



Decarbonisation routes for the Dutch industry towards 2040

Report prepared for Gasunie



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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 July 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



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 MtCO₂-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, CO₂ refers to total greenhouse-gas emissions expressed in CO₂-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



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.

This version replaces the report published on 9 July 2026 and includes a correction and an extension on page 36.

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 CO₂/year**, with **CCS expected to drive most reduction** (~21 Mt CO₂ of year, of which **83% through blue hydrogen**), followed by **direct iron reduction & electric furnaces in the steel sector** (~9 Mt CO₂/year), **partial electrification via hybrid boilers** (~6 Mt CO₂/year) and fuel substitution by **biomethane** (~4 Mt CO₂/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 CO₂ 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

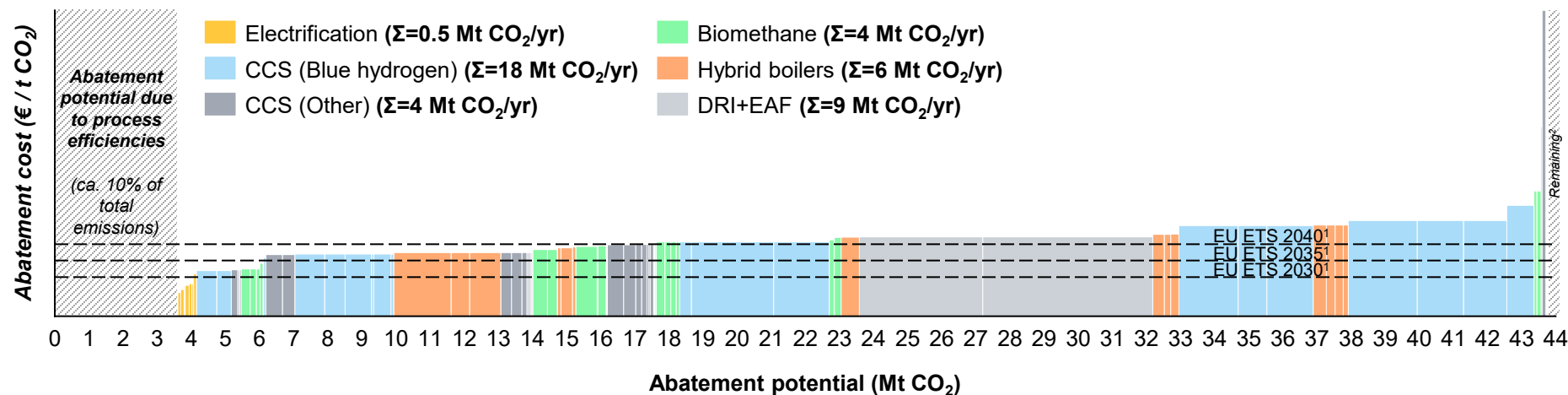
Technology pathways: constrained by physics, refined by economics

- From a technical standpoint, abatement options **vary markedly by sector**. The **top six emitting sectors** rely on high-temperature processes and often generate concentrated CO₂ 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 CO₂ 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

Executive summary

GHG abatement cost curve for Dutch Industry

(In €/t CO₂ & Mt CO₂/year, 2040P)



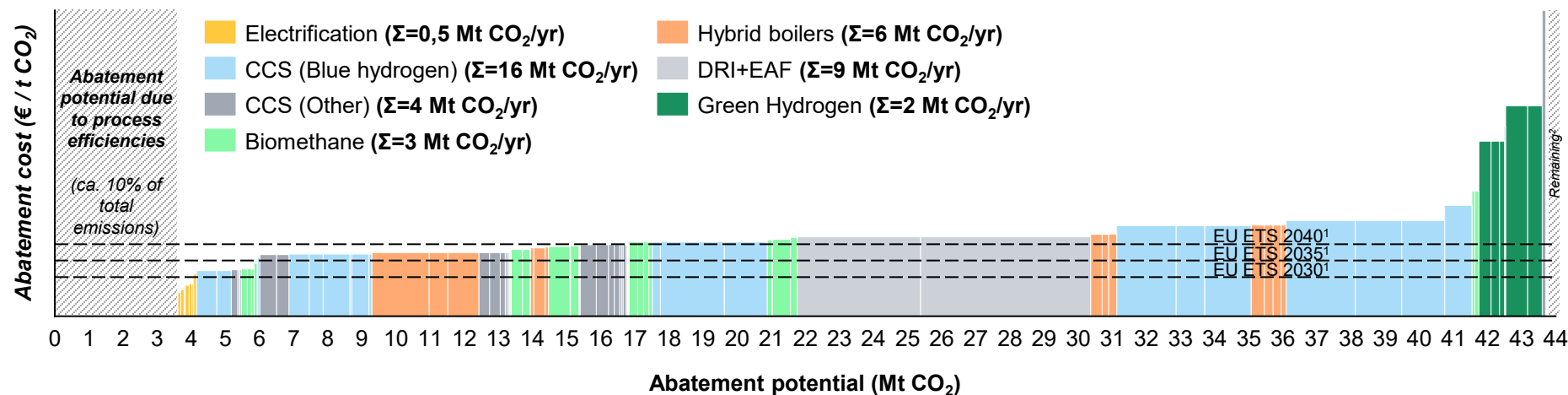
CCS, including blue hydrogen, dominates the transition

- Assuming industrial output remains broadly stable, achieving net zero across the sectors in scope requires emissions reductions of roughly **44 Mt CO₂ 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 CO₂ per year of reductions**
- Ca. 11 Mt CO₂ 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 CO₂ 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 CO₂ 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, CO₂ transport and storage infrastructure, hydrogen supply, and biomethane production are **expected to be sufficient and delivered on time**

Executive summary

GHG abatement cost curve for Dutch Industry

(In €/t CO₂ & Mt CO₂/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 2030³**, 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 CO₂ 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 CO₂ 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 *Speelvelddoets 2024*



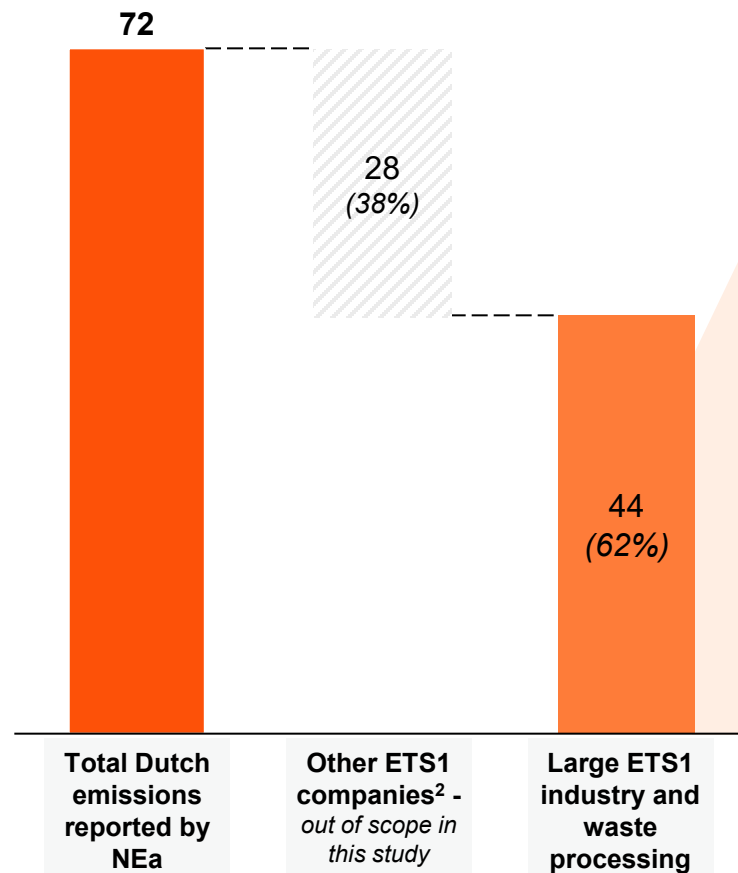
Introduction Dutch industry

The industry incl. waste processors in scope emits ca. 44 Mt CO₂/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 CO₂, 2020-2024 avg.¹)



Zoom-in: sector emission contribution



Key insights

- Total Dutch emissions covered under the EU ETS1 scheme are **72 Mt CO₂** (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 CO₂ (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 CO₂ (39%)** of the total Dutch industry emissions (based on 2020-2024 average)

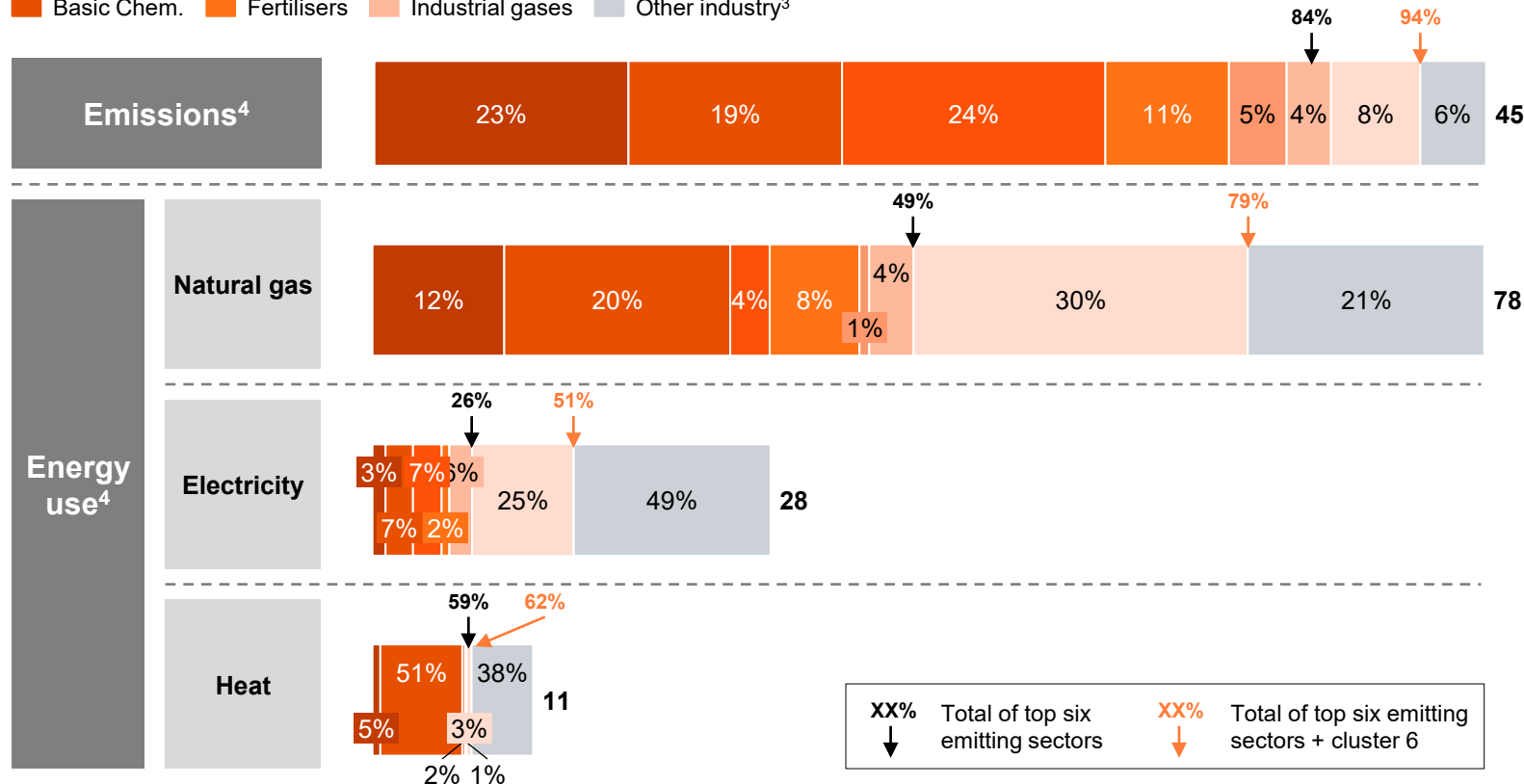
Beyond the top-emitting sectors, cluster 6 industries use a significant share of natural gas (30%) and contribute around 10% of industrial emissions

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

Emissions and energy use of large ETS industry¹ and waste sector in The Netherlands

(In Mt CO₂, 2024 and in TWh, average of 2020 – 2024²)

Refineries Steel Waste Cluster 6
Basic Chem. Fertilisers Industrial gases Other industry³



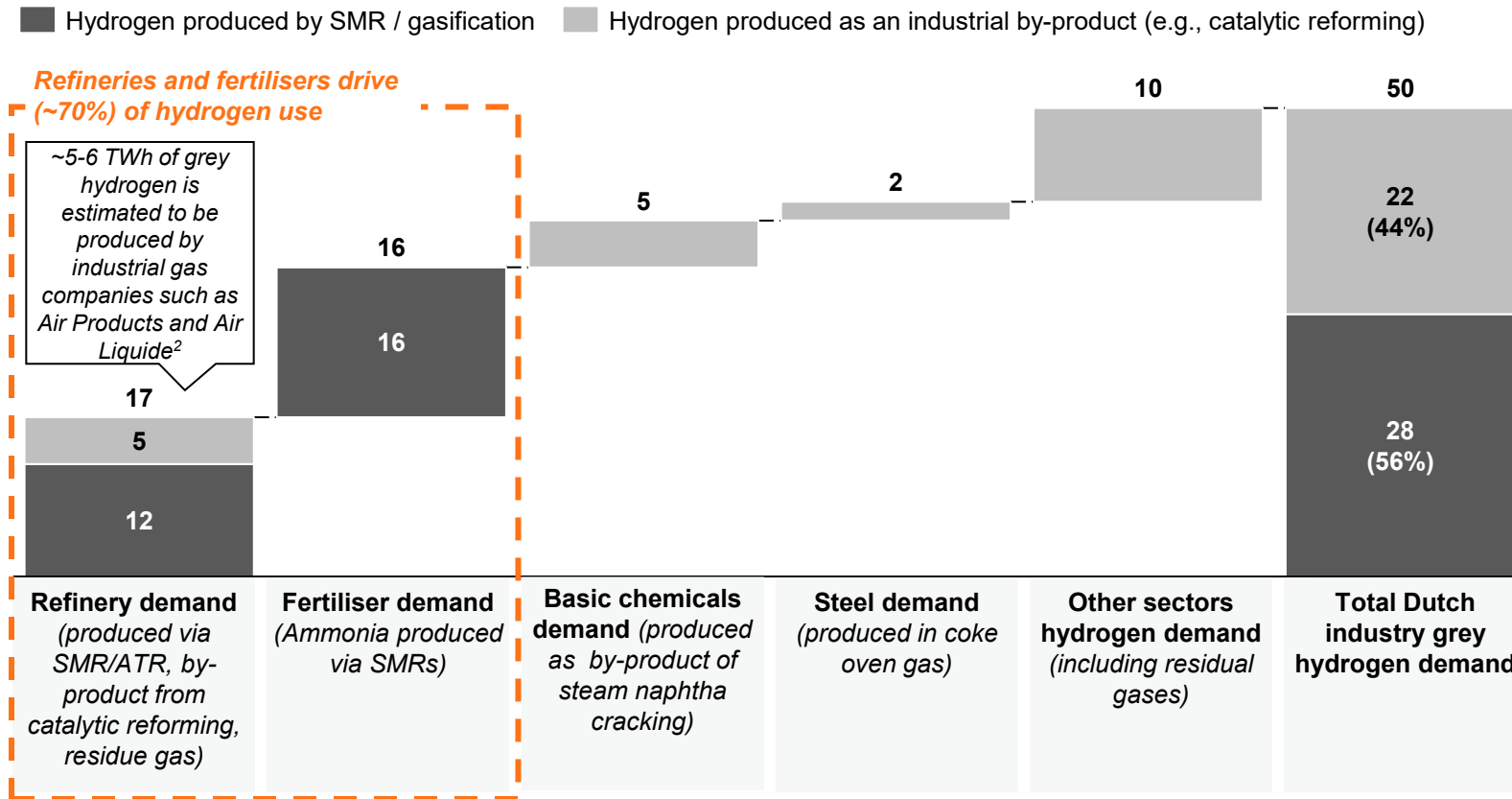
Key insights

- **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

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

Grey H₂ 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 H₂ 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-CO₂ production ratio for a typical SMR production

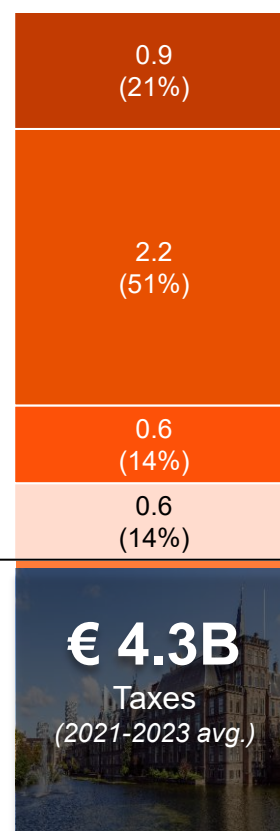
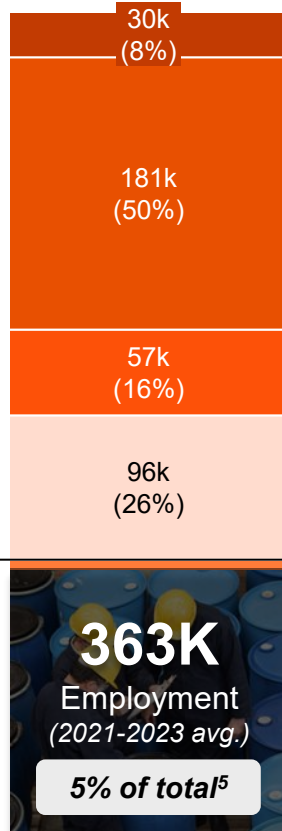
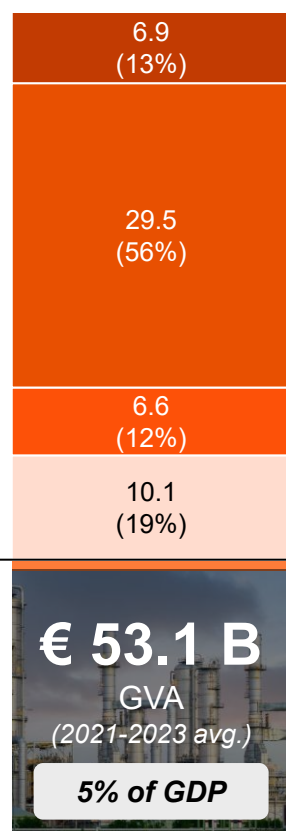
Sources: TNO, CBS

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 taxes¹ (based on 2021-2023 average)

Refineries Chemicals² Steel³ Other sectors⁴



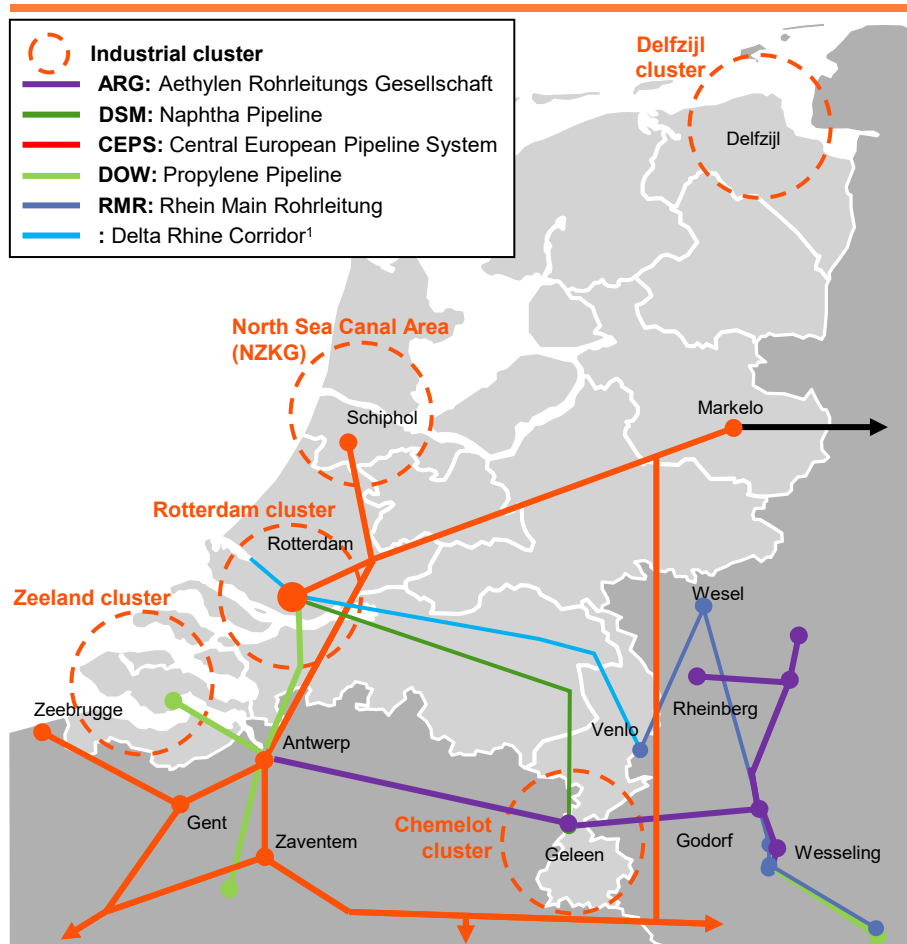
Key insights

- 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

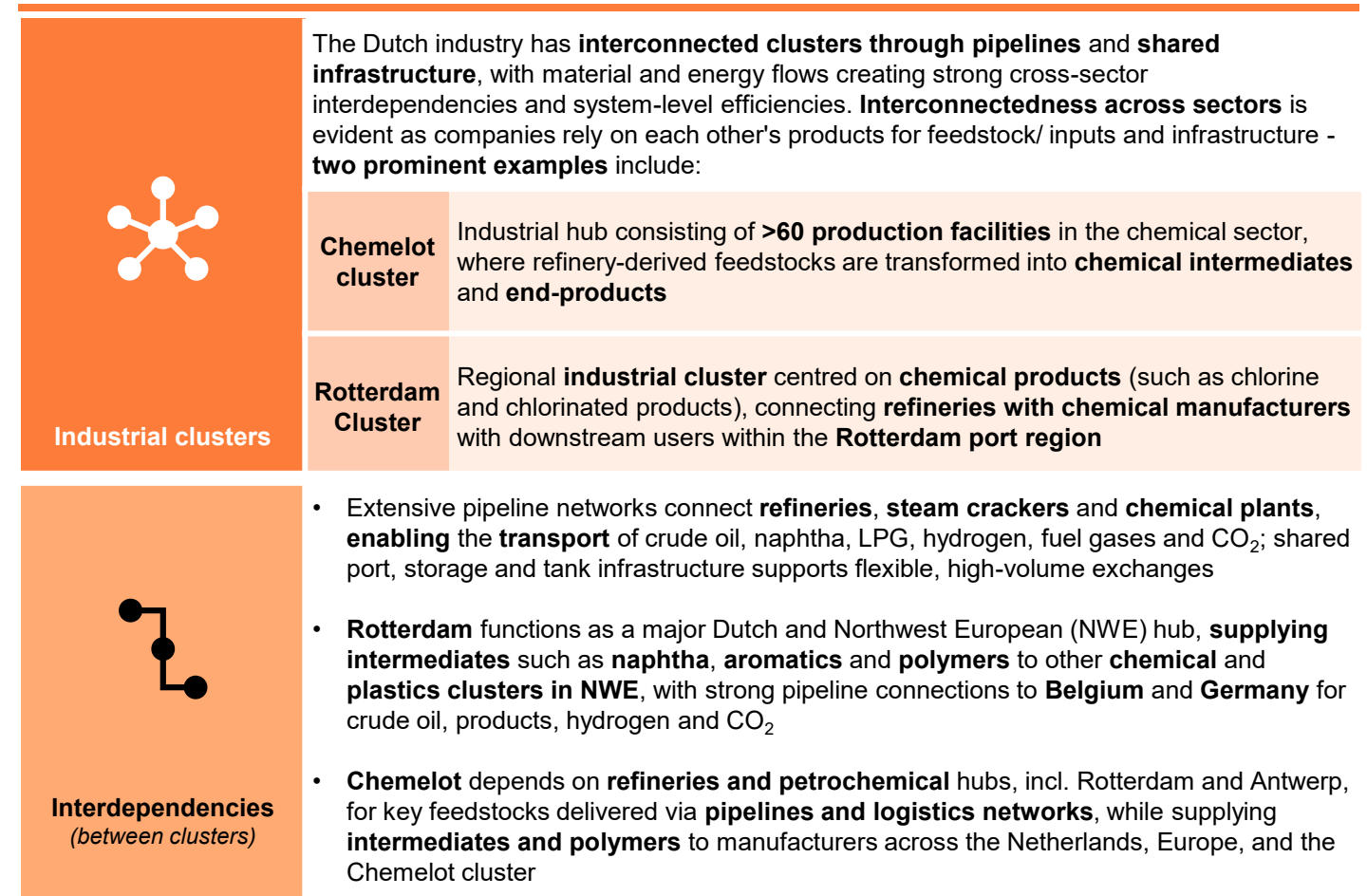
Dutch industry has interconnected clusters, where shared infrastructure and energy flows create strong cross-sector dependencies and system-level efficiencies

Industrial clusters & interdependencies

Regional connectedness



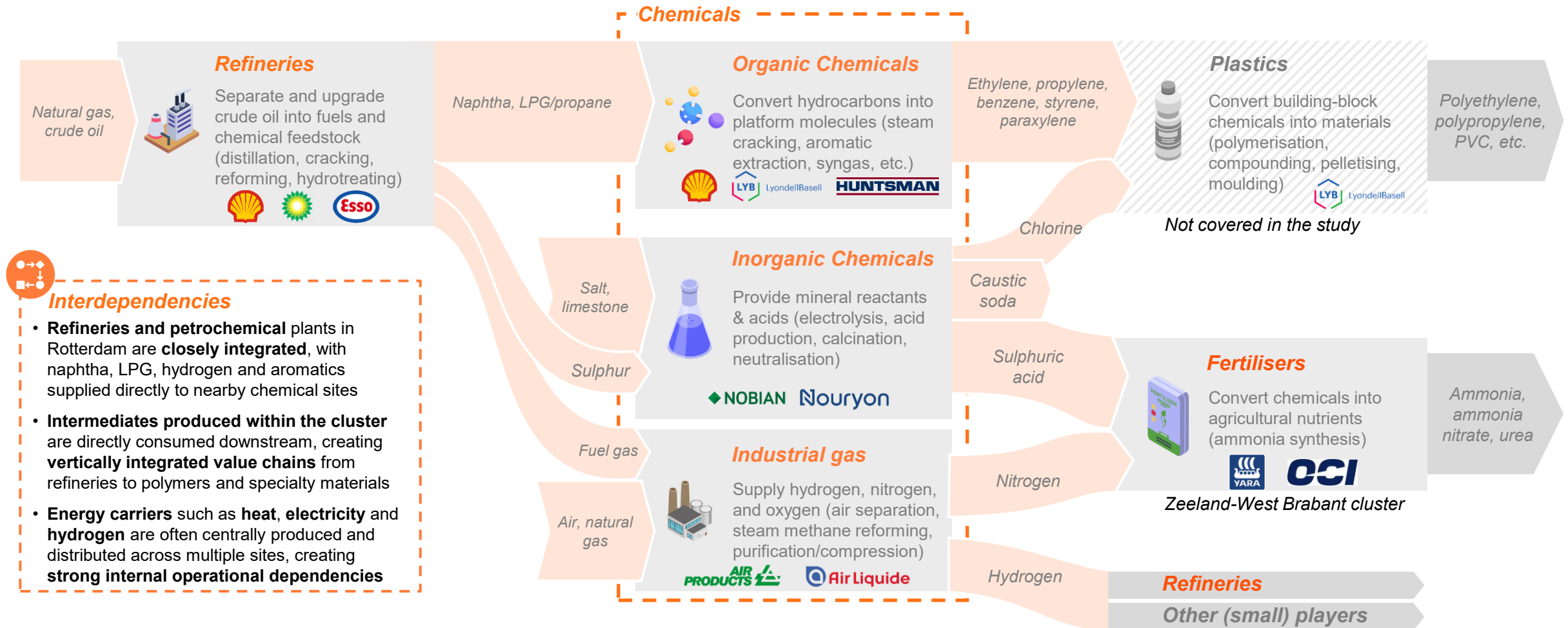
Interconnectedness



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

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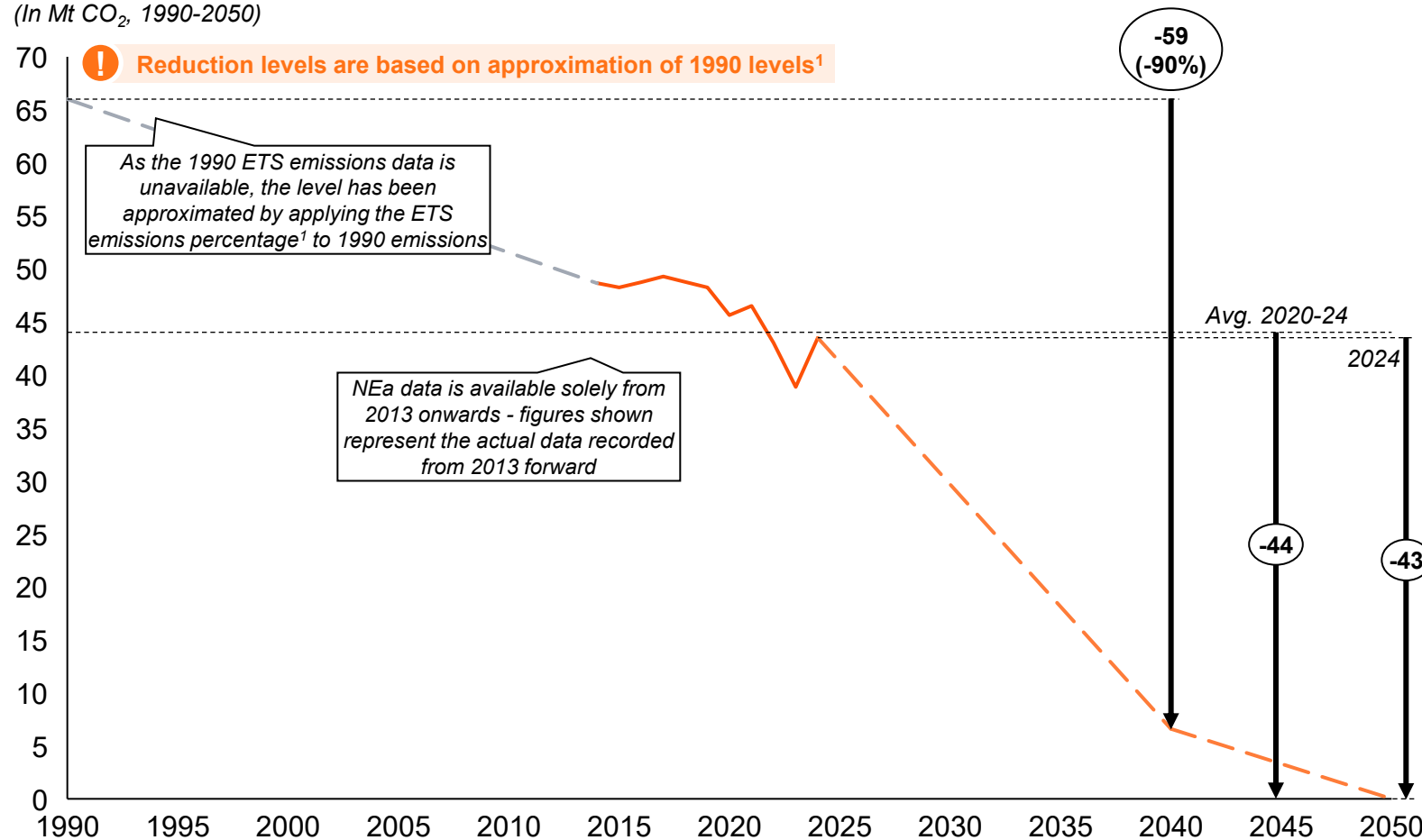


In the lead-up to achieving net zero by 2050, the large EU ETS industry, incl. waste mgmt., will need to reduce emissions by ca. 43 Mt CO₂/ yr compared to 2024 levels

Dutch industry ambition

Total Dutch ETS industry and waste emissions

(In Mt CO₂, 1990-2050)



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 MtCO₂/yr by 2040 relative to 1990, and a **trajectory to net-zero by 2050 (~43 Mt CO₂/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



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 CO₂ conc. in flue gases

Sector characteristics and possible abatement options

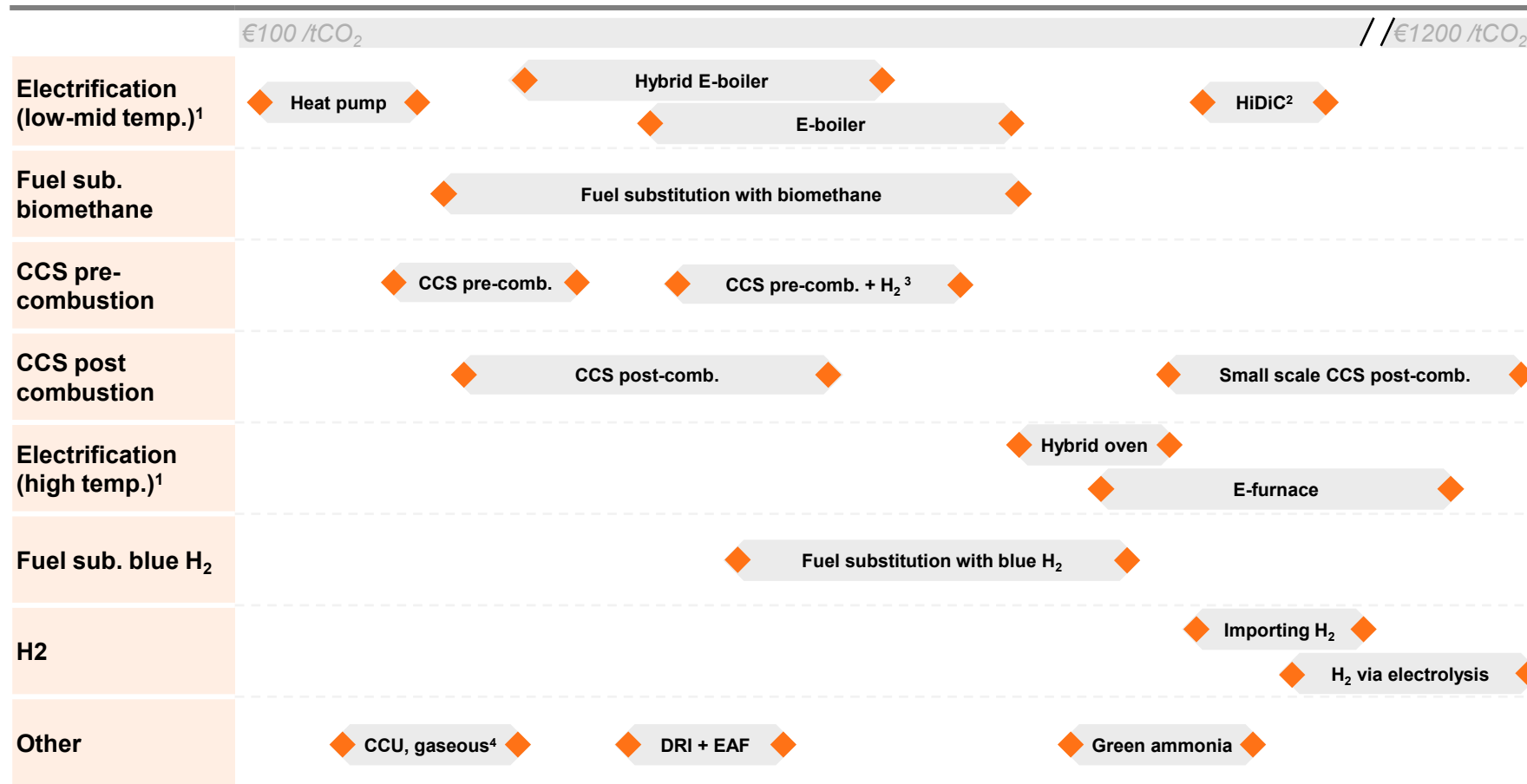
Sector	Key process characteristics		Abatement options							
	Process temperature	CO ₂ concentration	CCS		(Partial) fuel substitution		Electrification		Green ammonia (import)	Other
			Pre- comb	Post-comb	Hydrogen	Bio-methane	Low-mid temp. ¹	High temp. ²		
 Refineries	High (500-1000 °C) in furnaces, SMR 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

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

Unit cost of abatement options

Abatement options



Key considerations

- **Abatement costs shown reflect ranges** driven by differences in **CO₂ 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 CO₂ 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**

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

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)	-	-	-	-	-
 Fertilisers⁵	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)
 Waste⁶	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 & firing)	-	-	69% (Annealing, refining & conditioning, melting)	-	-	-

Key considerations

- **Fuel substitution with biomethane** excluded for top-emitting sectors⁷; 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 H₂ 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 CO₂/yr by 2040 requiring significant transport capacity	CO₂ transport and storage infrastructure is assumed to be available at large scale by 2040 (65.5 Mt CO₂/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 level¹ 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

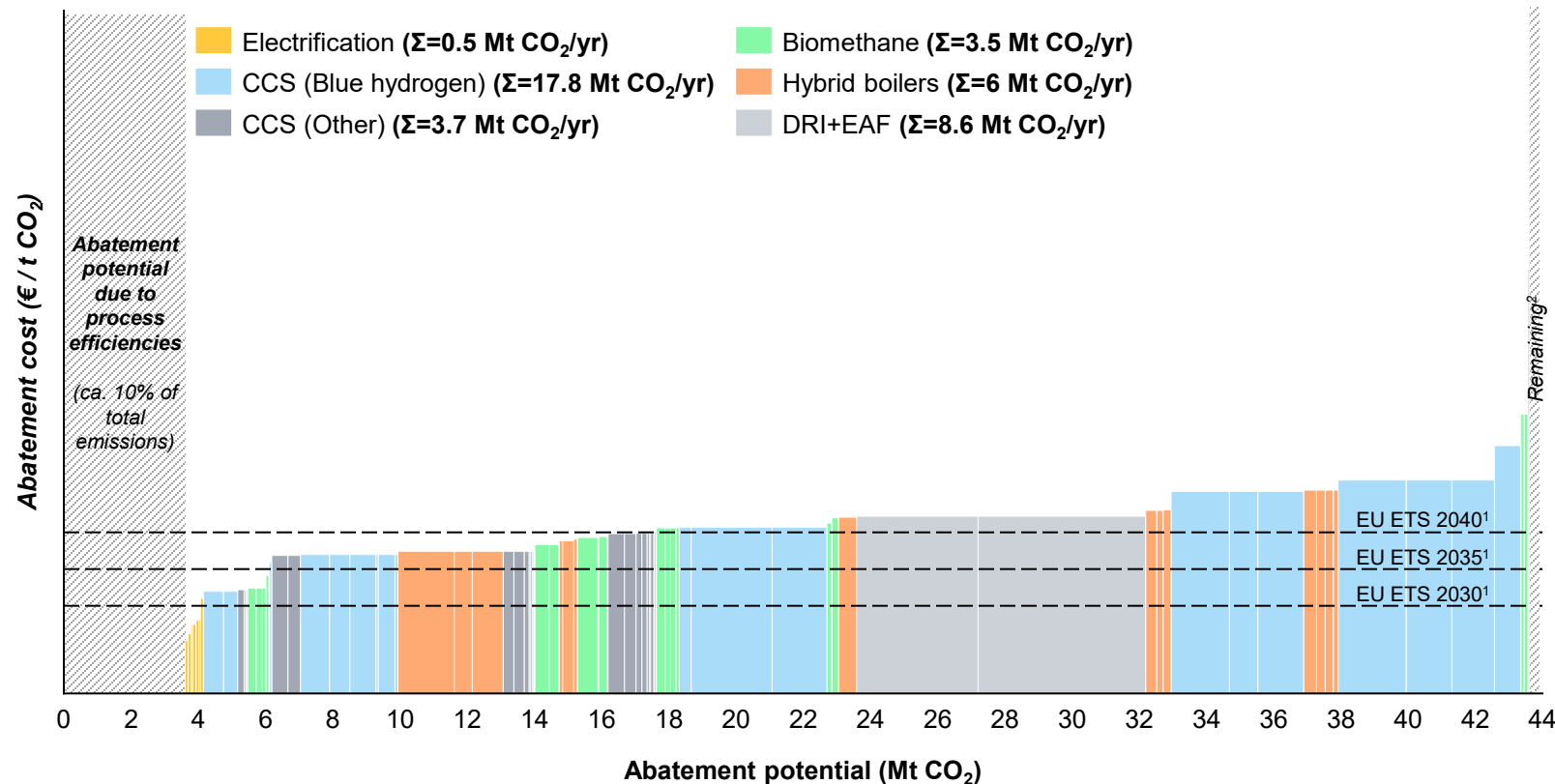
Assuming current industrial output, the most techno-economically efficient GHG red. pathway excl. policies will be dominated by CCS, biomethane & electrification

Most techno-economically efficient: Abatement cost curve

GHG abatement cost curve for Dutch Industry

(In €/t CO₂ & Mt CO₂/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 sectors¹, 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 solution² rather than CCS due to the technical challenges of capturing CO₂ 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 H₂ fired CHP;

3) Remaining ca. 1 Mt CO₂ 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

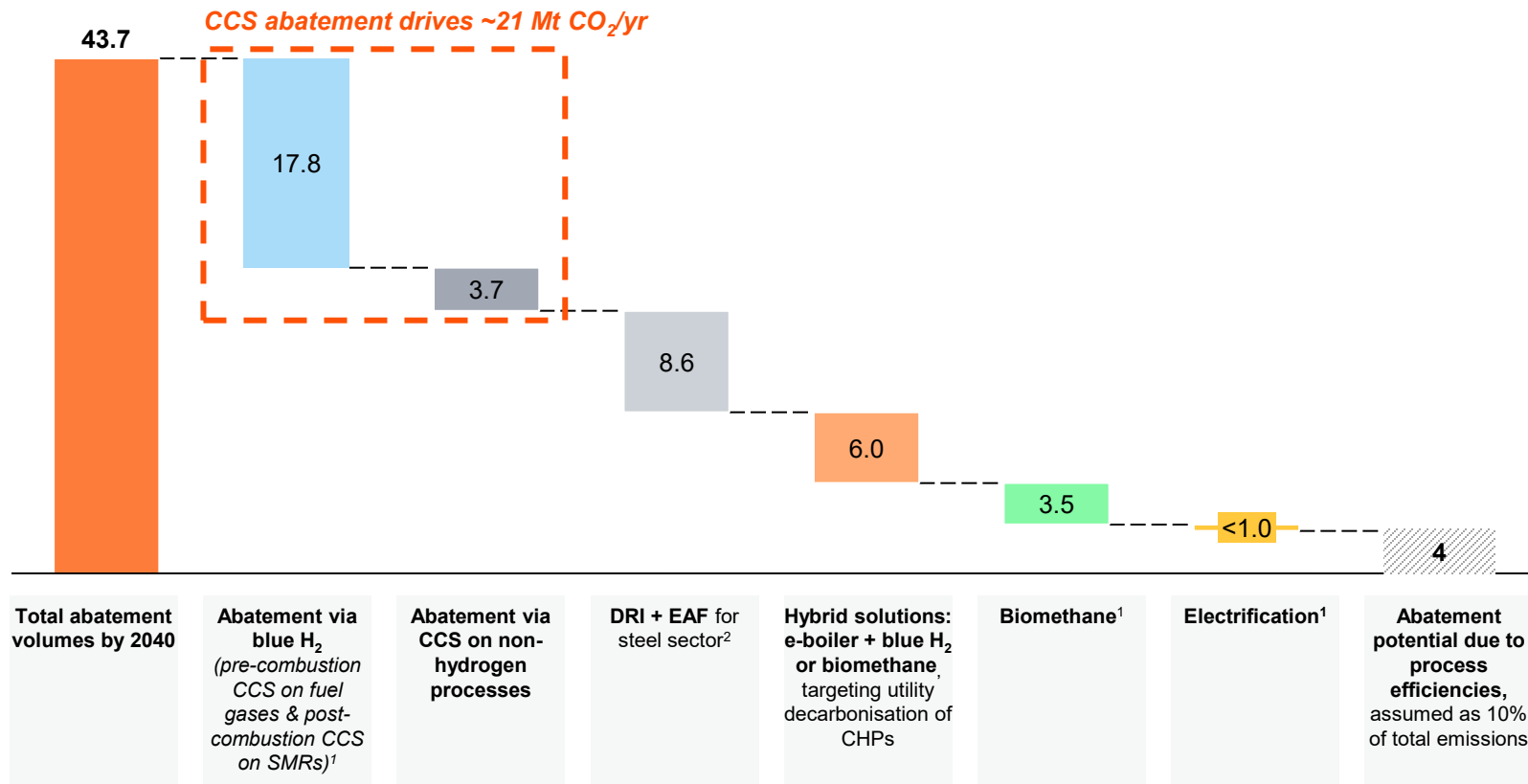
Sources: KEV, CBS, NEa, MIDDEN; PBL; CE Delft, EU ETS Impact assessment report (EC, 2024)

Ca. 21 Mt CO₂/yr is expected to be abated via CCS followed by DRI+EAF (8.6 Mt CO₂/yr) & hybrid E-boilers (6.0 Mt CO₂/yr)

Most techno-economically efficient: Abated CO₂ per option by 2040

CO₂ abatement volumes for Dutch industry
(In Mt CO₂/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 CO₂/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 CO₂/yr** across sectors, including on FCCs, waste incinerators, and DRI production for steel
 - Utility decarbonisation** contributes **~6 Mt CO₂/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 CO₂/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 CO₂/yr** through **DRI + EAF**, reflecting a structural transition in steelmaking rather than incremental abatement
 - Operational improvements** deliver **~4 Mt CO₂/yr** through ~5-10% process efficiency gains across sectors

RFNBO obligations from RED III could mandate green H₂ 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 H₂ 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
Fertilisers²	16 TWh	10 TWh	6 TWh	2.5 TWh	3.6 TWh	<i>Largest H₂ industrial user; 60% exempted nationally with remaining volumes in scope</i>
Refineries¹	RFNBO industry	n/a	1 TWh	0.4 TWh	0.6 TWh	<i>Limited H₂ industrial use, with main H₂ an intermediate for transport fuels</i>
	RFNBO Transport	n/a	17 TWh	1.5 TWh²		<i>H₂ contributes under the emissions-based transport RFNBO framework</i>
Other industry	2 TWh	- n/a	2 TWh	n/a	n/a	<i>RFNBO-relevant, but excluded from analysis due to fragmented sectoral use</i>

RFNBO obligated volumes could cause⁴ 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 H₂ use

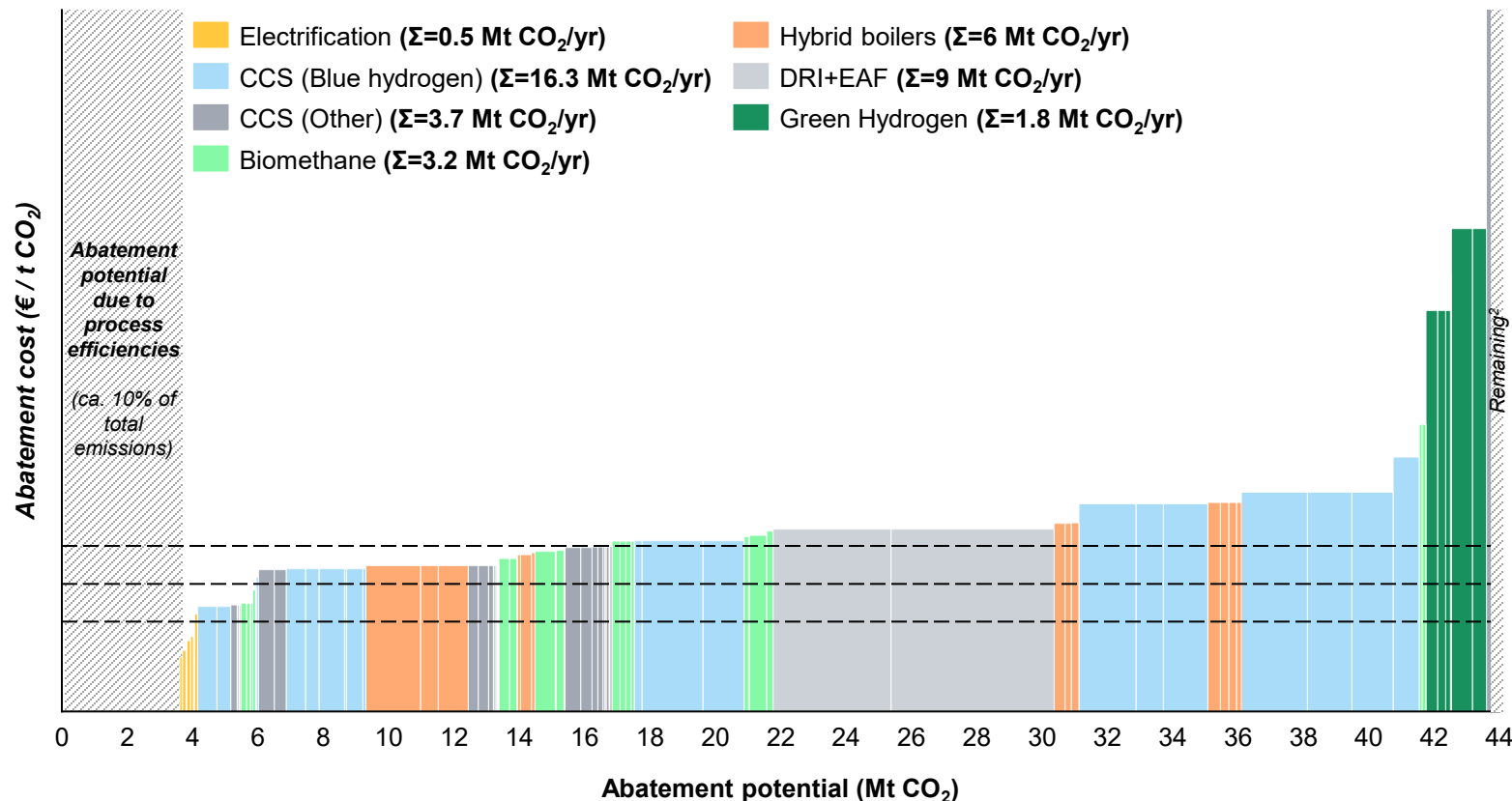
RFNBO adjusted: Abatement cost curve

GHG abatement cost curve for Dutch Industry

(In €/t CO₂ & Mt CO₂/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 sectors¹, 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 solution² rather than CCS due to the technical challenges of capturing CO₂ 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

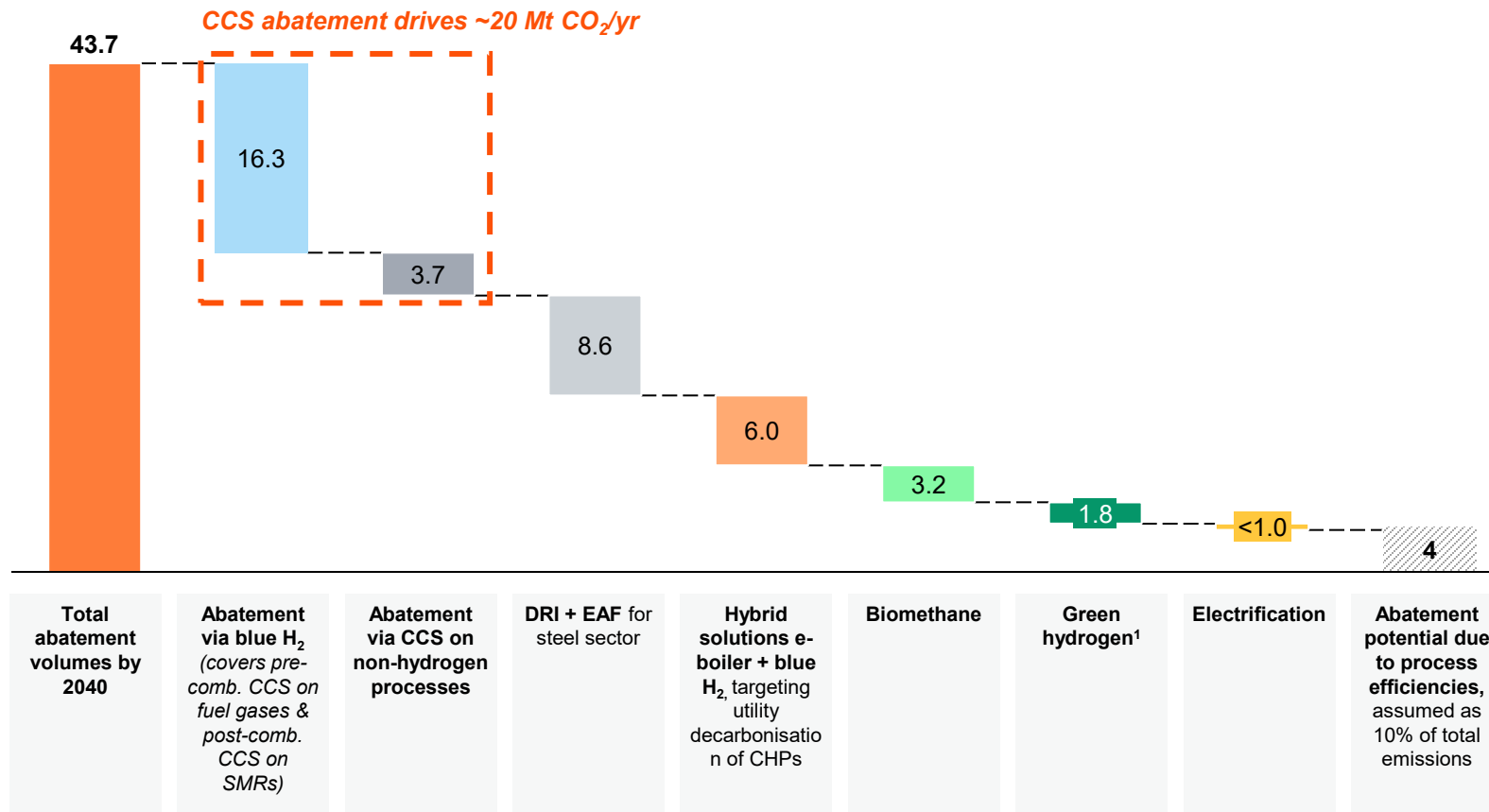
1) Given anticipated price increases as industrial demand enters the mix, i.e., limited supply, overall high level of demand & higher willingness to pay level from other sectors (i.e., transport and built env. due to penalties in the range of 300-400 €/t CO₂); 2) Electric boilers during low price hours combined with biomethane- or blue H₂ fired CHP; 3) Remaining ca. 1 Mt CO₂ 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 Speelveltoets 2024; Sources: KEV, CBS, NEa, MIDDEN; PBL; CE Delft; REDIII, EU ETS Impact assessment report (EC, 2024)

Resulting abatement from blue H₂ (ca. 16.3 Mt/yr) and biomethane (3.2 Mt/yr) lowers with respect to the policy agnostic abatement

RFNBO adjusted: Abated CO₂ per option by 2040

CO₂ abatement volumes for Dutch industry
(In Mt CO₂/year, 2040P)

! Assumes industry will stay at current levels



Key insights

- Several differences emerge between the most technoeconomically 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 H₂ drives the largest share of abatement with 16.3 Mt CO₂/yr, down 1.5 Mt CO₂/yr from the technoeconomic curve
 - **Biomethane still contributes a substantial share of abatement (~3 Mt CO₂/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 CO₂/yr** compared to the technoeconomic abatement curve
 - **Limited green hydrogen volumes (~2 Mt CO₂/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



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 CO₂ abated

Abatement cost calculation methodology

Definition

Average cost of reducing one ton of CO₂ emissions, calculated as the **additional cost** of an abatement measure **divided by the emissions abated** (€/t CO₂)

$$\text{Abatement unit costs} = \frac{\text{NPV}(\text{cost of green option} - \text{costs of grey alternative})}{\text{NPV}(\text{CO}_2 \text{ abated})}$$

$$= \frac{\text{NPV}(\text{CAPEX}) + \text{NPV}(\text{OPEX fixed}) + \text{NPV}(\text{OPEX variable})}{\text{NPV}(\text{CO}_2 \text{ abated})}$$

CAPEX

Upfront investment required to build and install abatement options

Key sources

- 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 CO₂**. 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*

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

Price assumptions¹

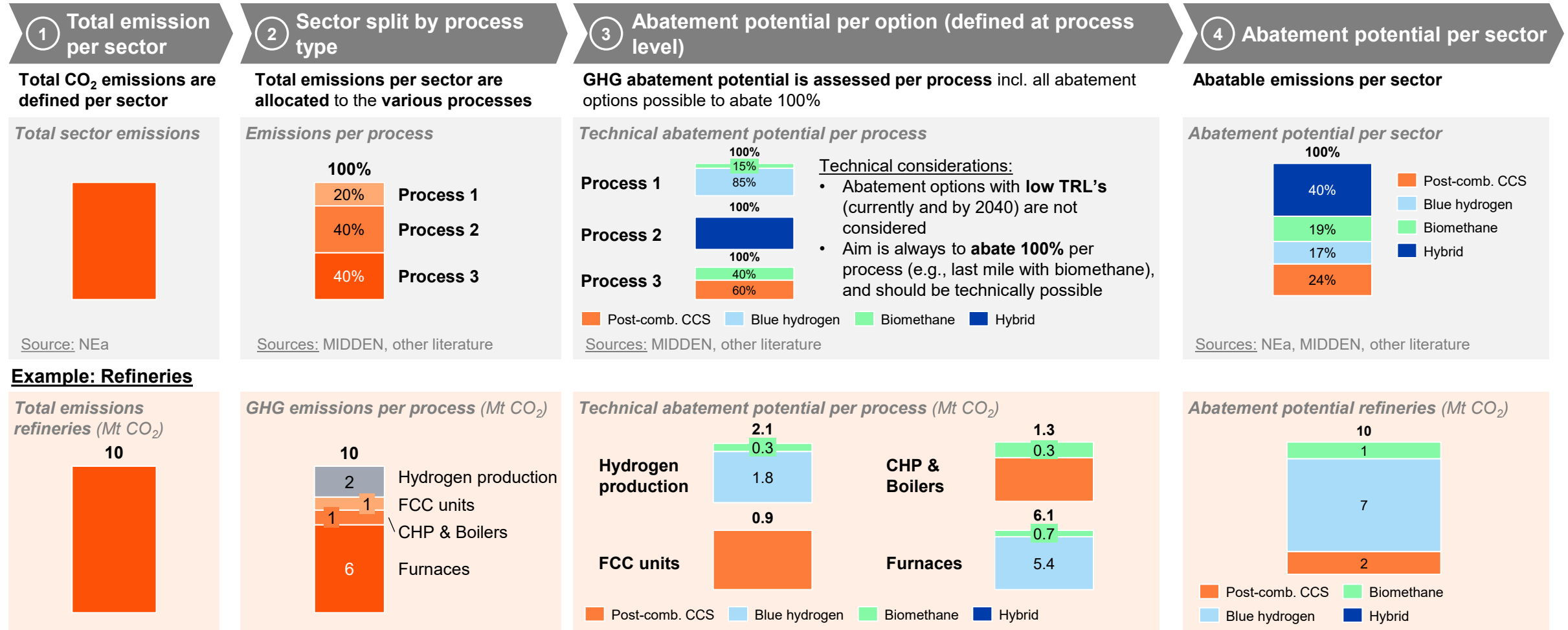
		2030 (in €/MWh LHV)				2035 (in €/MWh LHV)				2040 (in €/MWh LHV)				Key source(s)
		Commodity	Network	Tax	Total cost	Commodity	Network	Tax	Total cost	Commodity	Network	Tax	Total cost	
Electricity	Avg. price	69	23	<1	92	65	34	<1	99	65	41	<1	106	Fraunhofer, KEV 2025, EMBER
	Low price ²	25	23	<1	48	10	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 CO ₂)	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

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





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

Cluster ³	Location	Additional grid capacity required (MW)		Capacity TSO ¹ (MW)				Capacity DSO ² (MW)				Implementation feasibility of abatement (indicative)	
		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					–	–	46	–	Low	Medium
	Esso	61	86					–	–	24	2036	Low	Medium
	BP Rotterdam	52	80	518	879	1419	2030	–	–	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	–					–	–	0	–	Medium	High
	Zeeland Refinery	37	50	1200	2244	1440	2035	–	–	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
		Σ ~2,000 MW											

Key insights

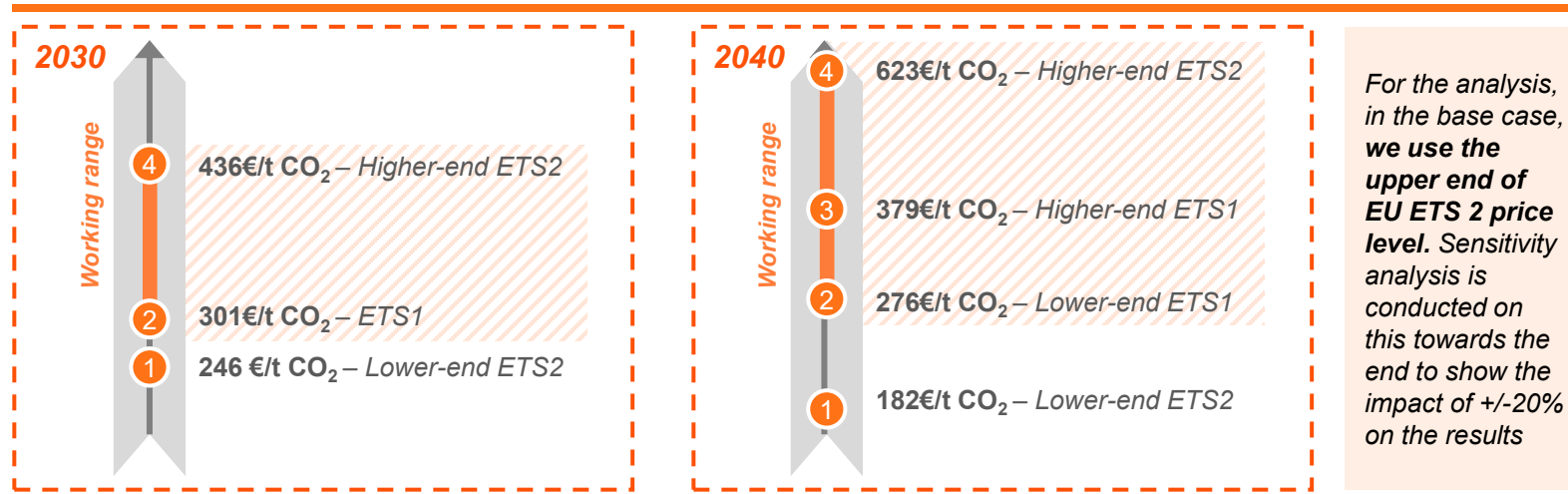
- Approximately **2 GW of extra grid capacity** is required for top emitters to accommodate CCS/CCU and electrification projects
- Industrial connections/ expansions require **capacity at both TSO and DSO level**; only sites with **direct TSO access** are exempted (e.g., TATA Steel IJmuiden), resulting 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
- However, 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. (Speelvelddtoets 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

Biomethane value drivers and price assumptions



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 **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)
- 3
- 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

Approach confirmed in discussion with industry stakeholders

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

Dutch CO₂ transport and storage capacity could scale to ~65 Mt by 2040; realisation remains uncertain

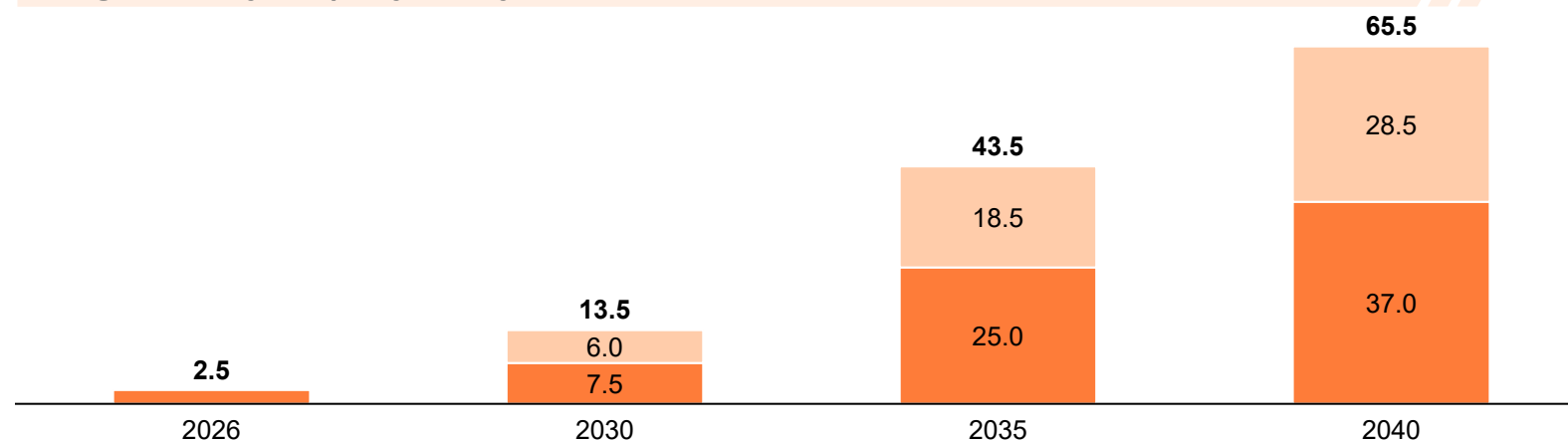
NL CO₂ transport and storage capacity

See deep-dive on next page

Projected available CCS transport and storage capacity (pipeline-based and liquified CO₂ transport) in Mt CO₂/year, 2030P -2040P

■ Pipeline-based CO₂ transport (incl. storage) ■ Liquified CO₂ shipping (incl. storage)

CO₂ 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 ₂ next 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. Abeona adds up to ~5 MtCO ₂ /yr injection capacity; 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 ₂ next & 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; Abeona adds up to ~5 MtCO ₂ /yr injection capacity; 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 assumptions

- **CCS transport capacity scales rapidly after 2030** as Aramis and Abeona ramp up alongside Porthos, increasing total system capacity from ~15 Mt in 2030 to ~45 Mt by 2035 and ~65 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 CO₂ shipping develops as a complementary route**, growing from ~7.5 Mt in 2030 to ~28.5 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**

There are several ongoing projects for CO₂ transport and storage

Deep dive: NL CO₂ transport capacity example projects

Non-exhaustive overview

CO ₂ transport	Project	Description	Status	Operation start	Capacity	Storage
Pipeline-based CO ₂ transport (incl. storage) & liquified CO ₂ shipping (incl. storage), imports	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/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	✗
	Abeona CCS	Open-access CCS/CCU ecosystem linking emitters, liquid CO ₂ (LCO ₂) terminals and horticulture in the Amsterdam/ NZKG region to offshore pipeline and marine injection (storage) infrastructure	• Pre-FEED ongoing, FEED start mid-2027 • FID expected 2029	• Subject to concept 2030-2032	• Total maximum 5 Mt/yr CO₂ injection capacity	✓
	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 CO₂/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 completed • Progress towards FID	• 2030 (indicative, aligned with Aramis timeline)	• ~5 Mt CO₂/yr Initial expansion	✓



A3

Industry deep-dives

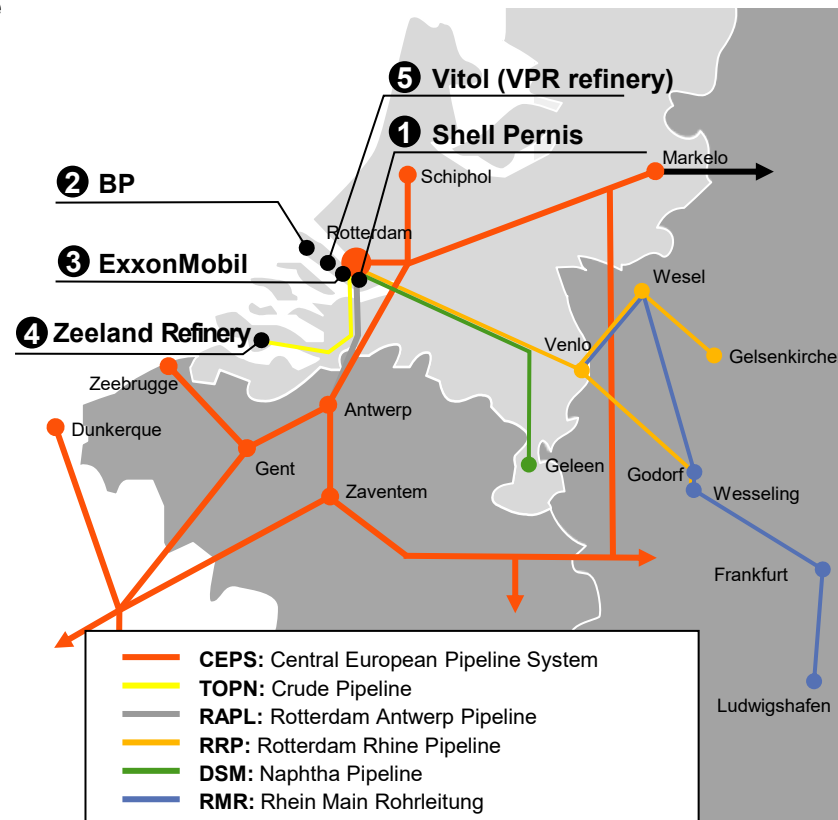
The Netherlands has 5 refineries, strategically positioned in proximity to major harbours and closely connected to clients in neighbouring countries

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 oil² – that serve the chemical manufacturing sectors, transport, aviation, shipping, residential and commercial energy, and power generation

Physical connectedness of NL refineries with ARRR¹ cluster



Energy profile

	Baseline (2020-2024 average)
CO₂ emissions (Mt/year)	10.4
Natural gas (TWh/year)	9.2
Electricity³ (TWh/year)	0.9
Hydrogen (TWh/year)	11.6
Crude oil & petroleum products (TWh/year)	36.7

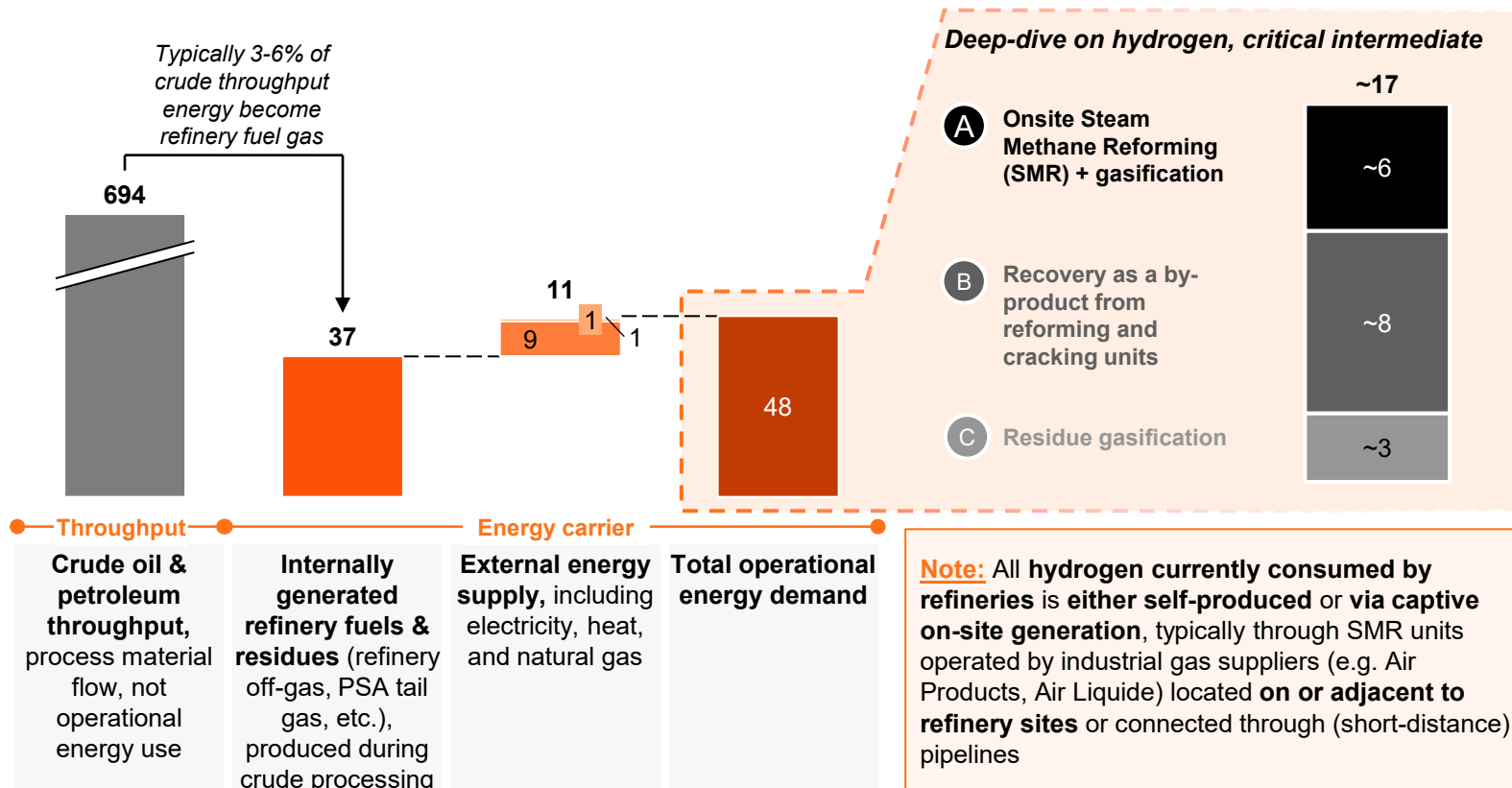
Refineries upgrade ~700 TWh of crude oil (inputs) into fuels, operating largely on internally recovered gases - 17 TWh of H₂ production at the core of the process

Refineries – Energy profile

Refinery input and energy use by carrier

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

■ Petroleum & crude oil fuel ■ Natural gas ■ Electricity ■ Heat



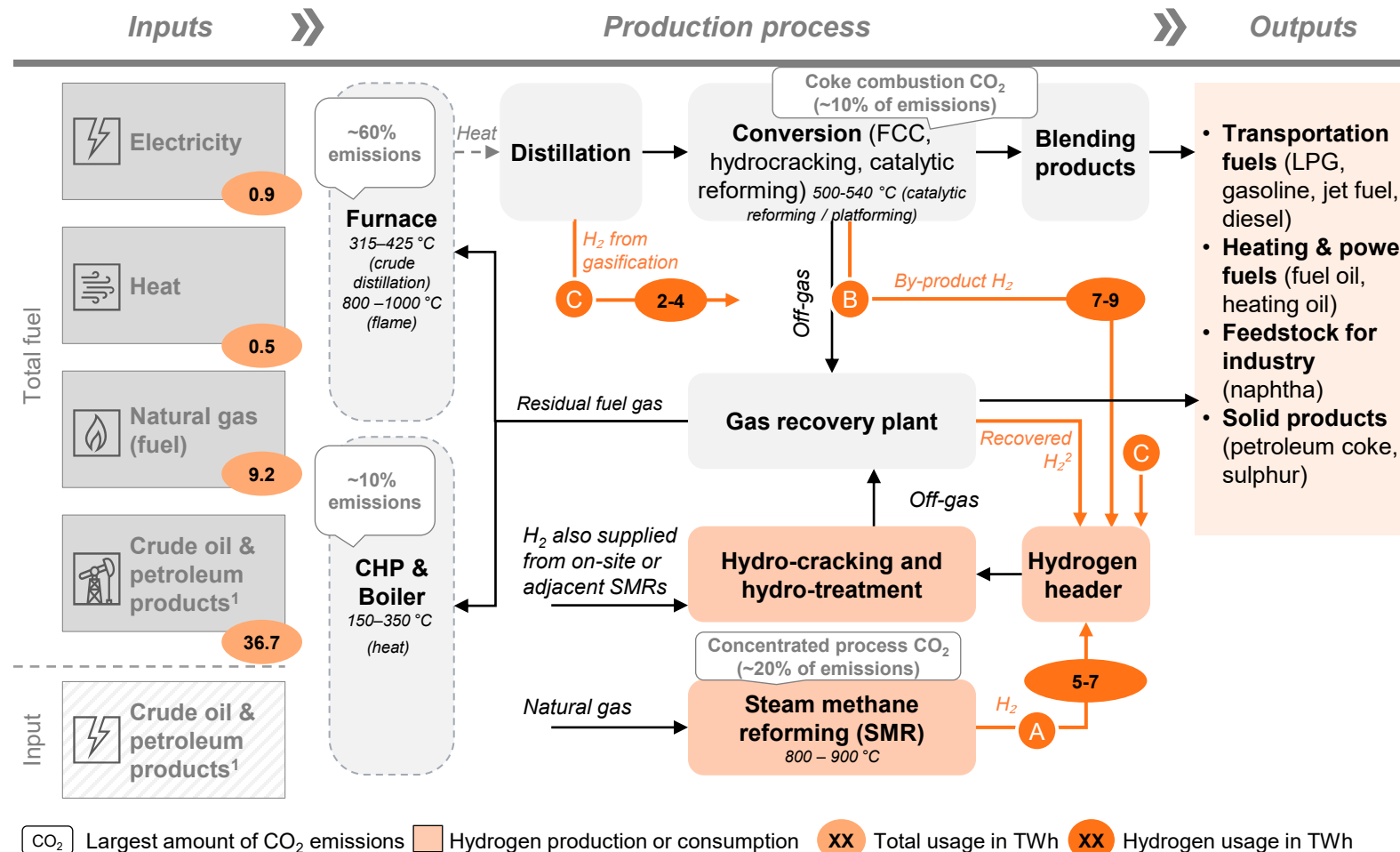
Key insights

- **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 :
 - **A Steam Methane Reforming (SMR)**¹: ~6 TWh
 - **B Recovery as a by-product**² from reforming and cracking units: ~8 TWh
 - **C Residue gasification**³ (site specific): ~3 TWh

Deep-dive on process on next page

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



Key insights

- Refineries emissions are mainly driven by 4 systems²:
 - Dilute flue-gas emissions from furnaces (~60%),** which provide high-temperature process heat across the refinery
 - Concentrated CO₂ at the SMR unit (~20%),** arising from hydrogen production for hydrocracking and hydrotreating
 - Coke combustion at the FCC regenerator (~10%),** where coke deposited on the catalyst is burned to supply conversion heat.
 - Boilers and CHP units (~10%),** providing heat and electricity to refinery processes and utilities
- Abatement pathways will therefore be defined across these systems**

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 CO₂	~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 H₂ 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+ H₂), and the water-gas shift reaction converts CO to CO₂ while producing H₂	~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 CO₂	~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 CO₂	>15%	High operating temperatures (~700–750°C)	n/a	Carbon originates from crude oil molecules, not the chosen fuel	CCS (post-combustion)

~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)

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	
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 CO₂ 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 CO₂ concentration, with flue-gas concentration assumed to be 7.5% CO₂ 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

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)

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	
Furnaces ~60% of total emissions 6.2 Mt CO ₂ /year	Blue H₂ 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

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)

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 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 CO₂ 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 CO₂ 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 cost	▼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		

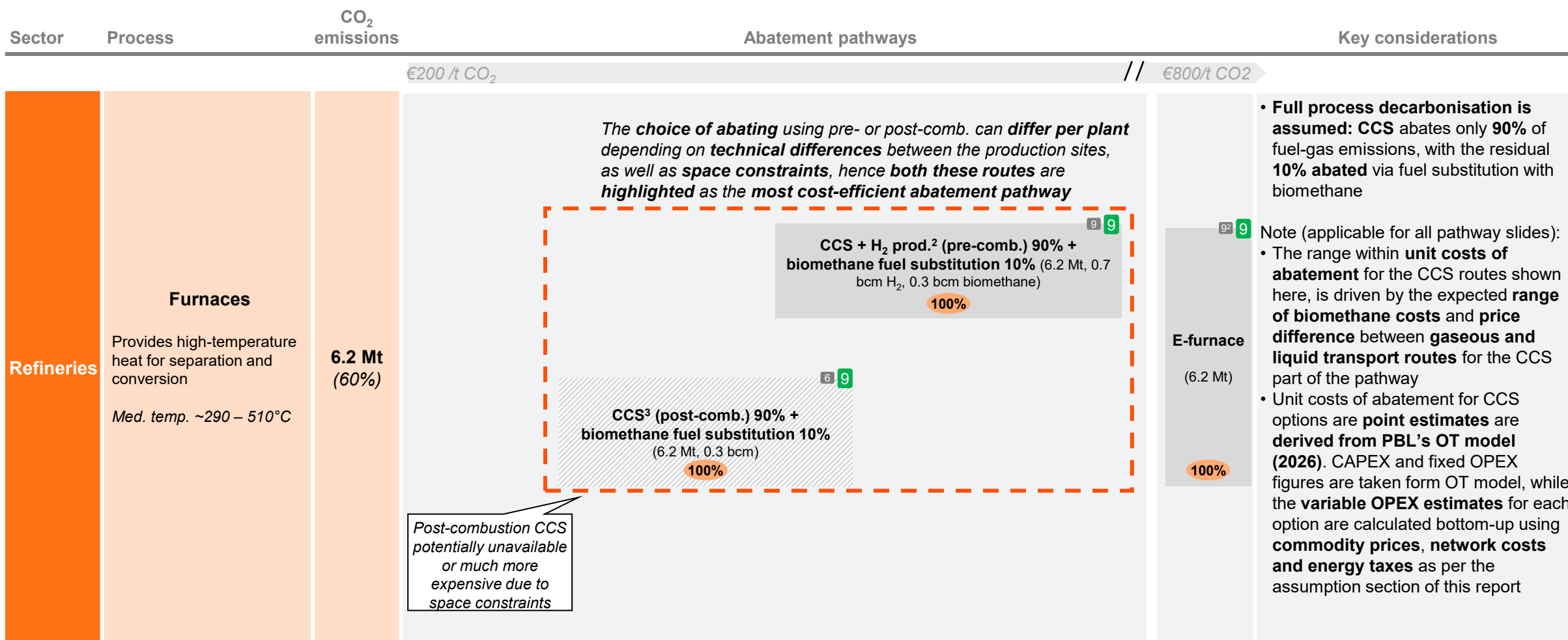
For CHP & boilers (10% of emissions), hybrid e-boilers with hydrogen may be the most techno-economically viable; for FCC units, only post-combustion CCS as a pathway

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%)	300-500 €/t CO ₂	Gaseous transport					Post-combustion CCS costs are highly sensitive to CO₂ concentration, with flue-gas concentration is assumed to be 5% CO₂ for CHP / boilers
				300-500 €/t CO ₂	Liquid transport					
	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					Post-combustion CCS costs are highly sensitive to CO₂ concentration, with flue-gas concentration assumed to be 17% CO₂ for FCC	
				<300 €/t CO ₂	-	-	-	▲ 0.2		▲ 0.3
				Liquid transport						
				<300 €/t CO ₂	-	-	-	▲ 0.2	▲ 0.3	

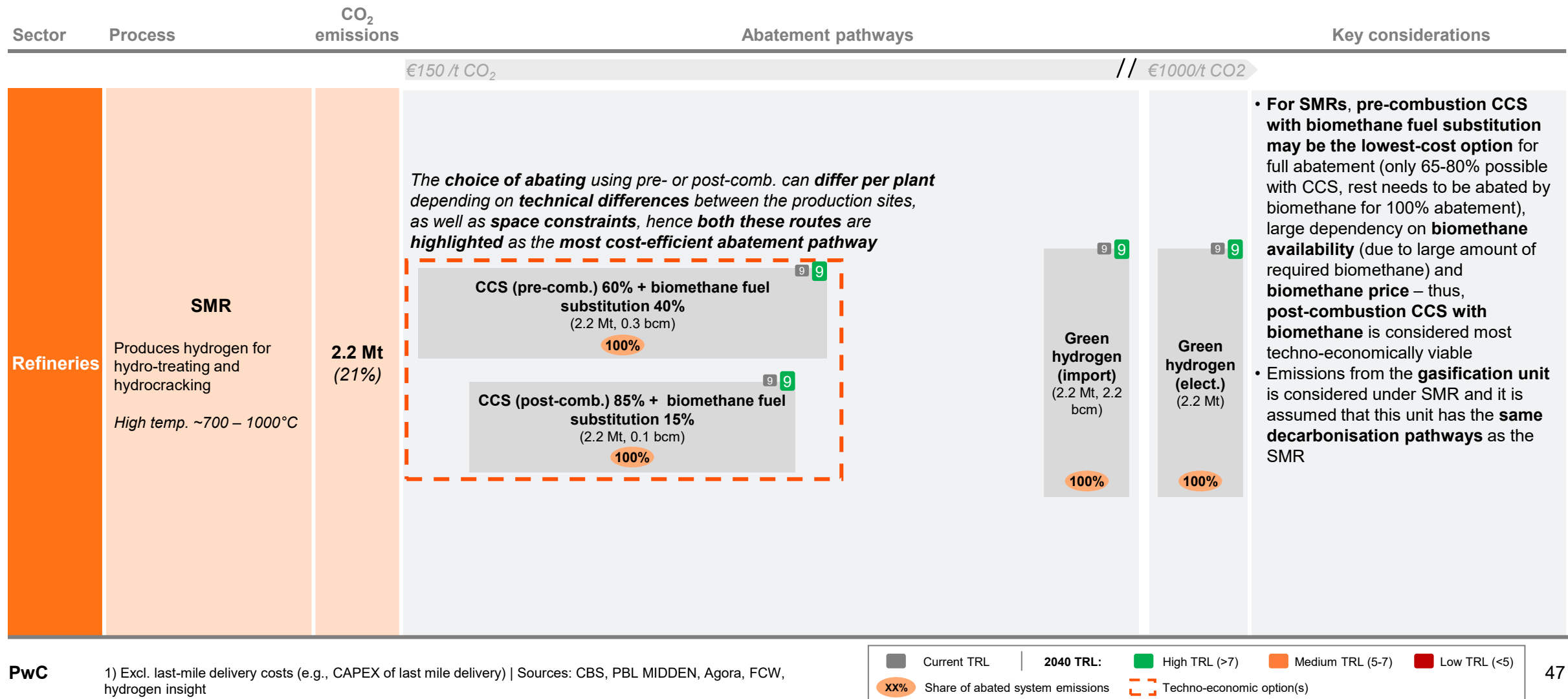
In the refinery sector, full abatement for the furnaces can be achieved through a combination of CCS (post or pre-comb. + H₂) and biomethane fuel substitution

Refineries – Abatement pathways (1/3)



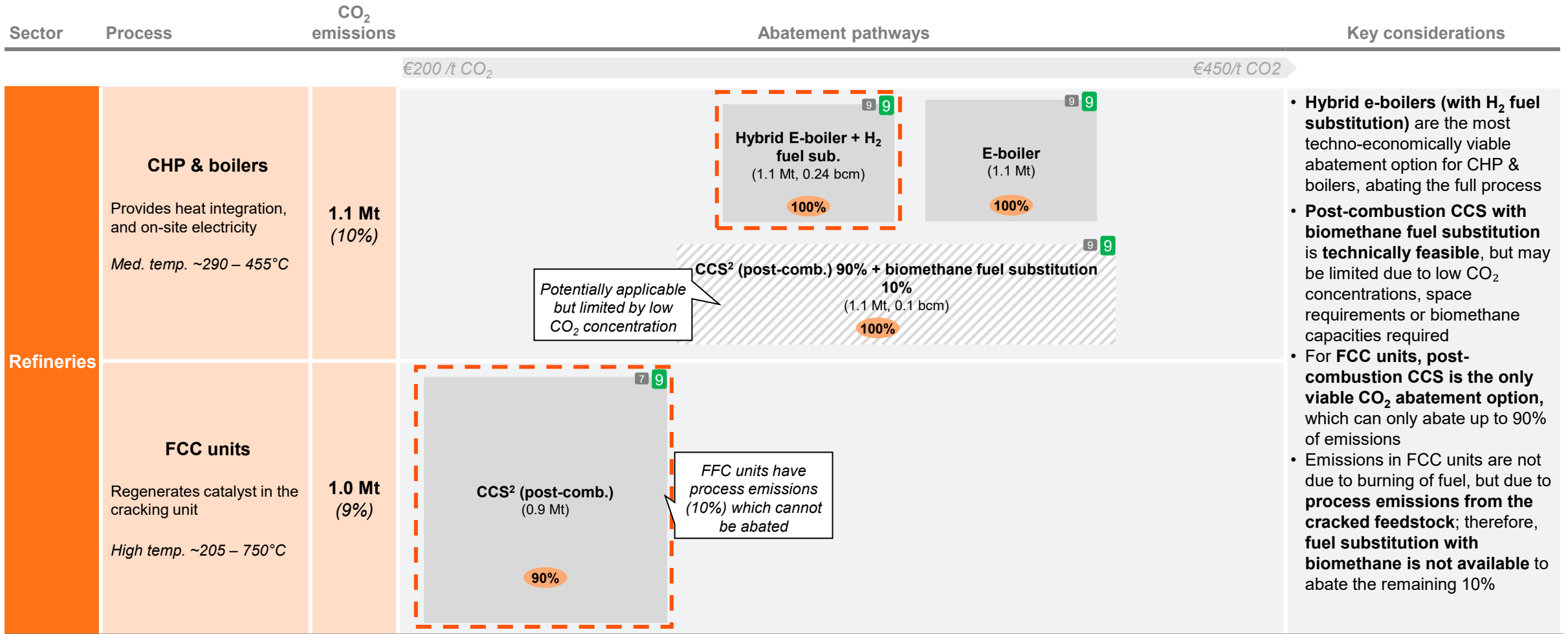
Full abatement for the SMRs can be achieved through a combination of CCS (post or pre-comb.) and biomethane fuel substitution

Refineries – Abatement pathways (2/3)



For CHP, hybrid e-boilers (with H₂) are more attractive than pure e-boilers assuming CCS is technically constrained; FCC can only be abated through CCS

Refineries – Abatement pathways (3/3)



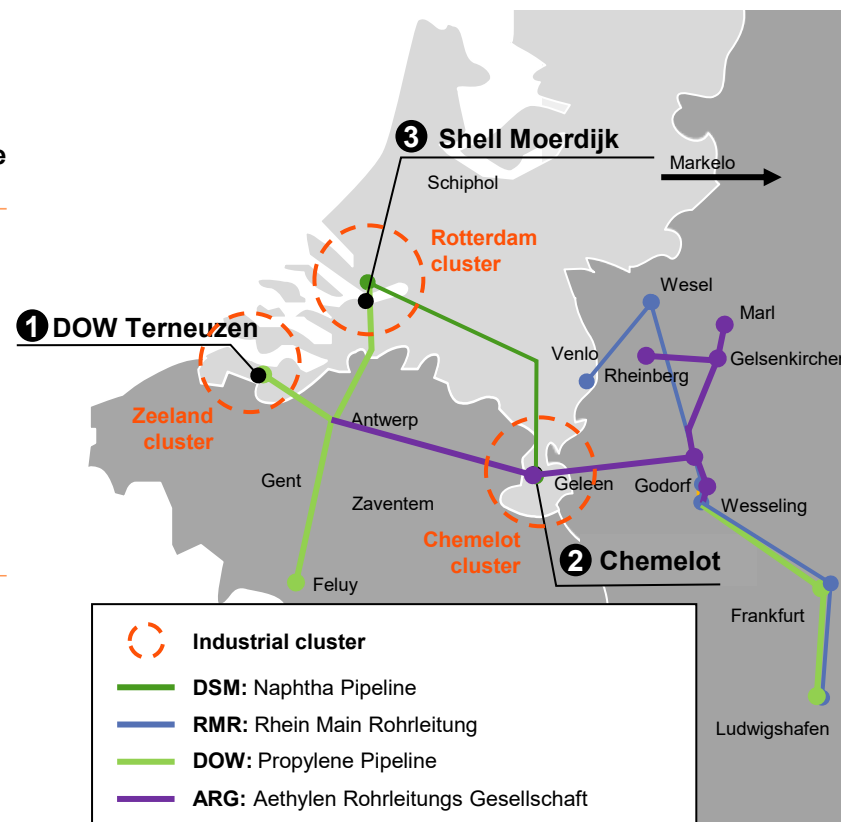
The Dutch organic basic chemicals (LVOC) sector anchored by steam crackers located in 3 main industrial clusters: Rotterdam, Zeeland, and Chemelot

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

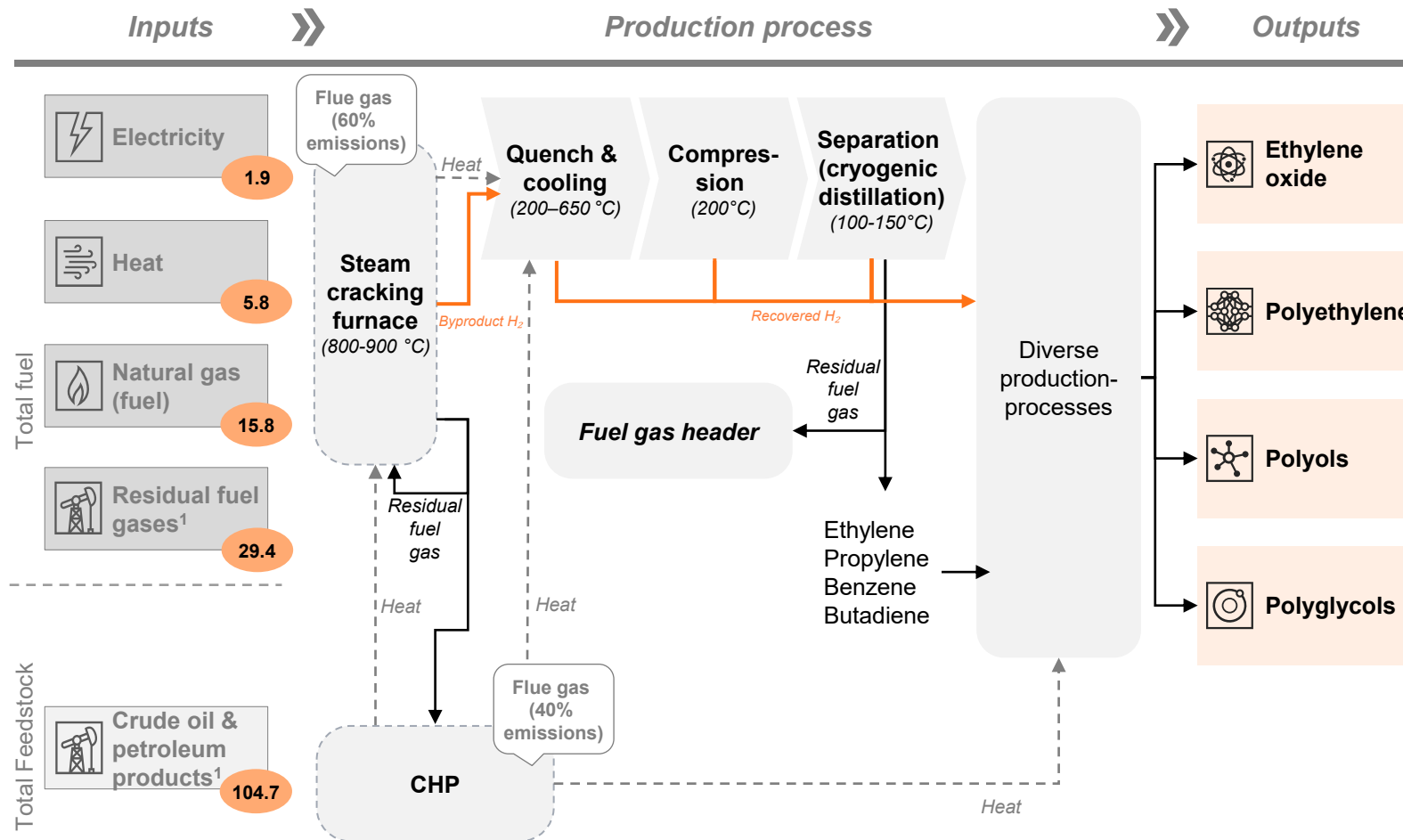


Energy profile

	Baseline (2020-2024 average)
CO₂ emissions (Mt/year)	8.7
Natural gas (TWh/year)	15.8
Electricity (TWh/year)	1.9
Hydrogen (TWh/year)	0.0
Heat (TWh/year)	5.8
Residual fuel gases (TWh/year)	29.4
Crude oil & petroleum products (TWh/year)	104.7
Natural gas (TWh/year)	1.7

Steam cracking is the primary source of CO₂ emissions accounting for ~60% of total emissions; heat and electricity supply by CHP contribute remaining ~40%

Basic chemicals – Process overview



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 CO₂ 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 (H₂ 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) H₂ 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 CO₂ 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 H₂ fuel substitution Biomethane fuel substitution Hybrid e-boiler

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)

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	
Steam cracking furnaces 61% of total CO ₂ emissions 5.4 Mt CO ₂ /year	Blue H₂ 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

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)

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	
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 CO₂ 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 CO₂ concentration, with flue-gas concentration is assumed to be 5% CO₂ for furnaces
				300-500 €/t CO ₂	-	-	-	▲1.6	▲5.8	
				Liquid transport						
				300-500 €/t CO ₂	-	-	-	▲1.8	▲5.8	

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)

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 39% of total CO₂ emissions 3.4 Mt CO₂/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					▲0.8	▲2.9	Post-combustion CCS costs are highly sensitive to CO₂ concentration, with flue-gas concentration is assumed to be 5% CO₂ for CHP / boilers
				<300 €/t CO ₂	-	-	-				
				Liquid transport							
300-500 €/t CO ₂	-	-	-	▲0.9	▲2.9						

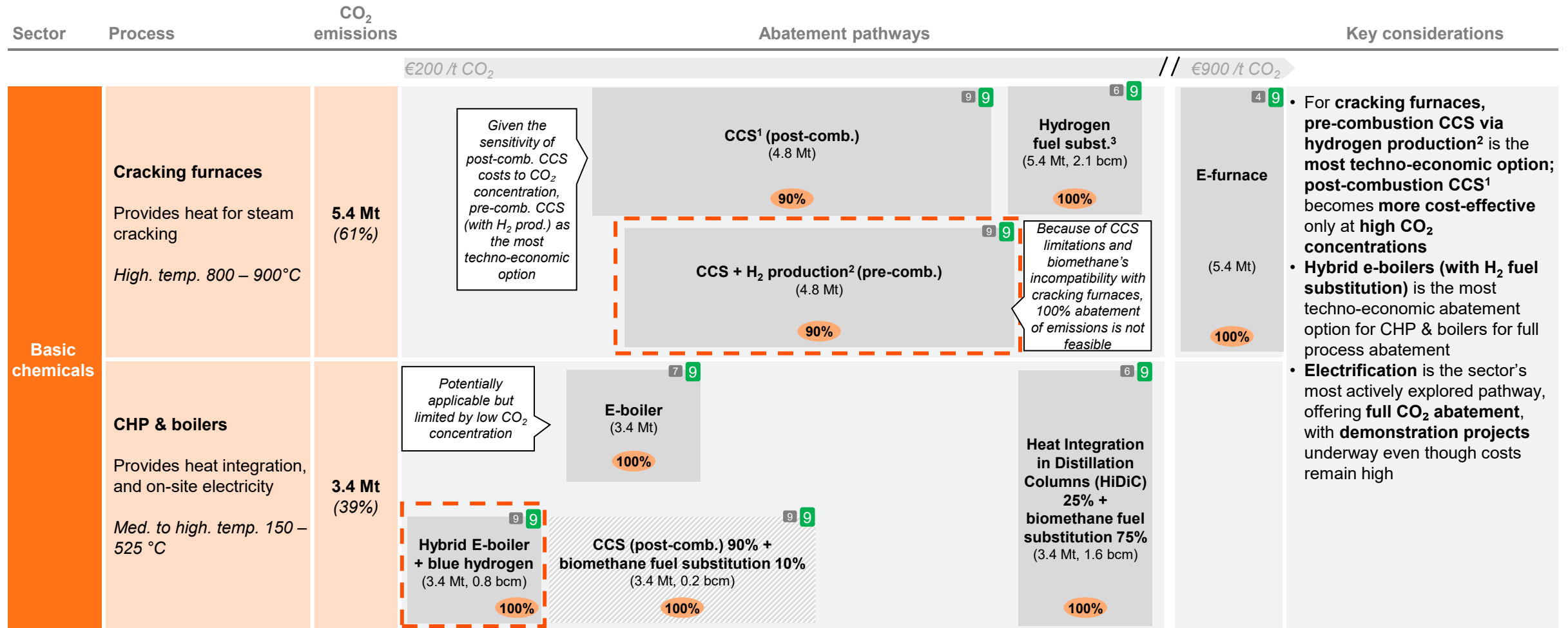
In addition, fuel substitution with biomethane or blue hydrogen can abate emissions from CHPs and boilers, but only delivers partial abatement (~64%)

Basic chemicals – Abatement options (4/4)

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 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 H₂ 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 H₂ requires modifying turbines and ensuring stable H₂ 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

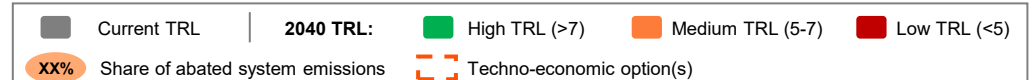
For basic chemicals, CCS + H₂ production is the most-techno-economic option for cracking furnaces; hybrid e-boilers (with H₂) is the abatement path for CHP's

Basic chemicals – Abatement pathways



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

1) Post-combustion CCS costs are highly sensitive to CO₂ concentration – flue-gas concentration is assumed to be 5% CO₂ 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



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

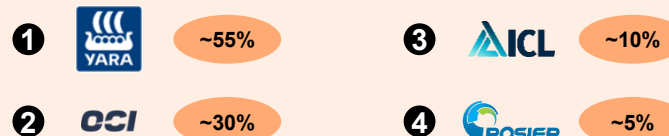
Sector overview

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

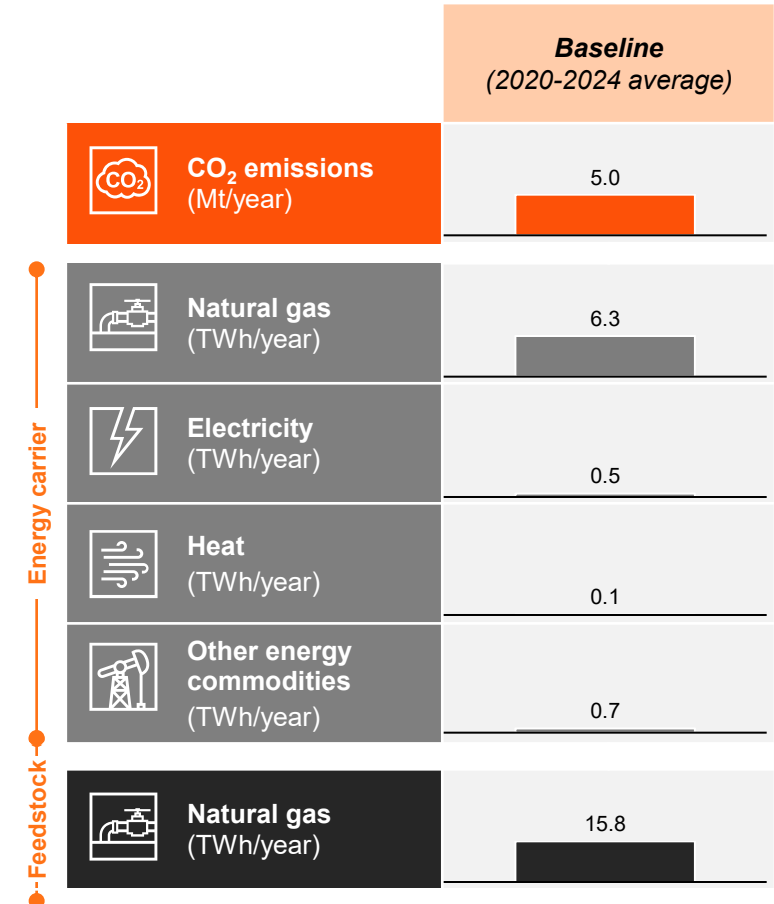
Locations of largest fertiliser plants, incl. market share



Market share¹



Energy profile



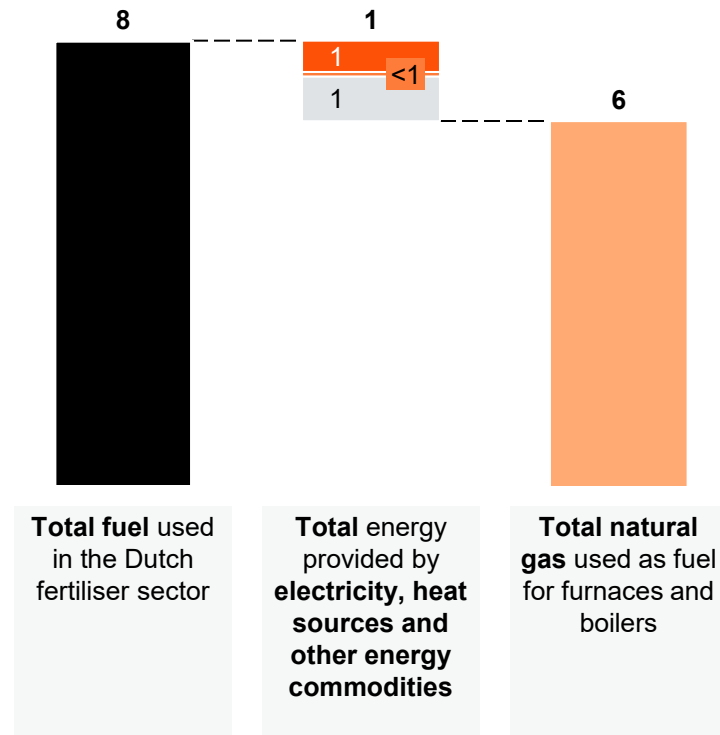
Large amounts of natural gas are used in fertiliser production, both as fuel (~6 TWh) and as feedstock (~16 TWh) for hydrogen production

Fertiliser – Energy profile

Fuel use

Fertiliser fuel use by carrier

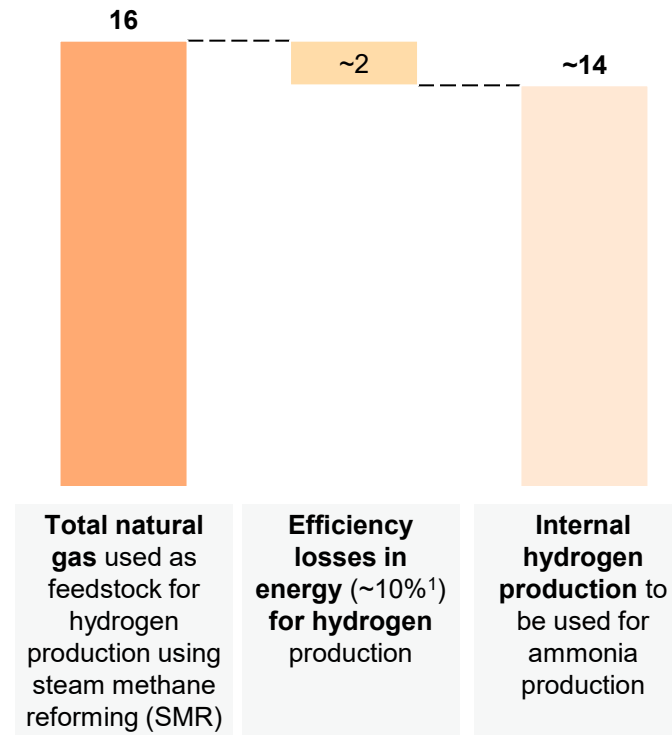
(In TWh, 5-year average 2020-2024)



Feedstock use

Natural gas feedstock use for hydrogen prod.

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



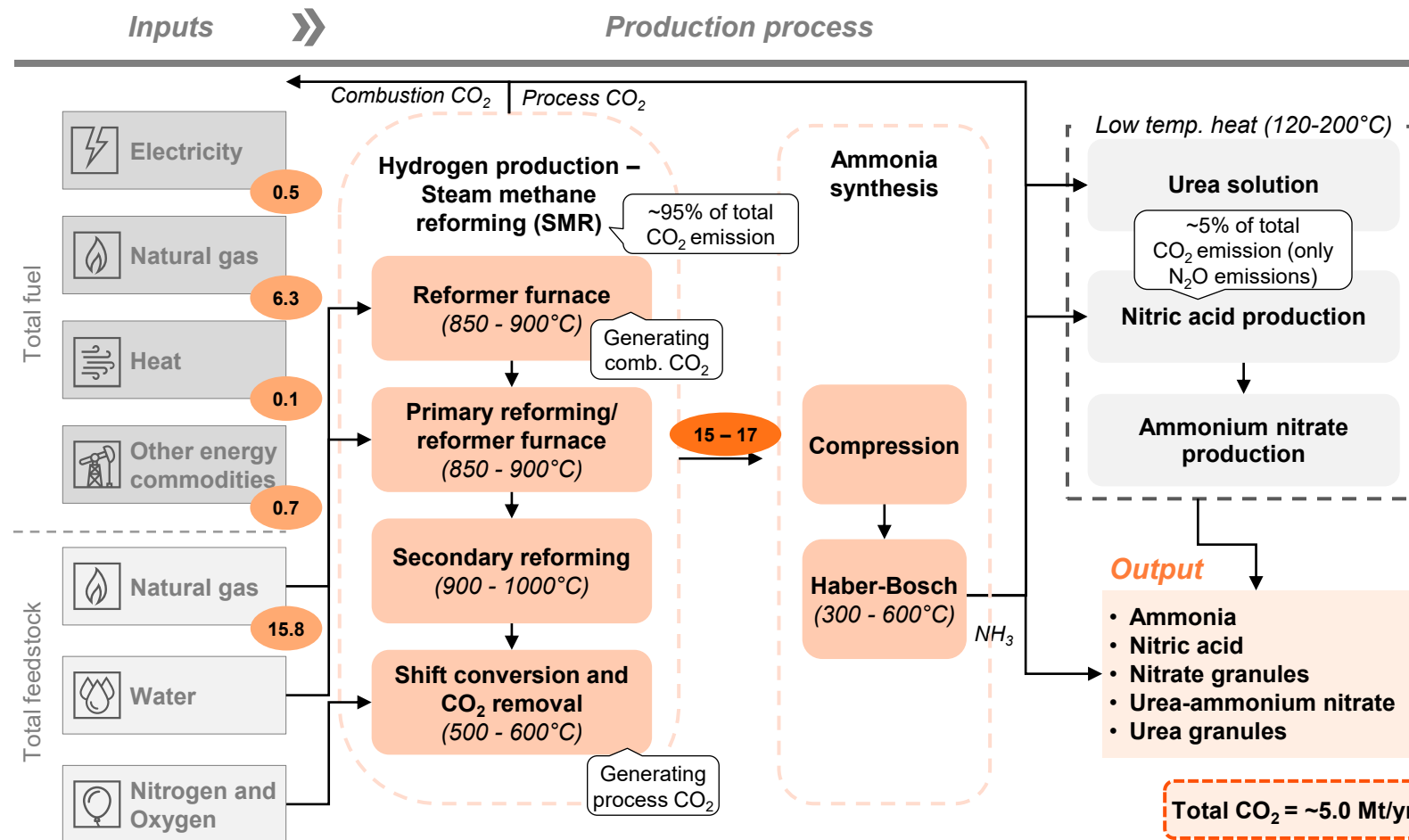
Key insights

- **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

■ Electricity
 ■ Heat
 ■ Natural gas
 ■ Hydrogen
 ■ Total coal and coal products
 ■ Total crudes/ petroleum products
 ■ Total other energy commodities

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 CO₂ 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

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 + H₂), and the water-gas shift reaction converts CO to CO₂ while producing H₂	~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 H₂ 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 CO₂ 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 N₂O and not CO₂ - Emissions in NL >70% less than European benchmark	~12–18% N₂O (not CO₂) 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 N₂O before the absorption tower

Fully abating SMR emissions via electrolysis or green hydrogen is costly - CO₂ for urea production to be supplied separately

Fertiliser – Abatement options (1/3)

Sub-process	Abatement option	Description	Abated CO ₂ ¹	Unit costs	Change in total fuel use (TWh/year)					Change in total feedstock use (TWh/year)		Key considerations (incl. TRL, challenges, etc.)
					Natural gas	Biomethane	H ₂	Electricity	Heat	Natural gas	Biomethane	
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 - CO₂ required for urea synthesis must be supplied from alternative sources, this option will eliminate process CO₂ 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 - CO₂ required for urea synthesis must be supplied from alternative sources, this option will eliminate process CO₂ currently used for urea

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)

Sub-process	Abatement option	Description	Abated CO ₂ ¹	Unit costs	Change in total fuel use (TWh/year)					Change in total feedstock use (TWh/year)		Key considerations (incl. TRL, challenges, etc.)
					Natural gas	Biomethane	H ₂	Electricity	Heat	Natural gas	Biomethane	
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 CO₂ for urea production for key players (under constant output assumptions caps the domestic CO₂ emissions that imports can avoid) - CO₂ required for urea synthesis must be supplied from alternative sources, replacing currently available process CO₂ - 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

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

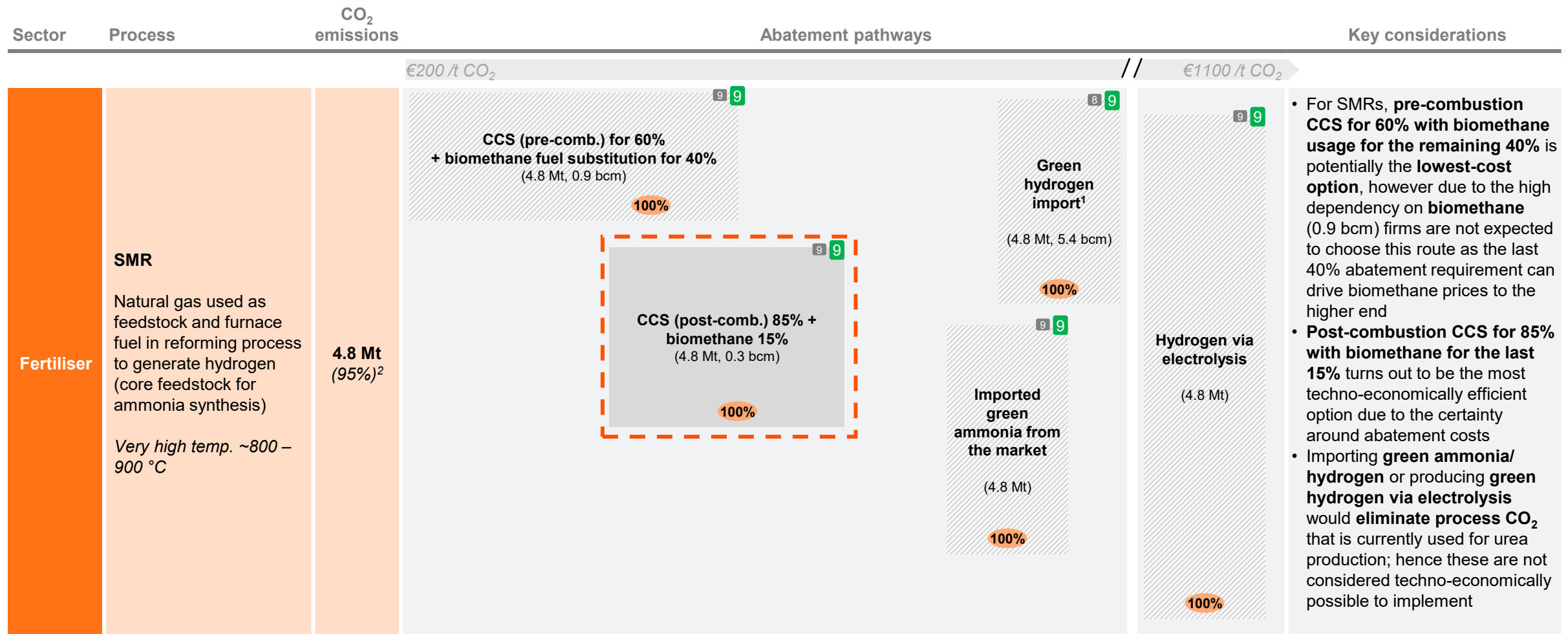
Fertiliser – Abatement options (3/3)

Sub-process	Abatement option	Description	Abated CO ₂ ¹	Unit costs	Change in total fuel use (TWh/year)					Change in total feedstock use (TWh/year)		Key considerations (incl. TRL, challenges, etc.)
					Natural gas	Biomethane	H ₂	Electricity	Heat	Natural gas	Biomethane	
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	-	-	

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 CO₂ 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 CO₂ 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 CO₂ 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



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

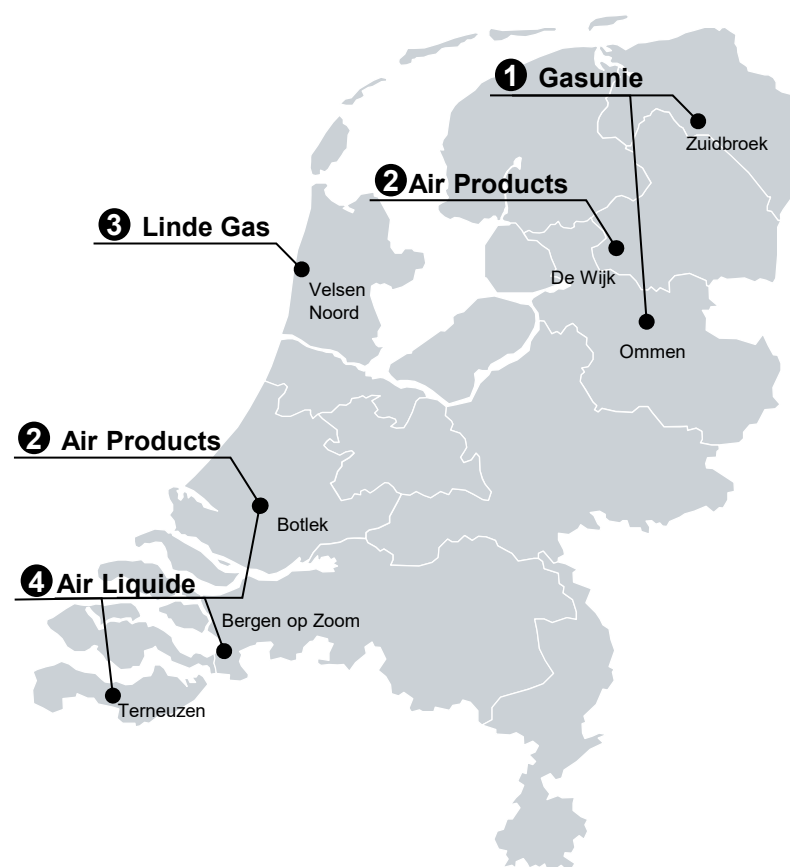
1) Green hydrogen imported by ship as green ammonia, so this would always be more expensive than importing green ammonia directly; 2) We focus on abating hydrogen production, as only process efficiency options are available for other processes within fertiliser | Sources: CBS, PBL MIDDEN, Science direct

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

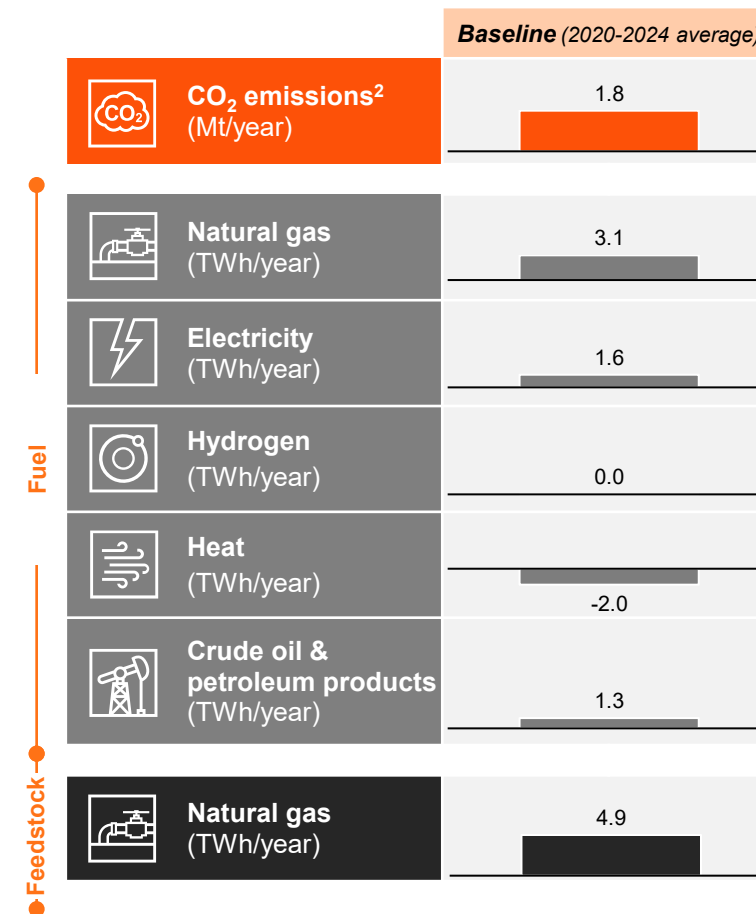
Industrial gases – Sector overview

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 CO₂
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

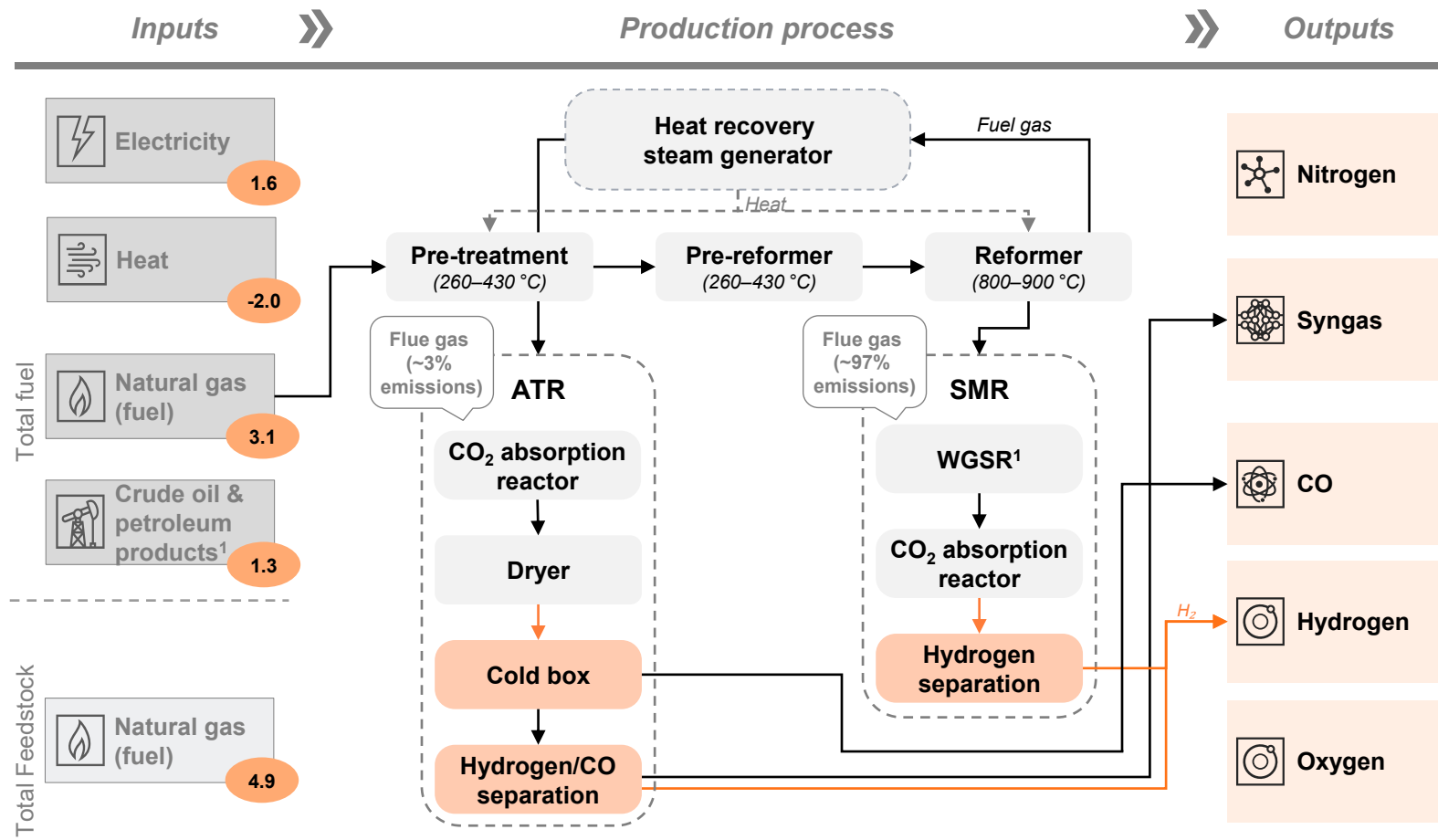


Energy profile



For industrial gases, SMR is the dominant production process and the primary source of CO₂ emissions, accounting over ~97% of total emissions

Industrial gases – Process overview



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 CO₂ emissions:

- Steam Methane Reforming (SMR) (~97%):** In this method, natural gas reacts with heat at 800–950 °C to produce syngas (H₂ + CO), followed by water-gas shift and pressure swing adsorption (PSA) purification steps to produce pure hydrogen
- 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 CO₂ emissions, stemming from both fuel combustion and the reforming reactions themselves

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 • CO₂ 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 • CO₂ 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 H₂/CO ratio	• Mix of natural gas and fuel gas	• CCS (pre-combustion) • Biomethane fuel substitution

SMRs can co-produce H₂ 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 CO₂ 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 CO₂ 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 CO₂ 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

For an SMR with pure hydrogen, these process emissions could be fully abated by either biomethane fuel substitution or green H₂ 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 (H₂) 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 CO₂ from reforming reactions; only abates combustion emissions - Application feasibility depends on availability of required volumes
	Electrolysis (Green H₂)	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 CO₂ 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
				Liquid transport						
				<300 €/t CO ₂	-	-	-	▲ 0.1	▲ 0.3	
				<300 €/t CO ₂	-	-	-	▲ 0.2	▲ 0.3	

Post-combustion CCS allows for higher reduction of CO₂ emissions (85%) than pre-combustion CCS (60%) at the pure H₂ 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 CO₂ 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 CO₂ 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 CO₂ 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	

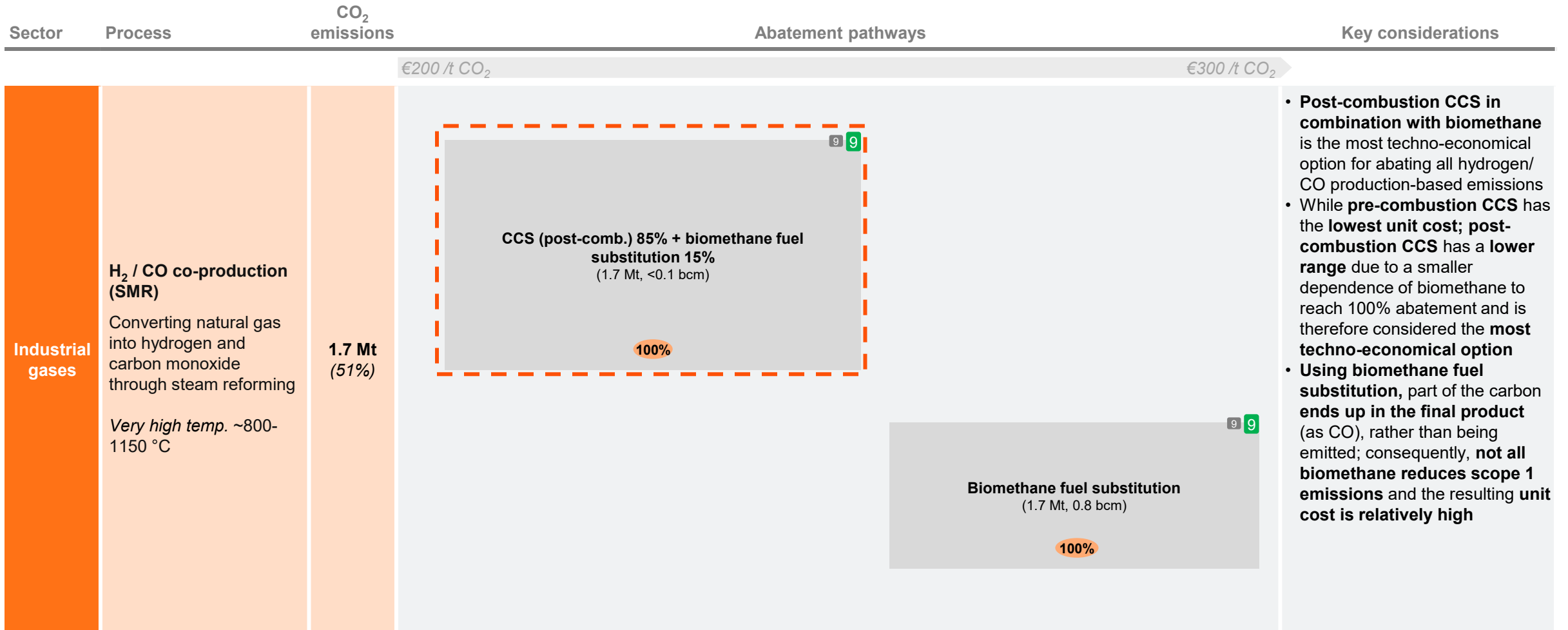
For ATR units (3% of emissions), post combustion CCS and biomethane as fuel can fully abate the ATR; unit prices are comparable for both options

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 CO₂ concentration, which improves capture efficiency and lowers energy consumption per tonne of CO₂ 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 H₂/CO co-production). It produces 'green syngas'. - Supply is constrained, with strong competition from other industries; application feasibility depends on availability of required volumes

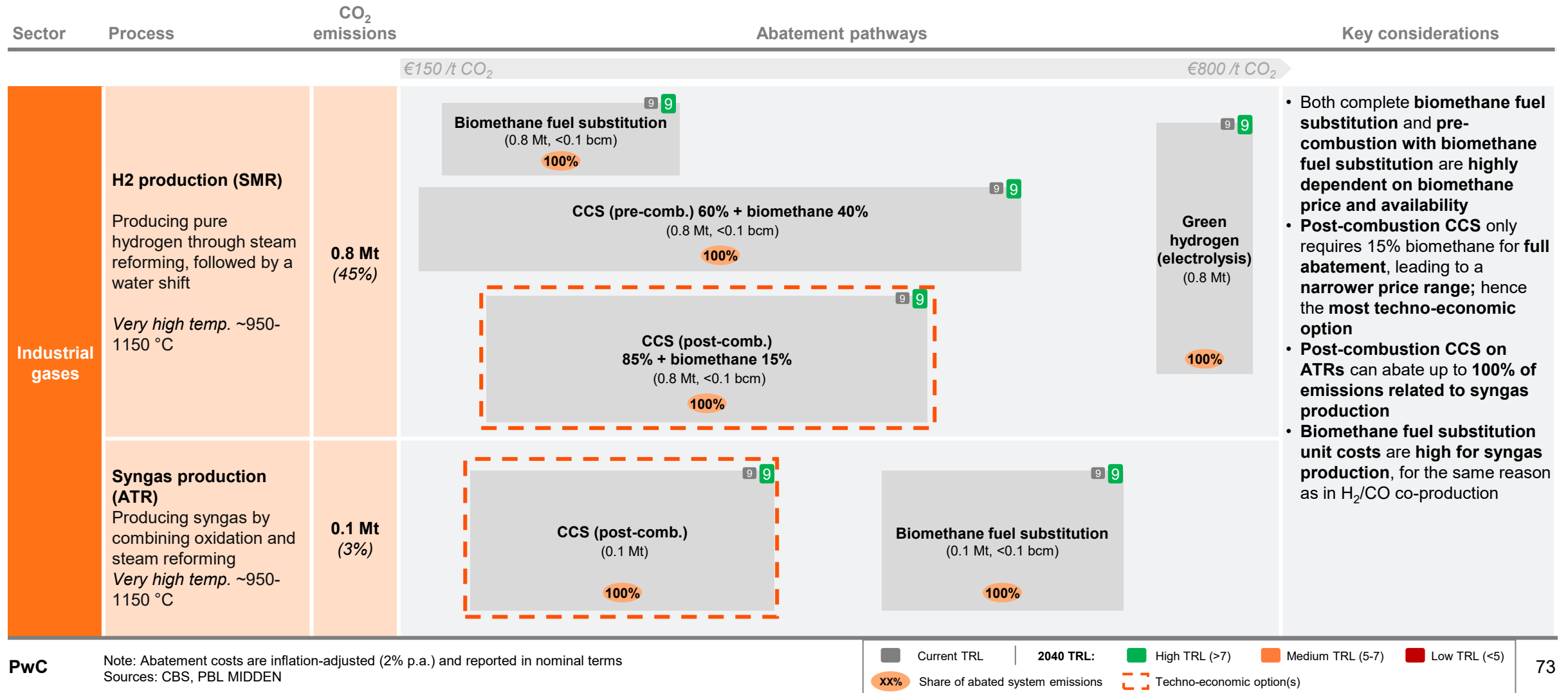
Combining post-combustion CCS with biomethane fuel substitution is the most techno-economical abatement option for hydrogen/CO production

Industrial gases – Abatement pathways (1/2)



H₂ 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)



Steel production in the Netherlands is highly concentrated, only at Tata Steel IJmuiden, and emits approximately 11.3 Mt CO₂ 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 CO₂ 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

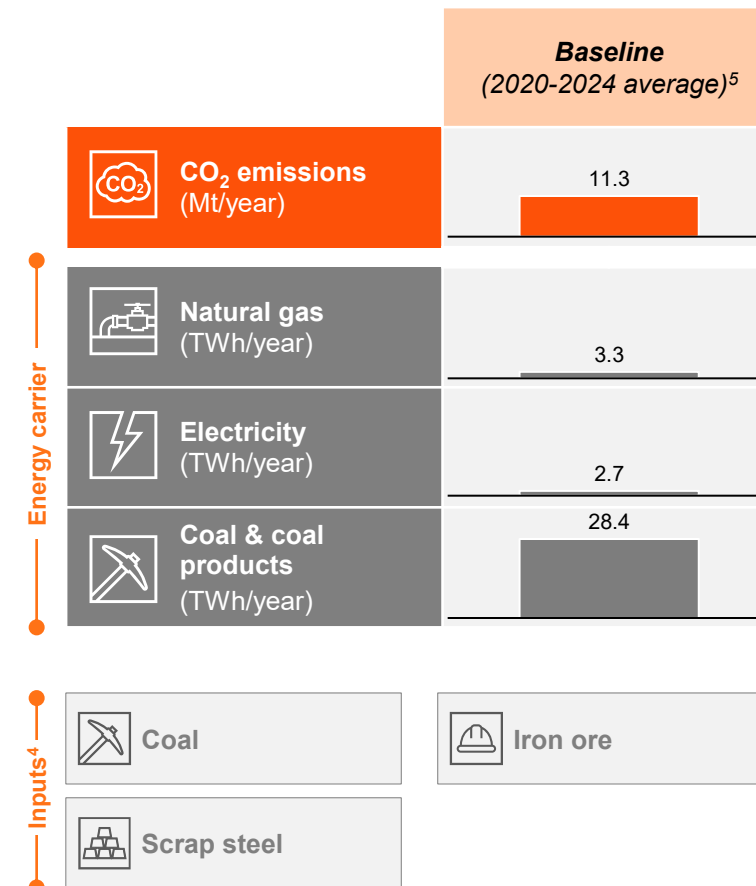
Location of steel plants, incl. sectors served



Sectors served¹

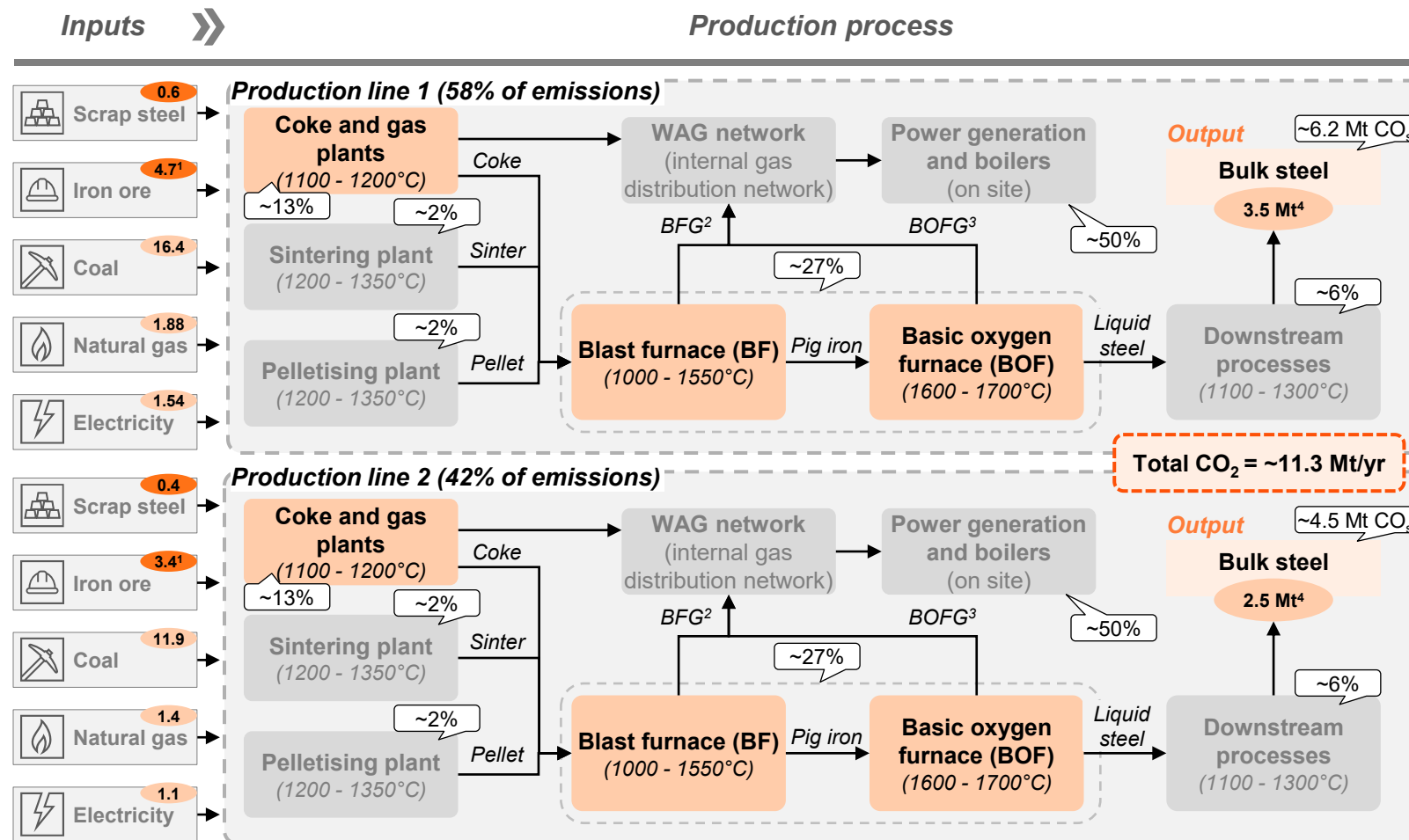


Energy profile



The current prod. process uses coal as fuel and feedstock to produce bulk steel;
~50% of CO₂ emissions come from power generation and boilers

Steel – Process overview



Key insights

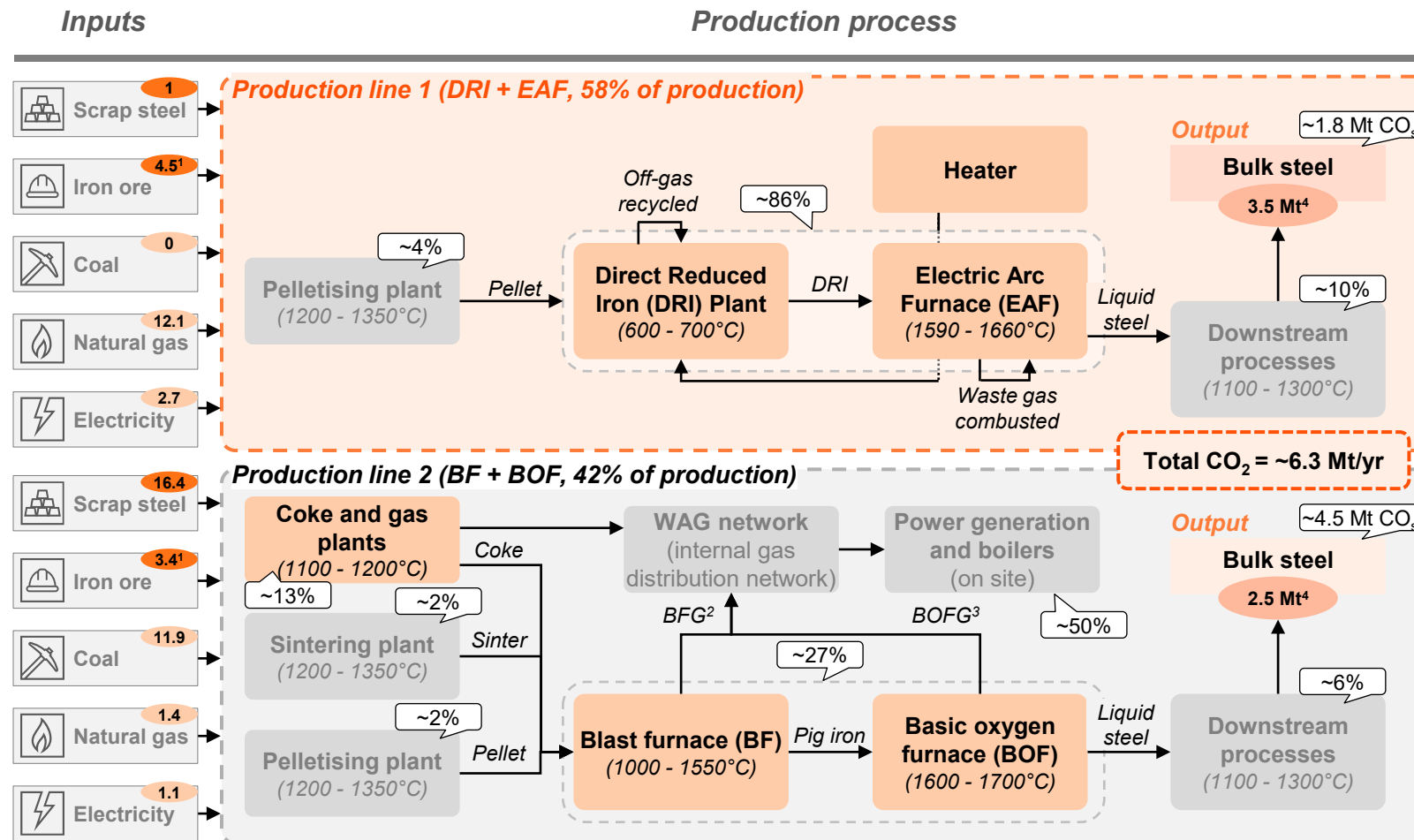
- Steel production relies heavily on **high- temperature chemical reduction**. This process is inherently **energy- and carbon-intensive**
- Most CO₂ emissions originate from the two **blast furnaces** and **basic oxygen furnaces**, which are used to produce **liquid steel**, accounting for **ca. 27% 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 CO₂; 3) Basic oxygen furnace gas, which consists mainly of CO and CO₂; 4) Based on the average bulk steel production from 2020 until 2024.

Sources: CBS, MIDDEN, NEa, energy.nl

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)

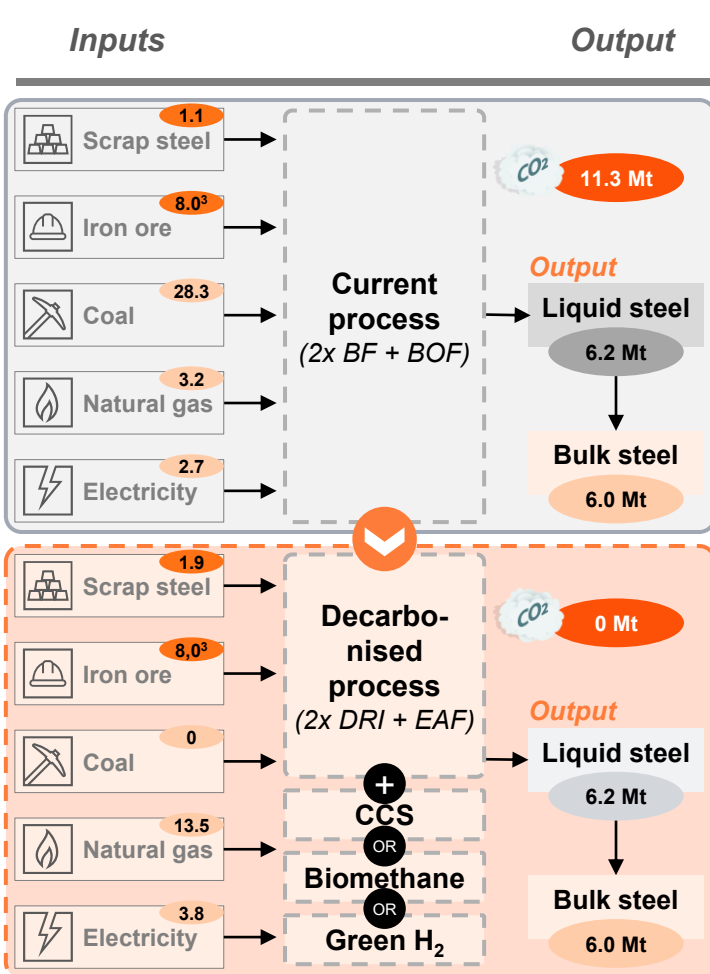


1) Based on the average t/tonnes of bulk steel from 2019/2020 until 2023/2024; 2) Blast furnace gas, which consists mainly of nitrogen, CO and CO₂; 3) Basic oxygen furnace gas, which consists mainly of CO and CO₂; 4) Based on the average bulk steel production from 2020 until 2024.

Sources: CBS, MIDDEN, NEa, energy.nl

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 €mIn 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**

Most production process steps in the steel sector are operated at very high temperatures (>1000°C) and off-gases with high CO₂ 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 - CO₂ emissions by devolatilisation of coal and combustion	~5-10% of CO₂ 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 - CO₂ emissions by combustion	~5-15% of CO₂ 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 - CO₂ emissions by combustion	~5-15% of CO₂ 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 - CO₂ from direct/ indirect reduction and fuel use	~20-25% of CO₂ 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 - CO₂ emissions mainly from fuel firing	~10-20% of CO₂ in BOFG	Very high op. temperatures (~1600–1700°C)	n/a	Consumes mainly heat	
Down-stream process	<i>Notable downstream process:</i> Reheating Reheats slabs/coils ahead of rolling and coating steel	~5% of steel emissions - CO₂ emissions mainly from fuel firing	~5-10% of CO₂ 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

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						
	2 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%)	<300 €/t CO ₂	Gaseous transport						- CCS is for abating remainder of emissions emitted by DRI + EAF (natural gas) - CO₂ capture inherent to the DRI process for 55% of the emissions, so only requires an additional capture installation for the other 45%						
					Liquid transport												
					-	-	-	▲ 0.19	▲ 0.69	-							
	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	- 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) - 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)						
												Gaseous transport					
												-	-	-	▲ 0.04	▲ 0.14	-
	4 CCS – pre-combustion	Collecting pure CO ₂ streams from DRI for permanent storage	▼ 0.2 Mt CO ₂ /year (-1.9%)	<300 €/t CO ₂	Gaseous transport						- CCS is for abating remainder of natural gas emissions from DRI + EAF - CO₂ capture inherent to the DRI process, so does not require an additional capture installation						
					Liquid transport												
					-	-	-	▲ 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)							

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

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 ~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
	2 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%)	<300 €/t CO ₂	-	-	-	▲ 0.14	▲ 0.50	-	- CCS is for abating remainder of emissions emitted by DRI + EAF (natural gas) - CO₂ capture inherent to the DRI process for 55% of the emissions, so only requires an additional capture installation for the other 45%
	3 + 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
	4 + 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)
	5 CCS – pre-combustion	Collecting pure CO ₂ streams from DRI for permanent storage	▼ 0.2 Mt CO ₂ /year (-1.4%)	<300 €/t CO ₂	-	-	-	▲ 0.03	▲ 0.10	-	- CCS is for abating remainder of natural gas emissions from DRI + EAF - CO₂ capture inherent to the DRI process, so does not require an additional capture installation
	6 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)

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

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

Steel – Abatement pathways summary¹

Sector	Process	CO ₂ emissions	Abatement pathways		Key considerations
			€250 /t CO ₂ // €1,500 /t CO ₂		
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 <i>Very high temp. ~1000 – 1700 °C</i>	10.7 Mt (95%)	Phase 1 & 2 DRI & EAF (natural gas) 81% & CCS (gaseous) 17% & biomethane 2% (10.7 Mt, 0.2 bcm) 100% Phase 1 & 2 DRI & EAF (biomethane) (10.7 Mt, 1.8 bcm) 100%	Phase 1 & 2 DRI & EAF with hydrogen 96% & CCS² (gaseous) 3% & biomethane <1% (10.7 Mt, <0.1 bcm) 100%	• 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 <i>Large temperature range dependent on specific process</i>	0.6 Mt (5%)	Biomethane fuel substitution (0.6 Mt, 1.4 bcm) 100%		

Waste processing plants incinerate solid waste and sludge, generating electricity and heat, emitting 2.4 Mt CO₂ 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.
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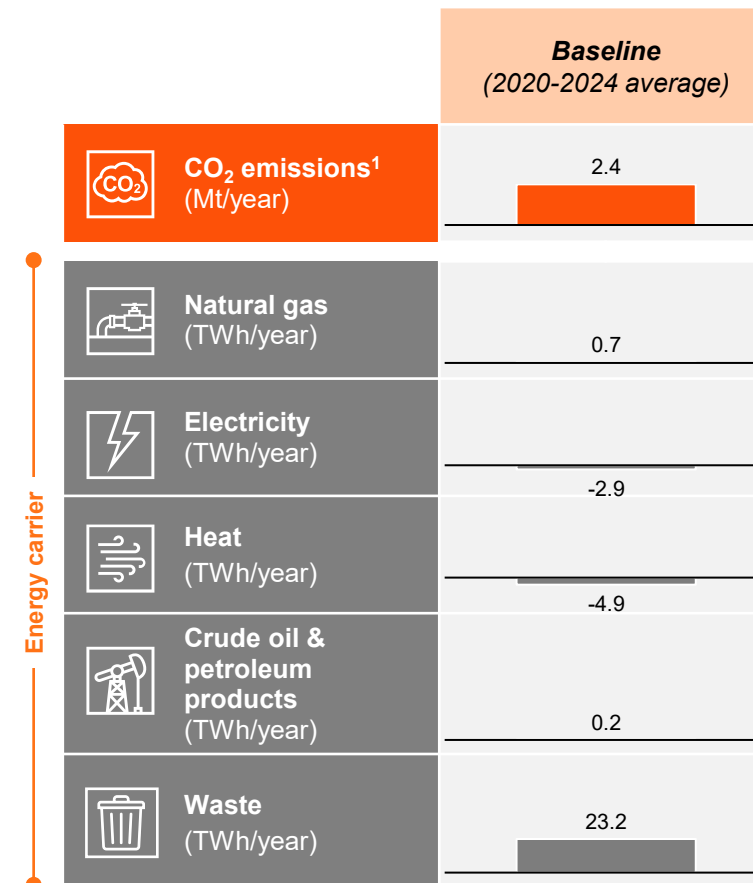
System integration & strategic positioning	- Sector processes waste produced in other sectors, as well as in other parts of the Dutch economy (e.g. residential waste) - Plants are spread out across the country, with most plants situated near the sea or near the German border Heat can be used for (low-temperature) applications in other sectors (e.g., in residential heating)
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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)
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Location of the largest waste incineration plants in the Netherlands by emissions in 2024

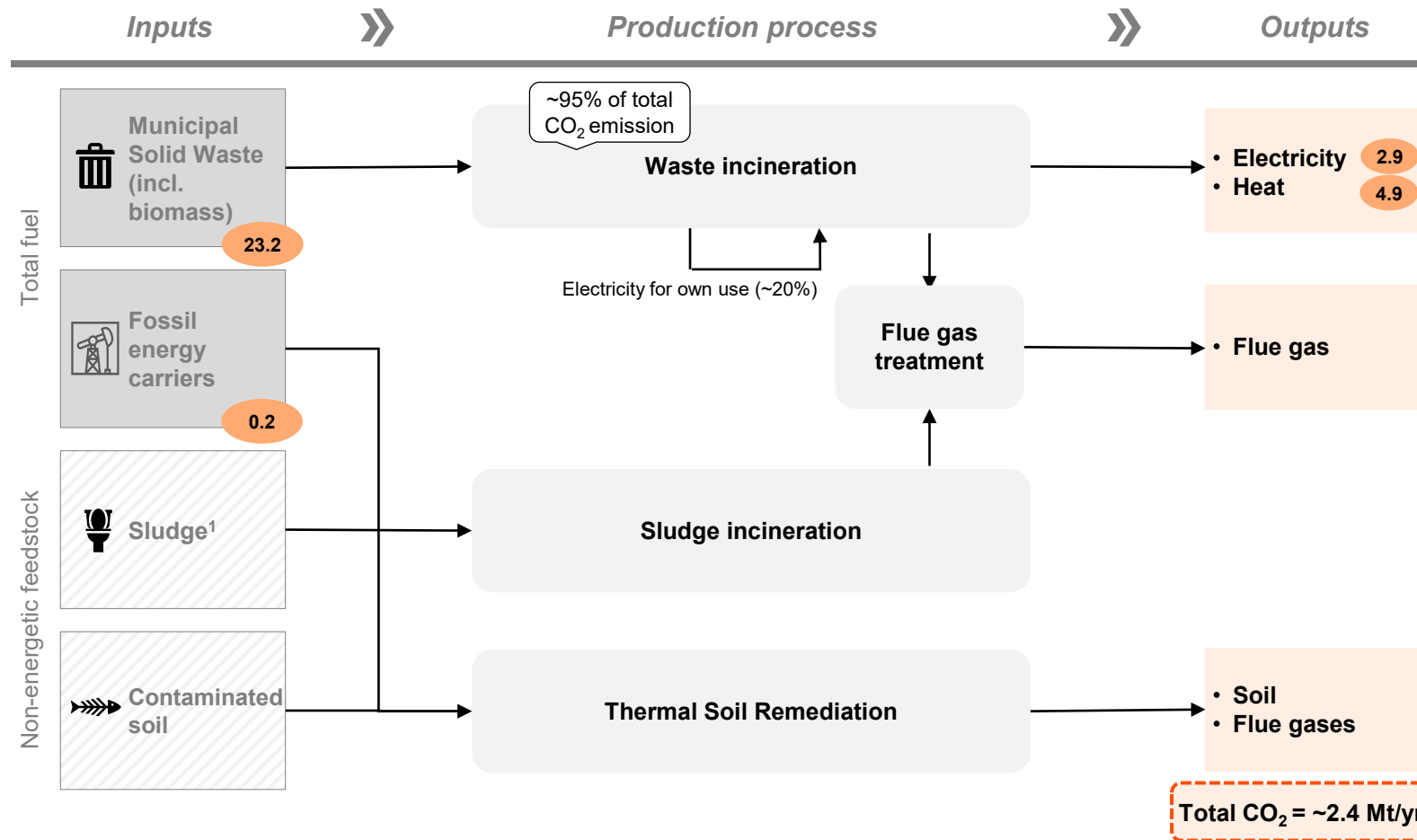


Energy profile



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



Key insights

- **Waste processing plants** mostly use incineration to dispose of waste, leading to **~10 Mt CO₂ 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**

Municipal solid waste incineration is the main driver for CO₂ 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 CO₂ 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)

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	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 CO₂ contributes significantly to the overall costs of this option - Oxy-fuel burning leads to higher CO₂ 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 CO₂ contributes significantly to the overall costs of this option - Regular CCS uses more heat and captures less CO₂ 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 CO₂ 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	

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 CO₂ emissions ~0.3 Mt CO₂/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 CO₂ contributes significantly to the overall costs of this option - Oxy-fuel burning leads to higher CO₂ 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	

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%)

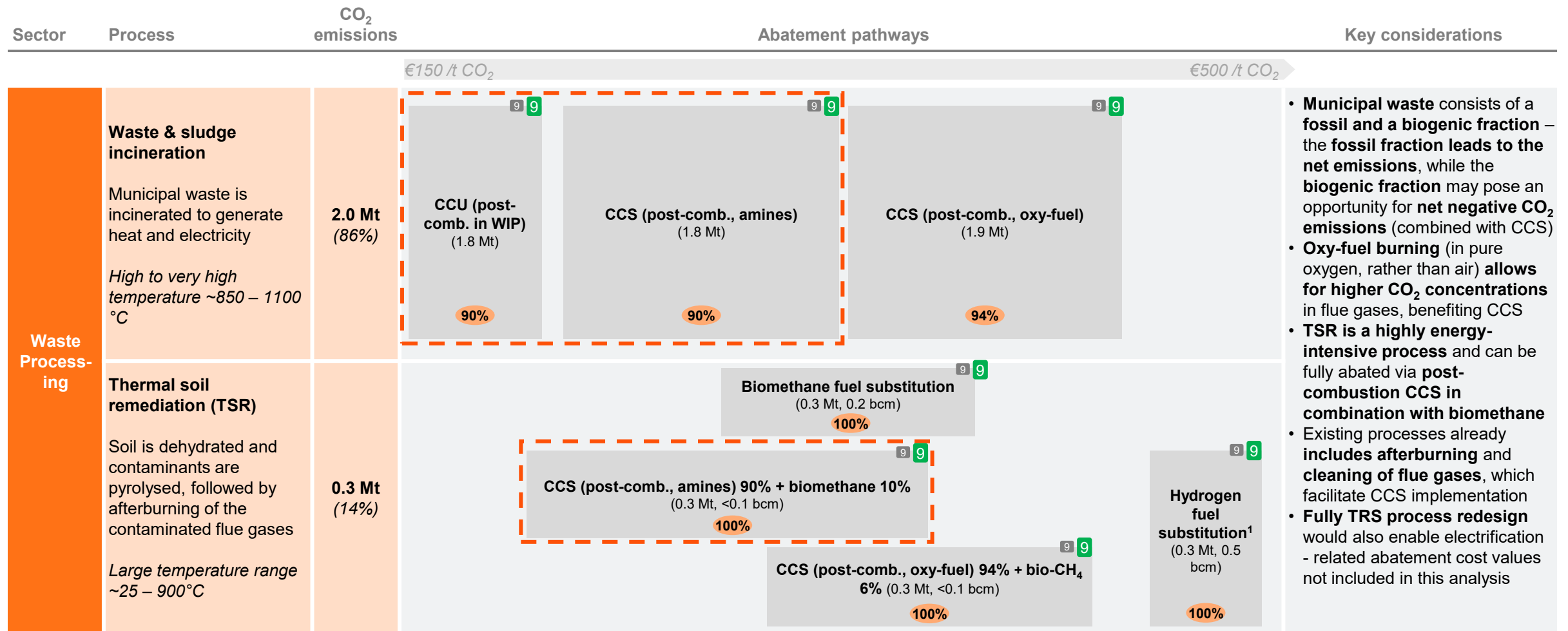
Waste processing – Abatement options (3/3)

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	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 CO₂ contributes significantly to the overall costs of this option - Regular CCS uses more heat and captures less CO₂ 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



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

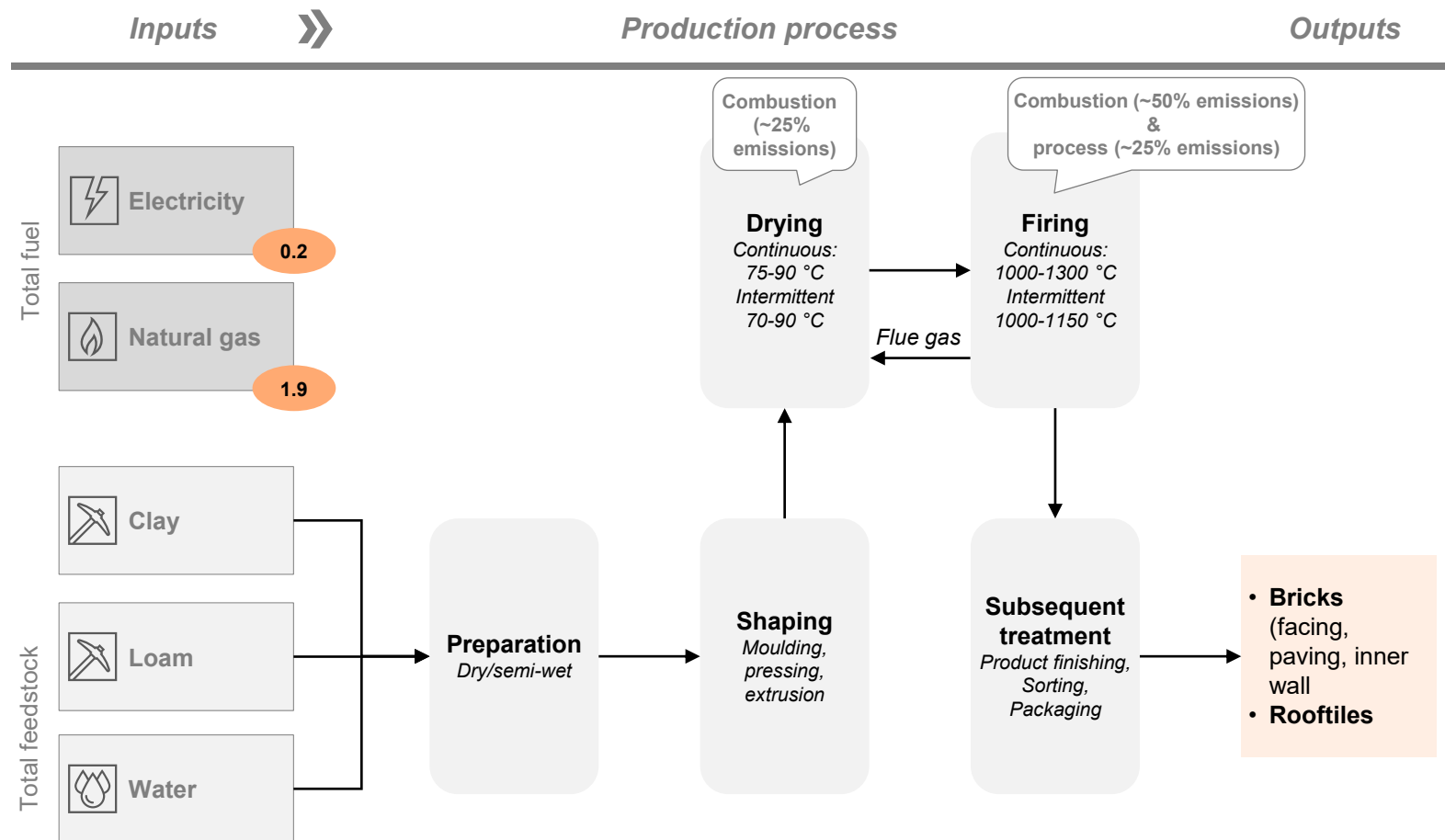
1 Bricks & rooftiles	34	3 Wall tiles	1
2 Floor tiles	1	4 Refractory products	1

Energy profile

	Baseline (2020-2024 average)
CO₂ 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

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



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 finalising 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 CO₂ that get's released during this reaction is responsible for **~25%** of total emissions

High temperatures produced by ovens, required for the ceramics firing process, primarily cause CO₂ 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 H₂ 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 emissions Release CO₂ 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 H₂ fuel substitution - Heat pump - CCS (post-combustion)

Only option available for abating calcination-based emissions

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)

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	
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 CO₂ 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 H₂ 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 H₂ burning - Hydrogen delivery and storage infrastructure remains underdeveloped³
	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

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 H₂; electrification is an alternative but constrained by technological feasibility

Ceramics – 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	
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 H₂ 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

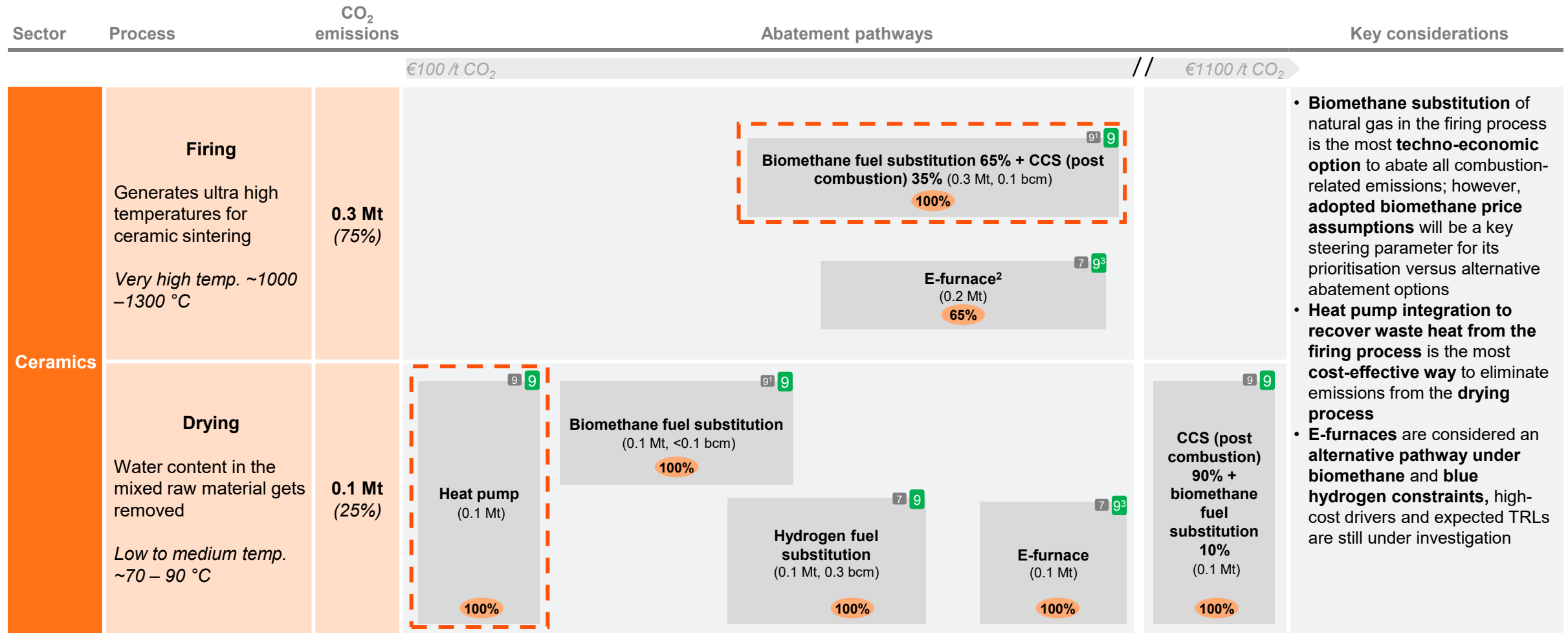
For drying, the need for additional heat generation can be eliminated by installing an industrial heat pump to optimally use waste heat of the firing kiln

Ceramics – Abatement options (3/3)

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	
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 CO₂ 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

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



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

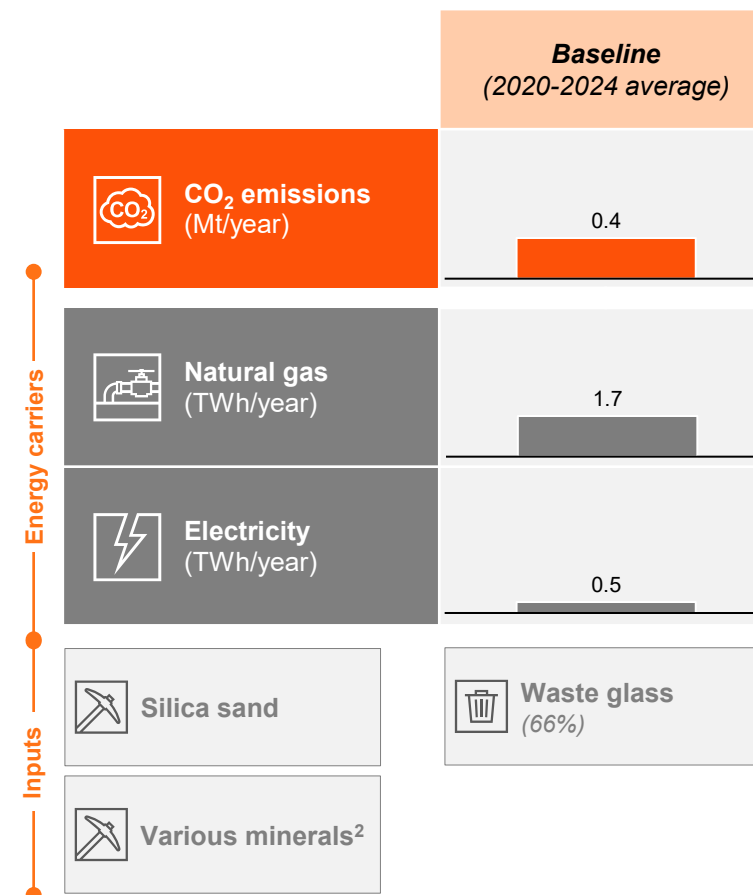
Location of the five container and tableware glass production plants in The Netherlands



Market share¹

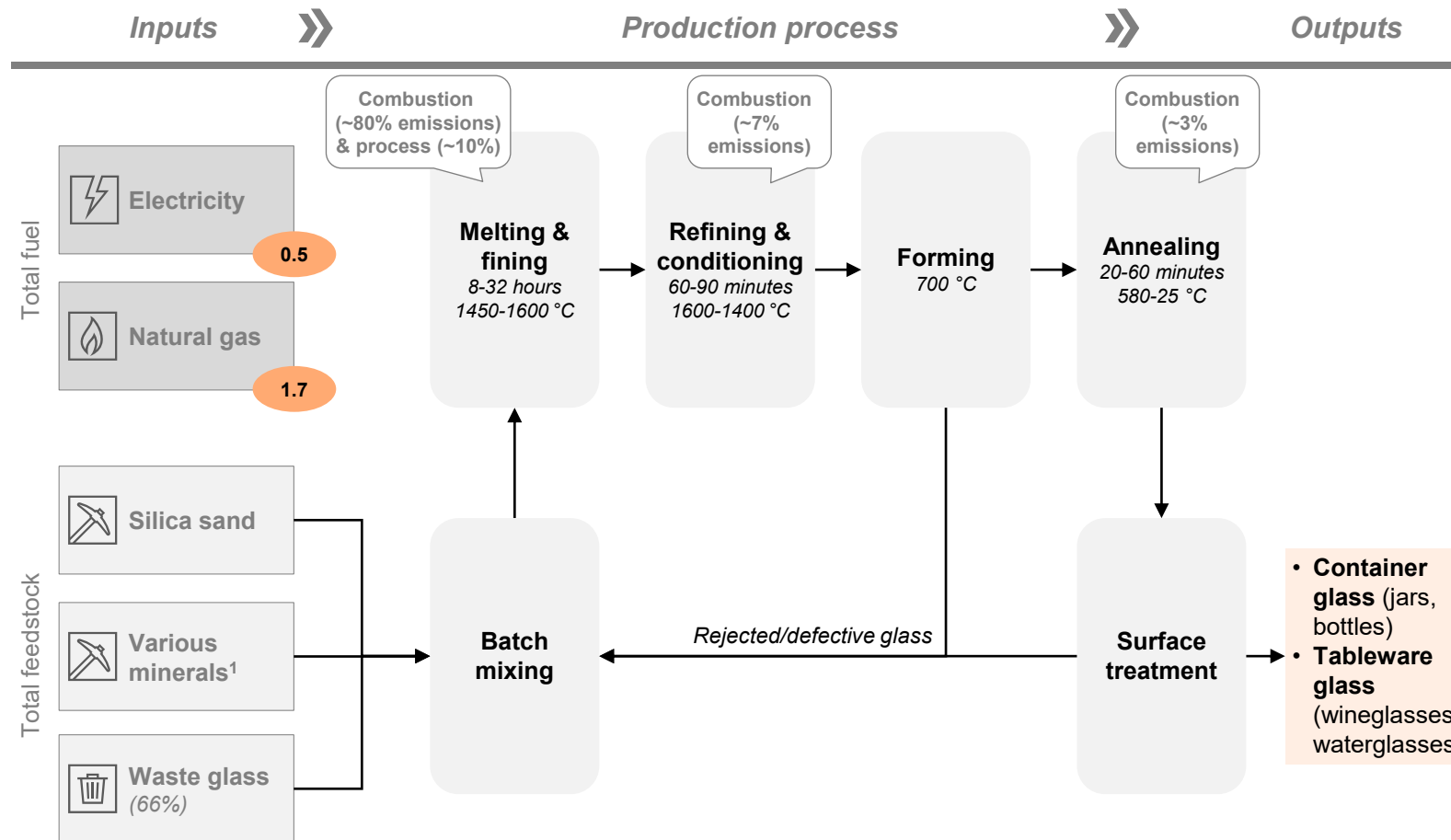


Energy profile



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



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 CO₂, accounting for the remaining **~12% of total emissions**
- **Waste glass** (cullet) constitutes a **large share of the glass feedstock** (~66%)

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	• Electrification • Blue H₂ 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 H₂ 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 H₂ fuel substitution • Biomethane fuel substitution • Post-comb. CCS

Only option available for abating carbonate-decomposition-based emissions

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)

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	
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 CO₂ 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 underdeveloped³	
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	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
	<0.1 Mt 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%	▼<0.1 Mt CO ₂ /year (-90%)	Gaseous transport					• Transportation and storage of captured CO₂ requires extensive infrastructure potentially unfeasible for Dutch glass production • Requires significant heat and electricity for regeneration, reducing overall system efficiency
					>500 €/t CO ₂ ²	-	-	-	▲ <0.01	
				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 underdeveloped³

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)					Key considerations (incl. TRL, challenges, etc.)		
					Natural gas	Biomethane	H ₂	Electricity	Heat			
Annealing ~3% of total emissions <0.1 Mt CO₂/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 H₂ 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 underdeveloped²		
	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					▲ <0.01	▲ <0.01	- Transportation and storage of captured CO₂ 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					▲ <0.01	▲ <0.01	
					>500 €/t CO ₂	-	-	-	▲ <0.01	▲ <0.01		

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

Sector	Process	CO ₂ emissions	Abatement pathways	Key considerations
			€200 /t CO ₂ → €700 /t CO ₂	
Glass	Melting & fining Ultra high temperatures are needed to melt the batch <i>Very high temp. ~1450 – 1600 °C</i>	0.2 Mt (~90%)	Biomethane fuel substitution 87% + CCS (post combustion) 13% (0.3 Mt, 0.1 bcm) 100% Hybrid oven 47% + biomethane fuel substitution² 53% (0.2 Mt, 0.1 bcm) 100% E-furnace² (0.2 Mt) 87% H₂ fuel substitution⁴ 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 <i>Very high temp. ~1450-1600 °C</i>	<0.01 Mt (~7%)	Biomethane fuel substitution (<0.1 Mt, <0.1 bcm) 100% E-furnace (<0.1 Mt, €546/t CO₂) 100% Hydrogen fuel substitution⁴ 80% + biomethane fuel substitution 20% (<0.1 Mt, <0.1 bcm H₂, <0.1 bcm bio-CH₄) 100% CCS (post. comb.) 90% + biomethane 10% (<0.1 Mt, <0.1 bcm) 100%	
	Annealing Gradually cooling down of the batch to strengthen the product <i>Large temperature range 25-580 °C</i>	<0.01 Mt (~3%)	Biomethane fuel substitution (<0.1 Mt, <0.1 bcm) 100% E-furnace (<0.1 Mt) 100% Hydrogen fuel substitution⁴ 80% + biomethane fuel substitution 20% (<0.1 Mt, <0.1 bcm H₂, <0.1 bcm bio-CH₄) 100% CCS (post. comb.) 90% + biomethane 10% (<0.1 Mt, <0.1 bcm) 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 CO₂ 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, fines group

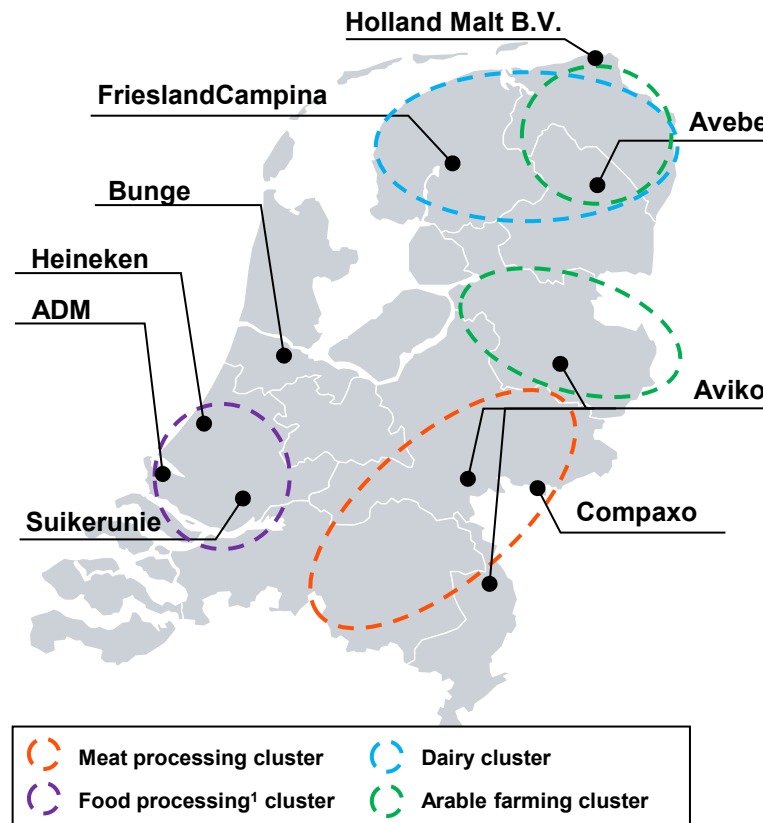
The Netherlands is a key exporter of beverages, dairy, and potato products, which are produced and processed in four clusters across the Netherlands

Food – Sector overview

Sector overview

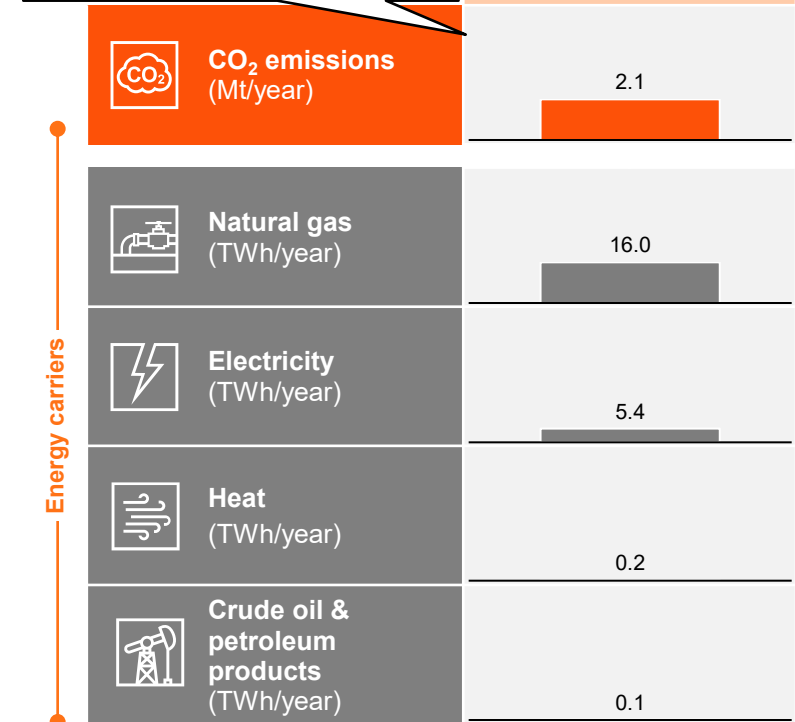
Sector definition	- Food manufacturing is based on the processing of agricultural inputs into (semi-) finished food products Dairy, meat, and potato processing dominate energy use and emissions in the Dutch food industry Emissions mainly come from heat-intensive processes like evaporation, sterilisation,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



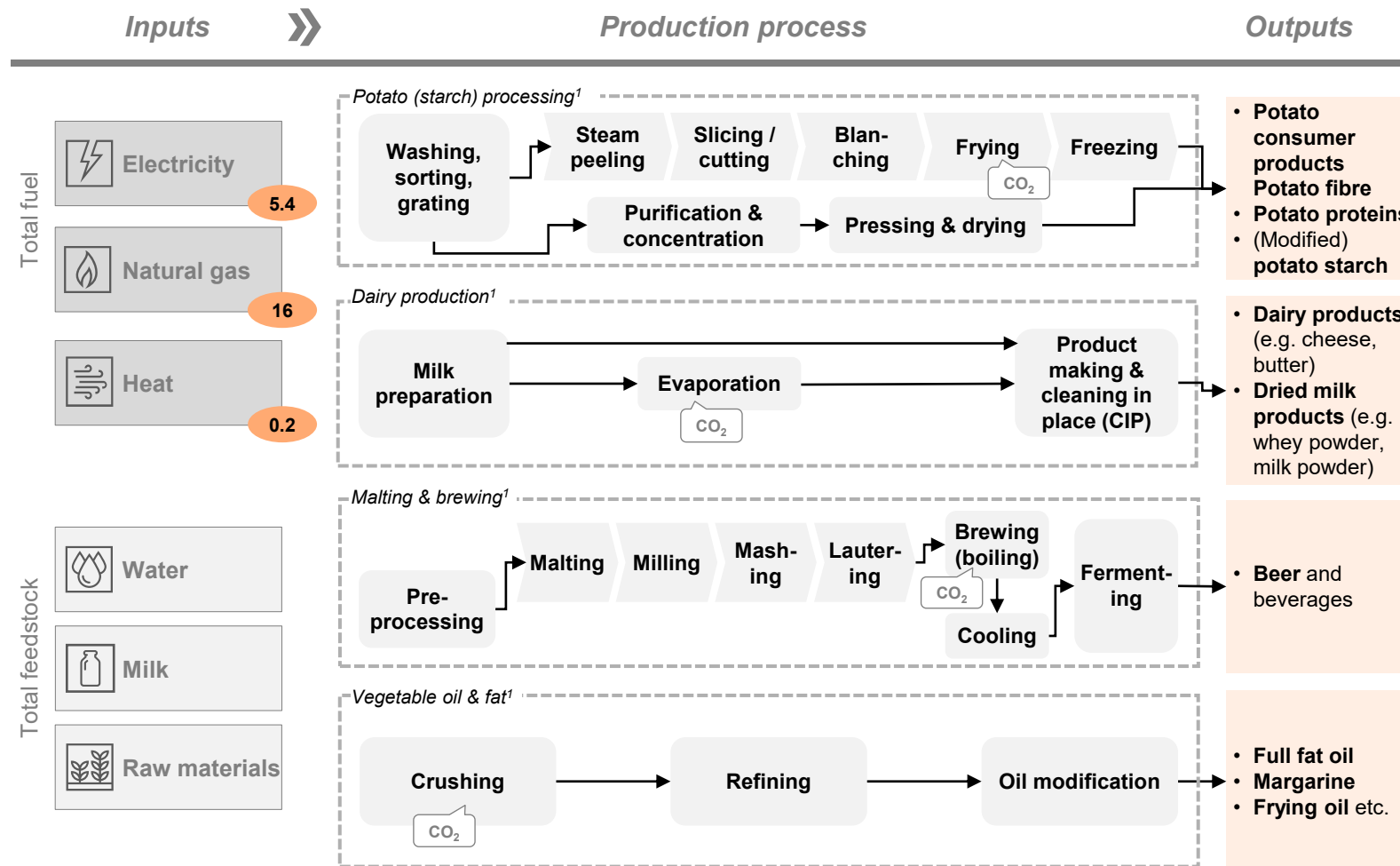
Energy profile

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



Across production plants, generating heat and/or electricity accounts for most fuel use and all CO₂ emissions within the subsectors of food

Food – Process overview



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 CO₂**
- **Refrigeration & cooling**, such as cooling tunnels, chillers, refrigeration plants and freezer systems consume significant amounts of electricity; they generate very little direct combustion-related CO₂, with **emissions** linked mainly to **upstream power generation**

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 emissions²	~4-15%	Low to medium operating temperature¹ (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 emissions²	~4-15%	Low to medium operating temperature¹ (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 or biomethane fuel Heat pump CCS (post-combustion)
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 emissions²	~4-15%	Low to medium operating temperature¹ (5-100 °C)	n/a	Natural gas is main fuel for steam boilers	Biomethane fuel substitution E-boilers Blue hydrogen fuel substitution Hybrid E-boiler +hydrogen or biomethane fuel Heat pump CCS (post-combustion)

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 CO₂ emissions by approximately 100%, necessitating advancements in e-heating technology and improvements to the electrical grid

Food – 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	
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 (CH₄ 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
	H₂ 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 underdeveloped³
	Hybrid e-boiler + blue H₂ 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 (CH₄ 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
	H₂ 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 underdeveloped³
	Hybrid e-boiler + blue H₂ 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

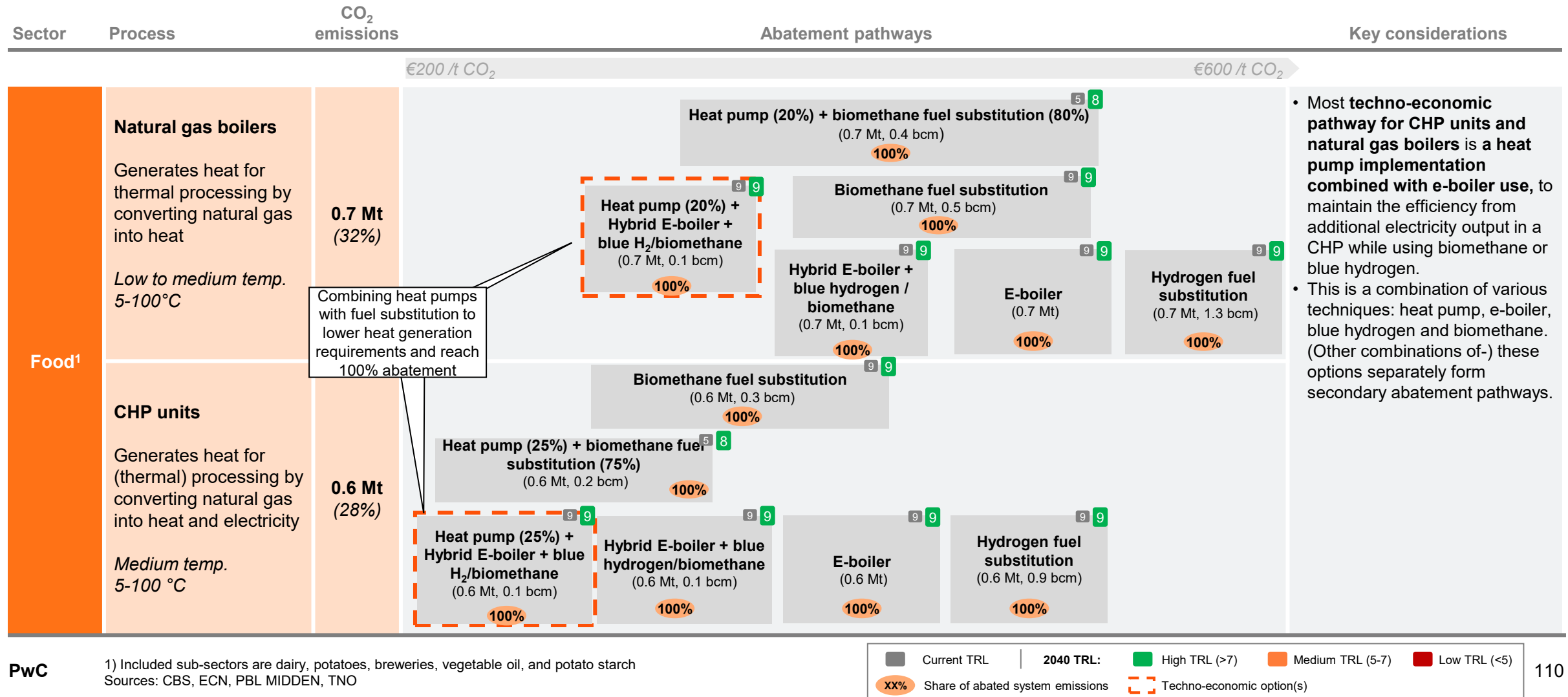
Food – Abatement options (3/3)

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	
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 (CH₄ 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 H₂ 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 underdeveloped³
	Hybrid e-boiler + blue H₂ 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

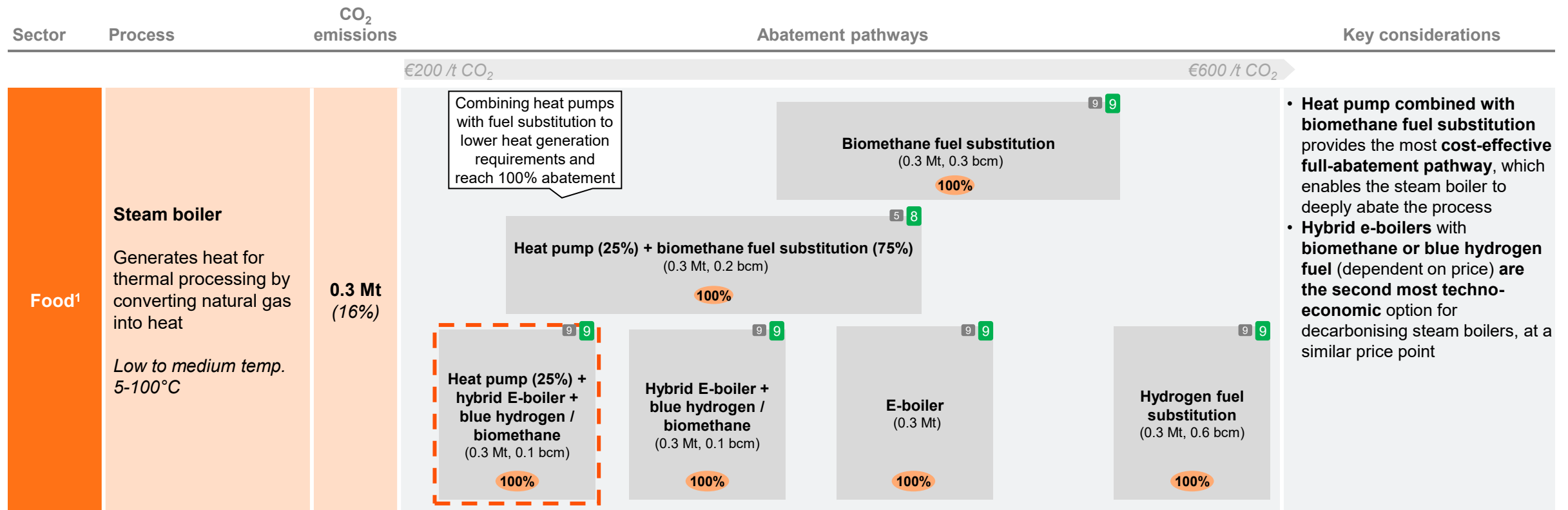
Heat pumps and hybrid e-boilers can substitute natural gas boilers and CHP units in the food sector

Food – Abatement pathways (1/2)



For the steam boilers, heat pumps combined with biomethane fuel substitution enables deep abatement of the process CO₂ emissions

Food – Abatement pathways (2/2)



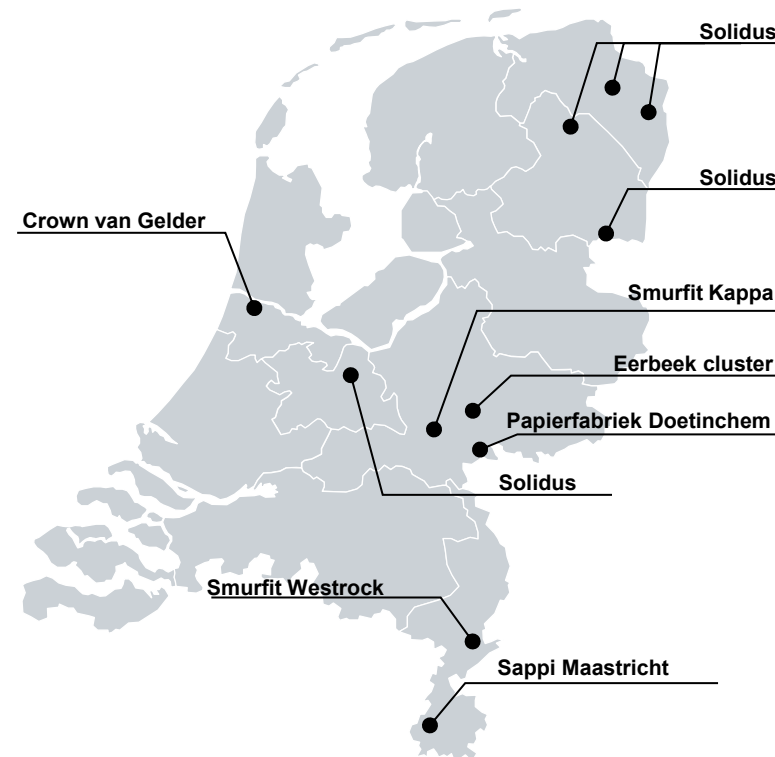
The Dutch paper manufacturing sector is highly fragmented, with numerous companies and various products, collectively emitting ~0.7 Mt of CO₂ emissions

Paper – Sector overview

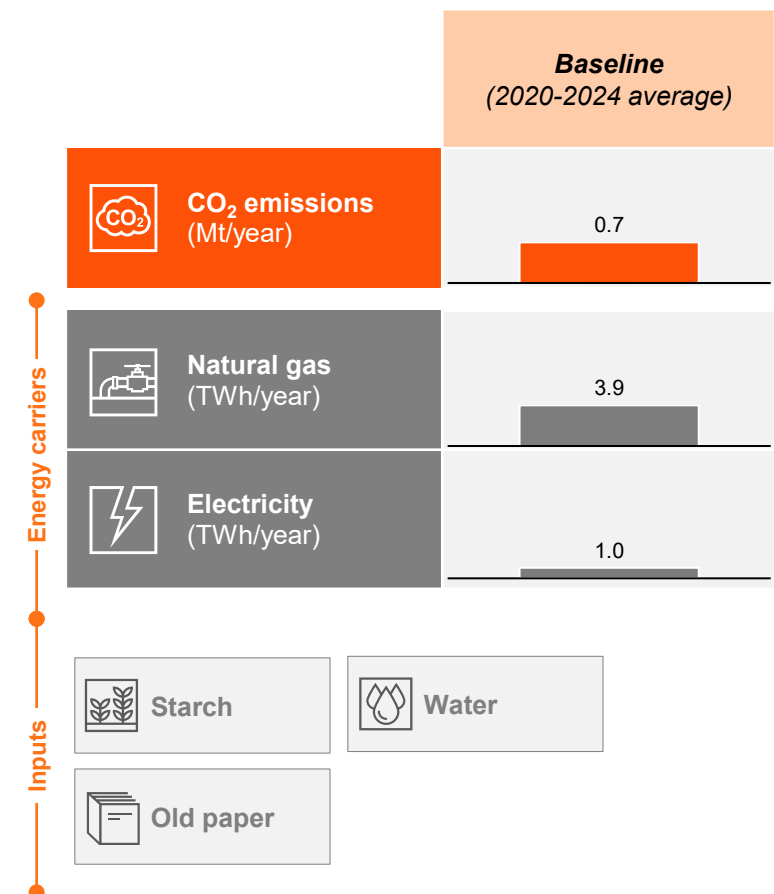
Sector overview

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 CO₂ - 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

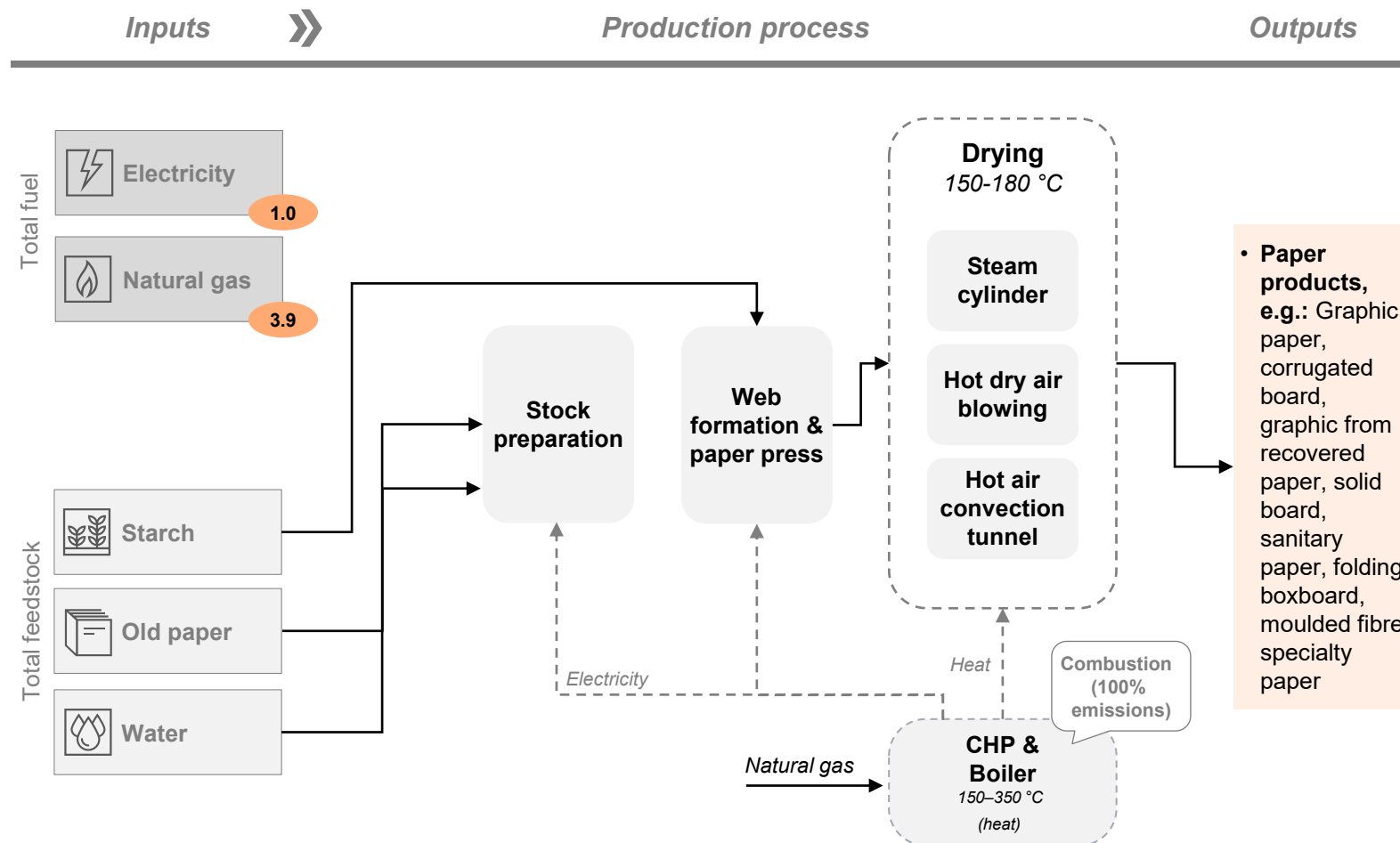


Energy profile



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

Paper – Process overview



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 CO₂ emissions in papermaking

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	

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

Paper – Abatement options (1/4)

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 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 (CH₄ content, pressure, contaminants) affect boiler performance and require continuous monitoring
	Hybrid e-boiler + blue H₂ 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

Heat pumps can abate a share of CHP emissions (45%); fuel substitution with blue H₂ can be used to fully abate the CHP

Paper – Abatement options (2/4)

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 75% of total direct CO ₂ emissions ~0.5 Mt CO ₂ /year	Blue H₂ 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

For natural gas boilers, the process can be fully abated via fuel substitution with biomethane or H₂; electrification (e-boiler) is still under development

Paper – 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	
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 H₂ 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

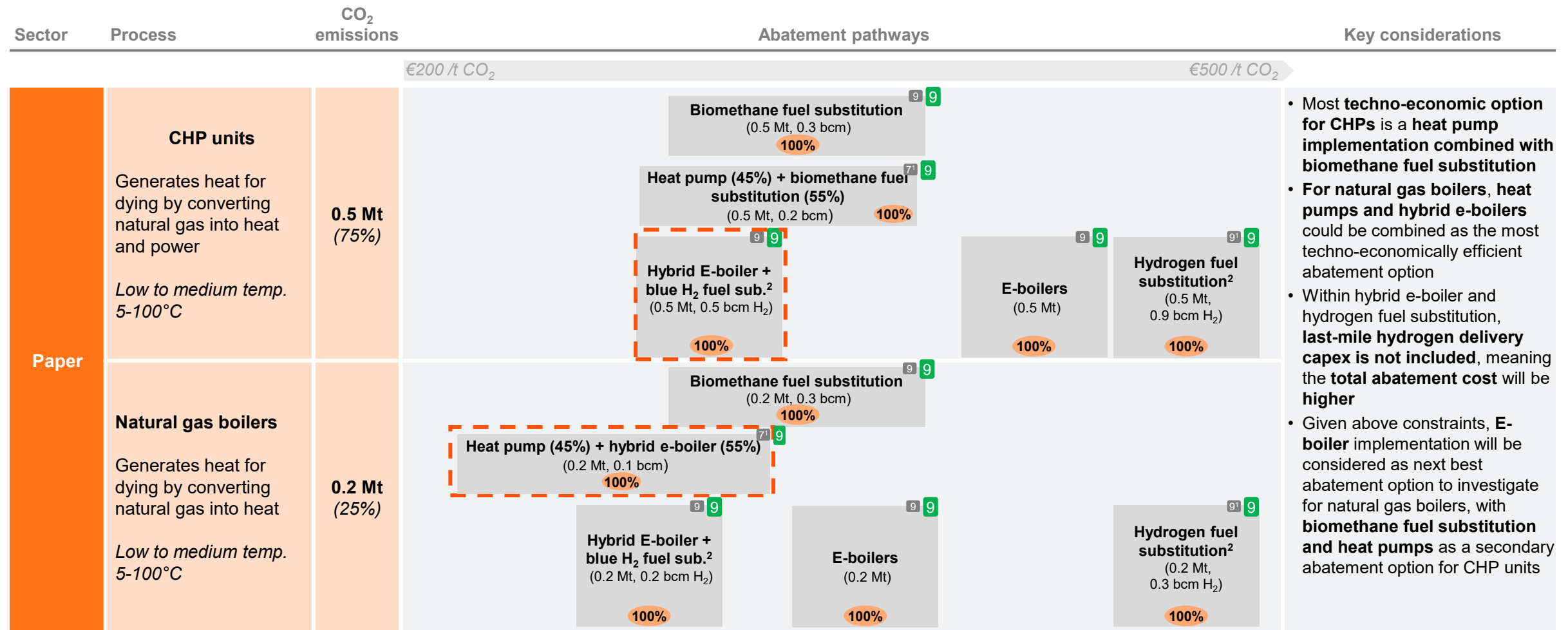
Partial decarbonisation of natural gas boilers is achievable through heat pumps (~45%), full abatement possible via hybrid e-boiler with H₂ fuel substitution

Paper – 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	
Natural gas boiler 26% of total direct CO ₂ emissions ~0.2 Mt CO ₂ /year	Hybrid e-boiler + blue H₂ 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

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





A4

Sensitivity analysis

Sensitivity analysis: CCS-driven abatement remains robust to input commodity price variations; electricity, biomethane and blue H₂ 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
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
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
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
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	24.6 TWh

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

 Price down
 Price up
 Volume (bcm)

Thank you

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