negative emissions (BECCS)
	③ **DRI + EAF with green H_2 from market**	Replacing BF and BOF with DRI & EAF, using green H_2 from the market, natural gas and electricity	**▼5.9 Mt CO_2/year** *(-52.7%)*	>500 €/t CO_2	▲2.41	-	▲21.40	▲1.17	-	▼16.44	• DRI and EAF technology is far developed (TRL of 9), but this option requires substantial green hydrogen production • High dependence on extra electricity capacity (potential generation shortage)
	+ **CCS – pre-combustion**	Collecting pure CO_2 streams from DRI for permanent storage	**▼0.2 Mt CO_2/year** *(-1.9%)*	*Gaseous transport* <300 €/t CO_2	-	-	-	▲0.04	▲0.14	-	• CCS is for abating remainder of natural gas emissions from DRI + EAF • CO_2 capture inherent to the DRI process, so does not require an additional capture installation
				Liquid transport <300 €/t CO_2	-	-	-	▲0.04	▲0.14	-	
	④ **DRI + EAF with green H_2 from market (biomethane)**	Replacing BF and BOF with DRI & EAF, using green H_2 from the market, biomethane and electricity	**▼6.2 Mt CO_2/year** *(-54.8%)*	>500 €/t CO_2	▼0.13	▲2.55	▲21.40	▲1.17	-	▼16.44	• DRI and EAF technology is far developed (TRL of 9), but this option requires substantial green hydrogen production • High dependence on extra electricity capacity (potential generation shortage)

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1) Abatement as percentage of total process emissions; 2) Based on costs for pure CO_2 stream and of dilute exhaust gases.
Sources: MIDDEN, CBS, NEa, FNV, TNO

The steel sector has same options in Phase 2 as well – to abate the second blast furnace, which is expected to be done at a later point in time towards 2040

Steel – Abatement options Phase 2

					Change in total fuel use (TWh/year)						
Sub-process	**Abatement option**	**Description**	**Abated CO_2[1]**	**Unit costs**	**Natural gas**	**Biomethane**	**H_2**	**Electricity**	**Heat**	**Coal**	**Key considerations** (incl. TRL, challenges, etc.)
Coke oven, pellet, sinter plant, blast furnace, basic oxygen furnace and energy generation *~40% of total emissions in phase 2* **4.5 Mt CO_2/year**	① **DRI + EAF (natural gas)**	Replacing BF and BOF with DRI & EAF, using natural gas and electricity	**▼3.6 Mt CO_2/year** *(-32.0%)*	300-500 €/t CO_2	▲7.43	-	-	▲0.85	-	▼11.91	• Well developed technology (TRL of 9), but requires building a new steel production line • DRI uses natural gas as a feedstock, but can use hydrogen in the future
	+ **CCS – pre- and post-combustion**	Collecting pure CO_2 streams from DRI (0.4 Mt) and additional CO_2 from exhaust gases (0.4 Mt) for permanent storage	**▼0.7 Mt CO_2/year** *(-6.9%)*	***Gaseous transport*** <300 €/t CO_2	-	-	-	▲0.14	▲0.50	-	• CCS is for abating remainder of emissions emitted by DRI + EAF (natural gas) • CO_2 capture inherent to the DRI process for 55% of the emissions, so only requires an additional capture installation for the other 45%
				Liquid transport <300 €/t CO_2	-	-	-	▲0.16	▲0.50	-	
	② **DRI + EAF (biomethane)**	Replacing BF and BOF with DRI & EAF, using biomethane and electricity	**▼4.5 Mt CO_2/year** *(-40.0%)*	300-500 €/t CO_2	▼0.10	▲7.52	-	▲0.85	-	▼11.91	• Biomethane substitution is highly dependent on limited supply and long-term price uncertainty • Does not make use of the CCS-potential inherent in DRI + EAF; combining CCS with lower amounts of biomethane is possible
	③ **DRI + EAF with green H_2 from market**	Replacing BF and BOF with DRI & EAF, using green H_2 from the market, natural gas and electricity	**▼4.3 Mt CO_2/year** *(-38.2%)*	>500 €/t CO_2	▲1.75	-	▲15.49	▲0.85	-	▼11.91	• DRI and EAF technology is far developed (TRL of 9), but this option requires substantial green hydrogen production • High dependence on extra electricity capacity (potential generation shortage)
	+ **CCS – pre-combustion**	Collecting pure CO_2 streams from DRI for permanent storage	**▼0.2 Mt CO_2/year** *(-1.4%)*	***Gaseous transport*** <300 €/t CO_2	-	-	-	▲0.03	▲0.10	-	• CCS is for abating remainder of natural gas emissions from DRI + EAF • CO_2 capture inherent to the DRI process, so does not require an additional capture installation
				Liquid transport <300 €/t CO_2	-	-	-	▲0.03	▲0.10	-	
	④ **DRI + EAF with green H_2 from market (biomethane)**	Replacing BF and BOF with DRI & EAF, using green H_2 from the market, biomethane and electricity	**▼4.5 Mt CO_2/year** *(-40.0%)*	>500 €/t CO_2	▼0.10	▲1.84	▲15.49	▲0.85	-	▼11.91	• DRI and EAF technology is far developed (TRL of 9), but this option requires substantial green hydrogen production • High dependence on extra electricity capacity (potential generation shortage)

1) Abatement as percentage of total process emissions; 2) Based on costs for pure CO_2 stream and of dilute exhaust gases

Sources: MIDDEN, CBS, NEa, FNV, TNO

The emissions from downstream steel making processes on-site can be fully abated by using biomethane as fuel substitution

Steel – Abatement options

Sub-process	Abatement option	Description	Abated CO_2[1]	Unit costs	*Change in total fuel use (TWh/year)*						Key considerations (incl. TRL, challenges, etc.)
					Natural gas	Biomethane	H_2	Electricity	Heat	Coal	
Downstream steel making *~6% of total emissions* **0.6 Mt CO_2/year**	**Biomethane fuel substitution**	Replacing natural gas with biomethane as fuel can fully eliminate direct CO_2 emissions in downstream steps	**▼0.6 Mt CO_2/year** *(-5.5%)*	**<300 €/t CO_2**	▼3.01	▲3.01	-	-	-		• Biomethane substitution deployment is highly dependent on limited supply and long-term price uncertainty • Biomethane will be used primarily to close residual emissions to reach full abatement after structural abatement options are deployed • Application feasibility depends on availability of required volumes
	Electrification	Some downstream processes may be fully electrified, eliminating direct CO_2 emissions	*n/a*	*n/a*	-	-	-	-	-	-	• Electrification is a potential decarbonisation option for downstream steelmaking • No information on abatement options and related cost levels for downstream steelmaking processes is provided in the utilised public sources, so this option was not considered further
	Hydrogen fuel substitution	Replacing natural gas with (blue or green) hydrogen as a fuel can fully eliminate direct CO_2 emissions in downstream steps	*n/a*	*n/a*	-	-	-	-	-	-	• Fuel substitution with hydrogen is a potential decarbonisation option for downstream steelmaking • No information on abatement options and related cost levels for downstream steelmaking processes is provided in the utilised public sources, so this option was not considered further

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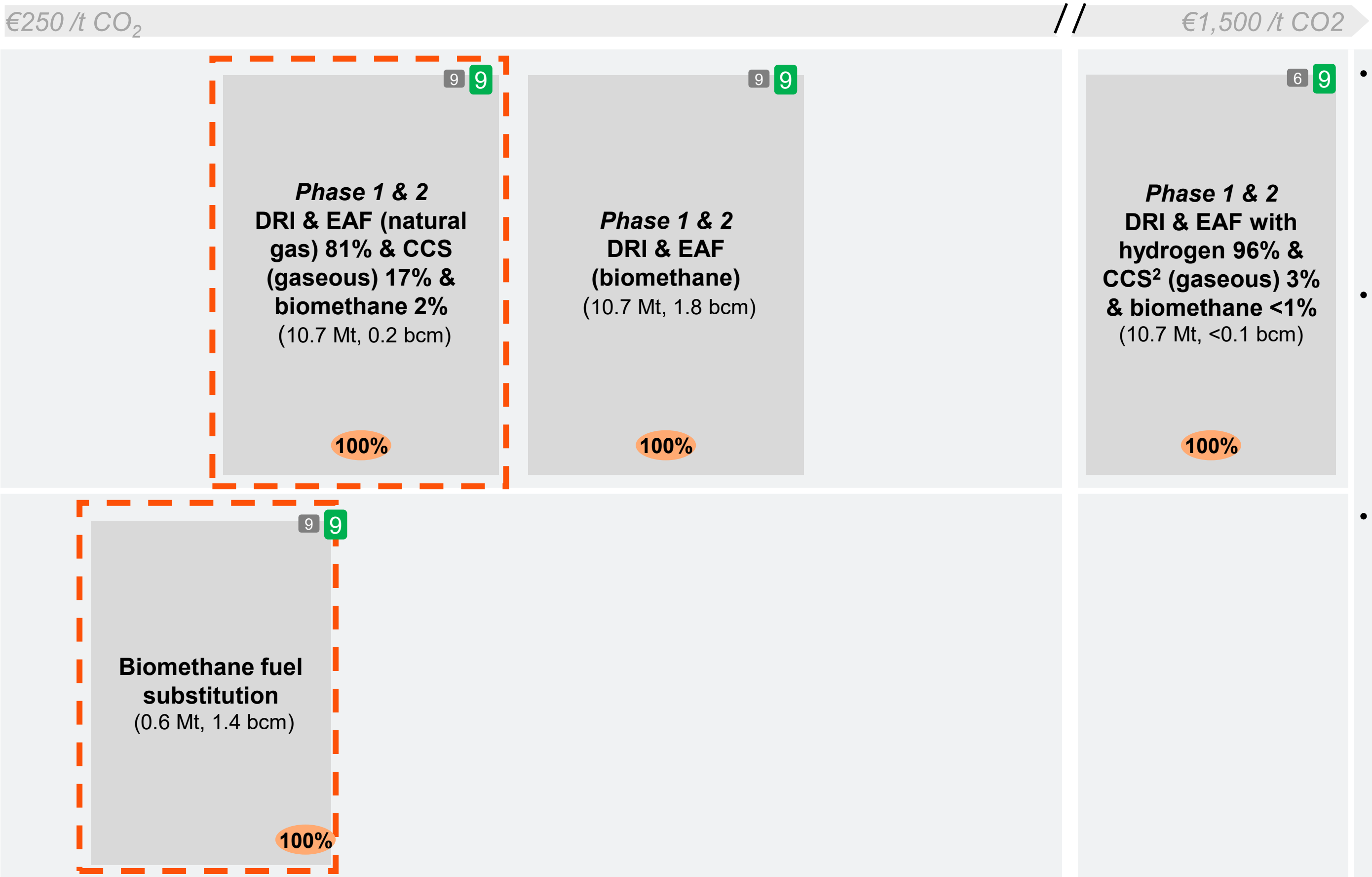
1) Abatement as percentage of total process emissions
Sources: MIDDEN, CBS, NEa, FNV, TNO

The DRI + EAF (natural gas) with CCS & partial biomethane route is the most cost-effective option

Steel – Abatement pathways summary[1]

Sector	Process	CO_2 emissions	Key considerations
Steel	**Coke oven, pellet, sinter plant, blast furnace, basic oxygen furnace and energy generation** Coke and natural gas are used as feedstock and furnace fuel across the integrated steelmaking route *Very high temp. ~1000 – 1700 °C*	**10.7 Mt** *(95%)*	- **DRI + EAF (natural gas)** with **CCS and biomethane substitution** is assumed to be the **most cost-effective near-term abatement option**, with hydrogen-based DRI + EAF as the long-term solution - A **DRI + EAF option using only biomethane** is more expensive than the one using CCS and natural gas, in part because the **carbon capture units** are already **part of the DRI + EAF setup** - Abating **downstream steelmaking emissions** is assumed to be only possible by substituting **natural gas** as **fuel** by **biomethane,** which will result in **100% abatement** of the process
	Downstream steelmaking Casting molten steel into semi-finished forms and processing such as hot/cold rolling *Large temperature range dependent on specific process*	**0.6 Mt** *(5%)*	



Abatement pathways

€250 /t CO_2 // €1,500 /t CO2

Coke oven, pellet, sinter plant, blast furnace, basic oxygen furnace and energy generation:

- 9 9 — *Phase 1 & 2* **DRI & EAF (natural gas) 81% & CCS (gaseous) 17% & biomethane 2%** (10.7 Mt, 0.2 bcm) — 100% (techno-economic option)
- 9 9 — *Phase 1 & 2* **DRI & EAF (biomethane)** (10.7 Mt, 1.8 bcm) — 100%
- 6 9 — *Phase 1 & 2* **DRI & EAF with hydrogen 96% & CCS[2] (gaseous) 3% & biomethane <1%** (10.7 Mt, <0.1 bcm) — 100%

Downstream steelmaking:

- 9 9 — **Biomethane fuel substitution** (0.6 Mt, 1.4 bcm) — 100% (techno-economic option)

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1) Abatement costs are inflation-adjusted (2% p.a.) and reported in nominal terms; 2) CCS is still required and possible in the hydrogen scenario because the DRI only takes in 80% of its energy as hydrogen, with the remainder being natural gas

Sources: CBS, PBL MIDDEN; company announcements

■ Current TRL	**2040 TRL:**	🟩 High TRL (>7)	🟧 Medium TRL (5-7)
XX% Share of abated system emissions		⬚ Techno-economic option(s)	🟥 Low TRL (<5)

Waste processing plants incinerate solid waste and sludge, generating electricity and heat, emitting 2.4 Mt CO_2 in 2024

Waste processing – Sector overview

Sector overview

Sector definition	• Waste processing sector **incinerates** municipal solid waste (MSW) and sludge, and **remediates** contaminated soil • Burning waste generates **electricity and heat as a by-product** • Only the **fossil fraction** of MSW is considered for net emissions, not the biogenic fraction.
System integration & strategic positioning	• Sector processes waste **produced in other sectors**, as well as in other parts of the Dutch economy (e.g. **residential waste**) • Plants are spread out **across the country**, with most plants situated near the **sea** or near the **German border** • **Heat** can be used for (low-temperature) applications in other sectors (e.g., in residential heating)
Products & end-use markets	• Excess **electricity** generated in waste incineration is supplied to the grid, with **heat** supplied for use cases across sectors • Main objective is **processing waste**, meaning that the type of **inputs** dictates the processes (rather than outputs)

Location of the largest waste incineration plants in the Netherlands by emissions in 2024

Energy profile

Energy carrier		***Baseline*** *(2020-2024 average)*
	CO_2 emissions[1] (Mt/year)	2.4
Energy carrier	**Natural gas** (TWh/year)	0.7
	Electricity (TWh/year)	-2.9
	Heat (TWh/year)	-4.9
	Crude oil & petroleum products (TWh/year)	0.2
	Waste (TWh/year)	23.2

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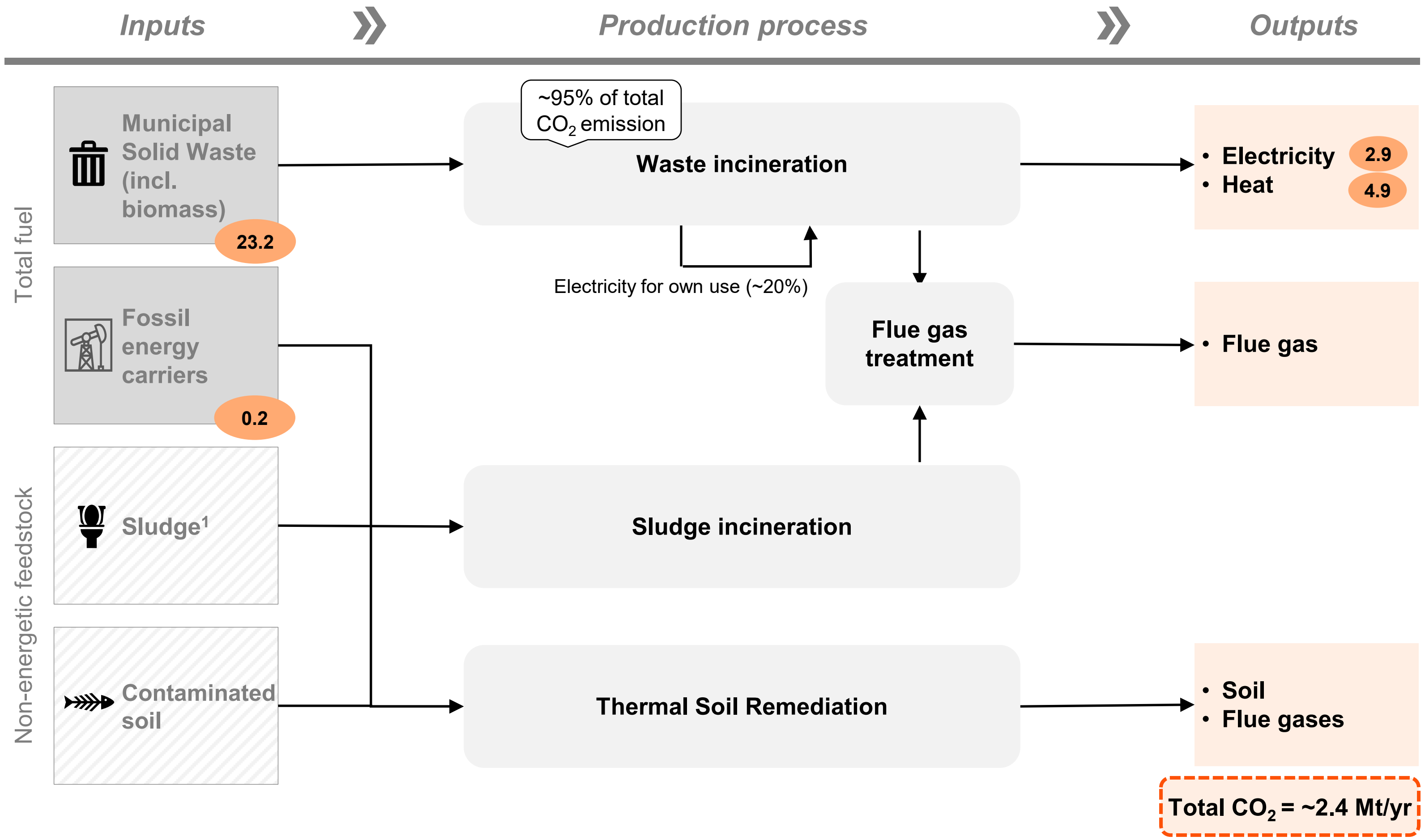
1) Most waste processing plants have only been included in NEa emissions numbers since 2024, so we use it as the baseline (rather than the 5-year average)

Sources: NEa

Almost all emissions in waste processing (95%) originate from solid waste incineration, driven by large share of municipal solid waste in the input stream

Waste processing



Inputs » *Production process* » *Outputs*

Total fuel

Municipal Solid Waste (incl. biomass) 23.2

Fossil energy carriers 0.2

Non-energetic feedstock

Sludge[1]

Contaminated soil

~95% of total CO_2 emission

Waste incineration

Electricity for own use (~20%)

Flue gas treatment

Sludge incineration

Thermal Soil Remediation

- **Electricity** 2.9
- **Heat** 4.9

- **Flue gas**

- **Soil**
- **Flue gases**

Total CO_2 = ~2.4 Mt/yr

Key insights

- **Waste processing plants** mostly use incineration to dispose of waste, leading to **~10 Mt CO_2 emissions per year** (~95%)
  - **Municipal solid waste** is incinerated for a **net energy surplus**, which is partially recovered in the form of **heat** and **electricity**
  - **Sludge** has a high moisture content, making its effective caloric content negligible or slightly negative
- Additionally, contaminated soil is cleaned in **Thermal Soil Remediation**, in which the soil is dehydrated and contaminants are pyrolysed, followed by afterburning of the contaminated flue gases
  - This process is a **net user of energy**, usually provided by **burning of natural gas**

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[1] Sludge incineration is close to energy neutral, as evaporation of vapour content | Sources: CBS, PBL MIDDEN

CO_2 Largest amount of CO_2 emissions ▨ Hydrogen production or consumption **XX** Total usage in TWh **XX** Hydrogen usage in TWh

Municipal solid waste incineration is the main driver for CO_2 emissions, for which CCS and CCU are the only viable abatement option

Waste processing – Key characteristics

Sub-processes	Key role	CO_2 emission mechanism	Typical CO_2 concentration	Operating temperature	Hydrogen involvement	Fuel dependence	Abatement options
Waste and sludge incineration	• **Incineration** reduces **sludge/ waste volume** and destroys organic matter and pathogens • **Heat** released during combustion is used to **produce heat and electricity**	• Direct **combustion** of **carbon waste** produce **86%** of sector emissions • **Biogenic waste incineration** is considered **carbon neutral**	• **~6-12%**	• **High to very high operating temperatures** (850 – 1100 °C)	• n/a	• **Municipal solid waste (MSW)** is the main fuel for incineration	• **CCU (post-combustion)** • **CCS (post-combustion, amines)** • **CCS (post-combustion, oxy-fuel)**
Thermal soil remediation	• **Organic contaminants** are removed by **heating up** soil • Thermal technologies are **effective** but require **high energy** input	• Heat required is provided by **fossil fuel combustion** • Resulting CO_2 emissions account for **14%** of sector emissions	• **~6-12%**	• **Large operating temperature range** (25 – 900 °C)	• n/a	• **Natural gas** is used to provide heat for soil remediation	• **Biomethane fuel substitution** • **Blue hydrogen fuel substitution** • **CCU (post-combustion)** • **CCS (post-combustion, amines)**

Sources: PBL MIDDEN, IEAGHG

Variations of CCS can be applied to all systems in waste and sludge processing, for a maximal emission reduction of 90-94%; some emissions will be abated via CCU

Waste processing – Abatement options (1/3)

Sub-process	Abatement option	Description	Abated CO_2[1]	Unit costs	*Change in total fuel use (TWh/year)*					Key considerations (incl. TRL, challenges, etc.)
					Natural gas	Biomethane	H_2	Electricity	Heat	
Waste and sludge incineration *~86% of total CO_2 emissions* **~2.0 Mt CO_2/year**	**Post-combustion CCS (oxy-fuel)**	Using pure oxygen instead of air for combustion allows for capturing up to 94% CO_2 emitted for long-term storage	▼**1.9 Mt CO_2/year** *(-94%)*	***Gaseous transport***						• Storage of captured CO_2 contributes significantly to the overall costs of this option • Oxy-fuel burning leads to higher CO_2 capture reduces heat requirements but requires pure oxygen input (which costs electricity to produce) and modified incinerators • Capture rates can reach higher levels than when using air for combustion
				<300 €/t CO_2	-	-	-	▲1.4	▲0.2	
				Liquid transport						
				300-500 €/t CO_2	-	-	-	▲1.4	▲0.2	
	Post-combustion CCS (amines)	Capturing CO_2 emitted for long-term storage can reduce emissions into the atmosphere by 90%	▼**1.8 Mt CO_2/year** *(-90%)*	***Gaseous transport***						• Storage of captured CO_2 contributes significantly to the overall costs of this option • Regular CCS uses more heat and captures less CO_2 than oxy-fuel CCS, but does not require oxygen input or modification to incinerators
				<300 €/t CO_2	-	-	-	▲0.3	▲1.2	
				Liquid transport						
				<300 €/t CO_2	-	-	-	▲0.4	▲1.2	
	CCU (post. comb. in WIP gaseous transport)	Captured CO_2 is transported and utilised in other industry instead of stored, cutting emissions by 90%	▼**1.8 Mt CO_2/year** *(-90%)*	**<300 €/t CO_2**	-	-	-	▲0.2	▲1.9	• Capturing CO_2 from exhaust flue gases requires significant amount of electricity and heat, reducing the overall efficiency of the process • CCU has relatively low CAPEX compared to CCS, leading to lower unit costs

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1) Abatement as percentage of total process emissions

Sources: MIDDEN, CBS, NEa

Thermal soil remediation can be fully abated using biomethane or blue hydrogen fuel substitution; CCS only abates for 94%

Waste processing – Abatement options (2/3)

Sub-process	Abatement option	Description	Abated CO_2[1]	Unit costs	*Change in total fuel use (TWh/year)*					Key considerations (incl. TRL, challenges, etc.)
					Natural gas	Biomethane	H_2	Electricity	Heat	
Thermal soil remediation (TSR) *~14% of total CO_2 emissions* **~0.3 Mt CO_2/year**	**Biomethane fuel substitution**	Natural gas used in the TSR process is replaced 1-on-1 by biomethane	▼**0.3 Mt CO_2/year** *(-100%)*	**<300 €/t CO_2**	▼1.6	▲1.6	-	-	-	• Due to the similar energy density of biomethane no significant changes to current furnaces are needed • Supply is constrained, with strong competition from other industries • Application feasibility depends on availability of required volumes
	Blue H_2 fuel substitution	The TSR process is adapted to accept hydrogen gas as a substitute for natural gas	▼**0.3 Mt CO_2/year** *(-100%)*	**300-500 €/t CO_2**	▼1.6	-	▲1.6	-	-	• Availability and cost of low-carbon hydrogen are major constraints • Higher flame temperatures may require burner modifications • Hydrogen delivery and storage infrastructure is still developing • Becomes attractive only when clean hydrogen becomes accessible at scale
	Post-combustion CCS (oxy-fuel)	Using pure oxygen instead of air for combustion allows for capturing up to 94% CO_2 emitted for long-term storage	▼**0.3 Mt CO_2/year** *(-94%)*	***Gaseous transport***						• Storage of captured CO_2 contributes significantly to the overall costs of this option • Oxy-fuel burning leads to higher CO_2 capture reduces heat requirements but requires pure oxygen input (which costs electricity to produce) and modified incinerators • Capture rates can reach higher levels than when using air for combustion
				<300 €/t CO_2	-	-	-	▲0.2	▲<0.1	
				Liquid transport						
				300-500 €/t CO_2	-	-	-	▲0.2	▲<0.1	

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1) Abatement as percentage of total process emissions

Sources: MIDDEN, CBS, NEa

In addition, emissions from thermal soil remediation can be abated via post-combustion CCS with amines (90%)

Waste processing – Abatement options (3/3)

					Change in total fuel use (TWh/year)					
Sub-process	**Abatement option**	**Description**	**Abated CO_2[1]**	**Unit costs**	**Natural gas**	**Biomethane**	**H_2**	**Electricity**	**Heat**	**Key considerations** (incl. TRL, challenges, etc.)
Thermal soil remediation (TSR) *~14% of total CO_2 emissions* **~0.3 Mt CO_2/year**	**Post-combustion CCS (amines)**	Capturing CO_2 emitted for long-term storage can reduce emissions into the atmosphere by 90%	▼**0.3 Mt CO_2/year** *(-90%)*	*Gaseous transport*						• Storage of captured CO_2 contributes significantly to the overall costs of this option • Regular CCS uses more heat and captures less CO_2 than oxy-fuel CCS, but does not require oxygen input or modification to incinerators
				<300 €/t CO_2	-	-	-	▲0.1	▲0.2	
				Liquid transport						
				<300 €/t CO_2	-	-	-	▲0.1	▲0.2	

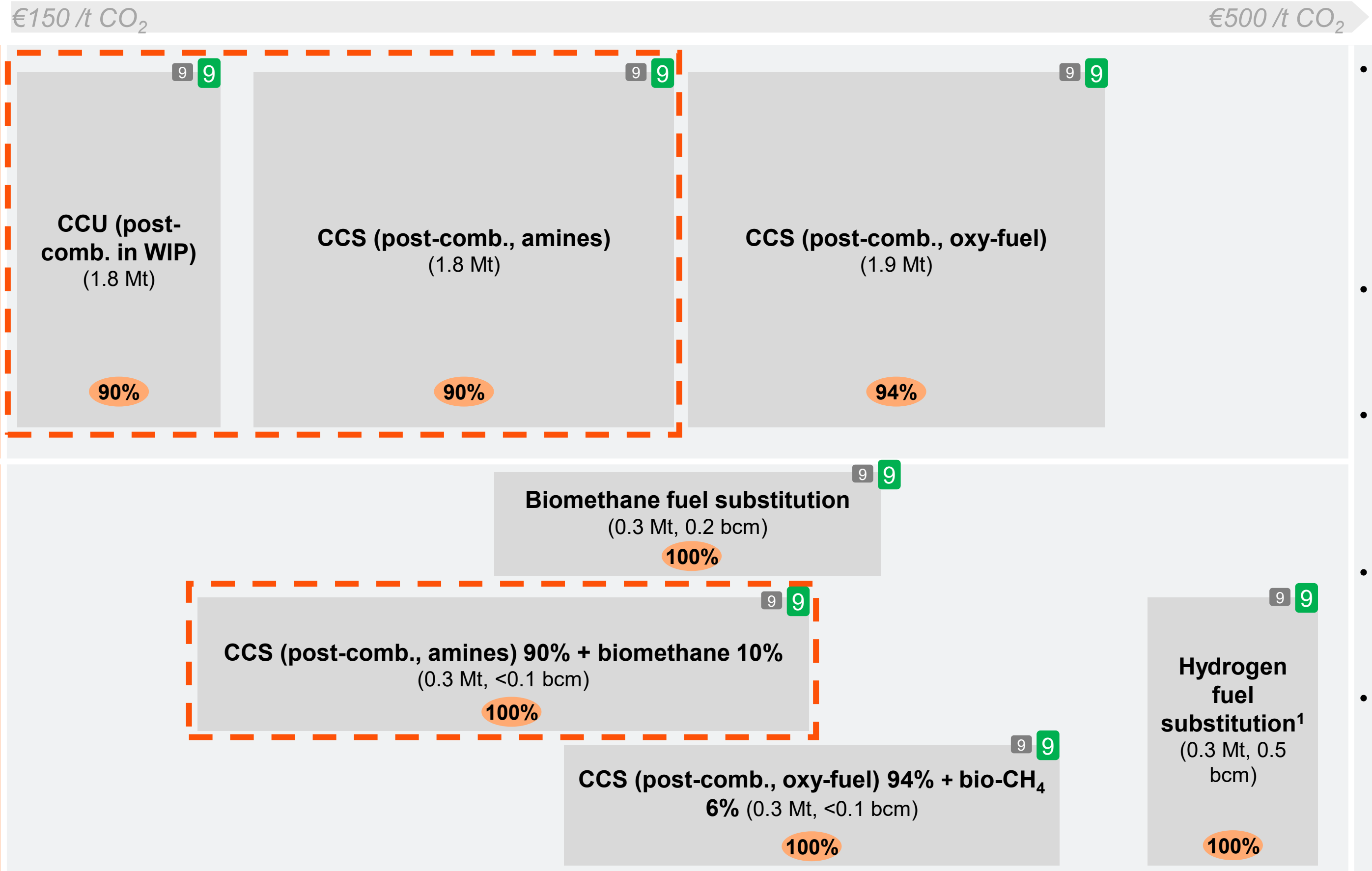
1) Abatement as percentage of total process emissions

Sources: MIDDEN, CBS, NEa

For the waste processing sector, post-combustion CCU/CCS is the most techno-economic route; biomethane can only bridge residual emissions of TSR

Waste processing – Abatement pathways

Sector	Process	CO_2 emissions	Abatement pathways	Key considerations
Waste Process-ing	**Waste & sludge incineration** Municipal waste is incinerated to generate heat and electricity *High to very high temperature ~850 – 1100 °C*	**2.0 Mt** *(86%)*	**CCU (post-comb. in WIP)** (1.8 Mt) 90% 9 9 **CCS (post-comb., amines)** (1.8 Mt) 90% 9 9 **CCS (post-comb., oxy-fuel)** (1.9 Mt) 94% 9 9	• **Municipal waste** consists of a **fossil and a biogenic fraction** – the **fossil fraction leads to the net emissions**, while the **biogenic fraction** may pose an opportunity for **net negative CO_2 emissions** (combined with CCS) • **Oxy-fuel burning** (in pure oxygen, rather than air) **allows for higher CO_2 concentrations** in flue gases, benefiting CCS • **TSR is a highly energy-intensive process** and can be fully abated via **post-combustion CCS in combination with biomethane** • Existing processes already **includes afterburning** and **cleaning of flue gases**, which facilitate CCS implementation • **Fully TRS process redesign** would also enable electrification - related abatement cost values not included in this analysis
	Thermal soil remediation (TSR) Soil is dehydrated and contaminants are pyrolysed, followed by afterburning of the contaminated flue gases *Large temperature range ~25 – 900°C*	**0.3 Mt** *(14%)*	**Biomethane fuel substitution** (0.3 Mt, 0.2 bcm) 100% 9 9 **CCS (post-comb., amines) 90% + biomethane 10%** (0.3 Mt, <0.1 bcm) 100% 9 9 **CCS (post-comb., oxy-fuel) 94% + bio-CH_4 6%** (0.3 Mt, <0.1 bcm) 100% 9 9 **Hydrogen fuel substitution**[1] (0.3 Mt, 0.5 bcm) 100% 9 9	



Techno-economic option(s): CCU (post-comb. in WIP), CCS (post-comb., amines); CCS (post-comb., amines) 90% + biomethane 10%

▇ Current TRL | **2040 TRL:** 🟩 High TRL (>7) 🟧 Medium TRL (5-7) 🟥 Low TRL (<5)

XX% Share of abated system emissions ⌗ Techno-economic option(s)

Note: Abatement costs are inflation-adjusted (2% p.a.) and reported in nominal terms

[1] Excl. last-mile delivery costs, CAPEX of last mile delivery of hydrogen is around €1M per km pipeline

Sources: CBS, PBL MIDDEN

The Netherlands hosts >35 ceramic manufacturing facilities, primarily located near rivers to facilitate easy access to clay and raw materials

Ceramics – Sector overview

Sector overview

Sector definition

- Ceramic production involves **shaping, drying, and firing clay feedstock** at **high temperature** to produce ceramic products
- **Bricks & rooftiles** are the focus, as this subsector is responsible for **~90% of the emissions** and **~95% of the production** (by volume)

System integration & strategic positioning

- Ceramic production is historically located **near the large rivers** in The Netherlands due to its **easy access to sedimentary clay** used as feedstock
- Of the 37 ceramic production plants, **34** produce **bricks and rooftiles,** the remaining three plants are all specialised in other ceramic product types

Products & end-use markets

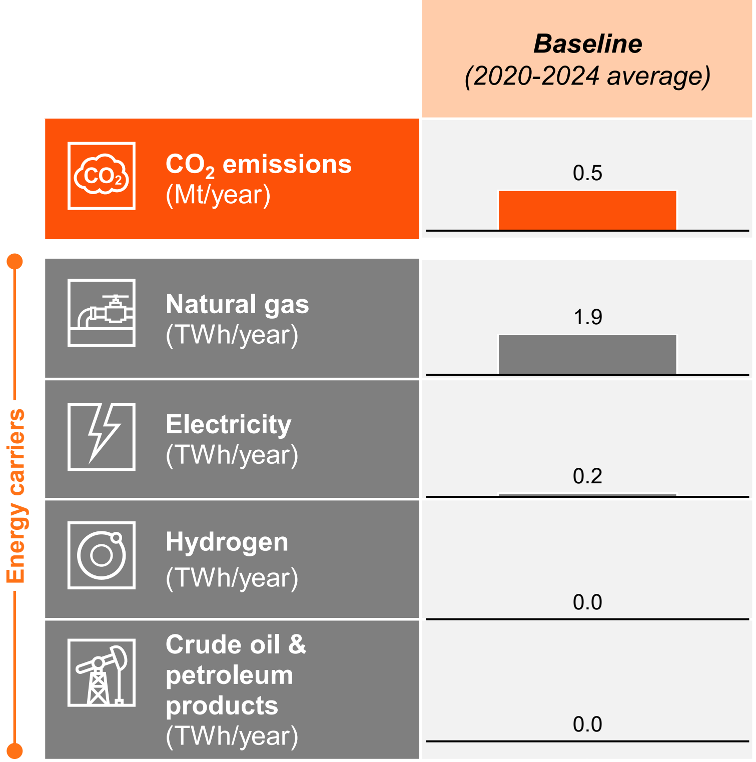
- Large quantities of bricks produced are used in the **construction sector,** including **facing bricks, paving bricks and inner wall bricks**

Location of the five largest ceramic plants in The Netherlands by production capacity

Number of plants per production type

① **Bricks & rooftiles**	34	③ **Wall tiles**	1
② **Floor tiles**	1	④ **Refractory products**	1

Energy profile



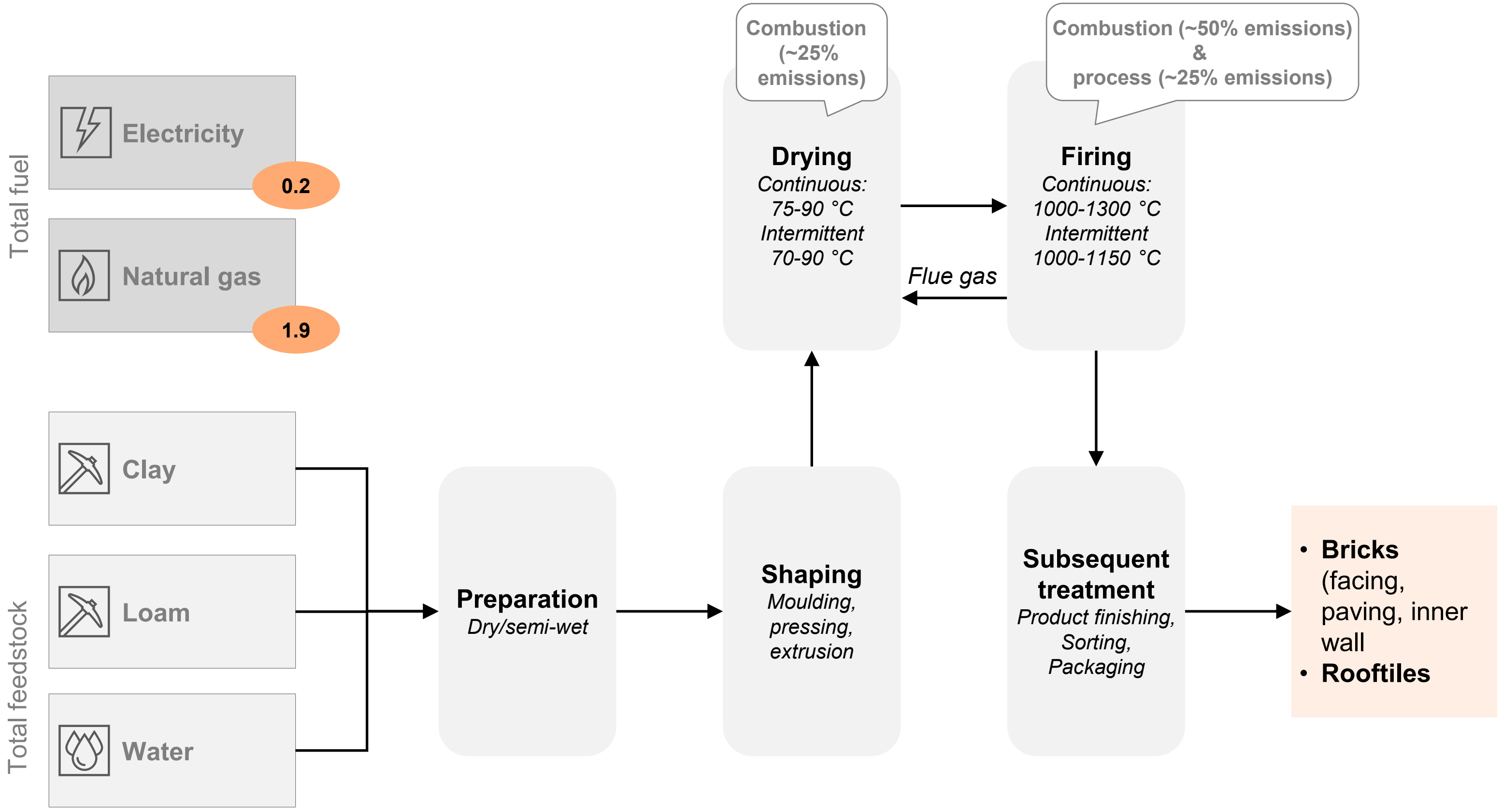
	Baseline *(2020-2024 average)*
CO_2 emissions (Mt/year)	0.5
Natural gas (TWh/year)	1.9
Electricity (TWh/year)	0.2
Hydrogen (TWh/year)	0.0
Crude oil & petroleum products (TWh/year)	0.0

Sources: CBS, PBL MIDDEN

Drying and firing are core processes in ceramics production; the heat required, generated by gas-fired furnaces, accounts for 75% of total emissions

Ceramics – Process overview

Inputs » *Production process* *Outputs*



Total fuel

Electricity 0.2

Natural gas 1.9

Total feedstock

Clay

Loam

Water

Combustion (~25% emissions)

Drying
Continuous: 75-90 °C
Intermittent 70-90 °C

Combustion (~50% emissions) & process (~25% emissions)

Firing
Continuous: 1000-1300 °C
Intermittent 1000-1150 °C

Flue gas

Preparation
Dry/semi-wet

Shaping
Moulding, pressing, extrusion

Subsequent treatment
Product finishing, Sorting, Packaging

- **Bricks** (facing, paving, inner wall
- **Rooftiles**

Key insights

- Ceramic production consists of a **preparatory** stage, **drying and firing** phase, which are responsible for the direct emissions of the production process, and finally a **product finishing stage**
- **75%** of all emissions originate from **furnaces burning natural** gas to reach the **required high temperatures**
- **Firing** accounts for **most of the combustion-based emissions** (due to the high temperature); during the **firing phase**, the raw material undergoes a **chemical process** called **calcination**, the CO_2 that get's released during this reaction is responsible for ~**25%** of total emissions

PwC

Sources: CBS, PBL MIDDEN

CO_2 Largest amount of CO_2 emissions 🟧 Hydrogen production or consumption **XX** Total usage in TWh **XX** Hydrogen usage in TWh

High temperatures produced by ovens, required for the ceramics firing process, primarily cause CO_2 emissions; with large dependence on natural gas as fuel

Ceramics – Key characteristics

Sub-processes	Key role	CO_2 emission mechanism	Typical CO_2 concentration	Operating temperature	Hydrogen involvement	Fuel dependence	Abatement options
Firing	• Dried material is either **continuously or intermittently fired** at **high temperature** in a specialised oven called a kiln • **Bricks are hardened by heating** them up below the materials' melting point • During this process, a chemical reaction called **calcination** takes place	• **~75% of ceramic production emissions** • **~33% of firing emissions** are released due to calcination of raw material as opposed to hydrocarbon combustion-based emissions	• **~8-10%**	• **High operating temperatures** (~1000-1300 °C)	• n/a	• **Largest use of natural gas within the sector**	• **Electrification of furnaces** • **Biomethane fuel substitution** • **Blue H_2 fuel substitution** • **CCS (post-combustion)**
Drying	• After **mixing, preparing and shaping** the raw material gets dried to **lower its water content** • Either continuous or intermittent drying is used • Heat is provided by hot flue gases from the firing process and by **natural gas fired** furnaces	• **~25% of ceramic production missions** • **Release CO_2 from hydrocarbon fuel combustion**, which **generates** the **heat** transferred to process streams for separation and reaction	• **~8-10%**	• **Low to medium temperature** (~70-90 °C)	• n/a	• Approximately equal split between **waste heat** from the firing kiln and **natural gas**	• **Electrification of furnaces** • **Biomethane fuel substitution** • **Blue H_2 fuel substitution** • **Heat pump** • **CCS (post-combustion)**

Only option available for abating calcination-based emissions

Sources: CBS, PBL MIDDEN, Science direct

Biomethane fuel substitution is the likely option for firing, as CCS, despite higher emission reductions, is less feasible due to its high costs

Ceramics – Abatement options (1/3)

					Change in total fuel use (TWh/year)					
Sub-process	**Abatement option**	**Description**	**Abated CO_2[1]**	**Unit costs**	**Natural gas**	**Biomethane**	**H_2**	**Electricity**	**Heat**	**Key considerations** (incl. TRL, challenges, etc.)
Firing *~74% of total CO_2 emissions* **~0.3 Mt (comb.: 0.2, calcination: 0.1) CO_2/year**	**CCS (post-combustion, liquid transport)**	Capturing CO_2 from furnace exhaust gases and storing it permanently can reduce furnace-related emissions by up to ~90%	**▼0.3 Mt CO_2/year** *(-90%)*	**>500 €/t CO_2** [2]	-	-	-	▲0.1	▲0.2	• Only option to abate calcination emissions • Liquid transportation by ship most likely option due to proximity to rivers of most ceramic factories • Transportation and storage of captured CO_2 requires extensive infrastructure rendering unlikely for Dutch ceramic production
	Biomethane fuel substitution	Replacing natural gas with biomethane as furnace fuel can fully eliminate direct CO_2 emissions from fuel combustion	**▼0.2 Mt CO_2/year** *(-65%)*	**300-500 €/t CO_2**	▼1.1	▲1.1	-	-	-	• Biomethane fuel substitution only abates combustion-based emissions, calcination emissions are not affected • Combining biomethane fired furnaces with CCS will result in net negative greenhouse gas emissions • Supply is constrained, with strong competition from other industries; application feasibility depends on availability of required volumes
	Blue H_2 fuel substitution	Replacing natural gas and fuel gas with blue hydrogen as furnace fuel can fully eliminate direct CO_2 emissions from fuel combustion	**▼0.2 Mt CO_2/year** *(-65%)*	**>500 €/t CO_2**	▼1.1	-	▲1.1	-	-	• Potential in hydrogen fired kilns is shown by a successful prototype • Only abates combustion-based emissions, calcination emissions are not affected • Research required to be done into the effect of higher NO_x emissions due to H_2 burning • Hydrogen delivery and storage infrastructure remains underdeveloped[3]
	E-furnace	Electrifying furnaces replaces fossil fuels with electricity, eliminating direct combustion emissions from this process step (subject to electricity carbon intensity)	**▼0.2 Mt CO_2/year** *(-65%)*	**>500 €/t CO_2**	▼1.1	-	-	▲1.0	-	• Piloted electric heating solutions include induction and resistive heating • E-grid constraints are a potential challenge due to the high electricity requirements • Only abates combustion-based emissions, calcination emissions are not affected

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1) Abatement as percentage of total process emissions; 2) High unit costs due to economies of scale; 3) Units costs exclude last-mile delivery costs, hydrogen pipeline CAPEX is estimated at ~€1 million per km

Sources: MIDDEN, CBS, KTH, FCW

Drying emissions can be fully abated through fuel substitution with biomethane or H_2; electrification is an alternative but constrained by technological feasibility

Ceramics – Abatement options (2/3)

					Change in total fuel use (TWh/year)					
Sub-process	**Abatement option**	**Description**	**Abated CO_2[1]**	**Unit costs**	**Natural gas**	**Biomethane**	**H_2**	**Electricity**	**Heat**	**Key considerations** (incl. TRL, challenges, etc.)
Drying *~26% of total CO_2 emissions* **~0.1 Mt CO_2/year**	**Biomethane fuel substitution**	Replacing natural gas with biomethane as furnace fuel can fully eliminate direct CO_2 emissions from fuel combustion	▼**0.1 Mt CO_2/year** *(-100%)*	300-500 €/t CO_2	▼0.6	▲0.6	-	-	-	• Biomethane can directly replace natural gas due to the similar energy composition of biomethane and natural gas - no significant furnace changes necessary • Combining biomethane fired furnaces with CCS will result in net negative greenhouse gas emissions • Supply is constrained, with strong competition from other industries; application feasibility depends on availability of required volumes
	Blue H_2 fuel substitution	Replacing natural gas and fuel gas with blue hydrogen as furnace fuel can fully eliminate direct CO_2 emissions from fuel combustion	▼**0.1 Mt CO_2/year** *(-100%)*	**>500 €/t CO_2**	▼0.6	-	▲0.6	-	-	• Potential in hydrogen fired kilns is shown by a successful prototype • Research still required to be done into the effect of higher NO_x emissions due to H_2 burning and possible negative effects on product quality • Hydrogen delivery and storage infrastructure remains underdeveloped; units costs exclude last-mile delivery costs, hydrogen pipeline CAPEX is estimated at ~€1 million per km
	E-furnace	Electrifying furnaces replaces fossil fuels with electricity, eliminating direct combustion emissions from this process step (subject to electricity carbon intensity)	▼**0.1 Mt CO_2/year** *(-100%)*	**>500 €/t CO_2**	▼0.6	-	-	▲0.6	-	• Piloted electric heating solutions include induction and resistive heating • E-grid constraints might also be a challenge due to the high electricity requirements • Simulations have proven electric drying to be the most energy efficient between hydrogen and gas-based drying

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[1] Abatement as percentage of total process emissions

Sources: MIDDEN, CBS, KTH, FCW

For drying, the need for additional heat generation can be eliminated by installing an industrial heat pump to optimally use waste heat of the firing kiln

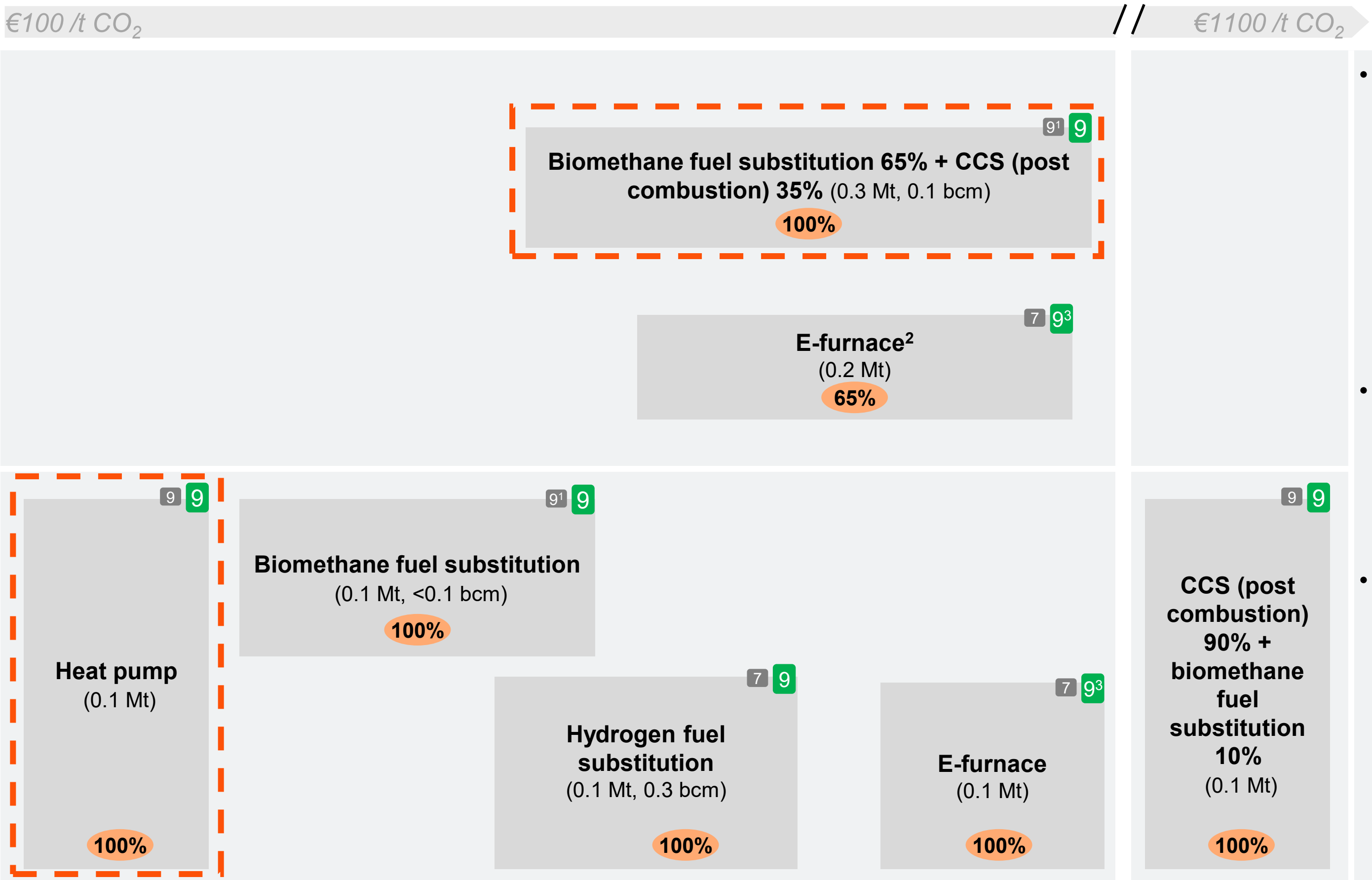
Ceramics – Abatement options (3/3)

					Change in total fuel use (TWh/year)					
Sub-process	**Abatement option**	**Description**	**Abated CO_2[1]**	**Unit costs**	**Natural gas**	**Biomethane**	**H_2**	**Electricity**	**Heat**	**Key considerations** (incl. TRL, challenges, etc.)
Drying *~26% of total CO_2 emissions* **~0.1 Mt CO_2/year**	**Heat pump**	Waste heat from the firing kiln is upgraded to the suitable temperature and transported to the drying phase to eliminate the need for combustion-based heat eliminating emissions	▼**0.1 Mt CO_2/year** *(-25%)*	**<300 €/t CO_2**	▼0.6	-	-	▲0.1	-	• Sufficient waste heat is produced in the firing stage to eliminate the need for additional fuel combustion in the drying process • Industrial heat pumps are commercially available (TRL 9) • Coefficient of performance set at 3.5 therefore greatly lowering energy requirements
	CCS (post-combustion, liquid transport)	Capturing CO_2 from furnace exhaust gases and storing it permanently can reduce furnace-related emissions by up to ~90%	▼**0.1 Mt CO_2/year** *(-22%)*	**>500 €/t CO_2**	-	-	-	▲<0.1	▲0.1	• Transportation and storage of captured CO_2 requires extensive infrastructure potentially unfeasible for Dutch ceramic production due to small scale of production plants • Liquid transportation by ship most likely option due to proximity to rivers of most ceramic factories

1) Abatement as percentage of total process emissions; ; 2) High unit costs due to economies of scale
Sources: MIDDEN, CBS

For ceramics, biomethane for firing and heat pumps for drying form the most techno-economic abatement pathways for deep abatement of the sector

Ceramics – Abatement pathways



Sector	Process	CO_2 emissions	Abatement pathways	Key considerations
Ceramics	**Firing** Generates ultra high temperatures for ceramic sintering *Very high temp. ~1000 –1300 °C*	**0.3 Mt** *(75%)*	9[1] 9 **Biomethane fuel substitution 65% + CCS (post combustion) 35%** (0.3 Mt, 0.1 bcm) **100%** 7 9[3] **E-furnace**[2] (0.2 Mt) **65%**	- **Biomethane substitution** of natural gas in the firing process is the most **techno-economic option** to abate all combustion-related emissions; however, **adopted biomethane price assumptions** will be a key steering parameter for its prioritisation versus alternative abatement options - **Heat pump integration to recover waste heat from the firing process** is the most **cost-effective way** to eliminate emissions from the **drying process** - **E-furnaces** are considered an **alternative pathway under biomethane** and **blue hydrogen constraints,** high-cost drivers and expected TRLs are still under investigation
	Drying Water content in the mixed raw material gets removed *Low to medium temp. ~70 – 90 °C*	**0.1 Mt** *(25%)*	9 9 **Heat pump** (0.1 Mt) **100%** 9[1] 9 **Biomethane fuel substitution** (0.1 Mt, <0.1 bcm) **100%** 7 9 **Hydrogen fuel substitution** (0.1 Mt, 0.3 bcm) **100%** 7 9[3] **E-furnace** (0.1 Mt) **100%** 9 9 **CCS (post combustion) 90% + biomethane fuel substitution 10%** (0.1 Mt) **100%**	

1) Technology in use in other sectors, not yet implemented in this sector; 2) Options only abates combustion-based emissions, maximal abatement is therefore 0.2 Mt of CO_2; 3)Technology is currently in full-scale prototype phase, assumed to be implementable in 2040; 4) Excl. last-mile delivery costs, CAPEX of last mile delivery of hydrogen is around €1M per km pipeline; 5) Abatement costs will increase due to economy of scale | Sources: CBS, PBL MIDDEN, Wienerberger, Vandersanden, hydrogenera

■ Current TRL | **2040 TRL:** 🟩 High TRL (>7) 🟧 Medium TRL (5-7) 🟥 Low TRL (<5)

XX% Share of abated system emissions ⬚ Techno-economic option(s)

Container and tableware dominate the Dutch glass industry, with 5 production plants accounting for ~80% of total glass sector emissions

Glass – Sector overview

Sector overview

Sector definition

- Glass manufacturing is based on the **high temperature smelting** of feedstock inputs to convert them into **final glass products**
- **Tableware and container production** is the focus, as this subsector is responsible for **~80% of the emissions** of Dutch glass industry; glass wool and glass fibre are the remaining subsectors

System integration & strategic positioning

- Glass production is clustered around **historic glass manufacturing,** notably Leerdam, while the plants in Dongen and Moerdijk are located **strategically in key industrial areas**
- **Container glassware** used in food and drink packaging industry is produced at the **top four production sites,** with tableware production concentrated at the remaining site

Products & end-use markets

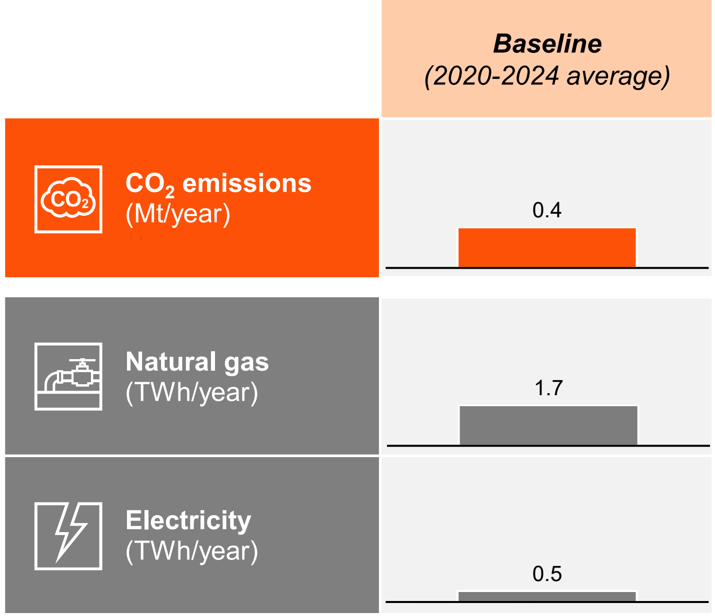
- End-products include **bottles and jars,** with beer bottles representing share of output, alongside a wide range of other glass end-product

Location of the five container and tableware glass production plants in The Netherlands

Market share[1]

①	Ardagh Glass	~30%
③	O-I	~20%
④	LCG	~5%
②	O-I	~25%
④	Ardagh Glass	~20%

Energy profile



	Baseline *(2020-2024 average)*
CO_2 emissions (Mt/year)	0.4
Natural gas (TWh/year)	1.7
Electricity (TWh/year)	0.5

Energy carriers

Inputs

- **Silica sand**
- **Waste glass** *(66%)*
- **Various minerals**[2]

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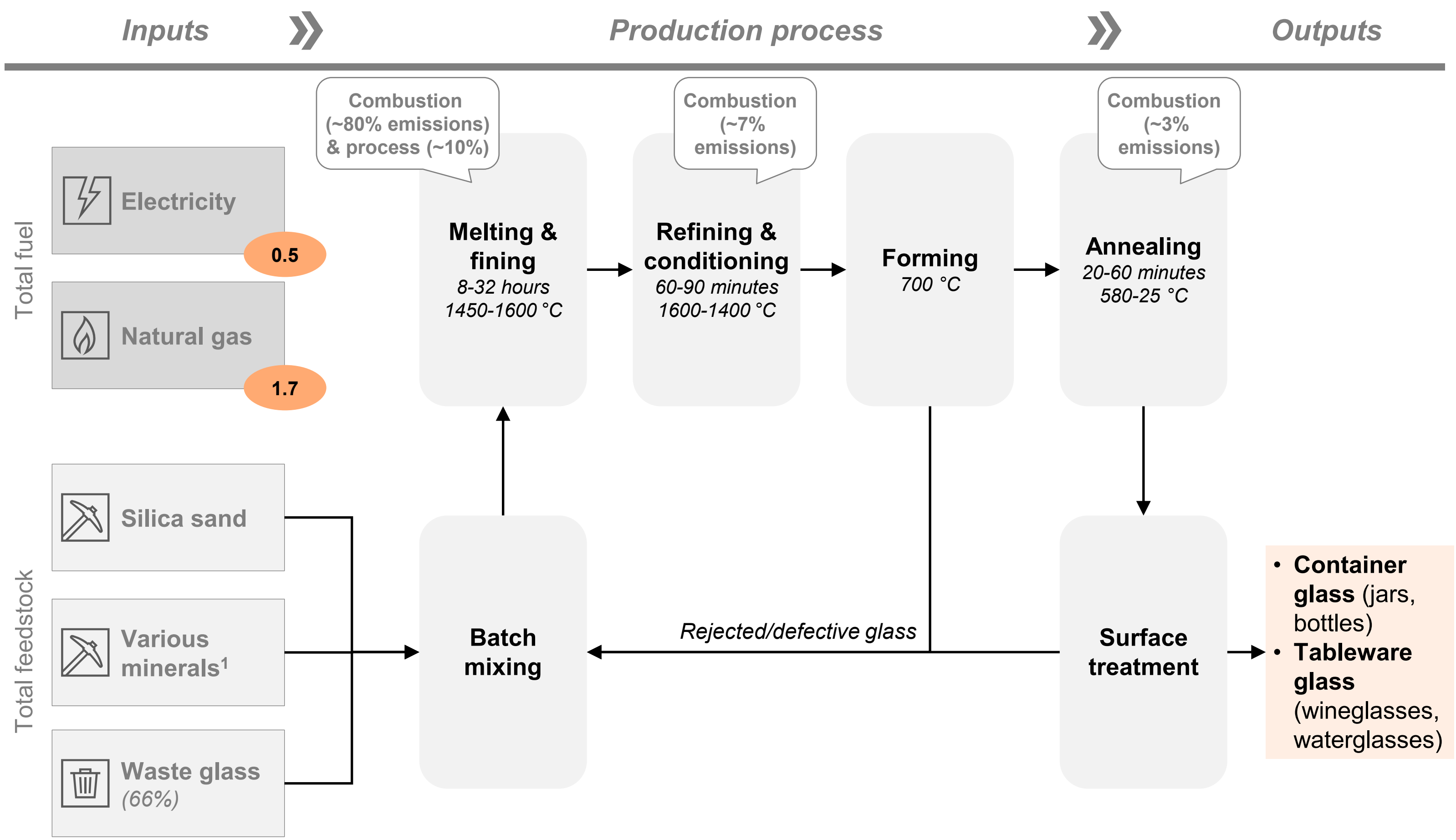
1) Based on production capacity; 2) Limestone, dolomite, sodium sulphate

Sources: CBS, PBL MIDDEN

Glass production is an energy-intensive sector driven by ultra-high temperatures across all stages, from melting and fining through forming and annealing

Glass – Process overview



Inputs | *Production process* | *Outputs*

Total fuel

Electricity 0.5

Natural gas 1.7

Total feedstock

Silica sand

Various minerals[1]

Waste glass *(66%)*

Combustion (~80% emissions) & process (~10%)

Melting & fining
8-32 hours
1450-1600 °C

Combustion (~7% emissions)

Refining & conditioning
60-90 minutes
1600-1400 °C

Forming
700 °C

Combustion (~3% emissions)

Annealing
20-60 minutes
580-25 °C

Batch mixing

Rejected/defective glass

Surface treatment

- **Container glass** (jars, bottles)
- **Tableware glass** (wineglasses, waterglasses)

Key insights

- **Melting furnaces (~90%)** provide the **ultra-high-temperature heat** (up to 1,600 °C) required to melt the glass batch (silica sand, minerals, and cullet); they are fired by **natural gas**, with long residence times during melting and fining driving most combustion-related emissions
- **Melting and fining** account for **the majority of combustion-based emissions**, due to the extended duration of this phase
- **Carbonate decomposition** within the batch releases process-related CO_2, accounting for the remaining **~12% of total emissions**
- **Waste glass** (cullet) constitutes **a large share of the glass feedstock** (~66%)

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[1] Limestone, dolomite, sodium sulphate
Sources: CBS, PBL MIDDEN

CO_2 Largest amount of CO_2 emissions ▨ Hydrogen production or consumption ● XX Total usage in TWh ● XX Hydrogen usage in TWh

Combustion-based emissions account for ~90% of emissions in the Dutch glass industry, driven by high temperatures required in the production process

Glass production – Key characteristics

Sub-processes	Key role	CO_2 emission mechanism	Typical CO_2 concentration	Operating temperature	Hydrogen involvement	Fuel dependence	Abatement options
Melting & fining	• **Combustion heaters** are used to melt the batch and cullet mixture • The raw materials are **melted**, **homogenised** and **fined** • Raw material spends **8-32 hours** in this phase	• **~90% of glass production emissions** • **~13% of melting emissions** are released due to decomposition of carbonates in raw material as opposed to hydrocarbon combustion-based emissions	• **~8-10%**	• **Very high operating temperature** (~1450–1600°C)	• n/a	• **Largest consumer of natural gas** **Only option available for abating carbonate-decomposition-based emissions**	• **Electrification** • **Blue H_2 fuel substitution** • **Biomethane fuel substitution** • **Post-comb. CCS** • **Hybrid oven**
Refining & conditioning	• **The molten batch** starts to cool down • gases in the molten batch causing **bubbles** is **absorbed** by the batch as solubility of gases increase	• **~7% of glass production emissions**	• **~8-10%**	• **Very high operating temperatures** (~1450-1600°C)	• n/a	• **Uses natural gas**	• **Electrification** • **Blue H_2 fuel substitution** • **Biomethane fuel substitution** • **Post-comb. CCS**
Annealing	• Blown containers are **heated up** rapidly and uniformly cooled down again to increase durability of products	• **~3% of glass production**	• **~8-10%**	• **Large temperature range** (~25-580°C)	• n/a	• **Uses natural gas**	• **Electrification** • **Blue H_2 fuel substitution** • **Biomethane fuel substitution** • **Post-comb. CCS**

Sources: CBS, PBL MIDDEN, Integrating carbon capture and utilization into the glass industry: Economic analysis of emissions reduction through CO_2 mineralization (Caudle et al, 2023)

Abatement options do not fully abate emissions from melting & fining processes, though post-combustion CCS alone can achieve up to 90% CO2 reduction

Glass – Abatement options (1/3)

					Change in total fuel use (TWh/year)					
Sub-process	**Abatement option**	**Description**	**Abated CO_2[1]**	**Unit costs**	**Natural gas**	**Biomethane**	**H_2**	**Electricity**	**Heat**	**Key considerations** (incl. TRL, challenges, etc.)
Melting & fining *~90% of total emissions* **~0.3 Mt (comb.: 0.2, carbonate decomp.:<0.1) CO_2/year**	**CCS (post-combustion)**	Capturing CO_2 from furnace exhaust gases and storing it permanently can reduce furnace-related emissions by up to ~90%	**▼0.3 Mt CO_2/year** *(-90%)*	***Gaseous transport***						• Only option to abate emissions originating from carbonate decomposition • Transportation and storage of captured CO_2 requires extensive infrastructure potentially unfeasible for Dutch glass production
				>500 €/t CO_2 [2]	-	-	-	▲0.1	▲0.2	
				Liquid transport						
				>500 €/t CO_2 [2]	-	-	-	▲0.1	▲0.2	
	Biomethane fuel substitution	Replacing natural gas with biomethane as furnace fuel can fully eliminate direct CO_2 emissions from fuel combustion	**▼0.2 Mt CO_2/year** *(-87%)*	**<300 €/t CO_2**	▼1.2	▲1.2	-	-	-	• Due to the similar energy density of biomethane no significant changes to current furnaces are needed • Supply is constrained, with strong competition from other industries • Application feasibility depends on availability of required volumes
	E-furnace	Electrifying furnaces replaces fossil fuels with electricity, eliminating direct combustion emissions from this process (subject to electricity carbon intensity)	**▼0.2 Mt CO_2/year** *(-87%)*	**>500 €/t CO_2**	▼1.2	-	-	▲0.8	-	• Innovation is still needed before full electrification can be implemented • Energy efficiency increases when using fully electric heating
	Blue H_2 fuel substitution	Replacing natural gas and fuel gas with blue hydrogen as furnace fuel can fully eliminate direct CO_2 emissions from fuel combustion	**▼0.2 Mt CO_2/year** *(-69%)*	**>500 €/t CO_2**	▼1.2	-	▲1.2	-	-	• Hydrogen fired furnaces are less efficient and the resulting flame is less radiative • Fossil fuels may need to be mixed in which will lead to less than 100% of combustion-based emissions being abated • Hydrogen delivery and storage infrastructure remains underdeveloped[3]
	Hybrid electric oven + natural gas	Natural gas fired furnaces are partially replaced with electrical heaters, abating a significant part of the emissions	**▼0.1 Mt CO_2/year** *(-47%)*	**>500 €/t CO_2**	▼0.8	-	-	▲0.6	-	• Hybrid solution of above-described electrification option • Due to technological constraints more likely to be implemented on the short term than full electrification

1) Abatement as percentage of total process emissions; 2) High unit costs due to economies of scale; 3) Units costs exclude last-mile delivery costs, hydrogen pipeline CAPEX is estimated at ~€1 million per km

Sources: MIDDEN, CBS, Practical approaches for evaluating radiative heat from high pressure hydrogen flame (Takeno & Yamamoto, 2024), NPVI

Refining & conditioning emissions can be fully abated through biomethane or electrification; CCS is less attractive due to high CAPEX at small scale

Glass – Abatement options (2/3)

Sub-process	Abatement option	Description	Abated CO_2[1]	Unit costs	*Change in total fuel use (TWh/year)*					Key considerations (incl. TRL, challenges, etc.)
					Natural gas	Biomethane	H_2	Electricity	Heat	
Refining & conditioning *~7% of total emissions* **<0.1 Mt CO_2/year**	**Biomethane fuel substitution**	Replacing natural gas with biomethane as furnace fuel can fully eliminate direct CO_2 emissions from fuel combustion	▼**<0.1 Mt CO_2/year** *(-100%)*	**<300 €/t CO_2**	▼0.1	▲0.1	-	-	-	• Due to the similar energy density of biomethane no significant changes to current furnaces are needed • Supply is constrained, with strong competition from other industries • Application feasibility depends on availability of required volumes
	E-furnace	Electrifying furnaces replaces fossil fuels with electricity, eliminating direct combustion emissions from this process step (subject to electricity carbon intensity)	▼**<0.1 Mt CO_2/year** *(-100%)*	**>500 €/t CO_2**	▼0.1	-	-	▲0.1	-	• Significant innovation is still needed before full electrification can be implemented, hybrid option where heat is provided by electricity and gas fired furnaces is more likely in the short term • Energy efficiency increases when using fully electric heating
	CCS (post-combustion)	Capturing CO_2 from furnace exhaust gases and storing it permanently can reduce furnace-related emissions by up to ~90%	▼**<0.1 Mt CO_2/year** *(-90%)*	***Gaseous transport*** **>500 €/t CO_2**[2]	-	-	-	▲<0.01	▲<0.01	• Transportation and storage of captured CO_2 requires extensive infrastructure potentially unfeasible for Dutch glass production • Requires significant heat and electricity for regeneration, reducing overall system efficiency
				Liquid transport **>500 €/t CO_2**[2]	-	-	-	▲<0.01	▲0.01	
	Blue H_2 fuel substitution	Replacing natural gas and fuel gas with low-carbon hydrogen as furnace fuel can fully eliminate direct CO_2 emissions from fuel combustion	▼**<0.1 Mt CO_2/year** *(-80%)*	**>500 €/t CO_2**	▼0.1	-	▲0.1	-	-	• Hydrogen fired furnaces are less efficient and the resulting flame is less radiative • Fossil fuels may need to be mixed in which will lead to less than 100% of combustion-based emissions being abated • Hydrogen delivery and storage infrastructure remains underdeveloped[3]

1) Abatement as percentage of total process emissions; 2) High unit costs due to economies of scale; 3) Units costs exclude last-mile delivery costs, hydrogen pipeline CAPEX is estimated at ~€1 million per km

Sources: MIDDEN, CBS

Full abatement of the annealing process is best achieved through biomethane fuel substitution, while CCS remains unattractive because of its high CAPEX

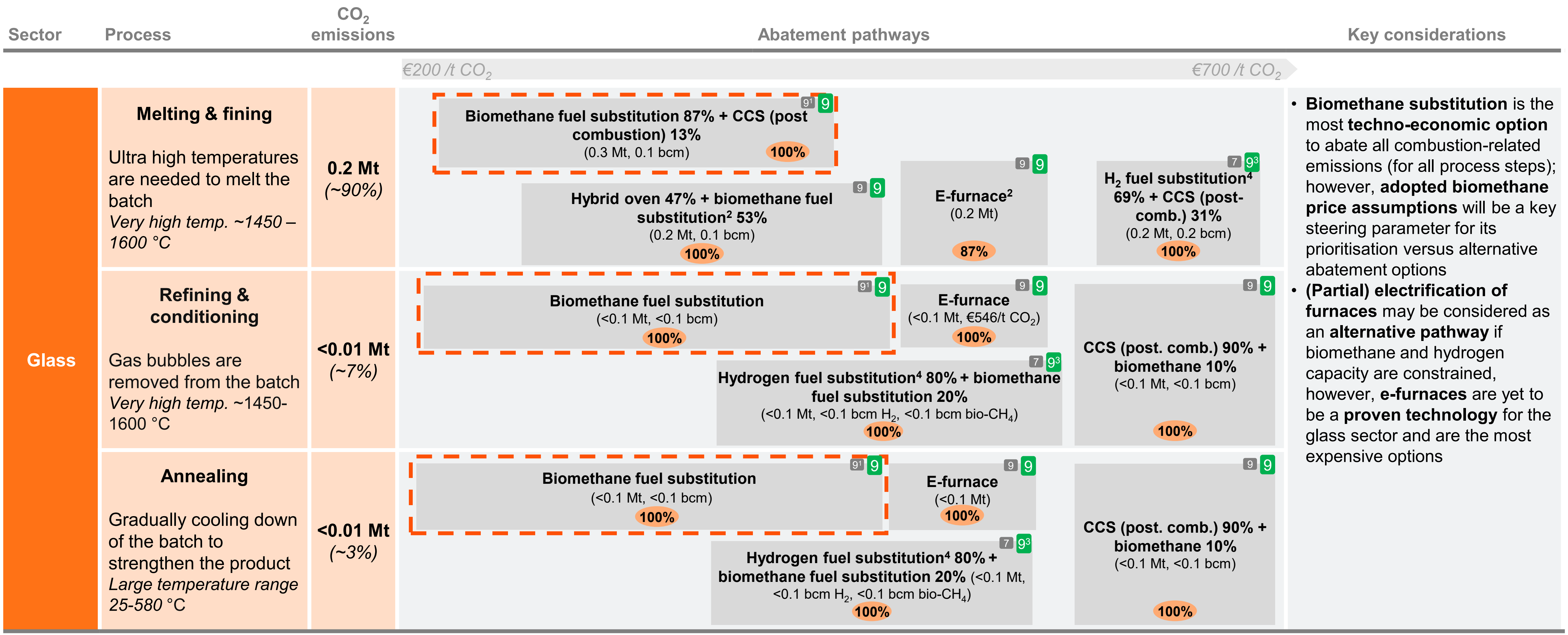
Glass – Abatement options (3/3)

Sub-process	Abatement option	Description	Abated CO_2[1]	Unit costs	*Change in total fuel use (TWh/year)* Natural gas	Biomethane	H_2	Electricity	Heat	**Key considerations** (incl. TRL, challenges, etc.)
Annealing *~3% of total emissions* **<0.1 Mt CO_2/year**	**Biomethane fuel substitution**	Replacing natural gas with biomethane as furnace fuel can fully eliminate direct CO_2 emissions from fuel combustion	**▼<0.1 Mt CO_2/year** *(-100%)*	**<300 €/t CO_2**	▼0.1	▲0.1	-	-	-	• Due to the similar energy density of biomethane no significant changes to current furnaces are needed • Supply is constrained, with strong competition from other industries • Application feasibility depends on availability of required volumes
	E-furnace	Electrifying furnaces replaces fossil fuels with electricity, eliminating direct combustion emissions from this process step (subject to electricity carbon intensity)	**▼<0.1 Mt CO_2/year** *(-100%)*	**>500 €/t CO_2**	▼0.1	-	-	▲<0.1	-	• Significant innovation is still needed before full electrification can be implemented, hybrid option where heat is provided by electricity and gas fired furnaces is more likely in the short term • Energy efficiency increases when using fully electric heating
	Blue H_2 fuel substitution	Replacing natural gas and fuel gas with low-carbon hydrogen as furnace fuel can fully eliminate direct CO_2 emissions from fuel combustion	**▼<0.1 Mt CO_2/year** *(-100%)*	**>500 €/t CO_2**	▼0.1	-	▲0.1	-	-	• Hydrogen fired furnaces are less efficient and the resulting flame is less radiative • Fossil fuels may need to be mixed in which will lead to less than 100% of combustion-based emissions being abated • Hydrogen delivery and storage infrastructure remains underdeveloped[2]
	CCS (post-combustion)	Capturing CO_2 from furnace exhaust gases and storing it permanently can reduce furnace-related emissions by up to ~90%	**▼<0.1 Mt CO_2/year** *(-90%)*	***Gaseous transport***						• Transportation and storage of captured CO_2 requires extensive infrastructure potentially unfeasible for Dutch glass production • Requires significant heat and electricity for regeneration, reducing overall system efficiency
				>500 €/t CO_2	-	-	-	▲<0.01	▲<0.01	
				Liquid transport						
				>500 €/t CO_2	-	-	-	▲<0.01	▲<0.01	

1) Abatement as percentage of total process emissions; 2) Units costs exclude last-mile delivery costs, hydrogen pipeline CAPEX is estimated at ~€1 million per km
Sources: MIDDEN, CBS

For glass, biomethane represents the techno-economic abatement route to 2040; however, the sector is investigating the use of e-furnace or hybrid ovens

Glass – Abatement pathways



€200 /t CO_2

€700 /t CO_2

Sector	Process	CO_2 emissions	Abatement pathways	Key considerations
Glass	**Melting & fining** Ultra high temperatures are needed to melt the batch *Very high temp. ~1450 – 1600 °C*	**0.2 Mt** *(~90%)*	9[1] 9 **Biomethane fuel substitution 87% + CCS (post combustion) 13%** (0.3 Mt, 0.1 bcm) 100% 9 9 **Hybrid oven 47% + biomethane fuel substitution[2] 53%** (0.2 Mt, 0.1 bcm) 100% 9 9 **E-furnace[2]** (0.2 Mt) 87% 7 9[3] **H_2 fuel substitution[4] 69% + CCS (post-comb.) 31%** (0.2 Mt, 0.2 bcm) 100%	- **Biomethane substitution** is the most **techno-economic option** to abate all combustion-related emissions (for all process steps); however, **adopted biomethane price assumptions** will be a key steering parameter for its prioritisation versus alternative abatement options - **(Partial) electrification of furnaces** may be considered as an **alternative pathway** if biomethane and hydrogen capacity are constrained, however, **e-furnaces** are yet to be a **proven technology** for the glass sector and are the most expensive options
	Refining & conditioning Gas bubbles are removed from the batch *Very high temp. ~*1450-1600 °C	**<0.01 Mt** *(~7%)*	9[1] 9 **Biomethane fuel substitution** (<0.1 Mt, <0.1 bcm) 100% 9 9 **E-furnace** (<0.1 Mt, €546/t CO_2) 100% 7 9[3] **Hydrogen fuel substitution[4] 80% + biomethane fuel substitution 20%** (<0.1 Mt, <0.1 bcm H_2, <0.1 bcm bio-CH_4) 100% 9 9 **CCS (post. comb.) 90% + biomethane 10%** (<0.1 Mt, <0.1 bcm) 100%	
	Annealing Gradually cooling down of the batch to strengthen the product *Large temperature range* 25-580 °C	**<0.01 Mt** *(~3%)*	9[1] 9 **Biomethane fuel substitution** (<0.1 Mt, <0.1 bcm) 100% 9 9 **E-furnace** (<0.1 Mt) 100% 7 9[3] **Hydrogen fuel substitution[4] 80% + biomethane fuel substitution 20%** (<0.1 Mt, <0.1 bcm H_2, <0.1 bcm bio-CH_4) 100% 9 9 **CCS (post. comb.) 90% + biomethane 10%** (<0.1 Mt, <0.1 bcm) 100%	

■ Current TRL | **2040 TRL:** 🟩 High TRL (>7) 🟧 Medium TRL (5-7) 🟥 Low TRL (<5)

XX% Share of abated system emissions ⬚ Techno-economic option(s)

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1) Technology in use in other sectors, not yet implemented in this sector; 2) Options only abates combustion-based emissions, maximal abatement is therefore 0.2 Mt of CO_2 3)Technology is currently in full-scale prototype phase, assumed to be implementable in 2040 4) Excl. last-mile delivery costs, CAPEX of last mile delivery of hydrogen is around €1M per km pipeline

Sources: CBS, PBL MIDDEN, Accelerating the European container glass industry's energy transition (FEVE), H2-glass, fives group

The Netherlands is a key exporter of beverages, dairy, and potato products, which are produced and processed in four clusters across the Netherlands

Food – Sector overview

Sector overview

Sector definition

- Food manufacturing is based on the **processing** of **agricultural inputs** into **(semi-) finished food products**
- **Dairy, meat, and potato** processing **dominate energy use and emissions** in the Dutch food industry
- **Emissions** mainly come from **heat-intensive processes** like evaporation, sterilisation, drying, and baking

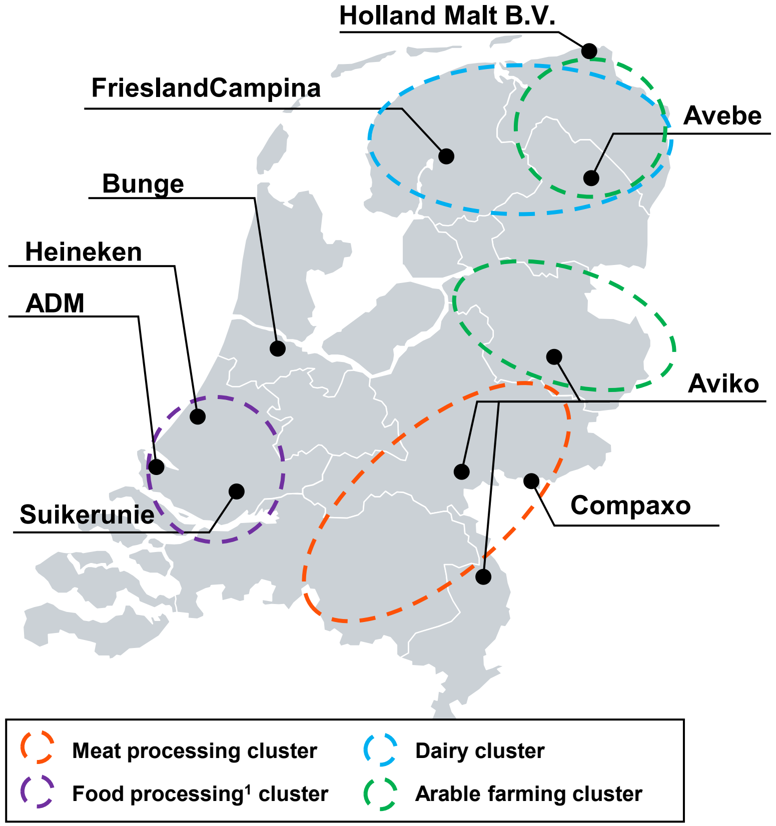
System integration & strategic positioning

- **Production facilities** are distributed across the Netherlands, with 4 clusters, located **strategically** near **key agricultural and logistics areas**
- Major **dairy and meat** processors manage **integrated supply chains** connecting farms, plants, distribution, and exports
- **Heat-intensive subsectors** (e.g., dairy, potato processing) are concentrated in **top industrial sites**, while **lighter processing** (packaging, blending, assembly) occur in **smaller facilities**

Products & end-use markets

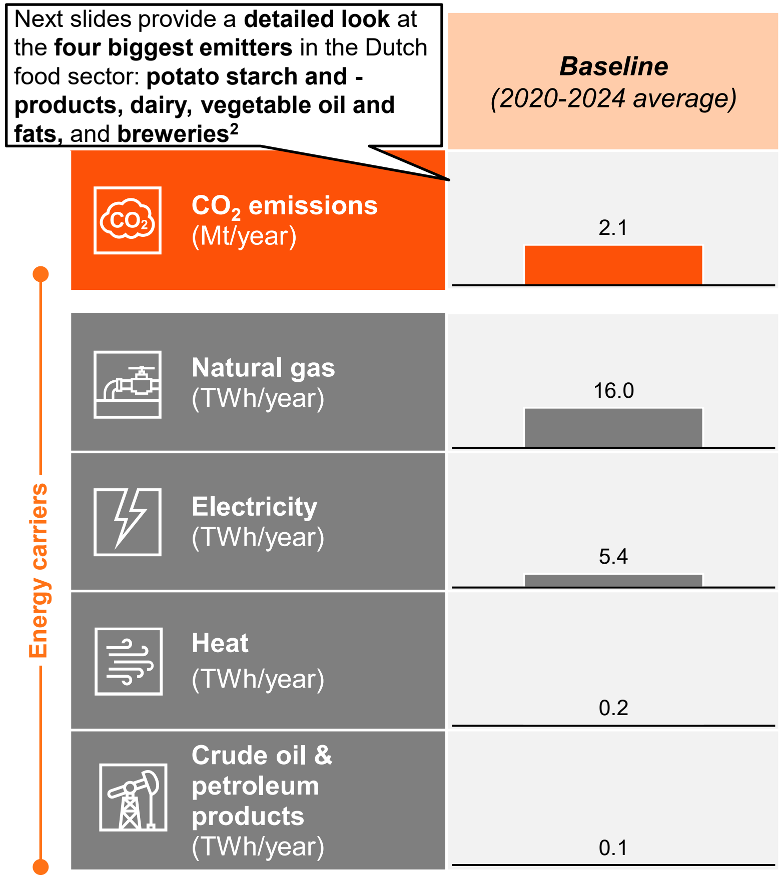
- **The Netherlands** is a **key exporter**, especially of cheese, infant formula, processed potatoes, and beverages
- **Main markets** include **retail**, **food service, and exports**, with strong demand from Europe supported by the country's strategic location and logistics

Location of the four processed food clusters and large production plants in The Netherlands



Energy profile

Next slides provide a **detailed look** at the **four biggest emitters** in the Dutch food sector: **potato starch and -products, dairy, vegetable oil and fats**, and **breweries**[2]



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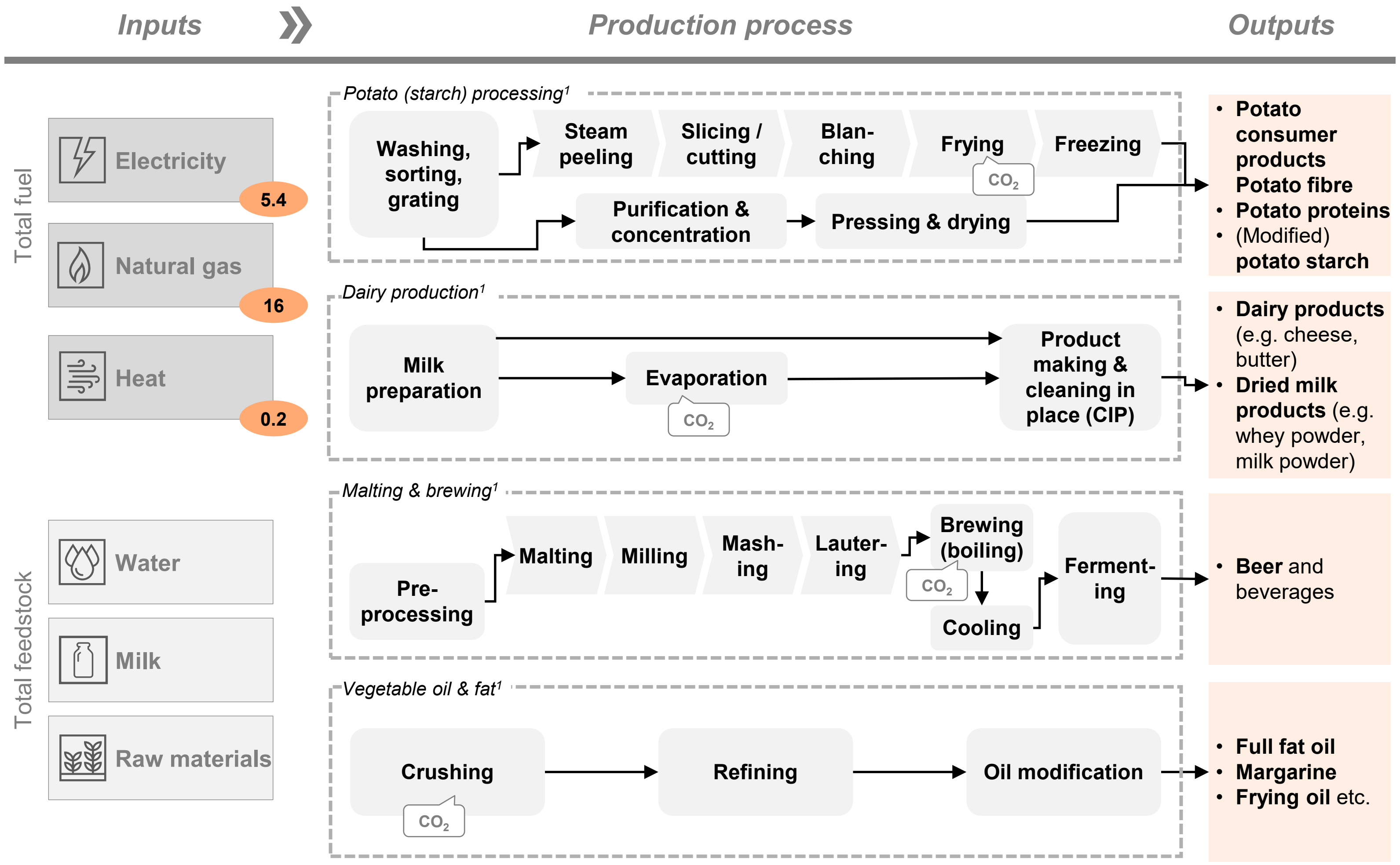
1) Zuid-Holland hosts diversified food-processing facilities with strong links to export channels; 2) The subsectors considered make up 75% of the sector's total emissions

Sources: CBS, PBL MIDDEN

Across production plants, generating heat and/or electricity accounts for most fuel use and all CO_2 emissions within the subsectors of food

Food – Process overview



Inputs » *Production process* *Outputs*

Total fuel

- Electricity 5.4
- Natural gas 16
- Heat 0.2

Total feedstock

- Water
- Milk
- Raw materials

Potato (starch) processing[1]

Washing, sorting, grating → Steam peeling → Slicing / cutting → Blanching → Frying (CO_2) → Freezing

Washing, sorting, grating → Purification & concentration → Pressing & drying

- **Potato consumer products**
- **Potato fibre**
- **Potato proteins**
- (Modified) **potato starch**

Dairy production[1]

Milk preparation → Product making & cleaning in place (CIP)

Milk preparation → Evaporation (CO_2) → Product making & cleaning in place (CIP)

- **Dairy products** (e.g. cheese, butter)
- **Dried milk products** (e.g. whey powder, milk powder)

Malting & brewing[1]

Pre-processing → Malting → Milling → Mashing → Lautering → Brewing (boiling) (CO_2) → Cooling → Fermenting

- **Beer** and beverages

Vegetable oil & fat[1]

Crushing (CO_2) → Refining → Oil modification

- **Full fat oil**
- **Margarine**
- **Frying oil** etc.

Key insights

Food processing emissions are mainly driven by **3 systems**:

- **Utility systems (100%)** (natural gas boilers, steam boilers and CHP units) supply the **heat** and a large share of the **electricity** needed for downstream operations such as drying, evaporation, CIP systems, HVAC, refrigeration compressors, packaging lines and plant-wide heating
- **Thermal processing units** include ovens, fryers, blanchers, pasteurisers, UHT systems and sterilisers that require medium- to high-temperature heat (typically 120 - 250 °C) and electricity, relying heavily on utility plants and therefore **emitting little to no direct CO_2**
- **Refrigeration & cooling,** such as cooling tunnels, chillers, refrigeration plants and freezer systems consume significant amounts of electricity; they generate very little direct combustion-related CO_2, with **emissions** linked mainly to **upstream power generation**

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1) The subsectors considered (dairy, potato products, breweries, vegetable oils and fats, and potato starch) make up 75% of the sector's total emissions

Sources: CBS, PBL MIDDEN

CO_2 Largest amount of CO_2 emissions ▨ Hydrogen production or consumption ● XX Total usage in TWh ● XX Hydrogen usage in TWh

Heat required in the food processing sector is produced by either natural gas boilers, steam boilers or CHP units, all burning natural gas to produce heat

Food – Key characteristics

Sub-processes	Key role	CO_2 emission mechanism	Typical CO_2 concentration	Operating temperature	Hydrogen involvement	Fuel dependence	Abatement options
Natural gas boiler	• Generates **heat** required in processes such as **peeling, blanching and evaporation** in **potato** and **dairy processing**	• **Fossil fuel combustion** results in 30% of total sector emissions[2]	• **~4-15%**	• **Low to medium operating temperature**[1] (5-100 °C)	• n/a	• **Natural gas** is main fuel for boilers	• **Biomethane fuel substitution** • **E-boilers** • **Blue hydrogen fuel substitution** • **Hybrid E-boiler +hydrogen or biomethane fuel** • **Heat pump** • **CCS (post-combustion)**
CHP	• Generates **heat** required in the boiling process in breweries • Generates **electricity** to be used in the production process, greatly increasing efficiency	• **Fossil fuel combustion** results in 30% of sector emissions[2]	• **~4-15%**	• **Low to medium operating temperature**[1] (5-100 °C)	• n/a	• **Natural gas** is main fuel for CHP units	
Steam boiler	• Generates **heat** required in processes such as **peeling, blanching** and **boiling** in **potato starch** and **oils & vegetables**	• **Fossil fuel combustion** results in 15% of sector emissions[2]	• **~4-15%**	• **Low to medium operating temperature**[1] (5-100 °C)	• n/a	• **Natural gas** is main fuel for steam boilers	

1) Differs between food processing subsectors; 2) Emissions don't add up to 100% as not all subsectors are considered in the analysis; The subsectors considered (dairy, potato products, breweries, vegetable oils and fats, and potato starch) make up 75% of the sector's total emissions

Sources: PBL MIDDEN

Electric boilers cut food CO_2 emissions by approximately 100%, necessitating advancements in e-heating technology and improvements to the electrical grid

Food – Abatement options (1/3)

					Change in total fuel use (TWh/year)					
Sub-process	**Abatement option**	**Description**	**Abated CO_2[1]**	**Unit costs**	**Natural gas**	**Biomethane**	**H_2**	**Electricity**	**Heat**	**Key considerations** (incl. TRL, challenges, etc.)
Natural gas boiler *~32% of total direct CO_2 emissions[2]* **~0.7 Mt CO_2/year**	**Biomethane fuel substitution**	Replace natural gas in boilers with upgraded biogas; drop-in replacement	▼0.7 Mt *(-100%)*	300-500 €/t CO_2	▼4.4	▲4.4	-	-	-	• Fully drop-in solution, with constrained supply and strong competition from utilities and other industries • Quality variability (CH_4 content, pressure, contaminants) requires monitoring and minor boiler adaptations
	E-boiler	Replace natural gas boilers with electric resistance boilers, eliminating direct combustion emissions from this process step (subject to electricity carbon intensity)	▼0.7 Mt *(-100%)*	300-500 €/t CO_2	▼4.4	-	-	▲4.5	-	• Requires substantial grid-connection upgrades for large processing plants • Offers strong flexibility and fast ramping to match variable heat demand • Integrates easily into existing production processes
	H_2 fuel substitution	Replace natural gas in boilers with blue hydrogen as furnace fuel can fully eliminate direct CO_2 emissions from fuel combustion	▼0.7 Mt *(-100%)*	>500 €/t CO_2	▼4.4	-	▲4.2	-	-	• Availability and cost of low-carbon hydrogen are major constraints • Higher flame temperatures may require burner modifications • Hydrogen delivery and storage infrastructure remains underdeveloped[3]
	Hybrid e-boiler + blue H_2 or biomethane	Optimising heat supply by combining electrified boilers during low-power price periods, while using biomethane or blue hydrogen during peak demand	▼0.7 Mt *(-100%)*	300-500 €/t CO_2	▼4.4	-	▲2.5	▲1.8	-	• Hybrid e-boilers reduces peak electricity demand through dual-fuel flexibility • Implied efficiency from full electrification/fuel substitution used to calculate energy deltas
	Heat pump	Upgrade existing low-temperature heat (often waste heat) to a usable temperature level for industrial processes	▼0.1 Mt *(-20%)*	<300 €/t CO_2	▼0.6	-	-	▲0.2	-	• Can be implemented to increase efficiency within production processes • Industrial high-temperature heat pumps are TRL 7 for many applications • Heat pumps are most effective for low- to medium-temperature heat (5-100°C)

1) Abatement as percentage of total process emissions 2) The subsectors considered (dairy, potato products, breweries, vegetable oils and fats, and potato starch) make up 75% of the sector's total emissions; 3) Units costs exclude last-mile delivery costs, hydrogen pipeline CAPEX is estimated at ~€1 million per km

Sources: PBL MIDDEN; CBS; NEa

Full abatement is possible through fuel substitution, e-boilers or hybrid options, heat pumps can only decarbonise a portion of CHP operations (25%)

Food – Abatement options (2/3)

Sub-process	Abatement option	Description	Abated CO_2[1]	Unit costs	*Change in total fuel use (TWh/year)*					Key considerations (incl. TRL, challenges, etc.)
					Natural gas	Biomethane	H_2	Electricity	Heat	
CHP *~28% of total direct CO_2 emissions[2]* **~0.6 Mt CO_2/year**	**Biomethane fuel substitution**	Replace natural gas in CHPs with upgraded biogas; drop-in replacement.	▼0.6 Mt *(-100%)*	<300 €/t CO_2	▼3.0	▲3.0	-	-	-	• Fully drop-in solution, with constrained supply and strong competition from utilities and other industries • Quality variability (CH_4 content, pressure, contaminants) requires monitoring and minor boiler adaptations
	E-boiler	Replace CHPs with electric resistance boilers, eliminating direct combustion emissions from this process step (subject to electricity carbon intensity)	▼0.6 Mt *(-100%)*	300-500 €/t CO_2	▼3.0	-	-	▲3.0	-	• Requires substantial grid-connection upgrades for large processing plants • Offers strong flexibility and fast ramping to match variable heat demand • Cogeneration of electricity is lost, additional electricity is therefore needed from the grid
	H_2 fuel substitution	Replace natural gas in boilers with blue hydrogen as furnace fuel can fully eliminate direct CO_2 emissions from fuel combustion	▼0.6 Mt *(-100%)*	300-500 €/t CO_2	▼3.0	-	▲2.9	-	-	• Availability and cost of low-carbon hydrogen are major constraints • Higher flame temperatures may require burner modifications • Hydrogen delivery and storage infrastructure remains underdeveloped[3]
	Hybrid e-boiler + blue H_2 or biomethane	Optimising heat supply by combining electrified boilers during low-power price periods, while using biomethane or blue hydrogen during peak demand	▼0.6 Mt *(-100%)*	<300 €/t CO_2	▼3.0	-	▲1.7	▲1.2	-	• Hybrid e-boilers reduces peak electricity demand through dual-fuel • Implied efficiency from full electrification/fuel substitution used to calculate energy deltas
	Heat pump	Upgrade existing low-temperature heat (often waste heat) to a usable temperature level for industrial processes	▼0.1 Mt *(25%)*	<300 €/t CO_2	▼0.6	-	-	▲0.2	-	• Heat pumps reduce on site heat demand • Heat and electricity production in a CHP are linked, reducing steam demand with a heat pump forces the CHP to ramp down, reducing on-site electricity generation and disrupting heat pressure levels across the site

1) Abatement as percentage of total process emissions 2) The subsectors considered (dairy, potato products, breweries, vegetable oils and fats, and potato starch) make up 75% of the sector's total emissions; 3) Units costs exclude last-mile delivery costs, hydrogen pipeline CAPEX is estimated at ~€1 million per km

Sources: MIDDEN; CBS; NEa

Heat pumps are lowest-cost abatement option for steam boilers, but their limited abatement potential means complementary options are needed for full abatement

Food – Abatement options (3/3)

					Change in total fuel use (TWh/year)					
Sub-process	**Abatement option**	**Description**	**Abated CO_2[1]**	**Unit costs**	**Natural gas**	**Biomethane**	**H_2**	**Electricity**	**Heat**	**Key considerations** (incl. TRL, challenges, etc.)
Steam boiler *~16% of total direct CO_2 emissions[2]* **~0.3 Mt CO_2/year**	**Biomethane fuel substitution**	Replace natural gas in boilers with upgraded biogas; drop-in replacement.	▼0.3 Mt *(-100%)*	300-500 €/t CO_2	▼2.2	▲2.2	-	-	-	• Fully drop-in solution, with constrained supply and strong competition from utilities and other industries • Quality variability (CH_4 content, pressure, contaminants) requires monitoring and minor boiler adaptations
	E-boiler	Replace gas steam boilers with electric resistance boilers, eliminating direct combustion emissions from this process step (subject to electricity carbon intensity)	▼0.3 Mt *(-100%)*	300-500 €/t CO_2	▼2.2	-	-	▲2.2	-	• Requires substantial grid-connection upgrades for large processing plants • Offers strong flexibility and fast ramping to match variable heat demand • Integrates easily into existing production processes
	Blue H_2 fuel substitution	Replace natural gas in CHP/boilers with blue hydrogen as furnace fuel can fully eliminate direct CO_2 emissions from fuel combustion	▼0.3 Mt *(-100%)*	>500 €/t CO_2	▼2.2	-	▲2.1	-	-	• Availability and cost of low-carbon hydrogen are major constraints • Higher flame temperatures may require burner modifications • Hydrogen delivery and storage infrastructure remains underdeveloped[3]
	Hybrid e-boiler + blue H_2 or biomethane	Optimising heat supply by combining electrified boilers during low-power price periods, while using biomethane or blue hydrogen during peak demand	▼0.3 Mt *(-100%)*	300-500 €/t CO_2	▼2.2	-	▲1.2	▲0.9	-	• Hybrid e-boilers reduces peak electricity demand through dual-fuel flexibility • Implied efficiency from full electrification/fuel substitution used to calculate energy deltas
	Heat pump	Upgrade existing low-temperature heat (often waste heat) to a usable temperature level for industrial processes	▼<0.1 Mt *(-25%)*	<300 €/t CO_2	▼0.5	-	-	▲0.2	-	• Can be implemented to increase efficiency within production processes • Industrial high-temperature heat pumps are TRL 7 for many applications • Heat pumps are most effective for low- to medium-temperature heat (5-100°C)

1) Abatement as percentage of total process emissions 2) The subsectors considered (dairy, potato products, breweries, vegetable oils and fats, and potato starch) make up 75% of the sector's total emissions; 3) Units costs exclude last-mile delivery costs, hydrogen pipeline CAPEX is estimated at ~€1 million per km

Sources: MIDDEN; CBS; NEa

Heat pumps and hybrid e-boilers can substitute natural gas boilers and CHP units in the food sector

Food – Abatement pathways (1/2)

Sector | Process | CO_2 emissions | Abatement pathways | Key considerations

Food[1]

Natural gas boilers

Generates heat for thermal processing by converting natural gas into heat

Low to medium temp. 5-100°C

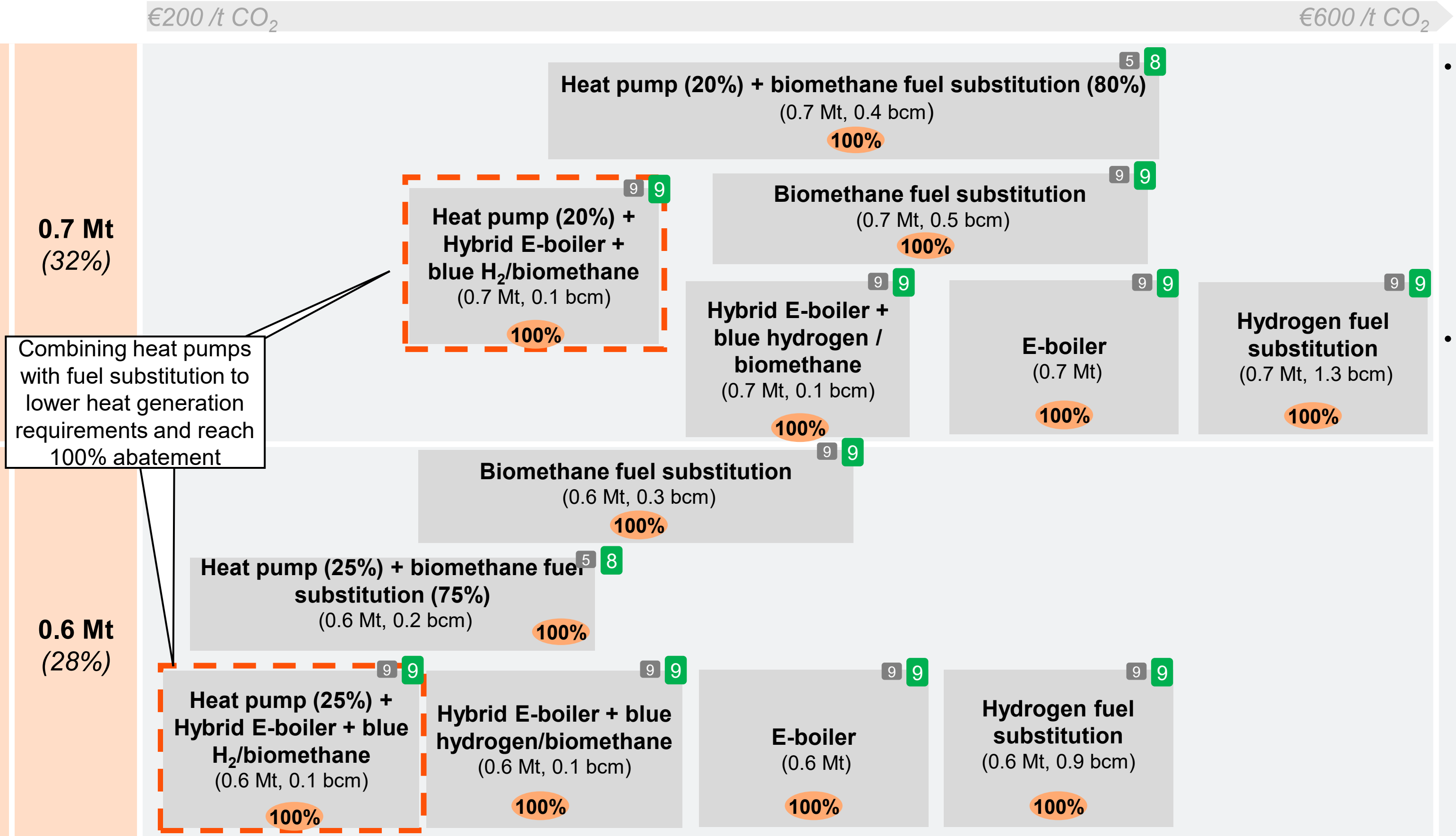
0.7 Mt *(32%)*

CHP units

Generates heat for (thermal) processing by converting natural gas into heat and electricity

Medium temp. 5-100 °C

0.6 Mt *(28%)*



Natural gas boilers:

Heat pump (20%) + biomethane fuel substitution (80%) (0.7 Mt, 0.4 bcm) 100%

Heat pump (20%) + Hybrid E-boiler + blue H_2/biomethane (0.7 Mt, 0.1 bcm) 100%

Biomethane fuel substitution (0.7 Mt, 0.5 bcm) 100%

Hybrid E-boiler + blue hydrogen / biomethane (0.7 Mt, 0.1 bcm) 100%

E-boiler (0.7 Mt) 100%

Hydrogen fuel substitution (0.7 Mt, 1.3 bcm) 100%

CHP units:

Biomethane fuel substitution (0.6 Mt, 0.3 bcm) 100%

Heat pump (25%) + biomethane fuel substitution (75%) (0.6 Mt, 0.2 bcm) 100%

Heat pump (25%) + Hybrid E-boiler + blue H_2/biomethane (0.6 Mt, 0.1 bcm) 100%

Hybrid E-boiler + blue hydrogen/biomethane (0.6 Mt, 0.1 bcm) 100%

E-boiler (0.6 Mt) 100%

Hydrogen fuel substitution (0.6 Mt, 0.9 bcm) 100%

Combining heat pumps with fuel substitution to lower heat generation requirements and reach 100% abatement

Key considerations:

- Most **techno-economic pathway for CHP units and natural gas boilers** is **a heat pump implementation combined with e-boiler use,** to maintain the efficiency from additional electricity output in a CHP while using biomethane or blue hydrogen.
- This is a combination of various techniques: heat pump, e-boiler, blue hydrogen and biomethane. (Other combinations of-) these options separately form secondary abatement pathways.

🟫 Current TRL | **2040 TRL:** 🟩 High TRL (>7) 🟧 Medium TRL (5-7) 🟥 Low TRL (<5)

XX% Share of abated system emissions ⬚ Techno-economic option(s)

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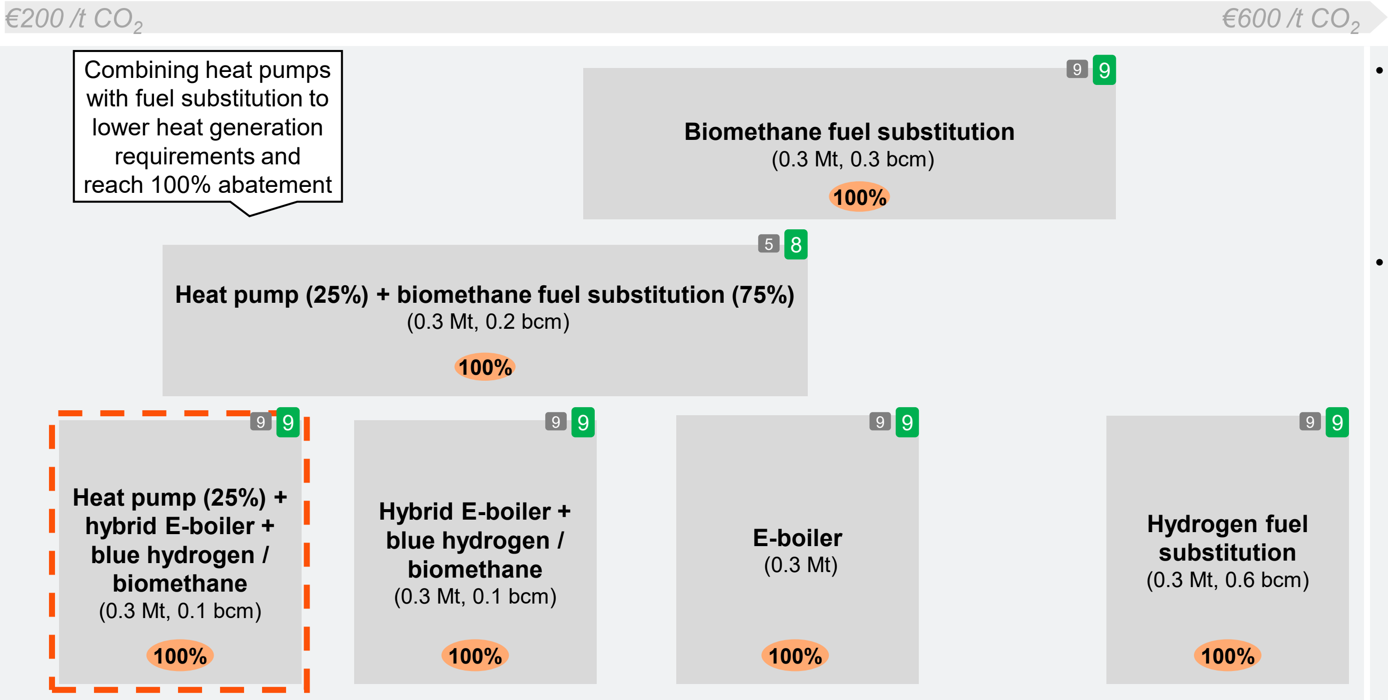
[1] Included sub-sectors are dairy, potatoes, breweries, vegetable oil, and potato starch

Sources: CBS, ECN, PBL MIDDEN, TNO

For the steam boilers, heat pumps combined with biomethane fuel substitution enables deep abatement of the process CO_2 emissions

Food – Abatement pathways (2/2)

Sector	Process	CO_2 emissions	Abatement pathways	Key considerations
Food[1]	**Steam boiler** Generates heat for thermal processing by converting natural gas into heat *Low to medium temp. 5-100°C*	**0.3 Mt** *(16%)*	*€200 /t CO_2* → *€600 /t CO_2* Combining heat pumps with fuel substitution to lower heat generation requirements and reach 100% abatement 9 9 **Biomethane fuel substitution** (0.3 Mt, 0.3 bcm) 100% 5 8 **Heat pump (25%) + biomethane fuel substitution (75%)** (0.3 Mt, 0.2 bcm) 100% 9 9 **Heat pump (25%) + hybrid E-boiler + blue hydrogen / biomethane** (0.3 Mt, 0.1 bcm) 100% 9 9 **Hybrid E-boiler + blue hydrogen / biomethane** (0.3 Mt, 0.1 bcm) 100% 9 9 **E-boiler** (0.3 Mt) 100% 9 9 **Hydrogen fuel substitution** (0.3 Mt, 0.6 bcm) 100%	• **Heat pump combined with biomethane fuel substitution** provides the most **cost-effective full-abatement pathway**, which enables the steam boiler to deeply abate the process • **Hybrid e-boilers** with **biomethane or blue hydrogen fuel** (dependent on price) **are the second most techno-economic** option for decarbonising steam boilers, at a similar price point

▨ Current TRL	**2040 TRL:**	🟩 High TRL (>7)	🟧 Medium TRL (5-7)	🟥 Low TRL (<5)	
XX% Share of abated system emissions	⬚ Techno-economic option(s)				

[1] Included sub-sectors are dairy, potatoes, breweries, vegetable oil, and potato starch

Sources: CBS, ECN, PBL MIDDEN, TNO

The Dutch paper manufacturing sector is highly fragmented, with numerous companies and various products, collectively emitting ~0.7 Mt of CO_2 emissions

Paper – Sector overview

Sector overview

Sector definition

- **Paper & board manufacturing converts pulp** (virgin or recovered fibres) into a wide variety of **paper and board grades**
- The sector includes **21 production sites** in the Netherlands, producing ~3 Mt/year of paper, emitting 0.7 Mt of CO_2
- Emissions mainly come **from heat production for thermal-energy-intensive processes**, particularly drying, resulting in high combustion-based fuel use

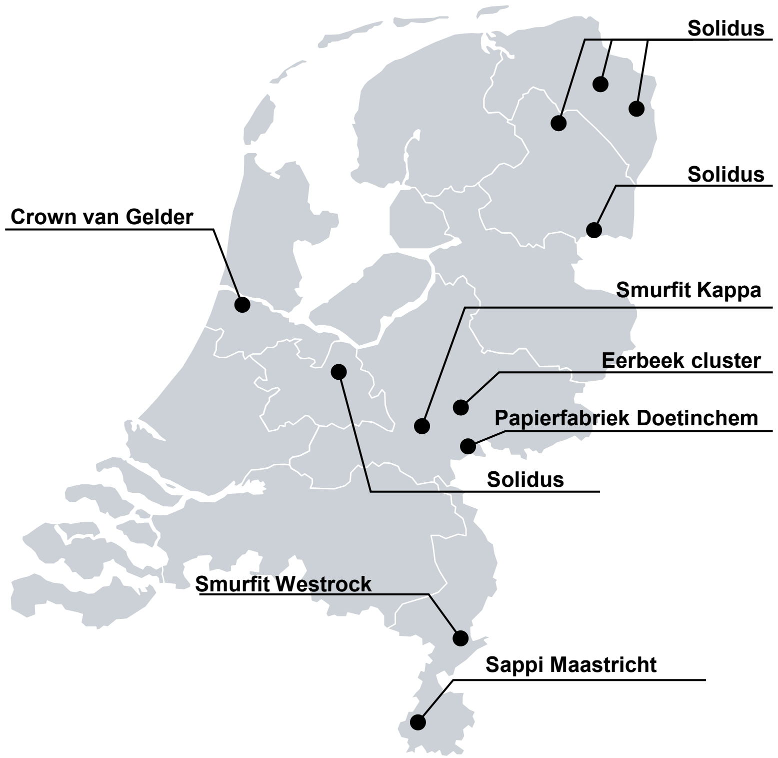
System integration & strategic positioning

- Paper mills are **geographically distributed across the Netherlands**, with concentrations in Gelderland, Limburg and Groningen clusters
- **High-energy-intensity subsectors** (e.g. corrugated board, solid board and graphic paper) are located in **large-scale industrial sites** with complex heat networks and CHP installations

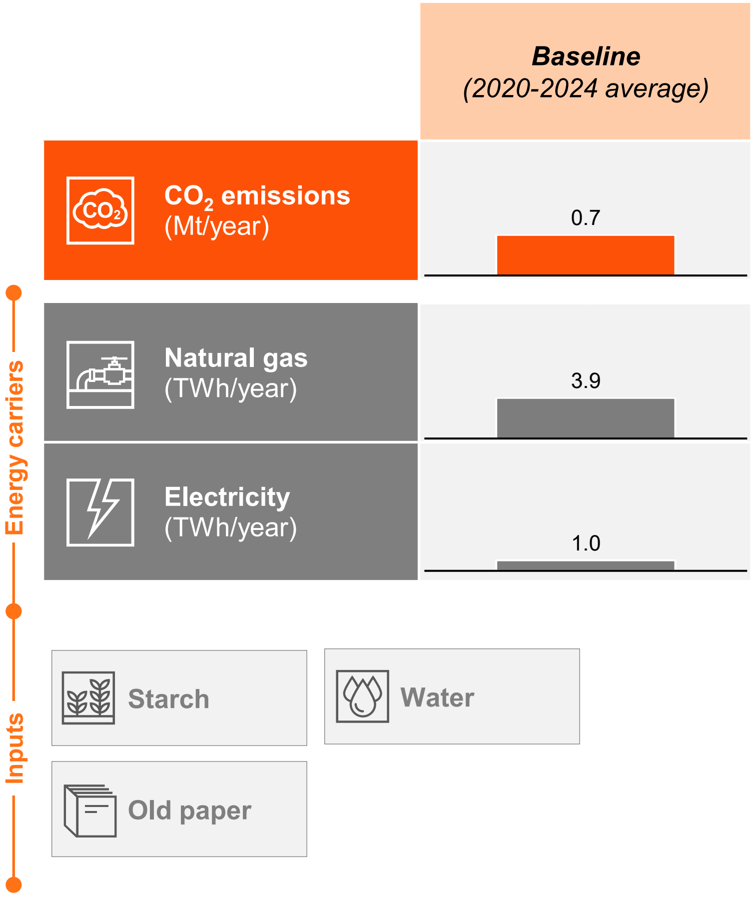
Products & end-use markets

- The Dutch sector produces a **broad portfolio**, serving **packaging**, **printing**, **hygiene**, and **industrial-material applications**

Location of the largest paper plants in The Netherlands



Energy profile



	Baseline *(2020-2024 average)*
CO_2 emissions (Mt/year)	0.7
Natural gas (TWh/year)	3.9
Electricity (TWh/year)	1.0

Starch

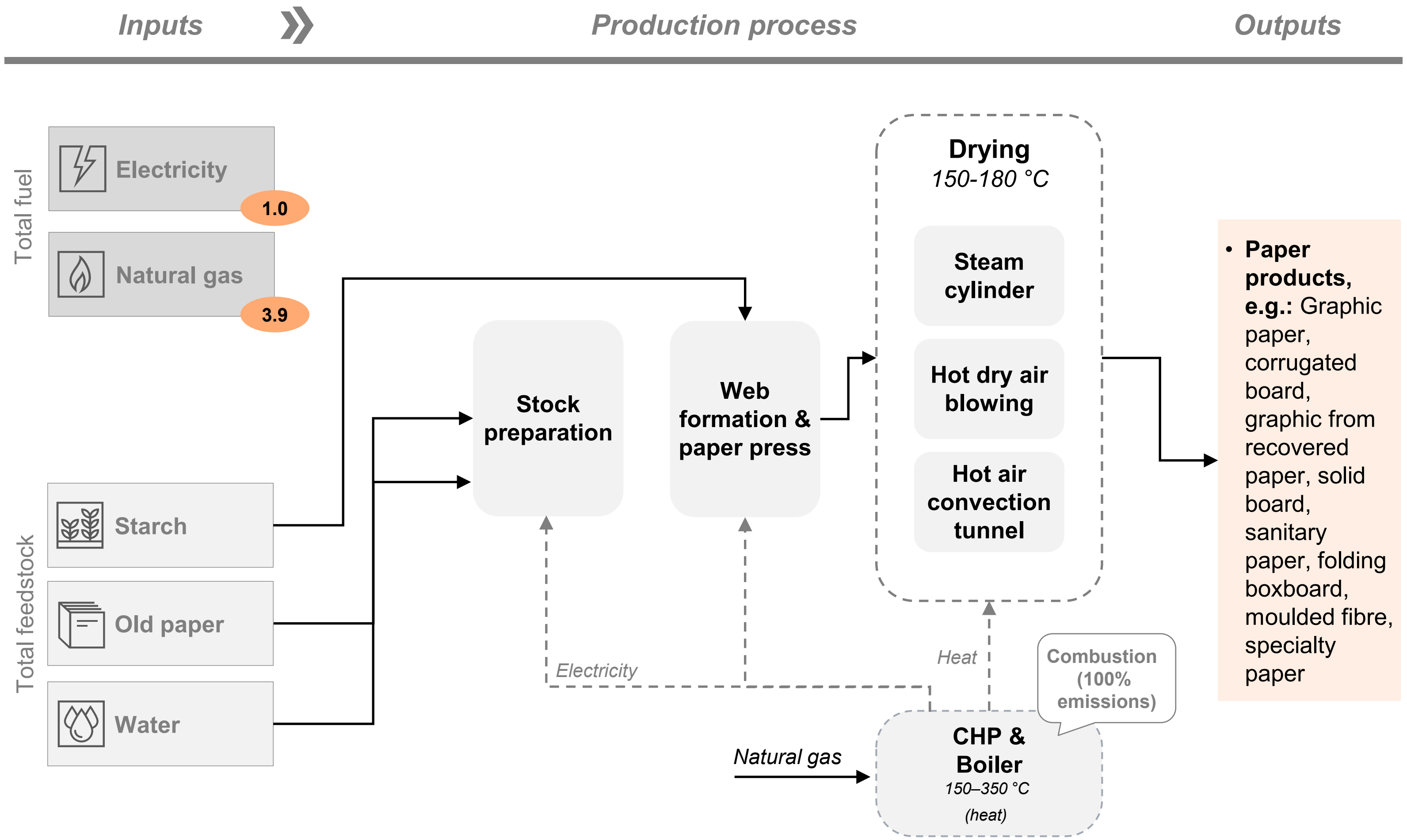
Water

Old paper

Sources: CBS, PBL MIDDEN

Combustion-based emissions (from CHP & boiler) dominate the Dutch paper industry, driven by high thermal demand of the drying process

Paper – Process overview



Inputs » *Production process* *Outputs*

Total fuel

Electricity 1.0

Natural gas 3.9

Total feedstock

Starch

Old paper

Water

Stock preparation

Web formation & paper press

Drying
150-180 °C

Steam cylinder

Hot dry air blowing

Hot air convection tunnel

Electricity

Heat

Combustion (100% emissions)

Natural gas

CHP & Boiler
150–350 °C
(heat)

- **Paper products, e.g.:** Graphic paper, corrugated board, graphic from recovered paper, solid board, sanitary paper, folding boxboard, moulded fibre, specialty paper

Key insights

- **Paper production emissions** are mainly driven by the following systems:

1. **Steam-boiler and CHP utilities (~100%)** supply **heat and electricity** in most mills. Generated heat and electricity feed drying, pulping, stock preparation, de-inking, bleaching, CIP systems, HVAC, and many ancillary operations. Most mills operate natural-gas boilers or CHP units, creating a steady baseline of combustion emissions
2. **Drying & thermal-processing systems,** including multi-cylinder dryers, hot air dryers, steam hoods, and coating-drying units, require very large amounts of medium- to high-temperature heat (typically 120–180 °C), relying on natural-gas-fired steam boilers, CHPs, or direct-fired hoods to evaporate water - which accounts for the majority of direct CO_2 emissions in papermaking

PwC Sources: CBS, PBL MIDDEN

CO_2 Largest amount of CO_2 emissions ▨ Hydrogen production or consumption XX Total usage in TWh XX Hydrogen usage in TWh

High pressure steam required in paper production processes is generated by either CHP units or natural gas boilers which burn natural gas to produce heat

Paper – Key characteristics

Sub-processes	Key role	CO_2 emission mechanism	Typical CO_2 concentration	Operating temperature	Hydrogen involvement	Fuel dependence	Abatement options
CHP	- Produces **high-pressure heat** required in the paper production process for **pulping, drying and machine operations** - Generates **electricity** to be used in the production process, greatly increasing efficiency	- **Fossil fuel combustion** results in 75% of sector emissions	- **~4-15%**	- **Low to medium operating temperature** (5-100 °C)	- n/a	- **Natural gas** is main fuel for CHP units	- **Biomethane fuel substitution** - **E-boilers** - **Blue hydrogen fuel substitution** - **Hybrid E-boiler + hydrogen/ biomethane fuel** - **Heat pump** - **CCS (post-combustion)**
Natural gas boiler	- Produces **high-pressure heat** required in the paper production process for **pulping, drying and machine operations**	- **Fossil fuel combustion** results in 25% of sector emissions	- **~4-15%**	- **Low to medium operating temperature** (5-100 °C)	- n/a	- **Natural gas** is main fuel for boilers	

PwC Sources: PBL MIDDEN

CHPs can be abated most cost-efficiently through (hybrid) fuel substitution that retains electricity production potential

Paper – Abatement options (1/4)

					Change in total fuel use (TWh/year)					
Sub-process	**Abatement option**	**Description**	**Abated CO_2[1]**	**Unit costs**	**Natural gas**	**Biomethane**	**H_2**	**Electricity**	**Heat**	**Key considerations** (incl. TRL, challenges, etc.)
CHP *74% of total direct CO_2 emissions* **~0.5 Mt CO_2/year**	**Biomethane fuel substitution**	Replacing natural gas in CHP units with upgraded biogas, serving as a drop-in fuel substitute that eliminates nearly all combustion-related emissions in the production process	▼0.5 Mt *(-100%)*	**<300 €/t CO_2**	▼2.9	▲2.9	-	-	-	• The feasibility of application will depend on the availability of the required biomethane volume for abatement • Quality variations (CH_4 content, pressure, contaminants) affect boiler performance and require continuous monitoring
	Hybrid e-boiler + blue H_2 or biomethane	Optimising heat supply by combining electrified boilers during low-power price periods, while using biomethane or blue hydrogen during peak demand	▼0.5 Mt *(-100%)*	**300-500 €/t CO_2**	▼2.9	-	▲1.6	▲1.3	-	• Hybrid option may be more likely than full electrification due to E-grid constraints and cheaper unit costs • Hydrogen delivery and storage infrastructure remains underdeveloped; units costs exclude last-mile delivery costs, hydrogen pipeline CAPEX is estimated at ~€1 million per km
	E-boilers	Replacing gas fired CHP units with electric resistance boilers	▼0.5 Mt *(-100%)*	**300-500 €/t CO_2**	▼2.9	-	-	▲2.4	-	• Electrification has high operational expenditure if electricity prices remain elevated and may require substantial grid-connection upgrades for large paper plants • Option offers strong flexibility and fast ramping to match variable heat demand, integrating easily into existing heat networks

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1) Abatement as percentage of total process emissions

Sources: MIDDEN; CBS; NEa

Heat pumps can abate a share of CHP emissions (45%); fuel substitution with blue H_2 can be used to fully abate the CHP

Paper – Abatement options (2/4)

					Change in total fuel use (TWh/year)					
Sub-process	**Abatement option**	**Description**	**Abated CO_2[1]**	**Unit costs**	**Natural gas**	**Biomethane**	**H_2**	**Electricity**	**Heat**	**Key considerations** (incl. TRL, challenges, etc.)
CHP *75% of total direct CO_2 emissions* **~0.5 Mt CO_2/year**	**Blue H_2 fuel substitution**	Replacing natural gas and fuel gas with blue hydrogen as furnace fuel can fully eliminate direct CO_2 emissions from fuel combustion	▼0.5 Mt *(-100%)*	300-500 €/t CO_2	▼2.9		▲2.7	-	-	• Higher flame temperatures may require burner modifications and create potential NOx concerns • Availability and cost of low-carbon hydrogen are major constraints, especially when it comes to the last • Hydrogen delivery and storage infrastructure remains underdeveloped; units costs exclude last-mile delivery costs, hydrogen pipeline CAPEX is estimated at ~€1 million per km
	Heat pump	Upgrade existing low-temperature heat (often waste heat) to a usable temperature level for industrial processes	▼0.2 Mt *(-45 %)*	300-500 €/t CO_2	▼1.3	-	-	▲0.4	▲0.1	• Heat pumps can be implemented to increase efficiency within production processes, and are most effective for low- to medium-temperature heat (5-100°C) • Industrial high-temperature heat pumps are TRL 7 (demonstration phase) for many applications

1) Abatement as percentage of total process emissions

Sources: MIDDEN; CBS; NEa

For natural gas boilers, the process can be fully abated via fuel substitution with biomethane or H_2; electrification (e-boiler) is still under development

Paper – Abatement options (3/4)

					Change in total fuel use (TWh/year)					
Sub-process	**Abatement option**	**Description**	**Abated CO_2[1]**	**Unit costs**	**Natural gas**	**Biomethane**	**H_2**	**Electricity**	**Heat**	**Key considerations** (incl. TRL, challenges, etc.)
Natural gas boiler *26% of total direct CO_2 emissions* **~0.2 Mt CO_2/year**	**Biomethane fuel substitution**	Replacing natural gas in CHP units with upgraded biogas, serving as a drop-in fuel substitute that eliminates nearly all combustion-related emissions in the production process	▼0.2 Mt *(-100%)*	<300 €/t CO_2	▼1.0	▲1.0	-	-	-	• The TRL is approximately 5-6, indicating that extensive commercial use is expected to be restricted • The feasibility of application will depend on the availability and the required volume for abatement
	E-boilers	Replacing natural gas boiler with electric resistance boilers	▼0.2 Mt *(-100%)*	<300 €/t CO_2	▼1.0	-	-	▲0.9	-	• High temperature heat pumps that provide the heat pressure and temperature levels required for paper and board production (150-180 °C) are still under development • Connecting heat pumps calls for certain adaptations to the production system
	Blue H_2 fuel substitution	Replacing natural gas and fuel gas with blue hydrogen as furnace fuel can fully eliminate direct CO_2 emissions from fuel combustion	▼0.2 Mt *(-100%)*	300-500 €/t CO_2	▼1.0	-	▲1.0	-	-	• Availability and cost of low-carbon hydrogen are major constraints • Higher flame temperatures may require burner modifications and create potential NOx concerns • Hydrogen delivery and storage infrastructure remains underdeveloped; units costs exclude last-mile delivery costs, hydrogen pipeline CAPEX is estimated at ~€1 million per km

1) Abatement as percentage of total process emissions
Sources: MIDDEN; CBS; NEa

Partial decarbonisation of natural gas boilers is achievable through heat pumps (~45%), full abatement possible via hybrid e-boiler with H_2 fuel substitution

Paper – Abatement options (4/4)

					Change in total fuel use (TWh/year)					
Sub-process	**Abatement option**	**Description**	**Abated CO_2[1]**	**Unit costs**	**Natural gas**	**Biomethane**	**H_2**	**Electricity**	**Heat**	**Key considerations** (incl. TRL, challenges, etc.)
Natural gas boiler *26% of total direct CO_2 emissions* **~0.2 Mt CO_2/year**	**Hybrid e-boiler + blue H_2 or biomethane**	Optimising heat supply by combining electrified boilers during low-power price periods, while using biomethane or blue hydrogen during peak demand	▼0.2 Mt *(-100%)*	<300 €/t CO_2	▼1.0	-	▲0.6	▲0.4	-	• Hybrid option may be more likely than full electrification due to E-grid constraints and cheaper unit costs • Hydrogen delivery and storage infrastructure remains underdeveloped; units costs exclude last-mile delivery costs, hydrogen pipeline CAPEX is estimated at ~€1 million per km
	Heat pump	Upgrade existing low-temperature heat (often waste heat) to a usable temperature level for industrial processes	▼0.1Mt *(-45%)*	<300 €/t CO_2	▼0.5	-	-	▲0.1	-	• Heat pumps can be implemented to increase efficiency within production processes, and are most effective for low- to medium-temperature heat (5-100°C) • Industrial high-temperature heat pumps are TRL 7 (demonstration phase) for many applications

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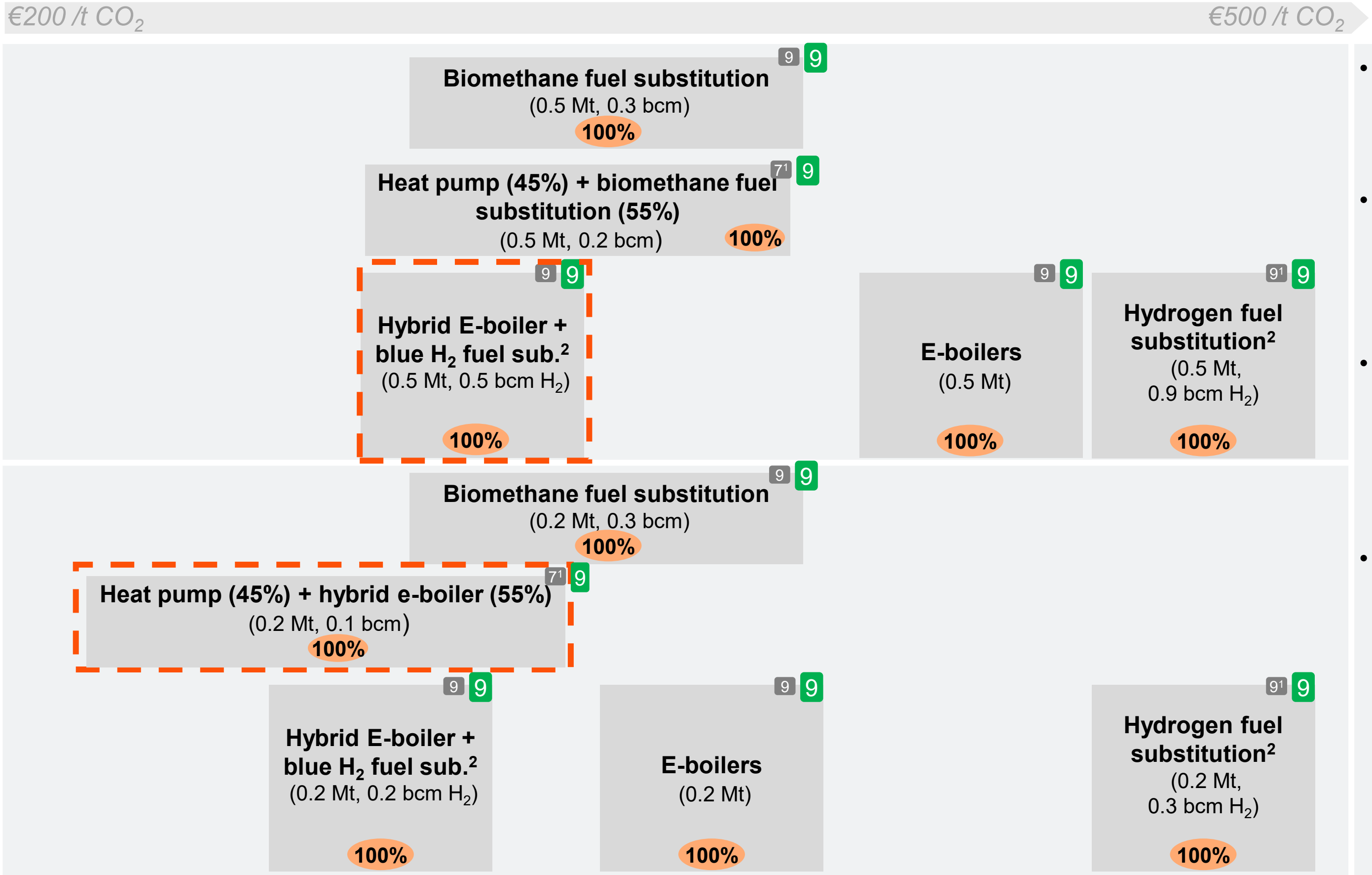
[1] Abatement as percentage of total process emissions

Sources: MIDDEN; CBS; NEa

For paper, heat pumps and hybrid e-boilers represent the techno-economically optimal abatement pathways for CHP units and natural gas boilers

Paper – Abatement pathways

Sector	Process	CO_2 emissions	Abatement pathways	Key considerations
Paper	**CHP units** Generates heat for dying by converting natural gas into heat and power *Low to medium temp. 5-100°C*	**0.5 Mt** *(75%)*	see diagram below	see list below
	Natural gas boilers Generates heat for dying by converting natural gas into heat *Low to medium temp. 5-100°C*	**0.2 Mt** *(25%)*	see diagram below	see list below



CHP units:

- **Biomethane fuel substitution** (0.5 Mt, 0.3 bcm) 100% — 9 / 9
- **Heat pump (45%) + biomethane fuel substitution (55%)** (0.5 Mt, 0.2 bcm) 100% — 7[1] / 9
- **Hybrid E-boiler + blue H_2 fuel sub.[2]** (0.5 Mt, 0.5 bcm H_2) 100% — 9 / 9
- **E-boilers** (0.5 Mt) 100% — 9 / 9
- **Hydrogen fuel substitution[2]** (0.5 Mt, 0.9 bcm H_2) 100% — 9[1] / 9

Natural gas boilers:

- **Biomethane fuel substitution** (0.2 Mt, 0.3 bcm) 100% — 9 / 9
- **Heat pump (45%) + hybrid e-boiler (55%)** (0.2 Mt, 0.1 bcm) 100% — 7[1] / 9
- **Hybrid E-boiler + blue H_2 fuel sub.[2]** (0.2 Mt, 0.2 bcm H_2) 100% — 9 / 9
- **E-boilers** (0.2 Mt) 100% — 9 / 9
- **Hydrogen fuel substitution[2]** (0.2 Mt, 0.3 bcm H_2) 100% — 9[1] / 9

Key considerations

- Most **techno-economic option for CHPs** is a **heat pump implementation combined with biomethane fuel substitution**
- **For natural gas boilers**, **heat pumps and hybrid e-boilers** could be combined as the most techno-economically efficient abatement option
- Within hybrid e-boiler and hydrogen fuel substitution, **last-mile hydrogen delivery capex is not included**, meaning the **total abatement cost** will be **higher**
- Given above constraints, **E-boiler** implementation will be considered as next best abatement option to investigate for natural gas boilers, with **biomethane fuel substitution and heat pumps** as a secondary abatement option for CHP units

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1) Technology in use in other sectors, not yet implemented in this sector; 2) Excl. last-mile delivery costs, CAPEX of last mile delivery of hydrogen is around €1M per km pipeline; 3) Abatement costs will increase due to economy of scale | Sources: CBS, PBL MIDDEN, Everllence, perspectives on the potential for CCS in the European pulp and paper industry (Jönsson, 2013), Cepi, Coldenhove, VSK

▩ Current TRL	**2040 TRL:**	🟩 High TRL (>7)	🟧 Medium TRL (5-7)	🟥 Low TRL (<5)
XX% Share of abated system emissions	⬚ Techno-economic option(s)			

A4

Sensitivity analysis

Sensitivity analysis: CCS-driven abatement remains robust to input commodity price variations; electricity, biomethane and blue H_2 compete within (hybrid-) e-boilers

Sensitivity analysis for key input commodities

Prices in €/MWh	Base case (2030-2040)	Range sensitivity	Change in volumes vis-à-vis base case per abatement technology				
			CCS[5]	Green hydrogen	Electrification	Blue hydrogen	Biomethane
Electricity price[1]	91.0 – 64.9	+/-20%	0.0 / 0.0	0.0 / 0.0	🟧 -3.7 / ▨ 9.9	▨ -4.2 / 0.0	(-0.7) (0.4) ▨ -7.0 / 🟧 4.3
Natural gas price[2]	35.3 – 28.0	+/-20%	0.0 / 0.0	0.0 / 0.0	▨ -3.6 / 🟧 3.0	🟧 -2.6 / 0.1	(-0.1) (0.4) 🟧 -0.6 / ▨ 4.0
Biomethane price	88.1 – 125.8	*Lower*: 77.5 ('30) – 106.2 ('40) *Upper*: 98.6 ('30) – 145.3[3] ('40)	0.0 / 0.0	0.0 / 0.0	▨ -3.3 / 🟧 3.6	▨ -2.4 / 0.1	(-0.4) (0.6) 🟧 -4.3 / ▨ 6.3
Blue hydrogen price	106.0 – 84.0	*Lower*: 94.9 ('30) – 75.2 ('40) *Upper*: 117.1 ('30) – 92.7[4] ('40)	0.0 / 0.0	0.0 / 0.0	▨ -3.4 / 🟧 1.9	🟧 -2.6 / ▨ 1.7	(0.1) (0.2) ▨ 0.5 / 🟧 2.1
Green hydrogen price	289.6 – 163.5	+/-20%	0.0 / 0.0	0.0 / 0.0	0.0 / 0.0	0.0 / 0.0	0.0 / 0.0
	Volumes in the base case		**21.4 Mtpa**	**0 TWh**	**20.8 TWh**	**66.7 TWh**	(2.5) **24.6 TWh**

▨ Price down

🟧 Price up

(XX) Volume (bcm)

Comments

- **CCS volumes remain robust** under ±20% variation across all cost parameters
- **Green hydrogen is not cost-competitive** as an abatement option in any process, even with a 20% cost reduction
- **Biomethane, electrification and blue hydrogen compete as fuels within hybrid e-boilers** - lower prices for one drive fuel substitution away from the other two, and vice versa for higher prices

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1) An increase in the electricity price is modelled with a proportional increase in the price of green hydrogen; 2) An increase in the price of natural gas is modelled with an increase in the price of blue and grey hydrogen and of biomethane (which is modelled as the natural gas price plus the price of EU ETS; 3) Corresponding to +-20% to EU ETS2; 4) Corresponding to +-20% to other costs than price of feedstock (natural gas), converted with 70% energy efficiency; 5) Includes CCS on the current hydrogen production, but not on additional hydrogen production as a result of rising blue hydrogen demand.

Thank you

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