Decarbonisation Technology

February 2025

Powering the Transition to Sustainable Fuels & Energy

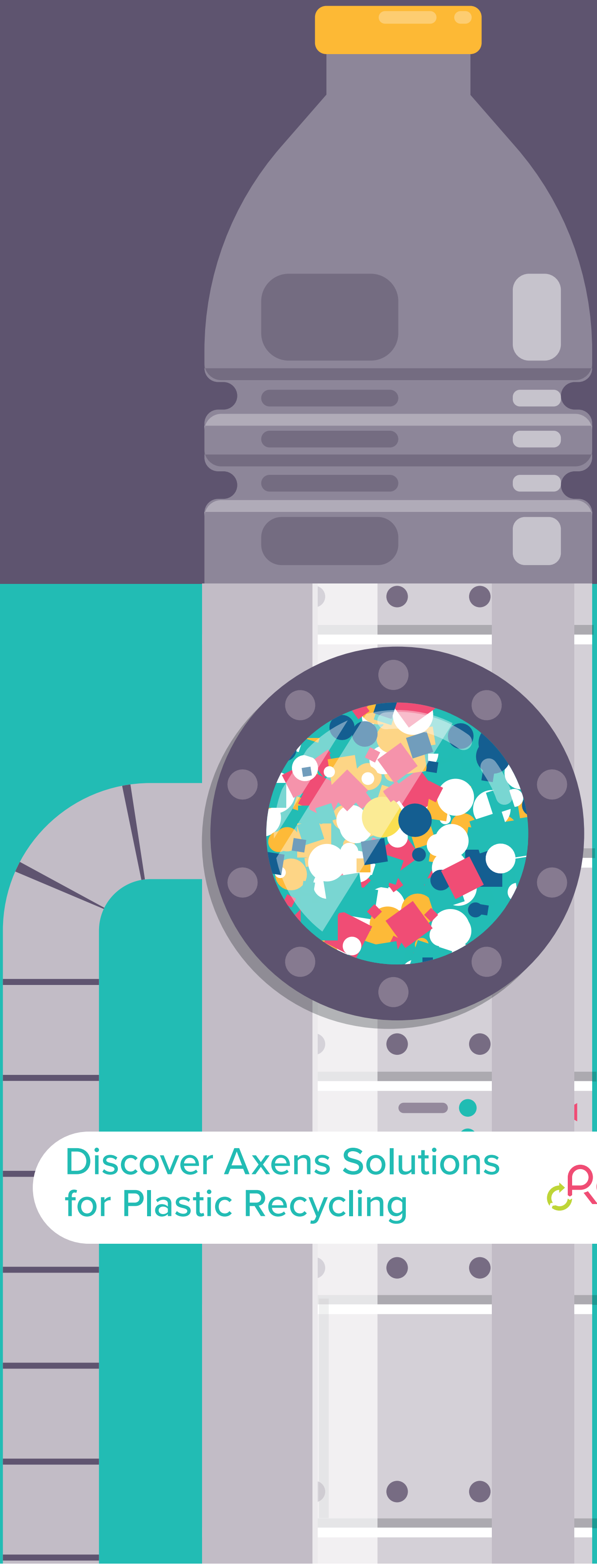
CO_2 MANAGEMENT AND LOW-CARBON HYDROGEN

CARBON NEUTRALITY

OUTLOOK FOR 2025

SAF: POTENTIAL OF DIVERSE FEEDSTOCKS

More than **Waste**



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Contents

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Cover Story
Parkland's Burnaby Refinery
Courtesy: *Parkland*

The International Meteorological Office has confirmed 2024 as the warmest year on record. It also noted that 2024 was the first year when the annual global average approached 1.5°C. This followed a run of increasing temperatures over the last decade. The human and economic cost of climate change continued to mount in 2024, with floods in South and Southeast Asia, China, and Europe and, most recently in 2025, the wildfires in Los Angeles.

Even given a sense of urgency, it will take decades to achieve the scale necessary to transition to a lower carbon energy system with a measurable reduction in global emissions.

An ongoing focus on energy efficiency during production processes will continue to reduce the emissions per unit of product or fuel. In the longer term, design initiatives to improve energy efficiency are expected to reduce the consumption of fuels and consequential emissions from aviation and shipping.

Actions to reduce methane from coal, oil, and gas operations are the most expedient ways to reduce overall emissions in the near term. In this regard, it is heartening that methane emissions have fallen in some countries, and the International Energy Agency (IEA) believes these can be reduced by 50% by 2030. Much of this can be done through wider deployment of known and existing technologies, as demonstrated by the best-performing countries and companies.

Extending the use of recycled materials in energy-intensive industries such as concrete, steel, and aluminium production offers economically attractive opportunities for near-term reductions in energy use and overall emissions. However, forecast growth in global demand for these materials will only be met by increased extraction and production. Installing carbon capture technology to capture the carbon from industrial flues offers a medium-term opportunity to reduce emissions from these energy-intensive industries on a meaningful scale.

The IEA global hydrogen review for 2024 reports that low-emission hydrogen capacity (both electrolysis and fossil fuels with CCS) is currently only 1% of total hydrogen production at 97 Mt. Should all announced projects proceed, an additional 49 Mt of low-emission hydrogen capacity could be added by 2030.

In 2024, the European Emissions Trading System (ETS) came into effect for ships trading in the EU, followed at the start of 2025 by the FuelEU maritime regulation. Bunker suppliers for shipping in the EU are now required to provide documentation to show the fuels meet the EU greenhouse gas (GHG) intensity standards. However, a challenging market for biofuels led to the introduction of anti-dumping measures in the EU, but not before several projects to build domestic capacity were cancelled in 2024.

There is a need to develop robust certification systems for all forms of renewable energy, hydrogen, low-carbon fuels, chemicals, and materials. The emergence of globally aligned certification systems is vital to reduce the risk of fraud and, just as importantly, to provide assurance throughout the supply chain.

Dr Robin Nelson

Key things to watch in 2025

A review of the oil, refining, chemicals, and liquid renewables industries in 2024, highlighting the key things to monitor this year

Alan Gelder
Wood Mackenzie

Introduction

The year 2024 marked a significant election period, with more than half of the world's population involved in the democratic process. In many countries, the incumbents remained in power but with reduced mandates. Populism prevailed in some form. The run-up to the US election was particularly long, with the victory by former President Trump and the clean sweep by the Republican party offering the potential of 2025 being very different from 2024.

2024 had many events that impacted global energy markets, with the Houthi rebels attacking maritime traffic around the Red Sea, disrupting shipping, and an escalation of the Israel/Hamas conflict. The conflict in the Middle East widened as Israel confronted Hezbollah in Lebanon and exchanged missile attacks with Iran. The Russia/Ukraine conflict ground on, with no significant breakthrough by either side.

2024 in review

❶ Oil market

Global oil demand reached a new high in 2024, but the oil market has been plagued by concerns that demand was weaker than projected with a focus on potential over-supply, as OPEC+ withheld significant supplies throughout the year. Plans for OPEC+ to increase supply through the easing of voluntary cuts were delayed, as oil prices weakened during the year, particularly in the second half of 2024. Oil prices, however, spiked upwards in moderate surges during periods of high geopolitical tension, such as when Israel was threatening to attack Iran's energy infrastructure. Oil prices fell quickly when tensions eased due to the ample spare capacity.

For 2024, oil demand growth has surpassed the increase in supply, with only a small gain in non-OPEC production for the year. That will change in 2025 when non-OPEC growth is equal to the projected increase in demand, which is another factor that weighed on oil prices late in 2024.

The concerns about demand centre on the forecasts for 2024 oil demand growth published by the Organization of the Petroleum Exporting Countries (OPEC) and the International Energy Agency (IEA), which have been unusually divergent, adding to the sense of confusion. Both organisations (and Wood Mackenzie) have been revising their demand growth projections downward as the year progressed. US inflation remained high, slowing the pace at which the US Federal Reserve could cut interest rates, delaying the shift to increased industrial production. China's economy started 2024 reasonably strongly but weakened as the year progressed, with a weak housing market depressing a key sector in the Chinese economy. Europe continued to struggle with high energy costs, weak competitiveness, and low investment levels.

Despite these woes, oil prices did not collapse and only briefly flirted at levels below $70/bbl.

❷ Refining

Refining margins were back to five-year average levels at the end of 2023. The global composite margin reset to (or just below) the five-year average, as shown in **Figure 1**. For Europe, the regional reference margin is at pre-pandemic levels. This was despite the disruptions of the Russia/Ukraine conflict and the Red Sea, both of which make global inter-regional trade less efficient and more costly, which would support refining margins.

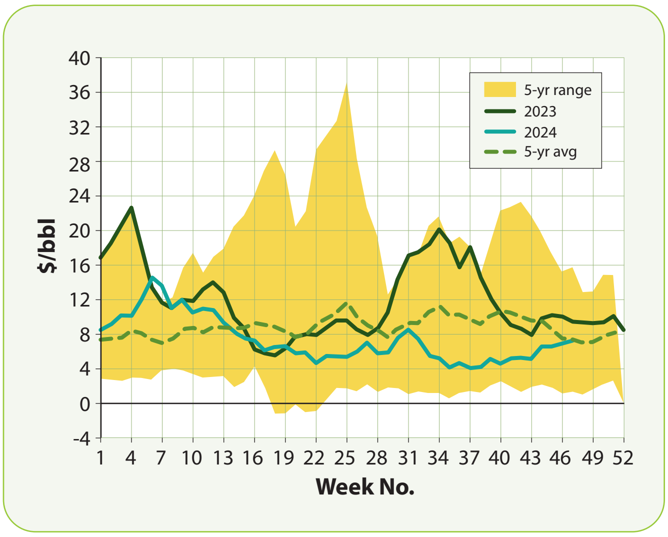

Figure 1 Weekly five-year range gross refining margin ($/bbl)

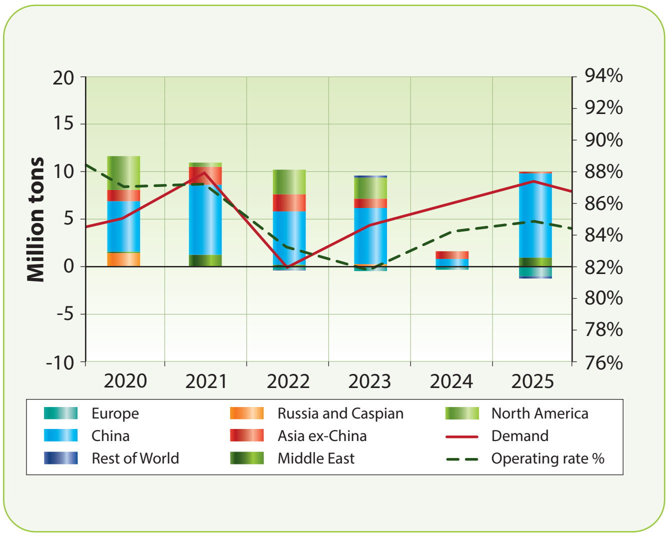

Figure 2 Global ethylene annual capacity change vs demand change

Refining margins returned to traditional norms, with competitively weak sites in both Europe and Asia suffering economic run cuts due to the low-margin environment.

These lower refining margins reflect several factors, with the key drivers being refinery capacity additions outpacing demand growth and several Very Large Crude Carriers (VLCCs) being cleaned and used to transport diesel/gasoil from the Middle East to Europe. This helped offset the impact of higher freight costs from vessels diverting around southern Africa. Refineries are complex to commission; however, facilities such as Dangote in Nigeria were successfully commissioned during the year, lowering the imports of gasoline to West Africa.

❸ Liquid renewables

The year 2024 was challenging for the economics of liquid renewables. Using US Renewable Volume Obligation (RVO) credit prices as a proxy for the health of the sector, the 2024 annual average price collapsed to just more than 50% of 2023 levels as the supply of renewable liquids grew strongly. This over-supply reflected a surge in capacity that was commissioned during 2024. Given that liquid renewables are predominately supplied as a blend component to road fuels, the combined 230,000 b/d decline in demand for diesel/gasoil across OECD Europe and the US, due to weak industrial production, exacerbated the supply overhang. This led to the harsh reality of numerous projects being cancelled, the most notable being Shell pausing its world-scale project in Rotterdam – a facility that was already under construction.

Liquid renewables are more expensive to produce than fossil fuels, so their growing adoption requires sustained and stable regulatory and policy support. Sweden provided a stark example of the risks of relying upon policy as the key pillar for an investment. Sweden's regulation focuses on greenhouse gas reductions, and for diesel, its target percentage reduction has been tightening from 21% in 2020 to 30.5% in 2023. However, this dropped to 6% in 2024 due to the high retail cost of diesel and its contribution to the cost-of-living crisis felt by the Swedish electorate. Sweden's diesel can now be largely delivered by blending with FAME, so there has been a marked drop in the need for renewable diesel, further weakening the economics of renewable diesel production in Europe.

❹ Commodity chemicals

The global olefins market continued its expansion in 2024, but the year marked a low point for ethylene capacity investments, as shown in **Figure 2**. Only 1.3 million tonnes per annum (Mtpa) of capacity was added in Asia, well below the 2020-2025 average of 8.7 Mtpa. In contrast, propylene capacity growth continued, primarily driven by propylene dehydrogenation (PDH) unit additions in China. PDH investments are expected to peak in 2024, reflecting poor margins.

Rationalisation efforts progressed in Europe and Asia, driven by overcapacity and sluggish demand growth. While European crackers maintained positive margins on average in 2024, significant closures have been announced for facilities in France, Italy, and the Netherlands. More closures are anticipated, given Europe's high production cost and weak industrial activity. In China, Sinopec and PetroChina outlined plans to phase out smaller, uncompetitive crackers between 2025 and 2026.

Asia's ethylene margins were negative due to overcapacity and weak economic growth. Conversely, US ethane crackers thrived based on their strong feedstock advantage.

In 2024, the polyethylene market faced rapid capacity expansion, shipping volatility, geopolitical tensions, rising trade barriers, and weak margins. Several facilities in Europe and Asia permanently closed due to declining demand for virgin polyethylene, stricter regulations, and unfavourable margins. Operating rates, especially in Asia, were pressured by fluctuating upstream prices and margin constraints. However, major capacity expansions, such as Sinopec's 1.2 Mtpa polyethylene plant in China and Reliance's 1.5 Mtpa polyethylene unit in India, helped alleviate local supply shortages.

Since 2022, aromatics pricing has been impacted by above-average octane values. The first half of 2024 continued to see aromatics pricing supported by the elevated alternative value in the gasoline pool. However, as forecasted, this pressure significantly reduced at the end of the 2024 driving season.

Freight disruptions have not been enough to avoid a persistent import substitution of aromatics derivatives in Europe and the Americas. China's capacity additions pressured margins globally. China has also structurally transitioned into an exporter of the largest benzene derivative – styrene. Aggressive pricing strategies have enabled Chinese producers of derivatives, such as purified terephthalic acid (PTA), to put pressure on their counterparts around the world. Europe has been the most impacted region, where rationalisation has been unavoidable.

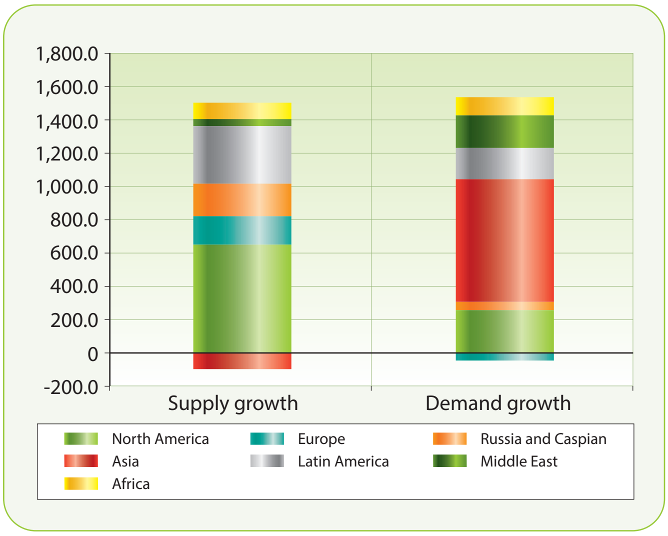

Figure 3 2025 global oil demand and non-OPEC supply growth

Key things to watch in 2025

❶ Oil market

Wood Mackenzie projects 2024 to be the low point of global GDP growth, with 2025 being stronger, the economy rebalancing to growth in both services and industrial production. Global oil demand growth is projected to increase to 1.2 million b/d for 2025, with oil demand growth across all regions except Europe. However, the challenge for OPEC+ remains, as shown in

> "Wood Mackenzie projects 2024 to be the low point of global GDP growth, with 2025 being stronger, the economy rebalancing to growth in both services and industrial production"

Figure 3, as global demand growth provides limited opportunity for OPEC+ to reduce their cuts without significantly weakening the oil price.

Wood Mackenzie's current Brent oil price projection for 2025 is in the mid-to-low $70s range. Besides the typical risks to the oil price around global GDP growth, geopolitical events and conflict, the recent re-election of President Trump could present a material downside risk to the oil price. The imposition of tariffs on all US imports would dent global economic growth, add inflationary pressure to the US consumer, and slow oil demand growth, which could

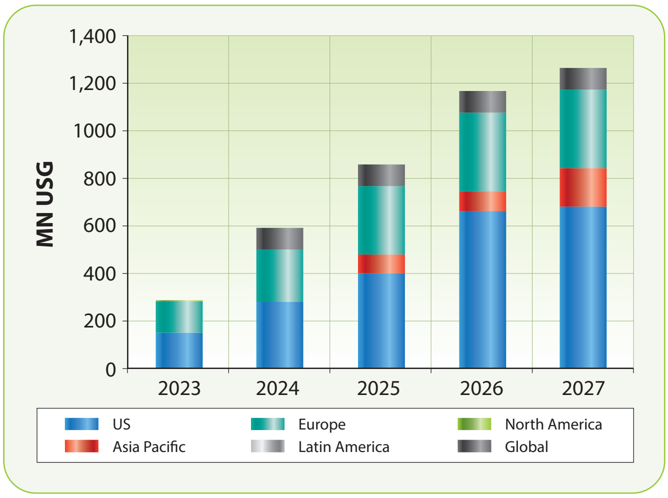

Figure 4 SAF expected demand from all offtake agreements by region

depress oil prices by around $5-7/bbl in 2025, with further declines likely thereafter.

❷ Refining

The CDU capacity investment wave witnessed in 2024 eases after Q1 2025, with crude distillation capacity effectively flat after Q1 as announced closures (Petrolneos at Grangemouth and LyondellBasell in Houston) and re-configurations (such as Shell at Rhineland) take place. Global refinery utilisation remains broadly flat as refinery projects commissioned in 2024 reach full commercial operations.

Refining margins are projected to remain at current levels through 2025. Oil demand growth can be met by the additional capacity that has become operational during 2024. The slow return of OPEC+ volumes should enable VLCCs to remain in distillate service for some time, keeping downward pressure on freight rates and limiting the upside to refining margins.

The potential imposition of US import tariffs provides an upside to US refining margins, given the support this will provide to US ex-refinery gate prices on gasoline, which is still imported in significant volumes into the US Atlantic Coast. Higher US crude runs represent a downward risk to refiners elsewhere, which, when combined with weaker global oil demand growth, could lower global composite gross refining margins for 2025 from ~$5/bbl by $2.5/bbl.

❸ Liquid renewables

The outlook for liquid renewables in 2025 is positive, as our outlook for stronger economic growth and a re-balancing of the economy has diesel/gasoil as the highest-demand growth fuel in 2025. Higher demand requires a greater volume of liquid renewable blending.

There are also two key policy support elements – the first is California's revisions to its Low Carbon Fuels Standard (LCFS). The low LCFS credit price seen over the past two years reflects an oversupply of low carbon intensity fuels, which has prompted the regulator to accelerate its carbon intensity reduction targets to capture the faster progress. The carbon intensity reduction target for 2025 has been increased by 9%, with the 2030 target raised from 20% to 30%. This will tighten the credit market in 2025 and subsequent years. The second mechanism is the European Union's requirement that aviation fuel contain a 2% minimum share of sustainable aviation fuel (SAF) by volume in 2025. As shown in **Figure 4**, this provides a material uplift to the demand for SAF, which will improve the economics of renewable liquid supply during 2025 and beyond. The EU's requirement for greater use of renewable and low-carbon fuels in the maritime sector also adds support to the demand for liquid renewables.

Besides the broader risks of tariffs and trade, the key risks to the outlook for liquid renewables are, again, policy-related. Firstly, policy can be volatile, with Sweden providing an example, as in August 2024, it increased the blending obligation to 10% from July 2025 onwards. Secondly, there is the risk that the small refiner exemption returns under the Trump presidency. This policy exemption eliminated the obligation for refiners under 75,000 b/d of crude input to blend the minimum volumes of renewable fuels into their products.

❹ Commodity chemicals

In 2025, global ethylene capacity is poised to resume its growth, with 8.8 Mtpa of new capacity coming online, the majority of which will be contributed by China. However, China's investment in PDH facilities is expected to slow, which could help ease the long-term oversupply in the propylene market.

Olefin margins are expected to remain under pressure in 2025. While stronger GDP growth is forecast for 2025, it will be challenging

Refining margins are projected to remain at current levels through 2025

for demand growth to absorb the far greater increase in supply. Steam cracker margins are not expected to recover until after 2027 when capacity additions begin to taper off.

Adding to the challenges, the potential imposition of a hefty import tariff – up to 60% – on Chinese goods by the Trump administration could significantly disrupt China's plastic exports. Such a measure would further strain demand growth, exacerbating pressure on the already oversupplied market.

In 2025, the global polyolefins market will face a complex mix of opportunities and challenges. Capacity expansions, particularly in Asia and the Middle East, will continue to meet demand across industries, namely those associated with industrialisation. Global utilisation is on a downward trend. Meanwhile, sustainability efforts will intensify, with companies investing in recycling technologies and circular economy initiatives. These factors, coupled with rising production costs, will drive a market that is both volatile and growth-oriented, with innovation and strategic capacity expansions helping to stabilise supply.

Octane levels are expected to remain close to levels seen in the second half of 2024. With the gasoline market lengthening in the Atlantic basin, polyester production will become the main factor dictating paraxylene (PX) margins. Benzene-naphtha spreads are projected to decrease starting in 2025 as the growth in supply gradually surpasses the growth in consumption.

China's capacities will continue to add pressure to global markets despite export-oriented Chinese players facing tougher conditions in 2025. Overcapacity in China and highly integrated chemical production will be key to its industry competitiveness in 2025. Trump's return to the White House and the increasing number of Anti-Dumping Duties applied to Chinese-origin products will be key to changes in global trade.

Operating rates are expected to continue recovering across the polyester value chain, while global styrene operating rates will start bottoming in 2025. However, rationalisation risk remains, especially in certain parts of Europe chains.

Conclusions

All parts of the extended oil value chain (from oil markets to aromatics and polyolefins) enter 2025 with ample spare capacity, making demand growth crucial to the commercial performance of the individual sectors.

Geopolitics and trade tariffs are critical uncertainties that need to be closely monitored, as these could play a key role in defining the winners and losers. Policy is a key risk for the viability of liquid renewables.

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Carbon neutrality as an opportunity for value creation

While challenges such as early-stage adoption and cost barriers persist, carbon neutrality efforts also provide clear opportunities for growth and resilience

Fred van Beuningen
Chrysalix Venture Capital

Additional headwinds are expected to be forthcoming in the global fight against climate change and the broader sustainability objectives of companies, notably in anticipation of the new US administration. We anticipate:

- **US withdrawal from the Paris Agreement**: Rejoining the global climate deal was one of the Biden administration's first executive orders, so it would be symbolic for the Trump administration to reverse this decision immediately. The Paris Agreement's three-year exit period is another factor to motivate an early announcement of the US withdrawal from participation (*UNFCCC, 2015*). Such instability in government policy is clearly not conducive to a positive investment environment.

> "Investors increasingly prioritise companies with robust decarbonisation strategies, recognising that addressing climate risks is essential for long-term business resilience and growth"

- **US scrapping of non-business-oriented climate funding**: A full repeal of the Inflation Reduction Act is unlikely, as it would hurt business interests in Republican states and is ultimately in the control of Congress. In the short term, defunding of other climate policies (such as funding for agencies and research projects) under the Trump administration is more likely.

However, despite such setbacks, carbon neutrality still represents a significant opportunity for creating strategic value.

Greenwashing was possible for some time, but with climate risks becoming increasingly apparent, fiduciary duty forces investors and industrial companies to be real and factual about climate risks to their portfolios and supply chains.

Investors increasingly prioritise companies with robust decarbonisation strategies, recognising that addressing climate risks is essential for long-term business resilience and growth. To achieve carbon neutrality, companies focus on value creation strategies such as asset decarbonisation, leveraging green premiums, developing new growth platforms, managing risks from supply chain vulnerabilities and carbon pricing, and shifting portfolios.

Tight timelines add to this urgency: achieving net-zero targets by 2050 requires a rapid transition to carbon-negative operations by 2030. However, a significant percentage of the technologies needed to meet these goals are still in early adoption or pre-commercial stages. Technologies like green hydrogen are currently too expensive, and carbon capture and utilisation (CCU) has not yet reached commercial scalability. Addressing these gaps requires early-stage investment, which is critical for developing scalable solutions.

To achieve its climate targets, the EU will require additional annual investments of about 2% of gross domestic product (GDP) between 2025 and 2030, comparable to the EU's R&D spending in 2022, which was estimated at 2.2% of GDP (*Eurostat, 2024*). With the European Green Deal, the EU has positioned itself as the global frontrunner in climate policy. Given the

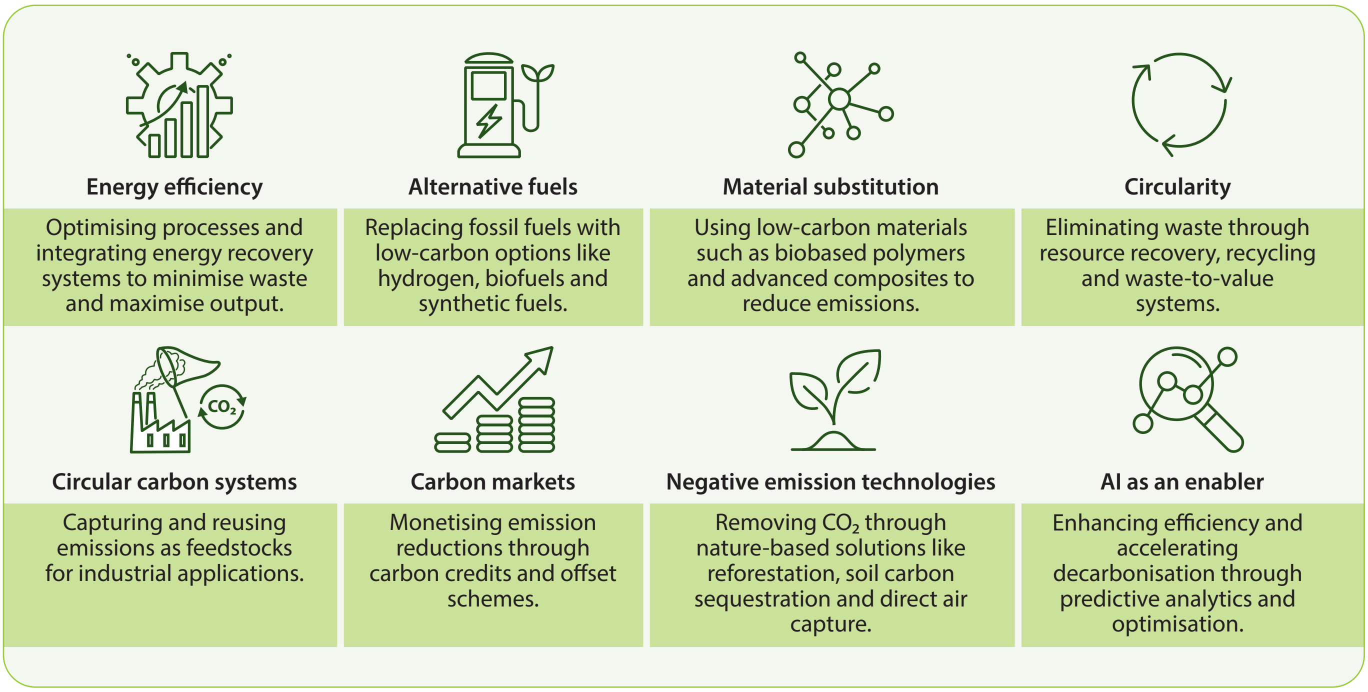

Figure 1 Key carbon neutrality levers and technologies

political economy of global climate action and the likely withdrawal of the US from the Paris Agreement, the success of the European Green Deal is vital for global decarbonisation to stand a chance. From this global perspective, it should be recalled that the cost of climate action is far lower than the cost of inaction.

How companies achieve their net-zero targets

Reaching net-zero goals requires a clear, strategic approach that combines different solutions:

- Deep decarbonisation by reducing emissions through technology and operational efficiencies.
- Carbon removal, both within and beyond the value chain, to address emissions that cannot be eliminated.
- Compensation through offsetting, which ensures residual emissions are balanced.

Success depends on aligning financial resources with these strategies. Companies with lower capital may start with efficiency improvements, while those with more resources can invest in advanced technologies or explore new business opportunities. Businesses that approach carbon neutrality as a chance to grow and innovate rather than as a cost can meet their goals while creating long-term value.

Key carbon neutrality levers and technologies

Decarbonisation relies on a range of technologies that address emissions reduction and removal across industries (see **Figure 1**).

Energy efficiency is a foundational element in optimising industrial processes to reduce emissions. Transitioning to alternative fuels, such as renewable energy and biofuels, is equally critical. Substituting traditional materials with low-carbon alternatives further reduces embedded emissions.

Digital technologies, including AI and advanced analytics, are instrumental in optimising resource use and enhancing decision-making across value chains. By leveraging data-driven insights, businesses can identify inefficiencies, streamline processes, and scale climate tech solutions more effectively. The integration of digital tools into decarbonisation strategies represents a vital step in future-proofing industries for a sustainable economy.

> “We need to shift from viewing carbon neutrality as a cost to seeing it as an opportunity for value creation”

Circularity is essential

Circularity could deliver up to 45% of the global greenhouse gas (GHG) emissions reductions needed to achieve net-zero worldwide (*Ellen*

Construction and Demolition waste (CDW) comprises all waste produced by the construction and demolition of buildings and infrastructure as well as road planning and maintenance. CDW covers a variety of materials, including concrete and building rubble, and accounts for more than one-third of all waste generated in the EU. Following the introduction of the Waste Framework Directive in 2008, most countries in the EU have established practices for separation, recovery, and reuse of CDW waste, with the best achieving recycling rates of up to 90% (*European Commission, 2024*).

MacArthur Foundation, 2021) and up to 56% of the carbon reductions needed to achieve net zero in the EU (*McKinsey & Co, 2024*). By reusing materials and minimising waste, circular systems reduce dependency on virgin resources and align with decarbonisation goals. They also create operational efficiencies and new opportunities for growth. Beyond recycling, circularity involves redesigning systems to eliminate waste entirely. Secondary raw materials can replace primary inputs, significantly lowering emissions. Negative emission technologies, such as nature-based solutions and carbon capture, further address emissions that cannot otherwise be avoided.

Circular concrete

Every year, the world produces 4.1 billion tonnes of cement, which accounts for 8% of global CO_2 emissions. At the same time, 3 billion tonnes of concrete waste is downcycled or discarded each year. Previously, no scalable or affordable technology existed to process waste concrete beyond downcycling, in which the material is downgraded or reused in lower-value applications like roadbeds. Globally, much of the discarded waste concrete rubble continues to be sent to landfill.

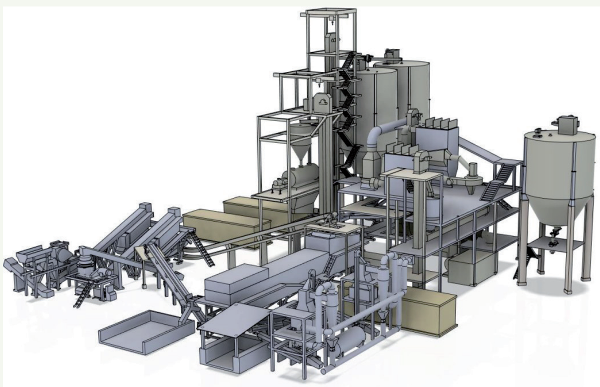

Figure 2 C2CA system for turning waste concrete into high-quality materials

Based in the Netherlands, C2CA (concrete to cement and aggregates) has developed an industrial-scale solution that transforms waste concrete into high-quality aggregates and sand, which are valuable raw materials for construction (see **Figure 2**). This circular approach facilitates concrete-to-concrete recycling, eliminating the need for virgin materials and reducing the amount of concrete rubble going to landfill as well as carbon emissions.

The recycling process begins with density-based separation to remove contaminants and extract reusable aggregates. This is followed by a thermal separation stage to refine the materials further. Finally, advanced quality control and tracing technologies, such as laser-induced breakdown spectroscopy (LIBS) and radio frequency identification (RFID), are used to guarantee material consistency and traceability, ensuring it meets industry quality standards.

By 2023, C2CA demonstrated its ability to scale this process, processing more than 1,000 tons of waste annually. The resulting materials, including coarse aggregates, fine aggregates, and ultra fines, are then used to produce new concrete, supporting a closed-loop system. This innovation not only reduces reliance on virgin resources but also provides a practical pathway to integrate circularity into the construction sector, significantly lowering its environmental impact.

Circularity in the metals sector

Steel is the most widely used metal, followed by aluminum. Both materials are readily recycled, with 90% steel and 37% aluminium reaching end-of-life now recycled in the EU. In their Net Zero Roadmap, the IEA requires the widespread adoption of innovations in both primary production and recycling of steel and aluminium to minimise emissions and meet growing demand (see **Table 1**).

There is scope to improve the environmental efficiency and cost of recovery and recycling processes. Companies like Sortera Technologies and Therm Ohm are taking the lead in implementing circularity in the metals sector. Sortera uses AI and sensor fusion technology to sort aluminum scrap by alloy and then recycle the scrap into high-value, low-carbon end products. Its high-throughput platform enhances resource recovery, ensures consistent material quality, and improves the efficiency of sorting processes in material-heavy industries.

Meanwhile, Therm Ohm has developed an innovative process to upcycle steel scrap by removing copper contamination. This breakthrough reduces feedstock costs, minimises DRI dilution, enhances the quality and value of electric arc furnace (EAF) steel production, and generates a sustainable copper byproduct. These efforts support circularity in metals production and contribute to decarbonisation goals.

Conclusion

Upcycling wood, metals, plastics, and concrete provides an important pathway to carbon neutrality. Materials are kept at their highest value and the energy used is from renewable sources. Venture investment in circularity offers a good opportunity, provided the fundamental economics are attractive and allow for rapid scale-up. The interplay between market drivers, economics, technology, and business models determines the viability of circular opportunities.

Circular carbon (CCU), also known as valorisation of CO_2, can be a future source of carbon for the production of chemicals, fuels, polymers, and materials. However, to meet current announced net-zero targets, global CCUS capacity needs to grow more than 100 times in the longer term, reaching 4-6 gigatons CO_2 by 2050 and decarbonising around 15 to 20% of today's energy-related emissions (McKinsey, 2024). Circular carbon is challenging because of cost and technology readiness, and some of the factors to watch out for are regulatory interventions, willingness to pay for lower carbon products, valorisation of CO_2 as a feedstock, and the development of the voluntary carbon removal markets.

	2022	2050
Steel		
Overall demand (Mt/a)	1,880	1,960
Share of recycled scrap metal	33%	48%
Share of net-zero iron production	0%	95%
Aluminium		
Overall demand (Mt/a)	108	146
Share of 2° production – recycled aluminium	36%	48%
Share of net-zero 1° production	0%	96%

Table 1 Required adoption of low-emissions primary production and recycling for steel and aluminium *Source: IEA, 2023*

Different industries have different carbon-neutral pathways. For the chemical industry, there are different sustainable carbon cycles, including using carbon from industrial processes and carbon derived from products that previously originated from fossil sources, as well as using carbon from plants (CEFIC, 2024).

"Achieving carbon neutrality requires a combination of enabling technologies, circular systems, and strategic investment"

Achieving carbon neutrality requires a combination of enabling technologies, circular systems, and strategic investment. While challenges such as early-stage adoption and cost barriers persist, carbon neutrality efforts also provide clear opportunities for growth and resilience. Businesses that act now to embrace climate tech and decarbonisation strategies will position themselves to succeed in the transition to a sustainable future and create new growth platforms.

VIEW REFERENCES

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Future focus: CO_2 management and hydrogen decarbonisation

Five years ago, the trajectory of hydrogen decarbonisation and CO_2 management was uncertain. There is still some time to act and plenty of good reasons to refocus

Stephen B Harrison
sbh4 Consulting

A fresh vision for fossil fuels

European and US debt is at an all-time high. Developing nations are struggling to feed their people and bring them basic healthcare provisions. The costs of war and plans for rising defence expenditure are eating into national budgets.

The notion that governments will be borrowing huge additional sums of money to pay for a net-zero future is unrealistic. We must accelerate progress with limited budgets, which means we should focus on achieving the best bang for our buck with hydrogen decarbonisation.

We must rethink the decarbonisation paradigm. 'Green' ideology and regulations suited for 2050, rather than 2025, have held back progress towards net zero for too long. It is not the 'greenest' projects that will proceed and receive infrastructure-scale investment; only the 'best' projects will be bankable. What does 'best' mean? To the bank, it means a clear business case with an acceptably low level of risk.

As we review carbon dioxide (CO_2) management and hydrogen decarbonisation mid-decade, it is abundantly clear that responsible use of fossil fuels is a reality that we must work with, not against, for many years to come. The use of fossil fuels with appropriate greenhouse gas (GHG) emissions mitigation is compatible with a net-zero vision. Fossil CO_2 and methane emissions to the atmosphere are the issue, not the use of fossil fuels per se. Let us attack the issues with razor-sharp precision, not get distracted by peripheral noise.

Sequester CO_2 that is already captured

When ammonia is made from steam methane reforming of natural gas, CO_2 leaving the

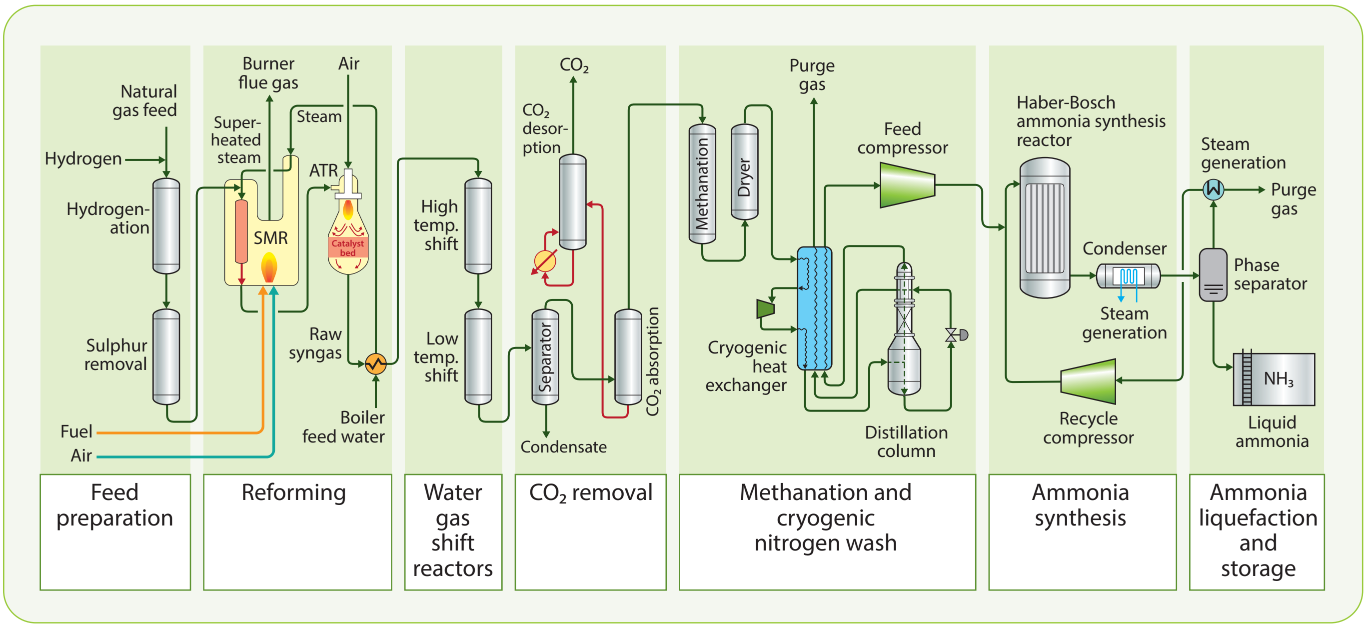
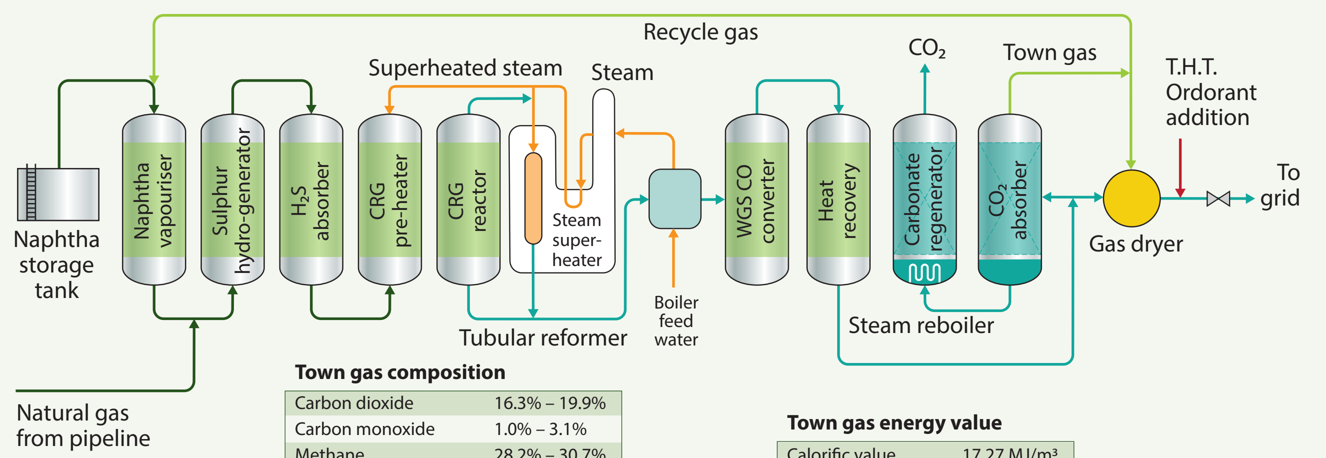


Figure 1 Air-fed ammonia production process



Town gas composition

Carbon dioxide	16.3% – 19.9%
Carbon monoxide	1.0% – 3.1%
Methane	28.2% – 30.7%
Hydrogen	46.3% – 51.8%
Nitrogen and oxygen	0% – 3.3%

Town gas energy value

Calorific value	17.27 MJ/m³
Specific gravity	0.52
Wobbe index	24

Figure 2 Hong Kong Town Gas – Tai Po catalytic rich gas naphtha/methane reformer and CO_2 capture process

reformer must be removed to enable the catalytic Haber-Bosch ammonia synthesis reaction to take place (see **Figure 1**). Every natural gas-fed ammonia plant already has a CO_2 capture facility. The Capex is spent, and the energy costs for CO_2 capture are committed. This CO_2 must be sequestered to reduce the CO_2 intensity of this ammonia. Large-scale projects for green hydrogen for ammonia production should not be prioritised until we have decarbonised existing natural gas-fed ammonia plants massively.

Coal-to-chemicals is another area of low-hanging fruit. Immediately after coal gasification, the raw syngas is fed to a Rectisol unit, where CO_2 and sulphurous gases are removed. At present, this CO_2 is blown to atmosphere, just like the CO_2 from ammonia production is vented on most ammonia plants today.

This captured CO_2 must be a priority for sequestration since the capital and operating costs of the Rectisol plant are absorbed into the overall costs of the coal-to-chemicals production. To reduce the CO_2 intensity of coal-to-chemicals, the only incremental costs are CO_2 transmission and sequestration.

In Hong Kong, Town Gas production already involves CO_2 capture to control the heating value of the product (see **Figure 2**). This CO_2 is vented to atmosphere. It should be sequestered.

Production of ethylene oxide on many petrochemical plants also requires CO_2 removal within the process to purge CO_2 (a byproduct of ethylene oxidation) from the process recycle. Also, natural gas processing removes CO_2 in midstream operations to ensure dry, acid-free gas enters the pipeline transmission infrastructure. These are tier 1 priorities for sequestration of captured CO_2.

Decarbonising refinery hydrogen

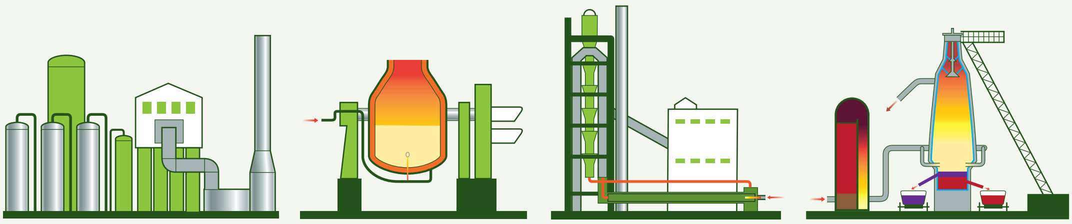
In many oil refineries, grey hydrogen produced from natural gas on steam methane reformers (SMRs) is used to produce marketable liquid fuels. The CO_2 from these SMRs is not captured at present. However, 60 to 70% of the CO_2 produced on the SMR is available at a very high partial pressure prior to the reformate gas mixture entering the hydrogen separation pressure swing adsorption (PSA) unit. The unit cost of CO_2 capture in this location is low.

New equipment and new energy would be required. But the incremental costs of capturing this CO_2 would be less than the incremental cost of implementing carbon capture and storage (CCS) to processes with more dilute CO_2 streams, such as power generation, cement, or steel making (see **Figure 3**).

Despite the ideal process conditions, there is not an overwhelming wave of SMR CO_2 capture projects being implemented because the business case is not strong enough. The costs of CO_2 emissions do not cover the costs of new equipment and the energy penalty.

CCS of CO_2 from SMRs would be 'good value for money' and help with the rapid decarbonisation of hydrogen production

Notes:
– CO_2 emissions are also associated with the energy and power requirements for this industry sector
– These can potentially be decarbonised with renewable power and electrical heating or microwaves
– CCS to capture CO_2 from the process and/or the associated energy production is possible



	Oil refining	Aluminium smelting	Cement making	Iron making
Application that releases CO_2	Hydrogen production from methane reforming for fuels desulphurisation	Reduction of alumina to aluminium using graphite electrodes	Reduction of limestone to calcium oxide	Reduction of iron ore to iron using coke
Chemical reaction producing CO_2	$CH_4 + H_2O \rightarrow CO + 3H_2$ $CO + H_2O \rightarrow CO_2 + H_2$	$2Al_2O_3 + 3C \rightarrow 4Al + 3CO_2$	$CaCO_3 \rightarrow CaO + CO_2$	$2Fe_2O_3 + 3C \rightarrow 4Fe + 3CO_2$ $Fe_2O_3 + 3CO \rightarrow 2Fe + 3CO_2$
Decarbonisation approach for CO_2 generated by the process	Use turquoise hydrogen or green hydrogen to avoid the reforming reaction; or feed the reformer with biomethane instead of natural gas	Use carbon from turquoise hydrogen production instead of carbon from fossil fuels to make the electrodes	Replace a portion of the limestone with alternative materials such as calcined clay to make clinker for cement	Use hydrogen instead of coke; or substitute coke with carbon from turquoise hydrogen production
Reactions for the decarbonised process	As above using renewable methane	As above using renewable graphite electrodes	Above reaction can only partially be avoided	As above using renewable carbon, or use hydrogen: $Fe_2O_3 + 3H_2 \rightarrow 2Fe + 3H_2O$
Other industries with similar applications	Ammonia, urea, methanol, gas-to-liquids	Gold and silver refining, electric arc furnace to melt scrap steel	– Lime making, as above – Refractory materials; $MgCO_3 \rightarrow MgO + CO_2$ – Glass making Na_2CO_3, $CaCO_3$, $MgCO_3$	None

Figure 3 Difficult-to-decarbonise industries – CO_2 is released from within the process

and refinery operations. Policymakers must recognise the benefits of hydrogen with any degree of reduced CO_2 intensity. The current criteria for 'blue' hydrogen are tight, and if a decarbonisation initiative does not get the 'blue' badge, the case is weak.

CO_2 intensity must be a sliding scale

The 'blue' hydrogen benchmark is relevant for new-build projects based on autothermal reformers (ATRs) or gas heated reformers (GHRs) with built-in CCS, but 2,000 SMRs operating today can be decarbonised with CO_2 capture equipment retrofits. This is 2025, and in many parts of the world, there has been significantly less progress towards declared net-zero targets than has been promised. 'More of the same' will not help us achieve 1.5°C and is unlikely to cap climate change at 2 or 3°C. We need high-impact action now – ideas that can rapidly and cost-effectively be deployed.

The costs and scalability of green, blue, or hydrogen of any degree of CO_2 intensity must be seen in the context of alternative industrial decarbonisation measures. The idea of a hydrogen project going for 'green, blue, or broke' has resulted in failed business cases and inhibited meaningful progress. CO_2 intensity is what matters. Every reduction in GHG emissions is beneficial.

Making a rapid impact means there is no room for the perfect to be the enemy of the good. We must accept that the next 30 years will be about rapid decarbonisation of existing infrastructure in addition to progressive development and deployment of ultra-clean technology. There must be support for GHG emissions reduction in all forms rather than CO_2 intensity thresholds, which indirectly promote some technologies above others.

Policy priorities for hydrogen and CO_2 management in the second half of this decade
Use the 'polluter pays' principle for GHG gas emissions with meaningful minimum costs (such as CO_2 €150 to €200 per tonne and others based on CO_2 equivalence). This will: ❶ Incentivise sequestration of CO_2 that is already captured from natural gas processing, ammonia and ethylene oxide production, and coal-to-chemicals. ❷ Incentivise capture of CO_2 from high partial-pressure process streams on SMRs. ❸ Eliminate the need for a threshold approach to CO_2 intensity with an arbitrary cut-off point for 'blue' hydrogen. The 'polluter pays' principle would, in effect, implement a sliding scale of embedded CO_2 and tax or incentivise based on that.
Broaden policy acceptance and viability of EOR and EGR as valid mechanisms for CO_2 sequestration.
Commit to building common CO_2 pipeline infrastructure to link fossil, geogenic, and biogenic CO_2 emitters with CO_2 storage/utilisation/removals locations.
Commit to building a colour-agnostic, common hydrogen pipeline infrastructure with underground hydrogen storage in salt or rock caverns.
Support projects that build the bankability of green hydrogen to allow a progressive ramp-up of green hydrogen as renewable power ramps up to support it.

Table 1

A fair assessment of CCS, EOR, and EGR

Despite some failures, disappointments, and poor reporting in certain carbon capture and geological storage (CCS) projects, there have also been many successes. The way to get better is to do more and learn faster. Enhanced oil recovery (EOR) and enhanced gas recovery (EGR) should also be seen as meaningful ways to store CO_2 in suitable geological formations.

Dismissal of EOR and EGR as valid CCS mechanisms due to concerns that they may increase fossil fuel production is not valid on a global scale. There is an abundance of crude oil and natural gas reserves in the Middle East and Russia; these nations will produce according to demand.

To say that EOR or EGR stimulate demand for fossil fuels is a flawed argument. Local production avoids the cost and environmental impact of fuels distribution. Extending the life of wells can increase economic efficiency. Policymakers must take a more supportive view of EOR and EGR as valid means of CO_2 sequestration. Also, when we consider the number of successful EOR schemes, underground geological storage of CO_2 has an overwhelmingly positive history.

Greenhouse gas emissions are the problem

Excessive CO_2 in the atmosphere is the problem now and will remain a risk for eternity. We must address the problem rather than favour one solution ahead of others. To do that is a risky guessing game that no policymaker can afford to make. In many areas, policy is no longer technology agnostic – it should return more closely to that principle.

Now more than ever, a focus on CO_2 emissions reduction and carbon dioxide removals (CDR), by whatever means, must be priorities. The costs of GHG emissions, whether they be CO_2, methane, F-gases, or others, must be paid by the polluter. Taxation of the polluter pays principle has driven the reduction of NOx and SOx emissions in several countries in northern Europe.

At present, CO_2 emissions are too cheap. The tax penalties or incentives for GHG emissions reduction are too weak. The cost of CO_2 emissions should be in the order of €150 to €200 per tonne (see **Table 1**). Methane, F-gases and nitrous oxide must be scaled in line with their CO_2 equivalence. Any concerns about unfair competition due to policies moving at different speeds around the world can be met with embedded CO_2 cross-border tax adjustments.

The EU ETS, US 45Q, and other 'carrot or stick' schemes around the world must set a cost to CO_2 emissions, ensuring there is a business case for decarbonisation investments. Even if there is a degree of GHG emissions cost fluctuation,

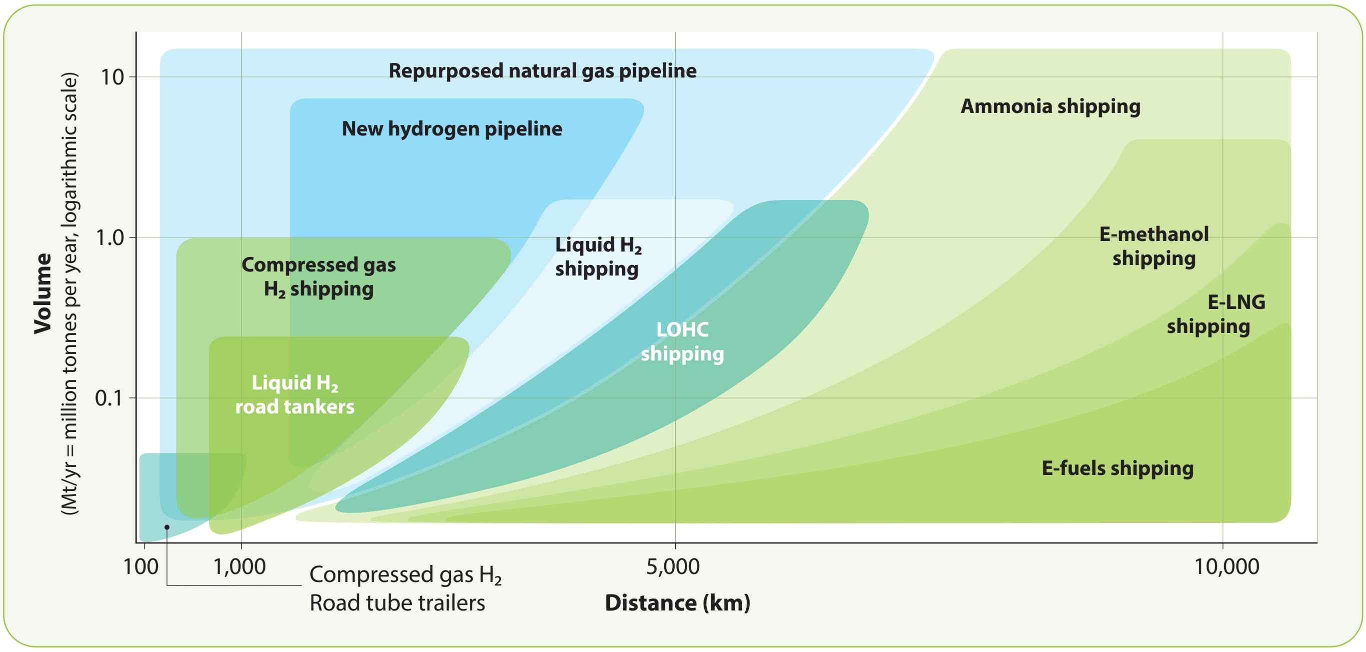


Figure 4 Hydrogen and hydrogen derivatives transport options when considering volume and distance

there must be a meaningful minimum to de-risk the business case. Higher avoided CO_2 emissions costs should be an upside rather than a risk multiplier and business case killer.

Common infrastructure for biogenic, geogenic, and fossil CO_2

The most important area for governmental focus in the second half of this decade must be a comprehensive pipeline network to link CO_2 emitters with CO_2 storage, utilisation, and removals projects (see Table 1**)**. Liquid CO_2 storage terminals will be required to allow aggregation and transportation modality transitions within the CO_2 logistics chain.

Western Europe is an ideal place to implement this concept. There is a dense industrial cluster and CO_2 storage potential in the North Sea. The Gulf Coast of the USA would have similarly high potential. In both locations, repurposing oil and gas pipelines could help offset some of the cost.

CO_2 entering and leaving the pipeline should be treated in the same way as biogas entering and leaving the gas transmission grid. Biogenic, geogenic, and fossil CO_2 must be allowed to mix and share the infrastructure. Metering and monitoring for mass balancing will be required as a key enabler. If this is not done, we will stimulate long-distance transportation of biogenic CO_2 for utilisation or CDR in parallel to fossil and geogenic CO_2 for geological storage. Allowing this parallel system to develop would be the most absurd waste of capital and resources.

Mass balancing and hydrogen purchase agreements

If we accept that hydrogen, produced by any means, will play a central role in future energy systems, pipeline infrastructure to move hydrogen around will also be an essential investment. Pipelines are, by far, the most economical way to move hydrogen short and medium distances over land. However, due to the long investment cycle and high capital requirement, there is no business case for this today, so a huge amount of belief and supporting capital from governmental bodies is required to get this underway (see **Figure 4**).

Low-cost, high-capacity underground hydrogen storage in salt and rock caverns must complement the pipeline network. It will enable seasonal supply and demand balances to be smoothed. It will also allow intermittent hydrogen production renewable power that would otherwise be curtailed, at exceptionally low cost.

As with the CO_2 pipeline, the hydrogen pipeline must operate in the same way the electricity grid carries green, grey, and pink electrons: the hydrogen pipeline must be colour agnostic. Hydrogen purchase agreements (HPAs), like renewable power purchase agreements, can be used to link green hydrogen producers with green hydrogen off-takers through a mass balance.

Development of common infrastructure is one of the most important roles that any government can play. The principles applied to build road networks, railway tracks, and electricity grids must be used to build pipelines. Planning CO_2 and hydrogen pipelines together will create synergies. Coordination is the key.

What it means to the private and public sectors

Pipeline and transmission infrastructure requires cross-border collaboration, rapid development of international pipeline and CO_2 purity standards, and massive investment in common infrastructure. It will also require regional peace and international security. There is ultra-important work to be done in many domains.

The role of governments must be to focus on effective and coherent policy development and common infrastructure enablement. The private sector, not governments, has the expertise and resources to excel in technology innovation, project finance, and project development.

Policy must focus on GHG gas emissions reductions as the problem. It must allow the solutions, such as renewable power generation, long-duration energy storage, hydrogen (of any colour), direct air capture, geological CO_2 storage, batteries, electrification of industrial processes, heat pumps, and energy efficiency, to evolve. Regulators must enable these solutions with permitting and must simultaneously remain broadly technology agnostic and avoid incentivising one solution ahead of another.

Nobody knew what trajectory hydrogen decarbonisation and CO_2 management would take five years ago. If we had, then policies and incentives would have been written differently. However, there is still some time to act and plenty of good reason to adjust and refocus in the second half of this decade. Policymakers must review this dynamic situation to set a clear direction in line with the latest facts, the best research, and likely technology deployment trajectories.

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Role of carbon-14 testing in advancing renewable fuels

Carbon-14 analysis offers actionable insights that drive regulatory compliance, enhance operational efficiency, and bolster economic benefits in the fuels industry

Haley Gershon **Beta Analytic**
Gary Lee **Parkland Refining**

In the dynamic landscape of renewable energy, carbon-14 analysis has emerged as a pivotal tool for verifying the biogenic content of biofuels and fuel gases. This methodology, central to the operations of international fuel distributor Parkland Refining, is helping the refinery lower its environmental impact. Parkland integrates renewable fuel sourcing, manufacturing, blending, carbon trading, and solar power into its strategies while promoting ultra-fast EV charging as part of its comprehensive sustainability goals.

This article focuses on the significance of carbon-14 analysis in improving internal refinery processes, ensuring regulatory compliance, boosting performance in the fuels industry, and overall providing a reliable means to verify the biogenic carbon content of biofuel blends and fuel gases.

> **"Understanding how renewable feedstocks contribute to fuel yields is vital, and carbon-14 testing removes ambiguities often associated with traditional mass balance methods"**

Understanding the importance of biogenic testing

Biogenic testing through ASTM D6866 carbon-14 analysis is reshaping the way the fuels industry assesses renewable content *(Beta Analytic, 2024)*. Carbon-14 analysis is used to determine the biomass-based (or biogenic content) vs fossil fraction of biofuels and other products. Since the carbon-14 isotope is only present in living or recently expired material, carbon-14 testing via accelerator mass spectrometry (AMS) is the most effective method to determine the amount of biogenic carbon vs petroleum-derived carbon in biofuel blends *(Beta Analytic, 2024)*.

According to the ASTM D6866-24 analytical standard, 'biogenic' is defined as containing carbon (both organic and inorganic) from renewable origins, such as agricultural, plant, animal, fungi, microorganisms, macro-organisms, marine, or forestry materials *(ASTM, 2025)*.

This methodology is able to indicate the percentage of biogenic carbon in a batch of gasoline, diesel, or sustainable aviation fuel, for example. By precisely determining the proportion of biogenic content, carbon-14 analysis supports industries in meeting regulatory requirements and fostering trust among regulators and consumers. For Parkland Refining, this verification is key to confidently marketing renewable fuels while ensuring compliance with low-carbon fuel standards (LCFS). Accurate biogenic testing also positions companies to align their products with the growing global demand for sustainability.

Enhancing refinery processes and performance

The application of carbon-14 analysis goes beyond compliance – it also plays a crucial role in optimising refinery operations to produce the most renewable fuel possible. Understanding how renewable feedstocks contribute to fuel yields is vital, and carbon-14 testing removes ambiguities often associated with traditional


The Burnaby Refinery has been part of the community since 1935

mass balance methods. Carbon-14 testing enables refineries to pinpoint the exact contribution of renewable materials, eliminating uncertainties and helping operators refine their processes more effectively and maximise renewable fuel production.

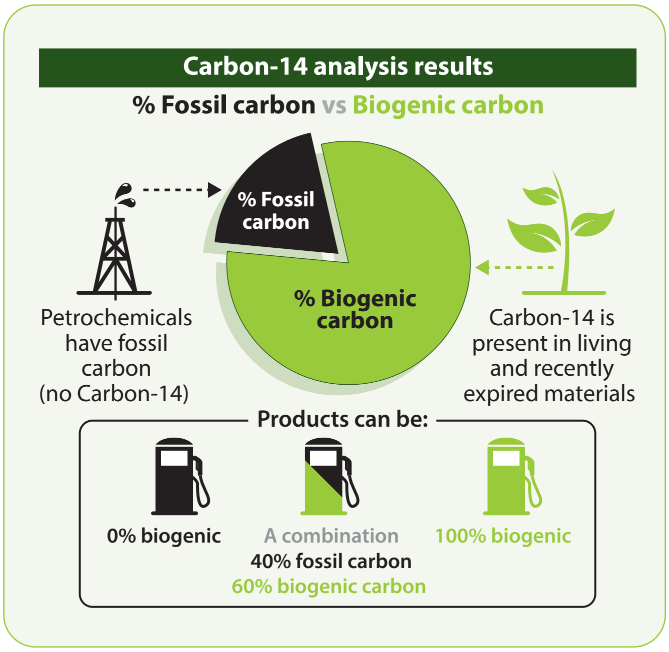
For example, using the carbon-14 method via AMS to measure biogenic content of barrels of renewable inputs such as canola oil, tallow, or used cooking oil allows refineries to identify the exact contribution of renewable materials to their outputs. This ensures that operational adjustments can be data-driven, improving productivity and reducing waste.

Navigating regulatory drivers

As the regulatory framework surrounding renewable fuels becomes more stringent, the need for biogenic testing is only expected to grow. In Canada, both the federal Clean Fuel Regulations (CFR) programme and British Columbia's LCFS mandate ASTM D6866 carbon-14 testing requirements under Method B (AMS) for biogenic analysis (*Gov. of Canada*, 2022) (*Gov. of Canada*, 2023), ensuring that producers can substantiate their renewable fuel credits. Under these regulations, producers must regularly measure and report the biogenic content of their fuels and co-processed products to qualify for credits.

Through the CFR, the Government of Canada aims to reduce pollution by 2030 by decreasing the carbon intensity (CI) of gasoline and diesel used in the country. The Canadian Ministry of Environment and Climate Change published a Quantification Method (QM) for co-processing in refineries under the CFR. The QM requires ASTM D6866 testing to measure the biogenic content of the co-processed feedstocks used and the low-CI fuels produced in registered projects (*Gov. of Canada*, 2022). Under the CFR, refineries like Parkland's have to submit monthly samples for carbon-14 testing on finished products and intermediates, for example, as part of credit accounting.

Under this programme, the government offers incentives for the development and adoption of clean fuels, technologies, and processes. For example, it establishes a credits market wherein producers and importers of gasoline and diesel must create or buy credits to comply with the reduction requirements. Extra credits can be sold or used in later years. Projects are required to measure the biogenic content of samples from each fuel, product, and hydrocarbon co-product via ASTM D6866 testing (*Gov. of Canada*, 2022). The biogenic content and CI of the co-processed low-CI fuel, co-processed low-CI product, and co-product produced for each fuel pathway must be determined.



Analysis reveals the percentage of fossil vs biogenic carbon content *Courtesy: Beta Analytic*

Furthermore, British Columbia's LCFS programme proposed an updated protocol in October 2023, adding ASTM D6866 testing for all co-processed fuels and co-products. Emissions reductions and corresponding credits are quantified based on the amount of co-processed low-CI fuels produced and their reduced lifecycle CI, using the biogenic content results obtained through ASTM D6866 testing (*Gov. of Canada*, 2023).

Technological precision: Comparing methodologies

Carbon-14 analysis is a well-established method that has been in use by many industries for several decades. Under ASTM D6866 Method B, carbon-14 measurements performed by commercial third-party laboratories are robust with accurate and precise results regarding the percentage of biogenic content.

Carbon-14 measurements under ASTM D6866 Method B represent a direct test method, whereas calculation-based approaches such as mass balance make claims based on material inputs in production (*ISCC*, 2024). For example, carbon-14 testing can provide verifiable data indicating that 5%, for example, is derived from renewable fuel (biogenic content), while the remaining portion is from other interactions in the refinery.

Calculation-based results lead producers to assume that all their biomass inputs end up in their facilities' outputs, despite the fact that the input of renewable feedstocks will often have different reactivity than their fossil counterparts and will not necessarily produce the same quantity of outputs. By basing calculations solely on production inputs rather than outputs, these methods can systematically over-report the renewable share of fuels.

Furthermore, ASTM-approved AMS Method B for carbon-14 analysis offers unparalleled precision compared to alternatives like Method C. Where ASTM D6866 Method B uses the AMS instrument to measure carbon-14, Method C uses liquid scintillation counting (LSC). In Method B, the AMS instrument directly measures the carbon-14 isotopes. However, in Method C, scintillation molecules indirectly absorb the beta molecules that release with the decay of carbon-14 and convert the energy into photons, which are measured proportionally to the amount of carbon-14 in the sample (*Baranyika, Piotrowski, Klusek, Michczynski, & Pawlyta*, 2022). In this case, since Method B directly measures the carbon-14 isotopes while Method C measures them indirectly, Method B is significantly more precise.

There are also limitations in the LSC technique due to the type of liquids that can be tested. While AMS is applicable to a larger range of products and is used to measure solid, liquid, or gaseous samples, clear or colourless liquids are the only sample types that can be measured accurately using the LSC method.

From a regulatory standpoint, under the CFR, ASTM D6866 Method B (AMS) or Method C (LSC) can be used. If using carbon-14 testing, the CFR AMS method requires monthly testing. However, the LSC method requires that the analysis be performed weekly. In terms of sampling and shipping samples for analysis, it is advantageous to conduct only monthly tests rather than weekly ones as they reduce operational burdens and costs while having an accurate method to rely on, which underscores the benefits of ASTM D6866 Method B.

Overall, compared to other test methods, the key advantage of carbon-14 analysis is that it is a standardised and direct measurement of any carbon-containing substance that produces highly accurate and precise values. In that

Parkland's Burnaby refinery is one of Canada's only remaining West Coast refineries

regard, it can stand alone as a quantitative indicator of the presence of biogenic vs petroleum feedstocks.

Economic benefits

From an economic standpoint, carbon-14 testing presents opportunities. The generation of renewable fuel credits, which can be monetised, incentivises producers to maximise their renewable fuel output. Accurate carbon-14 testing allows companies to optimise operations, which can translate into significant financial benefits.

Moreover, carbon-14 testing facilitates co-processing, where conventional and renewable feedstocks are blended. This method allows refineries to utilise existing infrastructure to transition to lower carbon intensity production without the high capital investments associated with building new facilities. The trust generated through reliable carbon-14 testing and accurate results reassures stakeholders that the biogenic content in fuel products is authentic, fostering a smoother transition to sustainable practices.

Path forward

As the renewable fuels sector evolves, biogenic testing is poised to play an even more critical role. Its uses are expanding to include additional applications, such as quantifying the biogenic carbon content of fuel gas and hydrocarbon gases (*Beta Analytic*, 2024). At Parkland Refining, carbon-14 testing has expanded beyond high-value products like gasoline and diesel to include propane and other fuel gases, ensuring the complete accountability of renewable feedstocks. Regulatory bodies across North America, the EU, and beyond increasingly require this analysis for hydrocarbon and fuel gases, underscoring its growing relevance.

Looking ahead, the integration of carbon capture technologies offers a complementary pathway to enhance sustainability. By capturing and repurposing CO_2 emissions from industrial processes, these technologies can work alongside carbon-14 testing to further lower the carbon intensity of fuels. Together, they represent a robust approach to decarbonising the energy sector and advancing the global transition to cleaner fuels.

In conclusion, carbon-14 analysis is at the forefront of the renewable fuel movement, offering actionable insights that drive regulatory compliance, enhance operational efficiency, and bolster economic benefits. As regulations evolve and technologies advance, this methodology will remain a cornerstone of sustainable energy strategies, paving the way for a cleaner, more sustainable future.

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Driving SAF production with feedstock diversity

Routes to producing SAF and the importance of having a diverse range of feedstocks to support the scale-up of this fuel for decarbonisation of the aviation sector

Paul Ticehurst
Johnson Matthey

As the aviation sector strives to reduce emissions, sustainable aviation fuel (SAF) has emerged as a key enabling solution (*IATA, 2024*). With global mandates and targets for SAF production increasing, relying on a single feedstock to make SAF is neither practical nor sustainable. Scaling up the industry requires a diversified feedstock approach and innovative technologies.

Hydroprocessed esters and fatty acids (HEFA), derived primarily from used cooking oil, have been a key focus for SAF production. Yet, the availability of HEFA feedstocks is limited, with 80% of HEFA feedstocks in the EU being imported (*Stratas Advisors, 2024*). As other regions establish their own domestic SAF targets, this dependency on imports creates risks to supply stability. Countries such as the US, the UK, and those in Europe, which have led the way with SAF mandates and incentives, must now diversify their feedstocks to ensure resilience and domestic production capabilities.

The Fischer-Tropsch (FT) process provides a scalable solution. This ASTM-approved technology converts syngas, a mixture of carbon monoxide (CO) and hydrogen (H_2), into hydrocarbons that can be upgraded into SAF. Syngas can be derived from a wide variety of feedstocks, including municipal solid waste (MSW), agricultural residues, forestry waste, and captured carbon dioxide (CO_2) combined with green hydrogen. By embracing the FT process, countries can expand their SAF production capabilities and reduce reliance on HEFA and feedstock imports. Companies like Johnson Matthey (JM) are leading advancements in syngas technology, helping SAF producers realise the benefits of feedstock diversity.

Global mandates and targets for SAF production are increasing

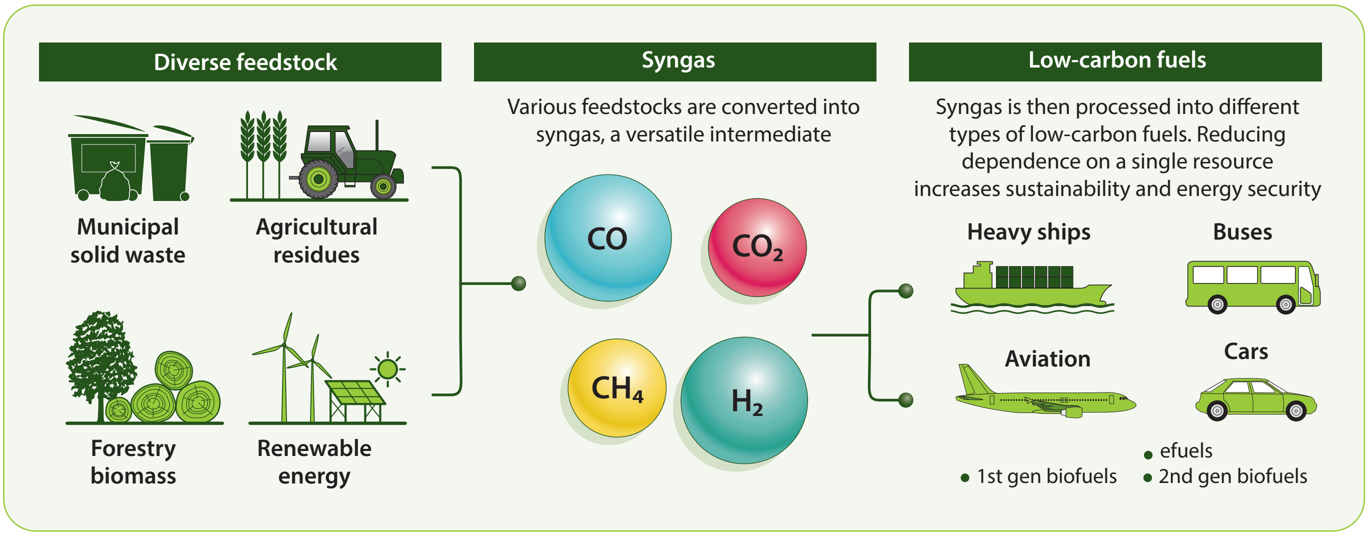

Figure 1 Process of producing sustainable aviation fuel

Fischer-Tropsch technology: Unlocking feedstock potential

The FT process is a transformative technology that enables SAF production from diverse feedstocks. The feedstocks below all qualify under the Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA):

- **Municipal solid waste (MSW):** Gasification of MSW not only provides syngas for SAF but can also reduce landfill use, addressing waste management challenges. JM's proprietary technology ensures syngas is cleaned and conditioned effectively.
- **Forestry residues:** Gasification of forestry waste utilises renewable resources and supports responsible forest management practices aimed at reducing wildfire risks (USDA, 2024).
- **Captured CO_2:** CO_2 emissions, combined with green hydrogen produced through renewable-powered electrolysis, can create syngas. JM's HyCOgen (reverse water gas shift) technology enables this process, promoting carbon reuse and climate change mitigation.
- **Agricultural residues:** Biomass such as corn stover, wheat straw, and rice husks can be converted into syngas, unlocking value from agricultural byproducts.

The SAF production process involves several stages: syngas production, FT catalysis using iron or cobalt-based catalysts, chemical reactions under controlled conditions (200-350°C and 10-40 bar) to form hydrocarbons, and upgrading through hydrocracking and distillation to produce SAF.

JM's FT CANS technology, developed in collaboration with bp, offers a step-change in the FT process. This superior catalyst and reactor design reduces catalyst requirements by 50%, lowering capital and operational costs. Its scalability allows plant sizes to be tailored to match available feedstocks, while advanced heat management improves reaction efficiency and product quality thanks to its innovative radial flow reactor design. The technology achieves CO conversion rates exceeding 90% (*Johnson Matthey, 2021*).

FT CANS technology has already been licensed to several large-scale projects. The Louisiana Green Fuels project will convert 1 million tonnes of forestry waste into 32 million gallons of biofuel annually while incorporating carbon capture and sequestration (CCS) to minimise carbon intensity. DG Fuels' plant in Louisiana is the largest announced SAF facility using FT CANS technology, converting sugarcane biomass into synthetic crude for SAF production. In Spain, Repsol and Aramco's eFuel plant integrates FT CANS with HyCOgen technology to produce synthetic fuels from CO_2 and green hydrogen.

Typically, biomass gasification plants produce a 1:1 mixture of CO and H_2 with insufficient H_2 to feed the FT process. Often, a water gas shift (WGS) reactor is used to increase the ratio of H_2, ensuring the correct ratio enters the FT reactor. However, this process also converts valuable CO into CO_2, which must be removed before FT synthesis, effectively acting as a carbon leak and reducing the overall carbon efficiency of the process. To avoid this leakage of valuable carbon from SAF feedstocks, additional H_2 can be added

Governments worldwide are introducing policies to accelerate SAF adoption

to ensure the correct ratio of gases. This removes the need for the WGS reactor, and operating the process in this way can comparatively increase SAF output, increasing the overall liquid product yield by around 60%. However, even this leaves a portion of the valuable carbon behind.

HyCOgen technology can use the CO_2 produced during biomass gasification and convert it into syngas with the addition of H_2. This not only prevents what could otherwise be waste CO_2 from potentially being released into the atmosphere but also transforms it into a valuable syngas feedstock for further fuel production. This capability can significantly enhance the economic viability of hybrid SAF plants, able to produce SAF from both biofeedstocks and via power-to-liquid. The overall result can be an increase in SAF output to more than 250% compared with the base case using WGS, without the need for additional feedstock carbon.

Overcoming challenges and ensuring a sustainable future

The potential for feedstock diversification to transform SAF production is immense, but challenges remain. Securing a consistent and scalable feedstock supply requires robust logistics and supply chain infrastructure. Additionally, achieving cost competitiveness with fossil fuels will demand economies of scale, technological advancements, and supportive policies. The environmental impacts of feedstock collection and processing must also be carefully managed, with practices such as responsible forestry and lifecycle carbon assessments ensuring sustainability.

Governments worldwide are introducing policies to accelerate SAF adoption. In the US, the SAF Grand Challenge targets 3 billion gallons of SAF production by 2030 and 35 billion by 2050, supported by significant federal investments in research and development. The EU has set SAF mandates requiring 6% of aviation fuel to be SAF by 2030, rising to 70% by 2050, with specific quotas for renewable fuels of non-biological origin. In the UK, the Government has committed to a 10% SAF target by 2030, promoting domestic production and capping HEFA usage to encourage feedstock diversification.

Estimates from the International Air Transport Association (IATA) suggest that using SAF can reduce lifecycle greenhouse gas emissions by more than 80% compared to fossil-derived jet fuel (IATA, 2024). By diversifying feedstocks and deploying advanced technologies like FT CANS and HyCOgen, the aviation industry can stabilise supply chains, meet global SAF targets, and significantly reduce emissions.

Achieving these goals will require collaboration between governments, industry leaders, and researchers. By unlocking the potential of diverse feedstocks, the SAF industry can create a more sustainable future for aviation while supporting energy security and global climate objectives.

Paul Ticehurst

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Managing corrosion risk in SAF and renewable diesel processes

Non-intrusive, real-time monitoring solutions can help manage the unique corrosion risks associated with biofuel feedstocks and processes

William Fazackerley
Emerson

As the world grapples with climate change and seeks to reduce its carbon footprint, the transportation sector has come under increasing scrutiny. Aviation and long-haul trucking, in particular, have faced challenges in transitioning away from fossil fuels. Sustainable aviation fuel (SAF) and renewable diesel have emerged as two promising alternatives that are reshaping the landscape of transportation fuels.

However, the shift to these sustainable fuels brings its own set of challenges. The production of SAF and renewable diesel involves complex processes and the use of diverse feedstocks, ranging from used cooking oils to agricultural residues. These new feedstocks and processes introduce novel corrosion risks that threaten the integrity of production facilities.

This article explores the evolution of biofuels, delves into the production processes of SAF and renewable diesel, examines the corrosion challenges faced by producers, and discusses the innovative monitoring solutions being employed to mitigate these risks.

Evolution of biofuels

To understand the significance of SAF and renewable diesel, it is essential to look at the evolution of biofuels over the past decade. Biofuels have gone through several generations, each addressing the limitations of the previous one.

First-generation biofuels, popular in the early 2000s, were primarily derived from food crops like corn, sugarcane, and other energy crops. While these fuels offered a renewable alternative to fossil fuels, they faced criticism for competing with land use for food production, consequentially driving up food prices and deforestation.

Second-generation biofuels, which gained traction in the 2010s, aimed to address these concerns by utilising non-food biomass such as agricultural and forestry residues likes wood chips. These fuels offered improved sustainability and reduced the risks of land use change and competition with food production. As these biofuels were not capable of directly replacing their hydrocarbon counterparts, blending limits were imposed, which limited their adoption.

Third-generation biofuels, emerging in recent years, focus on waste streams, including municipal solid waste (MSW), sewage sludge, and more advanced feedstocks like algae. These feedstocks promise even greater sustainability and potential for scalability and are available as a direct replacement to legacy fuels without blending limitations.

The latest development, sometimes referred to as fourth-generation biofuels, involves engineered organisms and carbon capture technologies to produce fuels with a negative carbon footprint.

Sustainable aviation fuel

SAF represents a significant leap forward in the aviation industry’s efforts to reduce its environmental impact. Unlike traditional jet fuel, SAF is produced from sustainable feedstocks such as used cooking oil, agricultural residues, and even MSW.

The International Air Transport Association (IATA) reports that in 2022, more than 300 million litres of SAF were produced (IATA, 2023). This figure is set to grow dramatically, with more

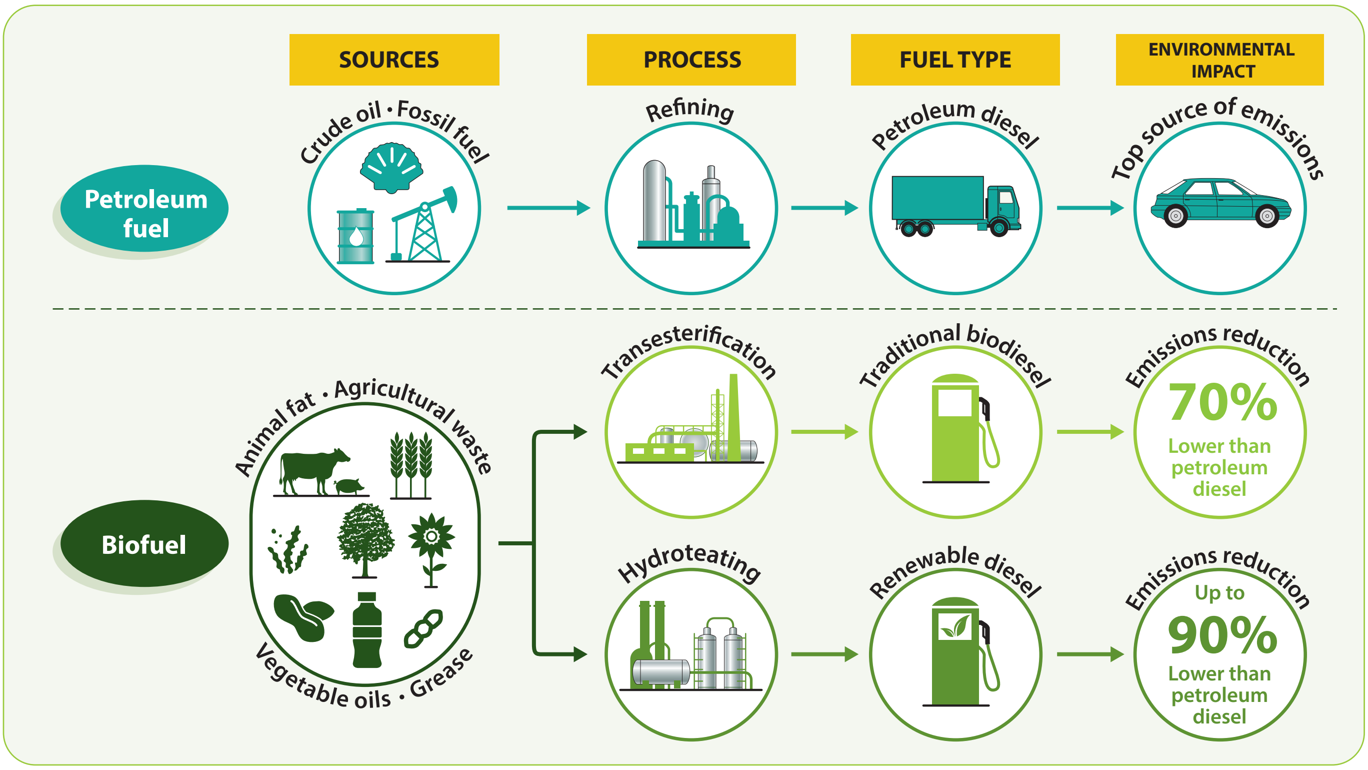

Figure 1 Progression of biofuels development has resulted in up to 90% lower emissions than from petroleum diesel

than 130 renewable fuel projects announced by more than 85 producers across 30 countries globally (*Thomsen, Mistry, & Block*, 2023).

Government incentives are playing a crucial role in driving SAF adoption. In the US, the Sustainable Aviation Challenge sets an ambitious goal for the airline industry to use 11 billion litres of SAF by 2030, equivalent to 15% of current jet fuel demand (*US DOE*, 2021), (*IATA*, 2022). The EU's Fit for 55 package includes a proposed 2% SAF blending mandate by 2025 under the ReFuelEU Aviation initiative (*European Commission*, 2022).

One of the key advantages of SAF is its drop-in capability, meaning it can be used in existing aircraft engines without modification. This characteristic makes it an attractive option for airlines looking to reduce their carbon footprint without investing in new aircraft or engine technologies.

Renewable diesel

While SAF is focused on decarbonising aviation fuels, renewable diesel is transforming the road transportation sector, particularly for heavy-duty vehicles and long-haul trucking. Renewable diesel should not be confused with biodiesel, an earlier biofuel that gained popularity in the past decade.

Renewable diesel offers several advantages over biodiesel. It burns more cleanly and efficiently, produces lower emissions, and can be used in high concentrations without blending with traditional diesel (see **Figure 1**). These characteristics make it an attractive option for fleet operators looking to reduce their environmental impact without significant changes to their existing vehicles.

The International Energy Agency (IEA) projects that renewable diesel production will triple by 2026 (*IEA*, 2022). This growth is driven by increasing demand from road and sea haulage sectors, which have limited options for transitioning away from traditional combustion engines in the short term.

Feedstock challenges and innovations

The choice of feedstock is crucial in the production of both SAF and renewable diesel. Early biofuel production relied heavily on vegetable oils, resulting in fatty acid methyl esters (FAME) or biodiesel. However, concerns about fuel blending and engine compatibility have shifted focus to hydrotreated processes for drop-in fuels.

Hydrotreated vegetable oils (HVO) have emerged as a popular option for producing drop-in fuels. These fuels closely resemble fossil-based fuels and offer better engine compatibility than traditional biodiesel.

To avoid first-generation biofeedstocks, producers are increasingly turning to waste materials including animal fats, used cooking oils, and greases. However, potential supply limitations have resulted in extending the use of wastes to include MSW and sewage sludges. An additional benefit of using these waste products is that they minimise landfill costs and offer financial benefits. However, maintaining consistent quality and supply can be challenging.

New regulations are emerging that require a minimum use of such third- and fourth-generation feedstocks, driving further innovation in this area.

Production processes and corrosion challenges

The production of SAF and renewable diesel involves significant modifications to existing refinery processes along with investment in advanced chemical processes that differ significantly from traditional petroleum refining. Most waste feedstocks require a pretreatment step, followed by hydrodeoxygenation (HDO) to remove oxygen and other contaminants, isomerisation or hydrocracking to achieve the desired fuel properties.

However, these new processes and feedstocks introduce novel challenges, particularly in terms of corrosion risk. The high acidity of some renewable feedstocks, combined with high temperatures and pressures in the refining process, can accelerate corrosion rates in equipment (see **Figure 2**). The main corrosion risks in biofuel production include:

- **Acidic corrosion:** Renewable feedstocks often contain a combination of fatty acids, long carbon chains with single or multiple double bonds, and branched acidic components like resin acids. These feedstocks typically have a much higher total acid number (TAN) compared to fossil fuel feedstocks, ranging from 0 to 200 mg KOH/g feed. This high acidity leads to localised thinning of metal surfaces, which intensifies with increased process temperatures and flow rates. While temperatures above 230°C pose a risk for fossil feeds, this threshold drops to 150°C for renewables due to their elevated acidity. The corrosion products, soluble iron salts, lack protective scales and can accumulate in catalyst beds, causing pressure drops and clogging. This type of corrosion can lead to significant equipment damage, potentially causing leaks or even catastrophic failure if left unchecked.
- **Microbiologically influenced corrosion (MIC):** MIC is caused by the metabolic byproducts of living organisms such as bacteria, algae, or

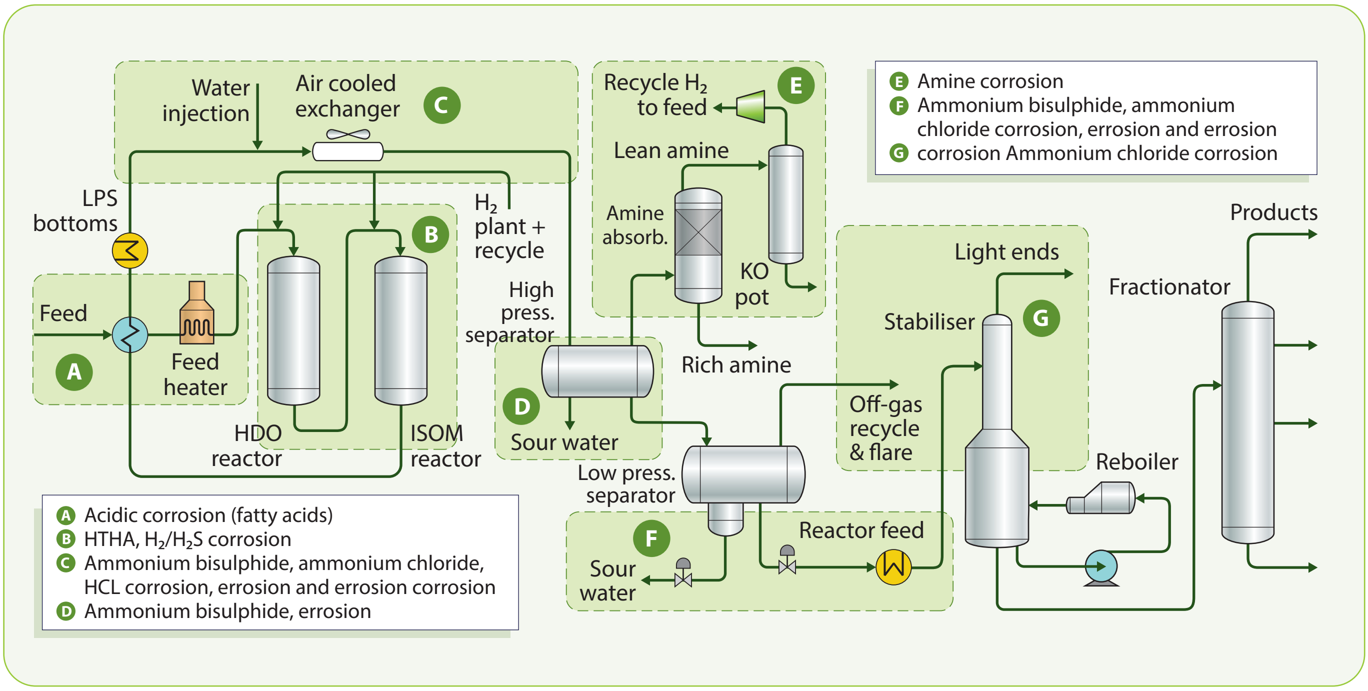

Figure 2 A basic overview of a biofuel production process, with the main corrosion mechanisms and areas of concern highlighted

fungi. It results in distinct localised corrosion, characterised by pitting, tubercles, and crevice corrosion, often occurring beneath biofilm deposits. MIC affects low-temperature areas throughout the process, from feedstock handling and tank farms to processing unit air coolers and final wastewater treatment facilities. The diverse nutrients available in biofuel processes, including inorganic elements and organic hydrocarbons and acids, promote micro-organism proliferation. MIC can cause severe localised damage, potentially leading to through-wall penetration and leaks. The unpredictable nature of MIC makes it particularly challenging to manage without proper monitoring.

- **High-temperature hydrogen attack (HTHA) (hydrogen embrittlement):** HTHA affects all equipment and piping operating above 430°F (221°C) and at partial pressures exceeding 200 psi (1.3 MPa). Under these conditions, hydrogen disintegrates into atomic hydrogen and infiltrates exposed steels. The gases formed cannot diffuse through the component, resulting in blister and bubble formation along grain boundaries and laminations. This progression leads to micro fissures, which amalgamate into larger fissures, ultimately causing cracks and equipment failure. HTHA is particularly insidious as it can occur without visible surface damage until catastrophic failure occurs.
- **High-temperature H_2/H_2S corrosion:** This generalised corrosion mechanism occurs at temperatures surpassing approximately 450°F (230°C) downstream of the hydrogen injection point in the presence of H_2S-containing process streams. The resultant scale exhibits strong adhesion and swells to five times its original volume relative to the lost metal. Its shiny grey appearance can be misleading, often masking the extent of the underlying damage. This type of corrosion can lead to significant wall thinning and potential equipment failure if not properly monitored and managed.
- **Carbonic acid (wet CO_2) corrosion:** When carbon dioxide (CO_2) dissolves in water, it creates carbonic acid (H_2CO_3), which results in a decrease in pH and consequently triggers generalised corrosion in carbon and low alloy steels. Areas characterised by higher process flow velocities, impingement, and turbulence may experience pitting and localised corrosion. Corrosion rates typically rise in the presence of both oxygen and CO_2 partial pressures, particularly where CO_2 condenses from the vapour phase. Within hydroprocessing effluent streams, the risk of severe corrosion emerges when process temperatures fall below the dew point. This type of corrosion can lead to general wall thinning as well as localised attacks, potentially compromising equipment integrity.
- **Ammonium bisulphide corrosion:** This localised corrosion phenomenon is particularly prevalent in hydroprocessing reactor effluent systems and has led to numerous reported failures. It also affects areas with entrained or condensed sour water, such as hydrocarbon lines, reactor effluent separators, and vapour lines from high-pressure separators. High concentrations of NH_4HS and the presence of cyanides contribute to accelerated corrosion. The corrosion manifests differently depending on flow regimes: areas with high flow experience general wall loss, while turbulent sections see intense localised corrosion. This can lead to rapid, localised metal loss and potential equipment failure if not properly managed.
- **Hydrochloric acid corrosion:** Chlorides within the feedstock undergo conversion into hydrochloric acid (HCl) within the hydrotreating reactor. This transformation poses a corrosion risk not only within the reactor effluent stream but also extends downstream to units like the sour water stripper. HCl can cause both general and localised corrosion, particularly affecting stainless steels and leading to pitting-like attacks. As HCl traverses process streams through fractionation sections, it can instigate severe dew point corrosion, especially when the first dew point droplet forms. This phenomenon is observed across overhead sections as process temperatures drop. The corrosion rates are highest under conditions of elevated concentration and temperature, posing a significant risk to equipment integrity.

Each of these corrosion mechanisms presents unique challenges in biofuel production facilities. Their complex and often interrelated nature underscores the importance of comprehensive monitoring strategies, such as the use of advanced, non-intrusive ultrasonic sensors. These monitoring solutions provide real-time data on equipment condition, enabling

operators to detect and address corrosion issues before they lead to significant damage or failure.

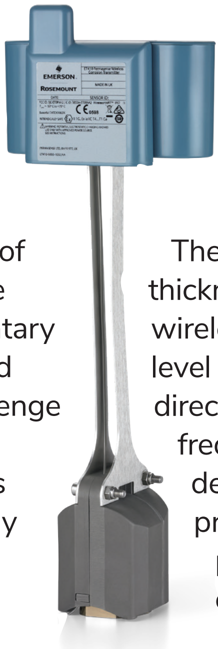

Figure 3 The Rosemount ET410 Corrosion and Erosion Transmitter allows high-temperature online thickness monitoring, ideal for biofuel applications

Managing corrosion risks

Traditional methods for measuring the risk of corrosion are based on processes that have existed for many decades, such as rudimentary corrosion modelling, manual inspection, and risk-based inspection (RBI). The main challenge posed by using these techniques is that in many of these novel processes, the process is far less predictable, introducing previously unforeseen levels of risk. To properly manage these unknown levels of risk, refiners are adopting innovative strategies, with a particular focus on advanced monitoring technologies. One increasingly popular approach is the use of online, non-intrusive corrosion monitoring systems.

Emerson's Rosemount Wireless Corrosion and Erosion Transmitters (see **Figure 3**) are designed to measure wall thickness in real-time, allowing operators to detect corrosion quickly and take preventive action. They can be installed without the need to penetrate the pipe or vessel wall, minimising installation costs and allowing monitoring in previously inaccessible locations.

These transmitters employ a patented Adaptive Cross-Correlation (AXC) technique, which significantly improves measurement accuracy, especially in challenging conditions such as those encountered in biofuel production (see **Figure 4**). This technology allows the transmitters to achieve a repeatability of up to 2.5 microns (0.0001in) in field conditions.

The transmitters typically transmit wall thickness measurements twice daily using wireless data retrieval, giving operators a high level of insight into the health of their assets directly from the desk (see **Figure 5**). This frequent data collection allows for the early detection of corrosion trends, enabling proactive maintenance strategies and potentially preventing costly shutdowns or equipment failures.

A case study from a major European refiner illustrates the effectiveness of this approach. The refiner repurposed an old hydrotreating unit to utilise renewable feedstocks such as vegetable oils and used cooking oil. Recognising the increased corrosion risk, they installed Rosemount Wireless Corrosion and Erosion Transmitters.

The transmitters were strategically placed in areas prone to corrosion, such as reactor effluent systems, high-temperature zones, and areas with potential for ammonium chloride or amine corrosion. By providing continuous data on wall thickness, the transmitters allowed the refiner to correlate corrosion rates with specific feedstocks and operating conditions. This insight has been invaluable in optimising processes and maintenance schedules. Moreover, thanks to their non-intrusive nature, the transmitters could be installed without any modifications to the existing equipment, minimising downtime and installation costs.

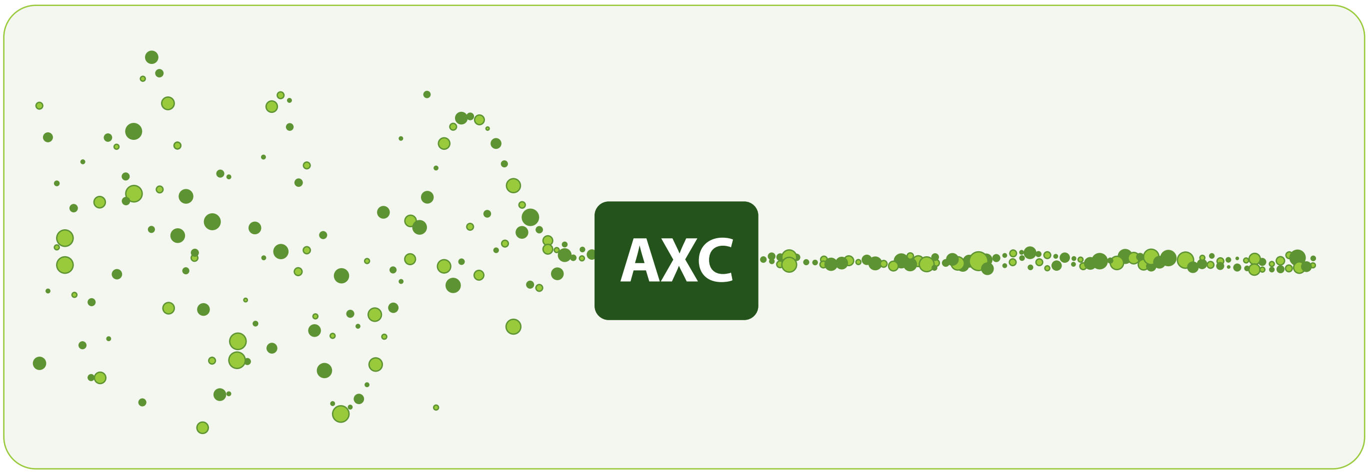

Figure 4 Adaptive Cross-Correlation (AXC) significantly improves the accuracy of the wall thickness and corrosion rate calculation

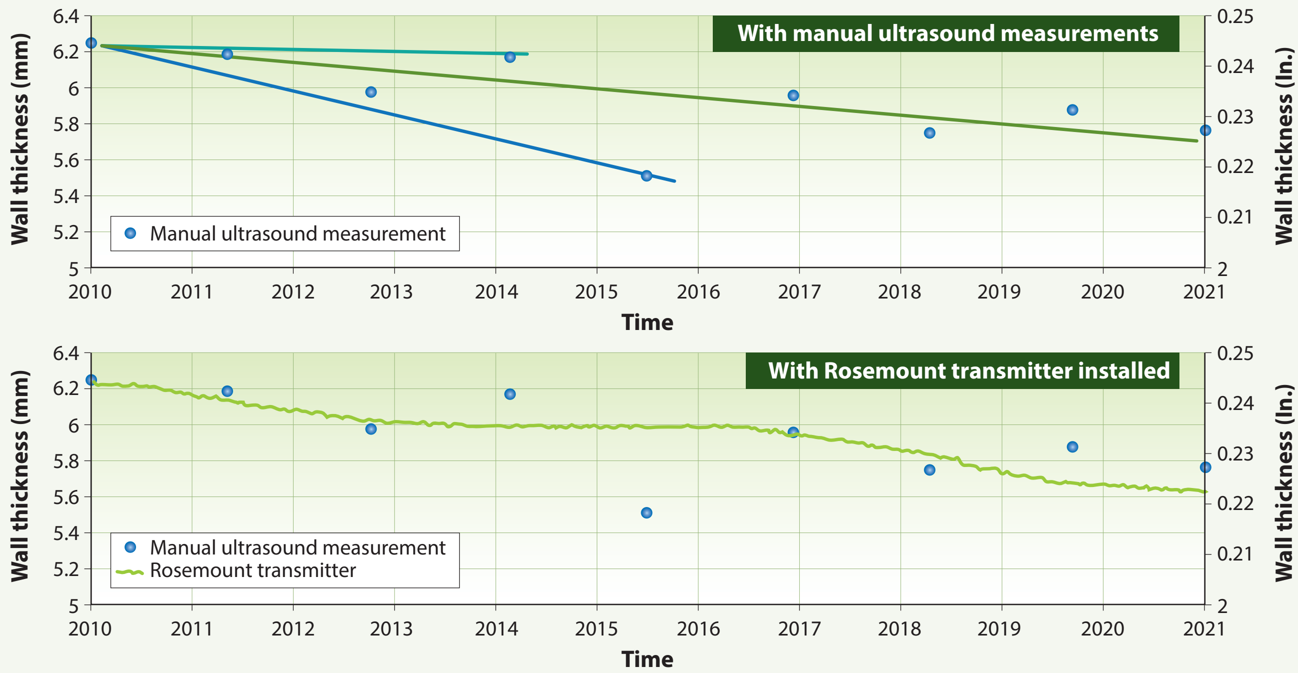

Figure 5 Online thickness monitoring provides the granularity in data required to understand periods of high and low corrosion, which can be correlated to process changes to minimise risk

Conclusion

The rise of SAF and renewable diesel marks a significant milestone in the decarbonisation of transportation. These advanced biofuels offer a path to reduce greenhouse gas emissions without requiring a complete overhaul of existing infrastructure, presenting a pragmatic solution to one of our most pressing environmental challenges.

The journey from first-generation biofuels to today's sophisticated SAF and renewable diesel has been characterised by continuous innovation and learning. This evolution extends beyond just the fuels themselves to encompass the entire production process, including how we monitor and manage the integrity of production facilities.

Online corrosion monitoring, once a novel technology, has now become an industry standard in biofuel production. The widespread adoption of solutions like Emerson's Rosemount Wireless Corrosion and Erosion Transmitters (see **Figure 6**) underscores the industry's commitment to safety, efficiency, and sustainability. These non-intrusive, real-time monitoring solutions have proven invaluable in managing the unique corrosion risks associated with biofuel feedstocks and processes. By providing continuous, accurate data on equipment condition, they enable proactive maintenance strategies, optimise operations, and ultimately contribute to the reliable, cost-effective production of sustainable fuels.

Figure 6 Example installation of Rosemount WT210 Transmitters

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Key elements of flow assurance in carbon capture and storage

The challenges and strategies involved in optimising CO_2 flow for safe and effective storage

Abbey Grant
Belltree Group

Emerging technologies such as carbon capture and storage (CCS) are crucial for reducing and removing anthropogenic carbon dioxide (CO_2) emissions from the atmosphere. Since the Paris Agreement in 2015, countries worldwide have set targets to limit global average temperatures from reaching 1.5°C above pre-industrial levels. The urgency to meet these targets has driven the development of CCS projects from previous concepts of CCS, such as enhanced oil recovery (EOR), which began in the 1970s. There are now 50 commercial-scale CCS projects operational and 534 in development worldwide *(Global CCS Institute, 2024)*.

Flow assurance plays a critical role in the CCS process, ensuring that CO_2 can be transported from its point of capture to its permanent storage site without disruptions. This involves maintaining CO_2 in its supercritical state during pipeline transport, managing pressure and temperature to prevent phase changes, and addressing potential risks like corrosion and blockages. New and developing CCS projects can anticipate and mitigate these challenges by making flow assurance a key factor in the successful deployment of CCS at scale, drawing on decades of experience with CCS in the oil and gas industry.

Selecting the appropriate subsurface storage location is also a crucial component of any CCS project. Using data-driven tools such as bMark can allow screening of potential storage prospects to help identify the optimum storage site. This article explores the intricacies of flow assurance in CCS, highlighting the challenges and strategies involved in optimising CO_2 flow for safe and effective storage.

Supercritical CO_2

CO_2 can be transported in any form, but it is often compressed into a liquid because it occupies significantly less volume compared to its gaseous form. When transported via pipeline, it is most efficient for CO_2 to be in its supercritical state with pressures higher than 74 bar and temperatures higher than 31°C. This represents highest point in which it can exist as a vapour and liquid in equilibrium *(TWI, 2010)*. In this state, CO_2 has

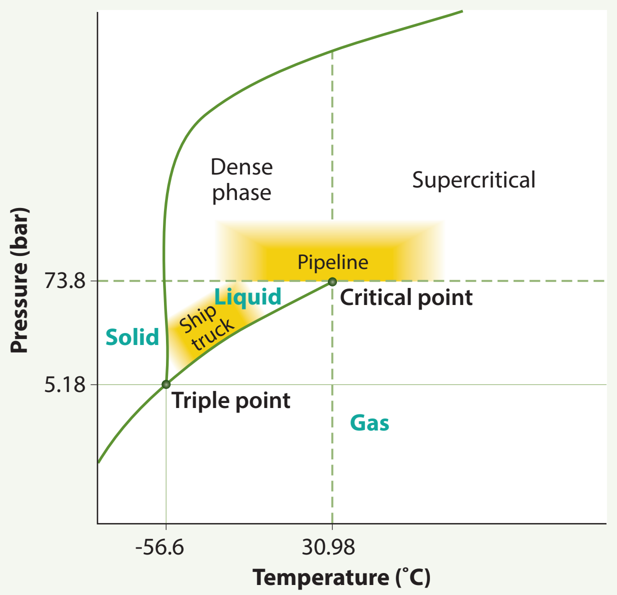

Figure 1 Phase diagram of CO_2, showing the estimated areas of operation for transport via ship, truck, and pipeline

Source: Simonsen et al., 2023

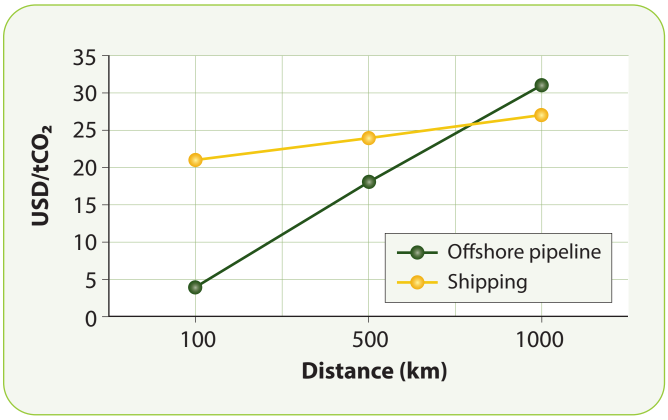

Figure 2 Cost (in USD) of transporting CO_2 via offshore pipelines and ship for distances of 100-1,000 km, assuming a capacity of 2 Mt/year

Source: IEAGHG (2020)

the density of a liquid but the viscosity of a gas *(Drax, 2022)*. The viscosity is up to 100 times lower than that of the liquid phase *(TWI, 2010)*, significantly reducing drag during pipeline flow. This improvement increases CO_2 throughput, leading to lower operational costs.

Figure 1 shows the various transport methods for CO_2 associated with the phase during operation. The difficulty with transporting CO_2 in this state is that it must remain supercritical, requiring the temperature and pressure to be maintained to avoid phase changes.

Pipeline transport of supercritical CO_2

Various methods for transporting CO_2 are available, including pipelines, ships, road, and rail. However, pipelines remain the most cost-effective and widely used option, particularly for long distances and larger volumes of CO_2. As shown in **Figure 2**, pipelines generally have a lower cost compared to ships for distances up to 800 km. Offshore pipelines, especially in regions like the North Sea, will be crucial for the development of commercial-scale CCS projects.

Currently, the US leads the world in the number of operational and developing CCS projects, supported by its extensive 5,000+ mile onshore CO_2 pipeline network. Many existing pipelines previously used for oil and gas can be repurposed for CO_2 usage, which helps to reduce the cost significantly. Reusing pipelines typically costs around 1-10% of constructing new ones *(Drax, 2022)* while also minimising the need for new infrastructure. However, to meet climate targets in the next few decades, approximately 100 times more pipeline infrastructure than currently available will be required *(Global CCS Institute, 2018)*.

To support the expansion of CCS pipeline networks, tools like bMark provide access to up-to-date data sources, including information on existing oil, gas, and CO_2 pipelines worldwide. This data is essential for planning, designing, and scaling up pipeline infrastructure effectively. **Figure 3** highlights the pipeline data for the US, available on bMark.

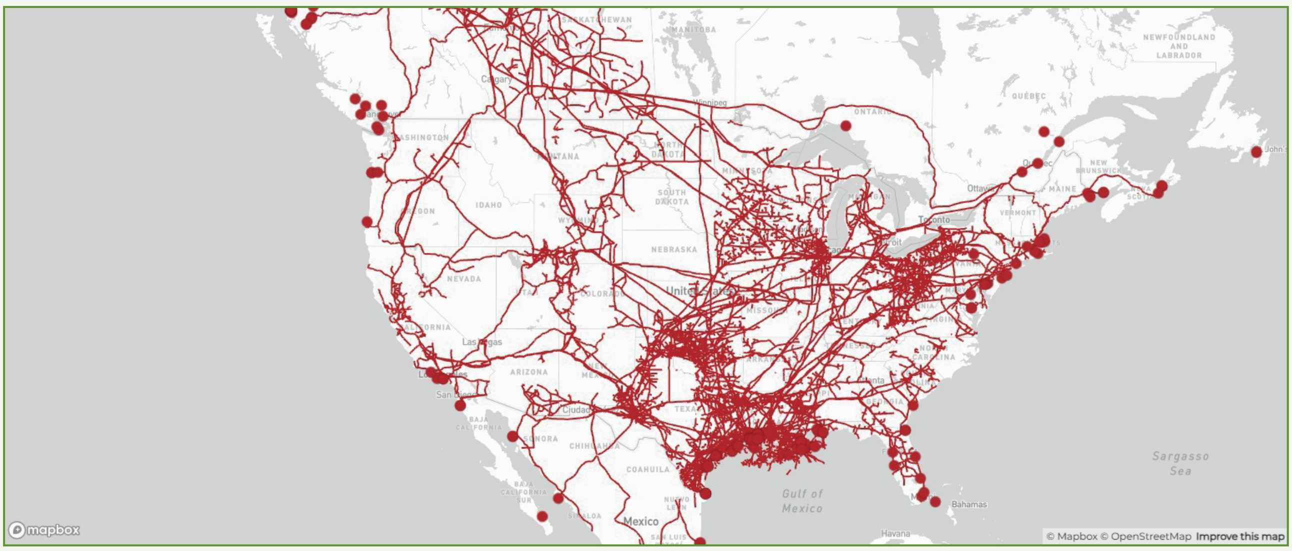

Figure 3 Pipelines data across the US *Source: Belltree bMark*

Safety of CO_2 transport

One of the main public concerns about CCS is the safety of CO_2 transport in pipelines and its secure storage underground. However, in EOR projects, CO_2 has been transported over decades, so it is not an unfamiliar technology. It poses no greater risk than oil and gas transport, which has a long history of safe management. Additionally, transporting CO_2 is much safer than other substances as it is not explosive or flammable when mixed with air *(Drax, 2022)*. A combination of governmental legislation and international standards will ensure maximum safety in CO_2 transport. Ultimately, one of the most important steps in safeguarding CO_2 transport via pipeline is flow assurance. This critical process involves understanding and mitigating the factors that could disrupt the flow of CO_2 from the capture point to its storage location.

Flow assurance

Flow assurance was initially based on ensuring the successful and economical flow of hydrocarbons from the reservoir to their destination. However, this now directly applies to the transport and injection of CO_2 during CCS projects. Flow assurance studies are an essential part of the design process for oil and gas operations, such as the front-end engineering and design (FEED) process. Factors affecting flow assurance include the formation of solids/blockages, pressure drop, temperature variation, and purity of the CO_2.

Among the factors involved in flow assurance, the primary concern is the potential for blockages within pipelines, whether it is hydrocarbons or CO_2. Studies focus on preventing and controlling the formation of solids which may block the flow. Many things can affect this, especially the pressure, temperature, and chemistry of the product flowing through the pipeline.

Pressure drop is one of the key concerns in flow assurance, with many contributing factors affecting wellbore pressure, fluid properties, and temperature. Here again, CO_2 injection projects can use the experience gained from the oil and gas industry. In hydrocarbon production, wellbore pressure is a significant factor in pressure drop, with up to 80% of the lost pressure occurring during the flow from the subsurface to the surface.

Fluid properties, such as viscosity and density, are also crucial. Fluids with lower density flow with less pressure drop, while higher viscosities cause more friction, leading to a greater pressure drop *(Böser and Belfroid, 2013)*. Temperature also influences flow assurance; higher temperatures typically decrease viscosity and density, which can limit pressure drop. However, temperature variations can also lead to a drop in pressure.

While these factors affecting hydrocarbon flow are present in terms of the flow of CO_2, the effects vary. The pressure drop due to the wellbore will not be the same with CO_2 because it is injected rather than produced. The fluid properties of CO_2 differ from hydrocarbons, and CO_2 is usually transported in its dense or supercritical phase. The purity of CO_2 and the presence of impurities can affect its

> **“Among the factors involved in flow assurance, the primary concern is the potential for blockages within pipelines, whether it is hydrocarbons or CO_2”**

viscosity and density in pipelines, nitrogen (N_2) having the greatest and hydrogen sulphide (H_2S) having the least impact on density and pressure loss.

The presence of certain impurities, including water (H_2O), sulphur oxides (SO_x), and nitrogen oxides (NO_x), can also affect the flow of CO_2 by increasing the risk of corrosion. Any water content within the pipeline can lead to corrosion, so an industry-standard limit of 500 ppm is maintained to minimise the risk *(Simonsen, et al., 2024)*. Conversely, the presence of other impurities, such as N_2, can bring down the water concentration levels in CO_2. In supercritical CO_2 environments, the addition of O_2 can increase corrosion in carbon steel, with severe corrosion occurring when both O_2 and H_2S are present. Therefore, the capture and processing of CO_2 for storage projects is critically important. Furthermore, some pipelines may need to be designed with specific materials to account for the presence of certain impurities, to reduce the risk of corrosion.

Single and two-phase flow

The transport of CO_2 is currently limited to single-phase flow, either in its dense or supercritical form. Existing tools for the flow assurance of hydrocarbons can be used for CO_2 if it remains in a single phase. If it is kept at high pressure and temperature, CO_2 will stay in its single, supercritical phase. However, as discussed previously, any leaks or depressurisation will risk CO_2 going into two phases. The two-phase flow of CO_2 is when the gas and liquid forms coexist. The issue with two phases in flow assurance is the potential for severe slugging within the pipeline, which involves the intermittent flow of gas and liquid.

Slugging can disrupt the flow, causing significant pressure and temperature variations that may cool pipelines, making them brittle and prone to rupturing (*Yang et al., 2021*). Again, these issues have been learned from the oil and gas industry, where slugging is a major challenge during production. Due to these disruptions in flow, various methods have been developed to identify and handle changes in phase, including dynamic models based on mass, momentum, and energy conservation. To manage the potential of phase changes within CO_2 pipelines, it is crucial to control the temperature and pressure within the pipeline to ensure stable conditions.

Reservoir injection

As the flow of CO_2 reaches its endpoint at the storage site in the subsurface, flow assurance remains equally important due to the change in pressure. The high pressures required to ensure CO_2 remains in its supercritical state could be met by the lower pressures at the injection point, depending on the site. For example, injection into a depleted hydrocarbon field with low pressures can result in adiabatic cooling, with the reduced temperatures possibly leading to hydrate formation and freezing of pore water (*Loeve et al., 2014*).

CO_2 injection into an aquifer is less likely to have the risk of pressure change and freezing, as no fluids have been extracted, therefore pressure remains stable. However, the risk of lower pressure within aquifers remains, depending on factors such as the depth of the aquifer, the height of the water column, and nearby hydrocarbon production, potentially changing the regional pressure. The advanced capabilities of software like bMark include accessing historical production data from reservoirs, as well as temperature and pressure data (see **Figure 4**), which can help further understand the characteristics of a potential CO_2 storage site.

CCS projects

The selection of appropriate locations for permanent CO_2 storage is also fundamental to

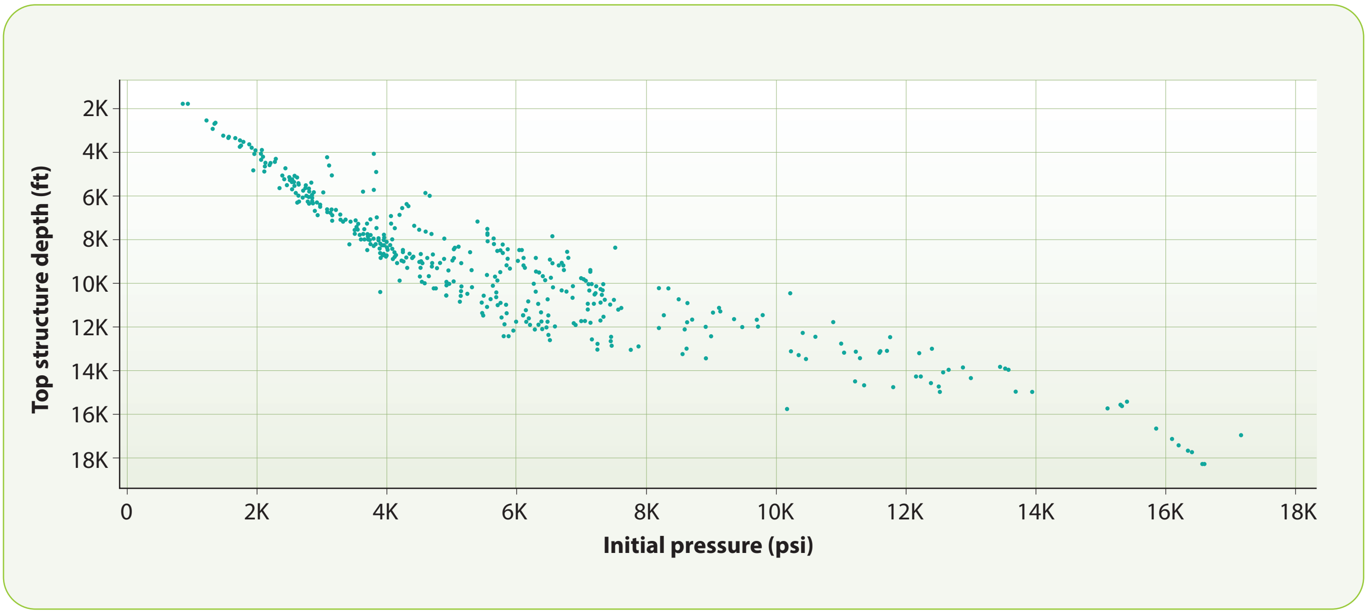

Figure 4 Depth vs pressure plot of fields in the North Sea *Source: Belltree bMark*

Figure 5 CCS projects in Europe *Source: Belltree bMark*

the success of a CCS project. While emissions from numerous industries contribute to global CO_2 levels, the current focus in CCS deployment should be on minimising costs and maximising captured CO_2 by prioritising industrial hubs and clusters.

Also, choosing project sites near existing CO_2 storage locations and infrastructure, such as pipelines, can further reduce costs by minimising transport distances and repurposing existing infrastructure. Tools like bMark are valuable for visualising active and planned CCS projects, identifying nearby pipelines for use, and offering key data such as the geological characteristics of potential storage sites. **Figure 5** highlights the CCS projects that are active or planned in Europe (from bMark).

Summary

As carbon capture and storage emerges as a vital strategy in combating climate change, ensuring the safe and efficient transport and storage of CO_2 becomes paramount. Flow assurance is a critical aspect of CCS, involving the management of factors such as pressure drops, temperature variations, and the risk of corrosion or blockages in pipelines.

Drawing on decades of experience in the oil and gas industry, flow assurance principles used for hydrocarbons are applied to CO_2 to prevent operational disruptions, especially during its transport in supercritical form. The transition from capturing CO_2 to its final geological storage demands meticulous planning, especially as the CO_2 enters subsurface reservoirs where pressure and temperature changes can lead to challenges like hydrate formation or phase changes.

By leveraging data-driven tools and incorporating detailed analyses during the early design stages, CCS projects can mitigate risks and enhance the stability of CO_2 flow throughout the process. As the global push for CCS accelerates, mastering flow assurance will be crucial for the safe and long-term sequestration of CO_2, ultimately contributing to global efforts to limit temperature rise and achieve climate goals.

> **“By leveraging data-driven tools and incorporating detailed analyses during the early design stages, CCS projects can mitigate risks and enhance the stability of CO_2 flow throughout the process”**

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Sand: an innovative approach to storing sensible heat

Sand batteries can help solve renewable energy challenges like intermittency and variability by storing excess energy and releasing it when needed

S Sakthivel and Atul Choudhari
Tata Consulting Engineers

Introduction

A variety of advanced energy storage systems are available, each leveraging different principles to store energy efficiently. Mechanical energy storage systems encompass various technologies. These include pumped hydro energy storage with a round-trip efficiency of 70-80%, flywheel energy storage with a cycle efficiency of 85-90%, compressed air energy storage, and gravity energy storage.

Thermal energy storage systems absorb and store heat in different forms, such as sensible heat storage, latent heat storage, thermochemical energy storage, and pumped thermal energy storage. Chemical energy storage methods include hydrogen and synthetic natural gas. Electrochemical energy storage systems comprise a range of batteries such as lithium-ion, sodium-sulphur, lead-acid, solid-state, nickel-cadmium, sodium-ion, and metal-air batteries.

Additionally, flow battery energy storage systems, including vanadium redox, polysulphide bromide, and zinc-bromine batteries, as well as emerging technologies like paper and flexible batteries, are part of this category. Electrical energy storage systems include electrostatic and magnetic energy storage, which stores energy in either electric fields or magnetic fields (*Mitali, et al., 2022*). Each system has unique advantages and applications, contributing to a robust and diversified energy storage landscape.

Among these different systems, thermal energy storage is pivotal for several compelling reasons. It can be used to balance renewable energy by storing excess power during periods of abundance, such as sunny or windy days, and releasing it when production is low, such as on cloudy or calm days. This capability ensures a steady and reliable energy supply, mitigating the inherent variability of renewable sources.

Additionally, thermal storage systems enhance grid stability and efficiency by storing thermal energy during off-peak periods and discharging it during peak demand times, effectively reducing the load on the grid during high-demand periods. Thermal energy storage also plays a significant role in cutting CO_2 emissions as it can be used to facilitate energy production or utilisation during periods when it is most cost-effective and environmentally friendly.

Thermal energy storage

Thermal energy storage systems have emerged as a highly cost-effective solution (*Sunku Prasad, et al., 2019*). Sub-categories include sensible heat storage (such as water, molten salt, rock, and sand). There is also latent heat storage, which uses phase change materials such as salt hydrates, metal alloys, or organics like paraffin waxes, as well as thermochemical, ice, and eutectic storage systems (*Ali, et al., 2024*).

Sensible heat storage is the simplest and most economical storage method, which makes use of a material's sensible heat capacity. Sensible heat storage materials can be either solid or liquid.

Solid storage materials offer various options, each with unique thermal properties. For instance, sand has a specific heat capacity of 0.703-0.8 kJ/kg·K and a thermal conductivity of 0.2-0.7 W/m·K, with a bulk density of 1,800 kg/m³ (*Tetteh, et al., 2024*). Aluminum, known for its high thermal conductivity of 237 W/m·K, is another excellent choice. Steel has a specific

Advantages and limitations of sensible, latent, and thermochemical heat storage systems			
Description	**Sensible**	**Latent**	**Thermochemical**
Advantages	▪ Efficient heat storage and release without changing phases ▪ Easy to load and unload ▪ Quick to insulate	▪ High storage density ▪ Temperature stability ▪ Compact system (i.e., smaller weight and volume)	▪ High volumetric storage density ▪ Low volume requirement ▪ Long energy preservation duration periods with limited heat loss ▪ Low storage (ambient) temperature
Limitations	▪ Cannot store or release energy at a constant temperature ▪ The system is bulky ▪ Requires more storage medium than latent heat systems to store the same amount of energy	▪ Low thermal conductivity and stability ▪ Medium heat of fusion	▪ Limited reactivity and reversibility of chemical reactions ▪ Requirement for harsh reaction conditions ▪ Toxic and corrosive byproducts from reactions

Table 1

heat capacity of 0.48 kJ/kg·K, whereas iron has a slightly lower specific heat capacity of 0.452 kJ/kg·K. These materials are effective due to their ability to absorb and retain heat efficiently *(Khatod, et al., 2022)*. On the other hand, liquid storage materials contain substances like therminol, engine oil, ethanol, butane, and propane. For example, water has a specific thermal heat capacity of 4.19 kJ/kg·K at 20-100°C, ethanol has 2.4 kJ/kg·K up to 78°C, butanol has 2.4 kJ/kg·K up to 118°C, and engine oil has 1.88 kJ/kg·K up to 160°C.

Sensible heat storage mediums made of solid materials have an advantage over liquids due to their ability to handle larger temperature fluctuations. Unlike liquids, solid thermal storages do not change phase, meaning they do not melt or flow, which eliminates the risk of leakage from the storage container. Conventional thermal energy storage methods, such as those using molten salt, have been widely adopted. However, these systems are expensive, have a limited lifespan, and often rely on materials that are harmful to the environment.

Latent heat storage, also referred to as phase change heat storage, operates by absorbing and releasing thermal energy during a material's phase transition. This type of storage has a higher energy density compared to conventional sensible heat storage due to the substantial enthalpy changes occurring during the phase transition. Typically, latent heat storage systems are lighter and more compact, which can result in reduced costs compared to sensible heat storage systems.

Latent heat storage utilising phase change materials has diverse applications, including solar thermal storage, enhancing energy efficiency in buildings, and recycling waste heat. Salt hydrates, for example, have latent heat capacities of 115.5-280 kJ/kg and phase change temperatures of 29-117°C. Paraffin wax stores about 202 kJ/kg of heat and changes phases at 40-45°C. Paraffin C_{14} has the highest latent heat of 228 kJ/kg. Salt eutectics, which are salt mixtures, have heat capacities of 74-790 kJ/kg and phase change at 13-767°C. Carbonate salts are used for high-temperature applications, with heat capacities of 142-509 kJ/kg and phase change temperatures of 732-1,330°C. These materials are chosen for their thermal properties to improve energy storage efficiency at different temperatures.

Thermochemical heat storage utilises reversible chemical reactions to store and release energy efficiently. Energy is stored as chemical compounds produced by an endothermic reaction. When these compounds recombine in an exothermic reaction, the stored energy is released as needed. The amount of heat stored is equal to the reaction's enthalpy. For example, zeolite has a heat density of about 200 kWh/m³, and silica gel has about 230 kWh/m³. **Table 1** presents the advantages and limitations of sensible, latent, and thermochemical heat storage systems.

Sand batteries can store large amounts of heat at high temperatures, making them ideal for applications needing stable and efficient heat retention. They help solve renewable energy challenges like intermittency and variability by storing excess energy and releasing it when needed, improving the energy grid's efficiency and reliability. Developing sand battery technology can lead to better thermal energy storage systems, providing a scalable and practical solution for both industrial and residential needs. This article explores the potential of sand batteries to contribute to a more sustainable and resilient energy future.

Sand battery benefits

Sand, used as sensible heat storage and commonly referred to as a 'sand battery', represents an innovative approach to energy storage. This method utilises the unique thermal properties of sand to absorb, store, and release heat efficiently. It offers a cost-effective and scalable solution for thermal energy storage, making it a promising technology for various applications, including renewable energy integration and industrial heat management.

Sand is widely distributed across diverse geological settings such as rivers, beaches, shallow seas, lakes, and desert dunes. Its primary constituents comprise silica (in the form of quartz), feldspar and additional minerals such as carbonates, micas, amphiboles, and pyroxenes.

Sand's thermal conductivity depends on its type, moisture content, and temperature. Dried coarse sand has an average thermal conductivity of 2.05 W/m·°C, while dry fine sand is about 1.76 W/m·°C. With a heat transfer coefficient of 0.06 W/m²·°C, sand can retain heat for extended periods. Additionally, it can store significant amounts of heat in a compact volume at temperatures of 800-1,000°C, making it an effective medium for thermal energy storage (*Odoi-Yorke, et al., 2024*).

Furthermore, sand is a cheap and abundant material. The sand battery offers several significant advantages over other thermal energy storage solutions. It can store large amounts of energy, requires low maintenance, and is highly scalable. In addition, CO_2 emissions are negligible during the operation of systems powered by clean electricity or heat sources. However, there are some carbon emissions associated with the construction materials and the construction phase itself.

Sand battery process

Typically, electricity is supplied to resistive heating coils to heat a sand bed, with air serving as the heat-carrying medium. The sand bed, composed of either pure sand or a mixture with metal scraps, can absorb heat up to temperatures of 800-1,000°C. The charging process involves transferring heat to the sand to store thermal energy, during which the sand's temperature

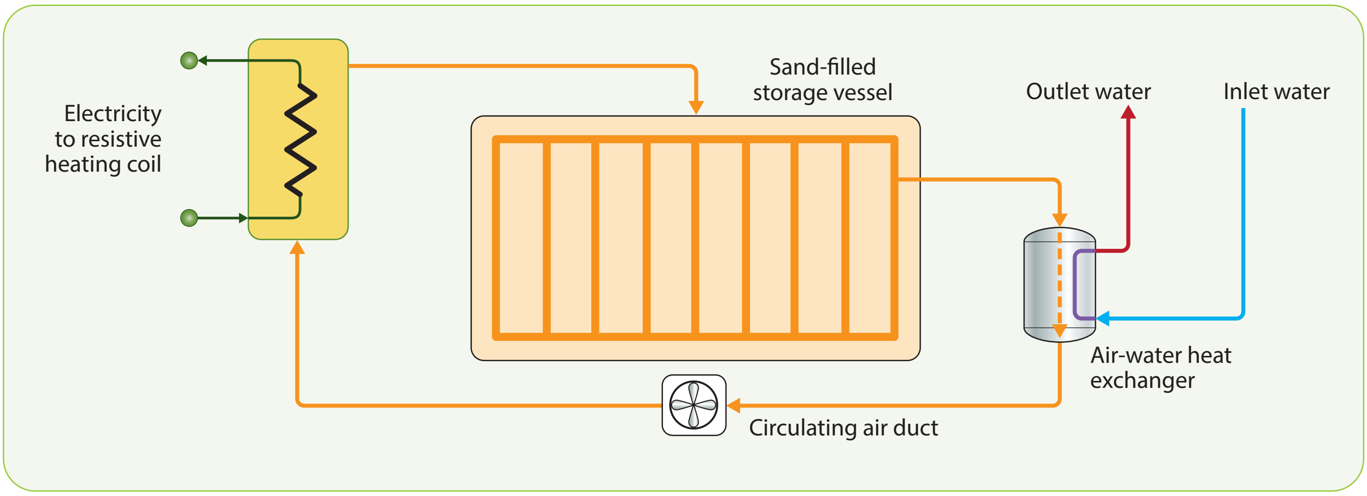

Figure 1 Schematic diagram of sand battery operation

increases until it reaches a threshold where the energy is fully stored. Charging times can vary based on the specific type of sand battery and the temperature of the heat source. During the discharging process, when thermal energy is required, the sand is exposed to a heat sink or another device that can extract the stored heat (by using water). As the sand's temperature drops, the stored energy is released as heat.

A typical sand battery operation is depicted in **Figure 1**. The heat stored within the sand can be used to heat water, which can be used in various heating applications, such as building heating systems. Sand can be maintained at approximately 500°C for several months using resistive heating, a technique that involves in-situ heating by passing an electric current through a resistive element. This process converts electrical energy directly into thermal energy, ensuring consistent and efficient heating of the sand bed over extended periods. The resistive heating method leverages the inherent properties of resistance units to generate and sustain high temperatures, making it a reliable and effective approach for long-term thermal energy storage.

This method effectively harnesses thermal energy for practical use, optimising the energy storage and release process for efficient heating solutions. A recent study (*Tetteh, et al., 2024*) demonstrated that adding metallic chips (such as aluminum, brass, and stainless-steel scrap) to sand significantly improves its thermal properties. In particular, brass-sand layers have significantly better thermal conductivity, whereas blends of sand and aluminum chips delivered well-balanced thermal performance. These configurations effectively mitigate inherent sand constraints, thereby enhancing the overall thermal efficiency of the packed bed.

The study found that mixing sand with 20% (by volume) aluminum and brass chips significantly increased the maximum heat rate (°C/min), achieving 1.7 times and 1.65 times the heat rate of pure sand, respectively. M/S Polar Night Energy has designed and commercialised a sand-based thermal energy storage system in Western Finland. M/S Polar claims their sand battery has a heating power of 100 kW with a capacity of 8 MWh and commenced utilisation in 2022. Furthermore, M/S Polar has a 3 MWh test pilot facility in Hiedanranta, Tampere, which is integrated with a local district heating grid, supplying heat to multiple buildings.

Sand batteries offer several advantages that make them an attractive energy storage solution. Their low capital and operational costs enhance accessibility and contribute to the cost-effectiveness of renewable energy systems. With proper maintenance, they have a long lifespan, ensuring reliable heat storage and release over many years, making them a durable and sustainable option.

Furthermore, they are highly scalable, so can store large amounts of thermal energy. This scalability is essential for managing variable energy production from renewable sources, ensuring a consistent and reliable energy supply during peak demand periods (*Jose, 2023*).

However, sand has several limitations. Sand batteries are less efficient than other energy storage technologies due to heat dissipation during charging and discharging, which leads to energy losses. Additionally, they gradually lose heat over time, impacting their energy storage capacity and requiring periodic recharging for optimal performance. Current research is focused on improving their efficiency and minimising energy losses. Enhancing insulation and containment strategies is essential to address this issue effectively.

Engineering design challenges

Designing sand-based batteries involves tackling several critical research and engineering challenges. Particle size and packing density significantly influence the battery's porosity and heat storage capacity, necessitating precise control over particle size distribution and packing configuration.

Ensuring material compatibility between sand and other battery components is crucial to prevent degradation or chemical reactions that could compromise performance. Maintaining cyclic stability over numerous charge-discharge cycles is essential, requiring careful management of thermal expansion and contraction to prevent mechanical failure. Enhancing heat transfer mechanisms within the sand medium is vital for enabling rapid charging and discharging processes while maintaining uniform temperature distribution. Optimising sand's thermal conductivity is also paramount to improving overall battery efficiency. Additionally, developing scalable manufacturing processes while ensuring cost-effectiveness is essential for large-scale deployment. Evaluating long-term durability and reliability under varied operational conditions, including thermal cycling and environmental exposure, is critical to fully harnessing the potential of sand-based thermal energy storage systems.

Conclusion

Sand-based thermal energy storage systems leverage the plentiful supply and advantageous thermal properties of sand as a storage medium. Studies have demonstrated improvements in heat holding capacity through the use of mixtures with metal scraps. While sand batteries show potential as environmentally friendly technology, further research and development is needed to enhance their heat-holding capacity and improve insulation within vessels to minimise heat loss. These advancements will be crucial in realising the full potential of sand-based systems for sustainable energy storage solutions.

Sand batteries enhance renewable grid stability by storing excess energy produced during peak solar and wind generation times and releasing it during high-demand periods, ensuring a balanced and stable energy supply. They also offer ancillary services such as frequency regulation and load shifting, further bolstering grid resilience and supporting the transition to a more sustainable energy infrastructure.

Sand batteries are cost-effective, with about 20% lower costs compared to traditional lithium-ion batteries. Compared with other materials, sand is abundant, making it attractive for large-scale applications. Government policies and incentives are driving investments and research, fostering innovation needed to accelerate the deployment of this promising technology.

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Unlocking the potential of waste heat recovery

Boosting efficiency and sustainability with waste heat recovery systems in the chemical industry

Sara Milanesi
Exergy International

Decarbonising chemical processes, much like other energy-intensive processes, is essential to achieve net zero by 2050 (*IEA, 2023*). In fact, the chemical sector accounts for approximately 14.5% of all industrial CO_2 emissions (1,342 Mt from a total of 9,316 Mt) and ranks as the largest industrial energy consumer (*IEA, 2022*).

Global demand for chemical products is expected to grow by around 2.5 times by 2050, leading to a projected increase in both energy and non-energy uses of raw materials, heat, and electricity from 47.6 EJ to 88 EJ per year (*Perego & Ricci, 2023*).

This scenario presents a unique challenge with respect to decarbonisation of the chemical industry as it is heavily reliant on fossil feedstocks (coal, crude oil, and natural gas) both as a source of energy and as raw materials.

Various technologies and measures can be deployed to reduce energy intensity and mitigate carbon emissions in the sector. These include the production and use of green hydrogen, carbon capture utilisation and storage (CCUS) solutions, circular reuse of plastic waste, replacement of fossil fuel raw materials with biomass, and improvements in energy efficiency for process heat.

Waste heat potential in the chemical industry

Among energy efficiency measures, the recovery of waste heat represents a viable

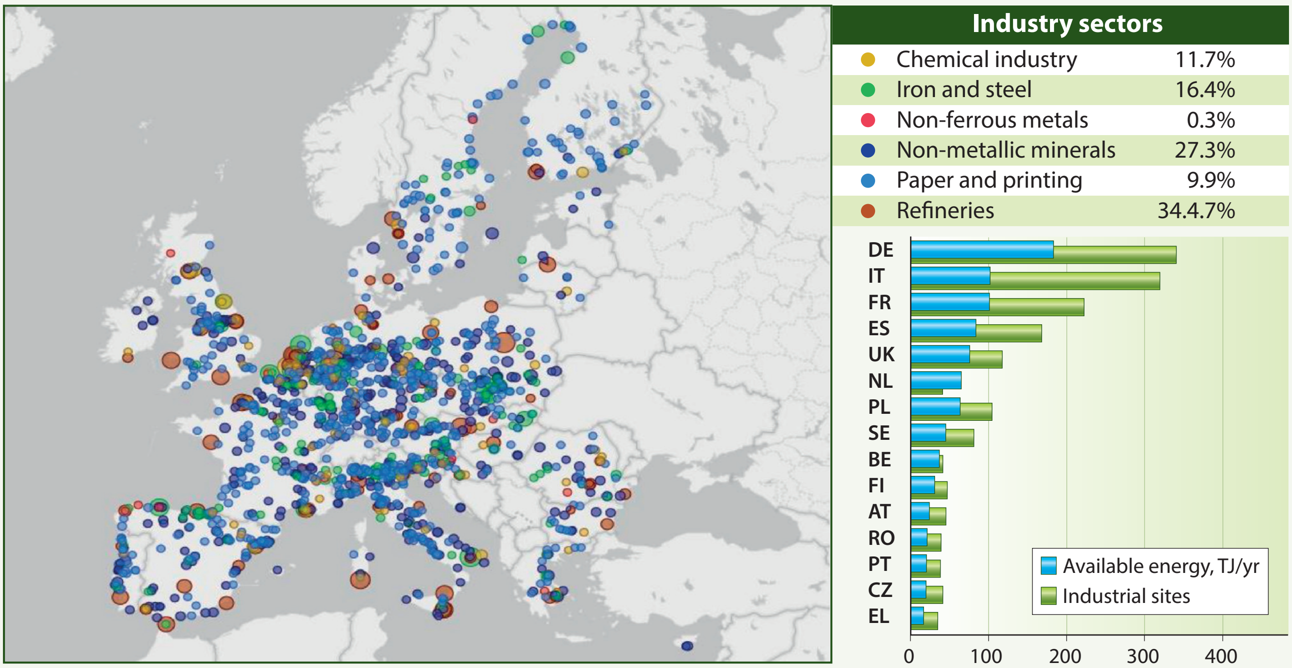

Figure 1 Map of industrial sites with significant waste heat recovery potential in Europe

Country	Clinker	Container glass	Flat glass	Paper	Primary steel	Second steel	Chemicals	Food and beverages	Refinery	Total
Belgium	33.4	0	12.1	8.1	14.9	0.3	391.2	130.5	11.2	602
Denmark	9.5	0	0	1.9	0	0	26.1	54.5	2.6	95
France	85.5	36.9	12.1	32.5	32	0.7	453	427.3	20	1,100
Germany	164.2	47.3	19.2	89.4	89.8	1.6	1,367	486.4	32.6	2,298
Italy	98.6	41.3	12.1	34.3	19.7	2.2	357.4	266	23.3	855
Netherlands	13	0	0	11	20.6	0	666.8	193.5	19.8	925
UK	43.1	26.7	9.1	17.4	30.6	0.2	300.2	254.7	19.8	702
Total	**447.3**	**152.2**	**64.6**	**194.6**	**207.6**	**5**	**3,562**	**1,813**	**129.3**	**6,577**

Table 1 Estimated potential for installation of ORC power plants per selected country and per industrial sector (in MW electricity production)

and rapidly deployable solution that can optimise energy use and enhance the overall sustainability of chemical processes.

In one study, the Knowledge Center on Organic Rankine Cycle Technology (KCORC) identifies the waste recovery potential for 1,175 energy-intensive industrial sites across seven EU countries (see **Figure 1**) (KCORC, 2022).

Estimates show that more than 50 MW of thermal energy is produced at each site, with 11.7% represented by the chemical industry. For waste heat sources above 250°C, considered more economically attractive, Organic Rankine Cycle (ORC) waste heat recovery plants could allow the installation of around 3.6 GW of electrical power in these industrial sites (see **Table 1**).

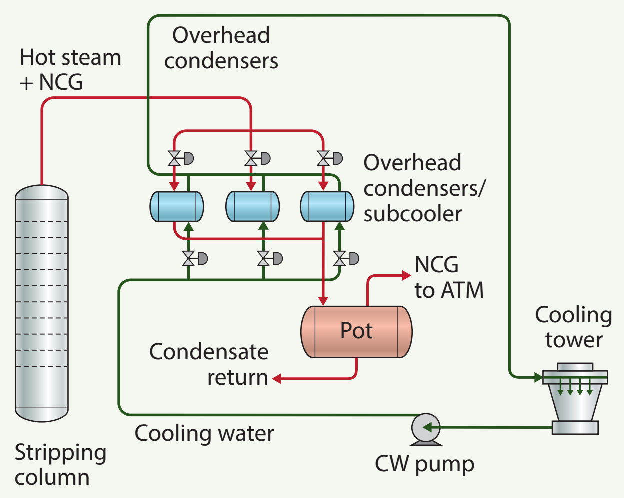

Figure 2 Traditional layout of chemical plant

Organic Rankine Cycle technology for waste heat recovery in the chemical sector

Exhaust heat is generated during various stages of chemical processes such as distillation, reaction processes, heat exchange and cooling systems, exhaust gases from combustion processes, and ventilation equipment.

This waste heat can be recovered and reused by employing different technologies depending on its characteristics and application.

One of the most efficient and economically viable technologies for waste heat recovery is the ORC, which operates effectively within a temperature range of 90°C to 400°C.

The ORC system is similar to the traditional Clausius-Rankine cycle, commonly used for electricity generation, but employs organic substances as the working fluid instead of water (steam). These substances have a lower boiling point and higher vapour pressure, making them more suitable for generating electricity from low-temperature heat sources. The organic fluid, which can be a hydrocarbon or a refrigerant, is selected based on its thermodynamic properties that best suit the available heat source. This allows for higher cycle and turbine efficiencies to be achieved.

The ORC operates as a closed thermodynamic cycle. Heat from a primary source warms and vaporises the organic fluid, which then expands through a turbine, producing mechanical energy that is converted into electricity. The fluid is then condensed and pressurised to restart the cycle.

Using an ORC cycle for waste heat recovery

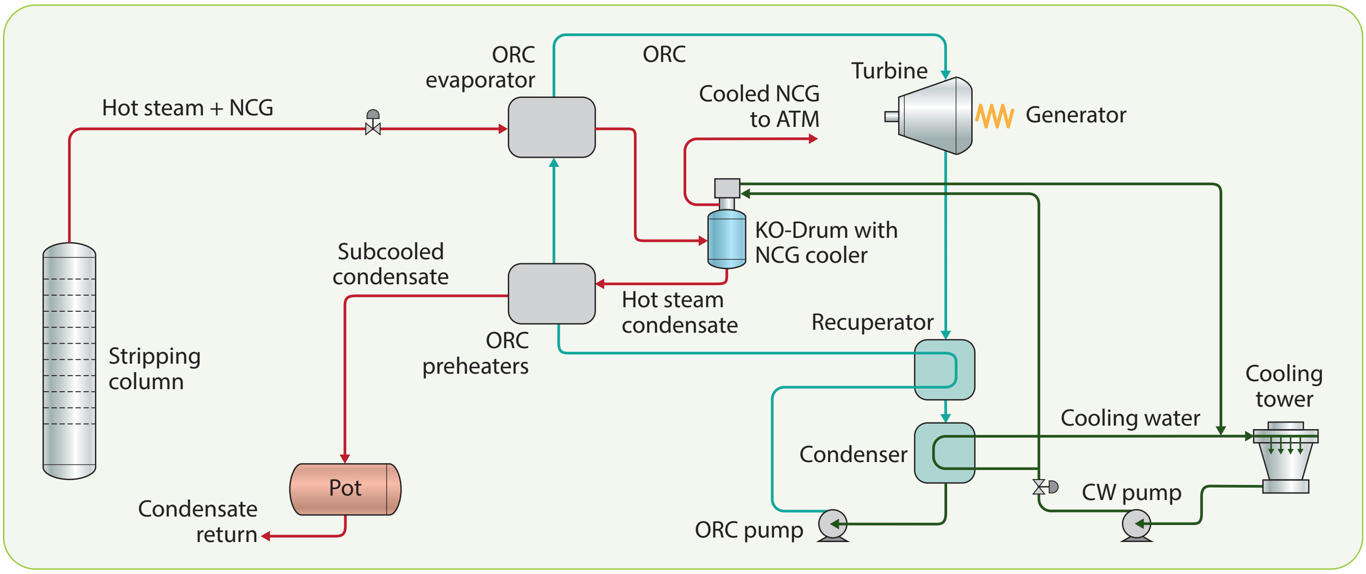

Figure 3 Layout with ORC WHR integration in the chemical process with overhead condensers

at low and medium-high temperatures or for small applications gives some advantages over a steam cycle, including:

- Higher efficiency and flexibility in operations, even at partial loads.
- Automated operations, which avoid dedicated trained personnel to run them.
- Low, easy maintenance and a long plant lifecycle.
- Enabling operation without water consumption by choosing an air-cooled condenser.

These characteristics make ORC technology a flexible, customisable solution suitable for retrofitting existing sites or greenfield installations.

In the chemical sector, ORC systems can recover waste heat from distillation processes by harnessing available heat from the overhead vapour of the distillation column and the non-condensable gas (NCG) stream from stripping columns. In these cases, the ORC system serves a dual function, providing significant benefits: it replaces the conventional condensers at the top of the column while simultaneously generating electrical energy (see **Figures 2** and **3**).

The process steam, NCG flow, and organic working fluid never come into contact, avoiding the potential issue of process steam and condensate contamination.

ORC waste heat recovery system with radial outflow turbine

Exergy International is a global provider of clean energy technologies and an expert in the design and supply of ORC systems. In 2009, the company introduced the Radial Outflow Turbine (ROT) for ORC systems (see **Figure 4**).

The unique configuration of Exergy's ROT allows for efficient conversion of thermal energy into mechanical power thanks to several technical features:

- Increased volumetric flow during expansion.
- Reduced leakage and rotor friction due to straight blades and radial design.
- Multiple inlets on the same rotor disk at different pressures.
- Up to nine stages on a single rotor disk, allowing for higher efficiency.
- Optimised pressure gradient distribution to limit vortex formation and fluid dynamic losses.
- Flexibility in choosing the cycle pressure with fewer technological limitations.
- Patented mechanical group, easily removable

Figure 4 Exergy's Radial Outflow Turbine

Figure 5 Overview of Exergy's ORC waste heat recovery installation at Sanfame's chemical plant

for quick and simple maintenance without fluid draining.
- Reduced rotation speeds, compatible with direct coupling to a generator.

Case study: Sanfame ORC waste heat recovery project

Jiangyin Xingjia New Material Co., part of the Sanfame Group, active in the chemical industry and polyester chemical fibre production, sought a low-carbon technology solution for a new greenfield polyethylene terephthalate (PET) manufacturing site of two production lines, each with a capacity of 750,000 tons per year.

Sanfame selected Exergy's ORC technology to achieve its sustainability goals. The plant comprises two ORC units, each rated at 2.9 MWe, for a total installed power of 5.8 MWe (see **Figure 5**). These units recover heat at 102°C from saturated polyester steam at the top of the stripping column and from the non-condensable gas (NCG) stream generated by the production process. This installation represents the highest power generation capacity ORC technology applied to the polyester industry.

The process steam flow and NCG are directed to the heat exchangers of the ORC system, which transfer the heat from the primary source to the organic working fluid of the ORC cycle. As the organic fluid heats up, it vaporises and passes through Exergy's high-efficiency ROT turbine, generating electricity.

The solution designed by Exergy provides a dual advantage: the ORC system repurposes exhaust heat to generate carbon-free electricity while simultaneously replacing the overhead condenser, used in the typical layout of the chemical plant. This dual functionality makes the system both efficient and cost-effective.

The ORC is fully integrated with the customer's process but does not interfere with chemical manufacturing operations, ensuring no impact on PET production capacity or rates, even during start-up and shutdown phases.

The electricity generated by the ORC plant is employed for internal consumption, meeting 20% of the factory's energy needs. The plant has been operating since October 2023. It is estimated to contribute to an annual CO_2 emissions reduction of approximately 20,000 tons, also avoiding the consumption of 8,500 tons of oil equivalent per year by replacing electricity from fossil fuels.

The plant underwent a technical evaluation by an external committee of academicians from the Chinese Academy of Engineering and senior engineers from independent engineering companies. The evaluation highlighted an impressive thermoelectric efficiency of 11.22% and an isentropic turbine efficiency of 88.69%.

Return on investment

An ORC waste heat recovery system installation in the industrial sector has a typical payback time of four to eight years depending on variables such as the electrical output of the ORC required, the plant configuration, the selling price of electricity and others. Incentives like carbon credits and additional premiums for saved CO_2 emissions can further shorten this period.

For the Sanfame project, the waste heat recovery system demonstrates an advantageous payback time, expected in three years.

Conclusion

Waste heat recovery systems are proven solutions for reducing the environmental impact and energy costs of energy-intensive industries. By decreasing reliance on fossil fuels, these systems also significantly cut carbon emissions, covering up to 30% of industrial energy needs.

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Harnessing the power of data for oil and gas in the energy transition

Effective electrification is instrumental in the industry's progress towards net zero and meeting decarbonisation goals

Daniel Mardapittas
Powerstar

The oil and gas (O&G) sector plays a critical part in the global energy transition, and more than 50 companies have now signed up to the Oil & Gas Decarbonization Charter (OGDC), launched at COP28. But who determines what an effective decarbonisation strategy looks like, and what is the role of electrification in this process?

This article considers incremental steps industry players can take to demonstrate progress towards net zero and looks at modern energy management technologies that can facilitate these ambitions.

Current pledges and future standards: Where are we now?

O&G will be critical for the foreseeable future, and the global demand for O&G looks set to continue through to the 2050s. According to one industry report, the demand for oil may peak in the 2030s and then decline towards 2050, with the speed of decline dependent on the progress of the energy transition. Peak gas demand looks further off, with a possible rise after 2040. There may, however, be a steep decline if electrification and renewable energy sources continue to grow rapidly *(McKinsey & Company, 2023)*.

Indeed, continued expansion in renewables and low-emission energy sources indicates that these could potentially make up 85% of global power generation by 2050. Projections such as these show that O&G will play a vital role in energy supply for the next few decades, but they also suggest longer-term precariousness. This points to a future requiring significant adaptations to existing practices and processes.

As a high-emitting sector, O&G recognises the need to decarbonise – to meet net-zero commitments and to secure the industry's place in the future of the global energy economy. To this end, the 50-plus signatories to the OGDC have committed to action across three areas:

❶ Net-zero operations by or before 2050.
❷ Aiming for near-zero upstream methane emissions by 2030.
❸ Zero routine flaring by 2030.

In this article, we concentrate on the first of these pledges – net-zero operations – and on electrification and the measurement of decarbonisation, where Charter signatories "aim to reach net-zero CO_2eq emissions (Scope 1 and 2) for operations under our control and, as applicable, engage with joint operating partners towards net-zero CO_2eq emissions (Scope 1 and 2), by or before 2050" *(COP28UAE, 2023)*.

As a high-emitting and complex sector, O&G faces very specific challenges, but it is also uniquely placed in having the skills, assets, and power to drive global decarbonisation. The Science Based Targets Initiative (SBTi) – a world-class standard for business to set, measure, and demonstrate progress on net zero – has recognised the complexities and challenges faced by O&G companies. To this end, SBTi are engaged in a development project for a new Standard for O&G companies, focusing on supply, demand, and finance *(SBTi, 2024)*.

Where this new standard considers supply, SBTi will require O&G companies to address processes and related emissions. The Terms of Reference for the Oil and Gas Standard Development project include specific project aims for a standard that "contains minimum required criteria, recommendations and guidance for the companies operating in the production of oil and gas to set 1.5°C-aligned science-based emission reduction targets across scopes 1,2 and 3." *(SBTI, 2023)*. While this project is underway, SBTi has put a pause on validations and commitments from companies in the fossil fuels sector.

In advance of the requirements of the forthcoming SBTi standard and in line with pledges made under the OGDC, O&G companies should be looking to their own infrastructure, operational activities and logistics: the avenues where incremental steps can make a difference. To set targets and measure progress in the absence of a new sector standard, O&G companies that prioritise data and digitisation can gain significant advantage by managing decarbonisation strategies and measuring and documenting success.

Data and digital assets to inform a decarbonisation strategy

Looking to energy efficiency and decarbonisation strategies, harnessing data and implementing AI-driven technologies can improve operational performance, reducing Scope 1 and 2 emissions while lowering energy costs. For example, better and greater data acquisition and usage can inform preventive maintenance, helping to reduce the risk of unexpected equipment failure. This can cut downtime for greater production efficiency while helping avoid unnecessary equipment replacement, thereby impacting on both production costs and emissions. As a feature from EY notes, "the most competitive and successful oil and gas companies will be those that accelerate the digitization trend: adopting new tools and techniques, including the Industrial Internet of Things (IIoT), analytics, big data, and robotic process automation (RPA) to transform operations from the wellbore to the back office" *(Adomaitis, 2022)*.

In this context, AI-driven energy management, when incorporated into a microgrid (see **Figure 1**), can provide critical data to drive energy efficiencies. A digital twin can offer the ideal environment in which to test and assess the efficacy of energy infrastructure projects, harnessing data for evaluation and mitigating potential issues before they occur through advanced modelling and simulation.

Figure 1 Microgrid controller

Electrification for emission reduction: How a microgrid fits into a net-zero strategy

The International Energy Association (IEA) estimates that electrifying upstream facilities could reduce total upstream CO_2 emissions by 60% *(IEA, 2024 p77)*. Hence, O&G companies committed to decarbonisation should be exploring the technologies that make electrification more feasible. This makes investment in a microgrid a compelling proposition. Implementing a microgrid solution is a complex project. However, the exponential growth in the market – estimated at $37.6 billion this year and projected to reach $87.8 billion before 2030 – indicates the extent to which microgrids are becoming an increasingly important element in the energy transformation toolkit. This technology has three significant benefits:

❶ Critical resilience for emergency power, which can be area-wide.

❷ Reduced emissions through better energy management.

❸ Potential to incorporate renewables, together with better cost efficiencies through sophisticated data and energy management software.

For O&G companies implementing electrification projects, the IEA notes that it is "important to ensure a continuous, reliable source of energy to maintain operations and ensure safety; several solutions are available to do so, including the use of batteries, hybrid systems or the retention of existing assets for back-up power" *(IEA, 2024 p77)*. As an essential element of a microgrid, a battery energy storage system (BESS) (see **Figure 2**) can provide this essential reliable power supply in an emergency if it incorporates uninterruptible

Figure 2 Inside a battery energy storage system

power supply (UPS). For complex sites with high energy usage, a BESS with UPS is far more efficient than traditional UPS for emergency power. For one Powerstar client, switching from lead-acid battery technology to a modern BESS with UPS has reduced annual energy spend by approximately £225,000 and cut 190 tonnes of CO_2 emissions.

The IEA estimates that more than half of global O&G production currently lies within 10km of an electricity grid, with three-quarters in areas with good wind or solar resources. While offshore sites will generally be more expensive to electrify, the IEA considers that grid connections can be a viable option for onshore O&G fields *(IEA, 2024 p78)*. Where a grid connection is feasible, the BESS can be used to draw down grid energy when at its lowest price and stored for use at peak times while maximising the use and flexibility of any on-site renewables, thus reducing Scope 2 emissions through effective and efficient management of grid energy alongside clean energy.

Harnessing the power of AI for data management and energy efficiency

For optimum management across a microgrid – where different assets, such as the BESS, on-site renewable generation, and electrified heat pumps are incorporated – AI-driven management controls are critical. These enable O&G companies to benefit from data collection and analysis for continual energy efficiency improvement.

A neural network-based AI-enabled controller, an energy management system (EMS) such as Powerstar's proprietary Energy Optimisation System (EOS), provides precise control and dynamically integrates energy technologies and assets into a cohesive network. Intelligent, real-time decision-making without the need for continuous human involvement is coupled with continuous learning. AI-driven EMS technologies create and continuously update a site's load profile, allowing for strategic load-planning. Changes in energy usage can be detected and responded to in real-time, and faults or power disruptions can be pinpointed. Power and resource demands can be adjusted for optimal performance across a site's energy management infrastructure.

Given the complexity of O&G infrastructure and the lack of a clear, financially profitable trajectory for decarbonisation, AI-led continuous learning can be an important asset for companies embarking on electrification. Sensors and equipment across a site can provide real-time data on energy usage, whereby the central computer actively learns and adapts, facilitating efficient site management as larger quantities of data become available.

AI integration empowers the management system, allowing it to improve performance progressively and to adapt to changing conditions. Data generated by remote monitoring across the microgrid is accessible via a user-friendly interface, allowing for better- informed and better-documented decisions. All of this contributes to a proactive, ongoing energy transition strategy.

De-risking complexity: How a digital twin can inform and justify electrification

Every O&G company embarking on or extending electrification needs to justify investment and change. Advanced modelling and simulation – the deployment of digital twins – can inform a sustainability strategy, enabling the evaluation of a multitude of scenarios and establishing the case for investment through data-driven cost-benefit analysis (see **Figure 3**). Complex projects – the interplay of processes and a range of variables – can be tested to determine their efficiency and effectiveness.

Looking to the 2030 decarbonisation challenge, including Scope 1 and 2 emissions, Deloitte pointed to the future of energy, where companies are "optimising production and reservoir management through the use of digital tools such as IoT sensors, digital twins, and virtual reality to model scenarios, monitor operations, track emissions and energy usage and proactively maintain equipment" *(Deloitte, 2020)*.

Through a digital twin, a site's existing energy consumption data is combined with an existing infrastructure map, and proposed energy management solutions and their interactions with the site can be assessed before any installation is commissioned. Harnessing data allows for stress-testing: building a digital twin enables the evaluation of technologies in diverse conditions and for potential issues to be identified and rectified at the design stage. For example, where there may be conflicts between existing infrastructure and planned electrification technologies, these can be identified at the outset. This approach provides the necessary issue resolution, helping to ensure the crucial reliability of power and optimising performance at the earliest opportunity in the project timeline.

O&G companies may be looking for a range of options for both short- and longer-term electrification. The accumulation of data through AI-driven microgrid EMS can assist in the evaluation of these opportunities. When considering investor appetite for O&G electrification and sustainability, comprehensive modelling of intricate Behind the Meter power flows and systems can improve investor confidence to gain vital funding and project approvals. This is particularly powerful if the energy management technology partner has genuine grid emulators that are able to recreate real-time grid supply on the digital model and thus guarantee accuracy.

Conclusion

O&G is in a state of flux. The sector has a huge role to play through the energy transition and beyond. Fifty-plus companies – accounting for more than 40% of global oil production – have signed up to the OGDC, pledging their commitment to net-zero operations by 2050. Yet many decarbonisation elements are outside of their direct control. Managing and documenting

Figure 3 Deploying a digital twin can inform a sustainability strategy

Scope 1 and 2 emissions is vital for companies seeking to thrive in the coming decades. Mitigation is critical on the journey to net zero.

Companies wanting to plan, monitor, measure, and demonstrate steps towards decarbonisation through the energy transition need accurate data. While negotiating Scope 3 emissions presents a more complicated challenge than Scope 1 and 2 – as is true for all sectors – the electrification of O&G operational processes and infrastructure has a significant role to play in addressing overall net-zero ambitions and commitments.

O&G is vital to the global economy and is a sector uniquely placed to lead a secure energy transition. It has the expertise, infrastructure, and experience in managing complex projects and complicated supply chains – all necessary to negotiate net zero. The sector has the appetite for innovation that is vital for global decarbonisation. Throughout the energy transition, data – its collection, management, and capacity to inform short- and longer-term sustainability strategies – is crucial.

Along the net-zero journey, energy management technologies such as microgrids, AI-driven energy management, and digital twins can make decarbonisation less of an unknown quantity. Data-driven insights into energy infrastructure can help de-risk investment in electrification, smoothing the path to net zero.

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Solutions for heat tracing in renewable diesel production

The production and processing of renewable diesel require careful heat management throughout different steps of the refining process

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nVent

Introduction

With global decarbonisation strategies and sustainability requirements, renewable diesel has emerged as a promising alternative to conventional fossil fuels. The US Energy Information Administration (EIA) predicts a 30% increase in renewable diesel production in 2024 and 2025 (*US EIA*, 2024).

Renewable diesel, derived from biological materials, offers significant environmental benefits such as reduced greenhouse gas emissions and decreased reliance on non-renewable resources. However, its production and processing present unique challenges, especially in process heat tracing. This article delves into these complexities and presents innovative solutions to address them.

Comprehending renewable diesel

What is renewable diesel?

Renewable diesel, also known as hydrotreated vegetable oil (HVO), is a biofuel produced from renewable resources like vegetable oils, animal fats, and waste cooking oils. Unlike biodiesel, which is made through transesterification, renewable diesel is produced through hydrotreating. This process removes oxygen and creates a fuel that is chemically similar to petroleum diesel.

Benefits of renewable diesel

The advantages of renewable diesel are manifold. It offers a drop-in replacement for conventional diesel, meaning it can be used in existing diesel engines without any modifications. Renewable diesel also boasts superior performance characteristics, such as higher cetane numbers and better cold-flow properties. Additionally, it significantly reduces greenhouse gas emissions and particulate matter, contributing to improved air quality and public health.

Role of process heat tracing

Importance of heat tracing

In industrial processes, maintaining the proper temperature of fluids is crucial to ensure efficient operation and product quality. Heat tracing is the process of applying heat to pipes, vessels, and other equipment to maintain or raise their temperature. This is especially important in cold climates or processes involving high-viscosity fluids, where the risk of solidification or freezing is high.

Challenges in renewable diesel feedstocks

Renewable diesel feedstocks, such as vegetable oils and animal fats, present unique challenges for heat tracing. These feedstocks have higher viscosity and lower pour points than comparable petroleum-based feedstocks, making them more prone to solidification at lower temperatures. Secondly, the presence of impurities and variability in feedstock composition can further complicate the heat tracing process. Finally, as with petroleum-based feedstocks, plant oil and animal waste feedstocks for renewable diesel may arrive at the refinery via rail, ship, truck, or pipeline. To ensure flow, these feedstocks require a prescribed temperature maintenance from unloading and distribution areas to storage facilities 100% of the time.

Figure 1 Raychem heating cable with HPR technology

Innovative solutions for heat tracing challenges

Addressing the challenges of renewable diesel feedstock requires a comprehensive heat management system (HMS). This system includes engineering, power distribution, electric heat trace products, control and monitoring, thermal insulation, and instrument winterisation.

Designing an HMS solution for the feedstock area of a renewable diesel refinery depends on the location of the feedstock unloading system and the availability of power distribution to support electrical heat tracing. For instance, unloading feedstocks from a ship may involve long piping distribution systems from piers and jetties, while unloading from a truck or in-plant railcar may offer closer access to the operating refinery. When the feedstock delivery system is near the refinery, self-regulating (SR) technology is ideal for heating cables.

Self-regulating heating cables

SR heating cables are an effective solution for maintaining consistent temperatures for the movement and storage of renewable diesel feedstock. These cables adjust their heat output based on the surrounding temperature, ensuring energy efficiency and preventing overheating. Their ability to provide uniform heating makes them ideal for use in pipelines and storage tanks.

Since sustainability is a key component of the energy transition, Raychem SR heating cable with high power retention (HPR) technology and a 30-year design life, ensures the performance and long product design life to meet critical sustainability requirements.

Electrical contractors typically prefer to work with SR heat tracing cables whenever possible because they are easy to design and install. This is a result of the unconditional T ratings and cut-to-length installation. The process maintain temperatures of the typical feedstocks in this industry are also a great fit for the power temperature curves of the high-temperature SR heating cables displayed in **Figure 1**. In this case, 277V is the optimum power, if available, to ensure maximum designed circuit lengths while minimising the impact on the overall power distribution of new or retrofit refinery operations.

Figure 2 Raychem longline heating system

Longline heating systems

When the renewable diesel feedstock delivery points are on ship docks or from distant railway access, this often means greater distances between the delivery point and the refinery itself. Due to the heat management requirement of the feedstocks, the piping distribution systems in these scenarios are best designed using longline heat tracing technologies like Skin-effect Tracing Systems (STS), which can carry heating power longer distances, as shown in **Figure 2**.

STS systems can be designed to operate for up to 50 km from a single power point. The critical solution that this heat tracing technology brings to this industry is the opportunity to provide the feedstock process temperature maintenance desired with little power distribution required, often from a single power point location. If the long pipeline from the ship unloading to the refinery were heat traced with SR technology, multiple power circuits would be required, which means more breakers, power distribution cabling, resistance

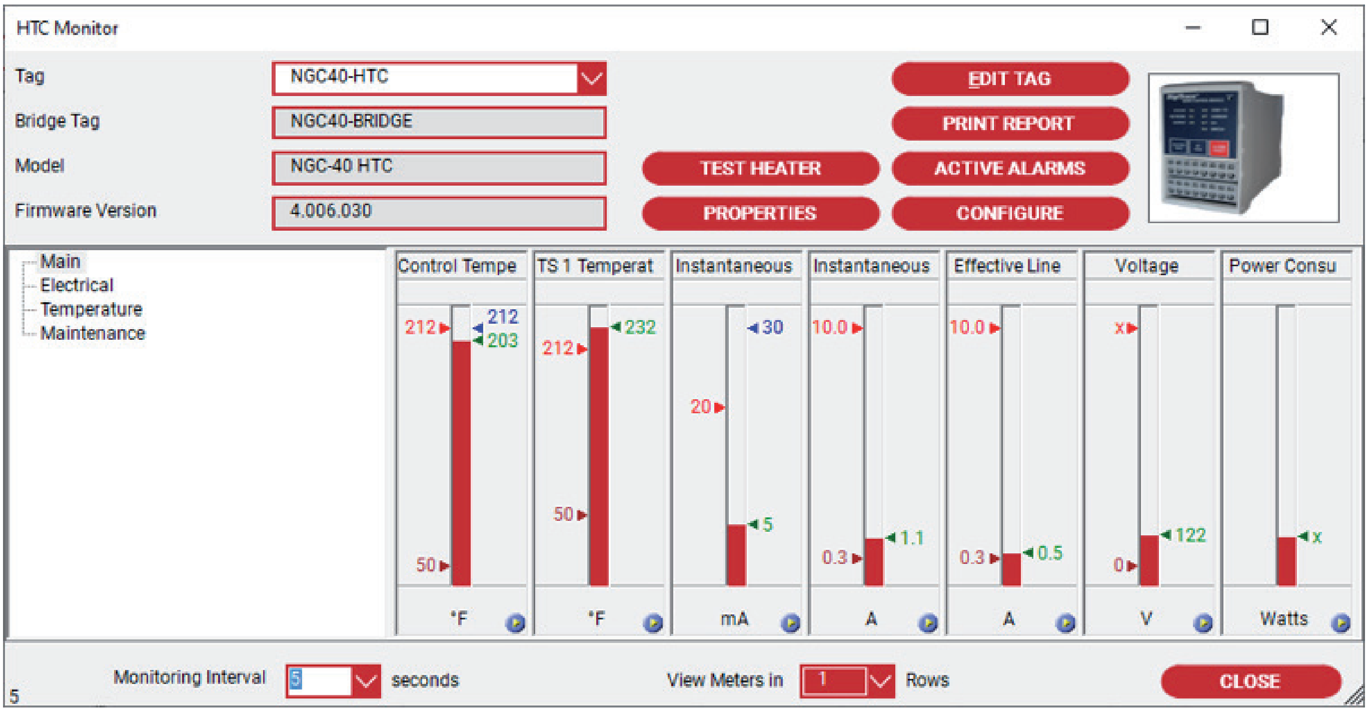

Figure 3 Raychem Supervisor software graphical user interface

temperature detectors (RTDs), controllers, and SR connection kits.

Integration with process control systems

SR and longline heating technologies both depend on connected advanced electrical heat trace (EHT) control and monitoring systems to ensure operational reliability, maintenance, energy efficiency, and performance. Process temperature maintenance control of the feedstocks can be achieved using RTDs for line sensing process control or thermocouples for direct process temperature control. One challenge not referenced is the potential variability of the feedstocks being delivered to a renewable diesel refinery. Delivery of plant oils, animal fats, and waste will certainly vary, and this could result in the need for unique process maintenance temperatures depending on the feedstock and the feedstock mix.

Integrating heat tracing systems with advanced process control systems can significantly enhance their effectiveness. Process control systems can monitor temperature, flow rates, and other critical parameters in real-time, allowing for precise adjustments to heating output. This not only ensures optimal process conditions but also reduces energy consumption and operational costs.

Raychem Supervisory Software (see **Figure 3**) can be programmed to manage the heat required for varying batches and recipes of the incoming feedstocks.

There is also the option to manually adjust process maintenance temperatures remotely from the control room or other location as different feedstocks are delivered (see **Figure 4**).

“Supervisory software programs certainly offer a lot more capabilities as part of the heat management system at a renewable diesel refinery, including maintenance and operational activities like alarm management”

Supervisory software programs certainly offer a lot more capabilities as part of the HMS at a renewable diesel refinery, including maintenance and operational activities like alarm management.

For longlines, Raychem Pipeline Supervisor (RPS) is a temperature monitoring software solution that offers remote monitoring of long pipelines with critical fluids. This software utilises distributed temperature sensing (DTS) data that is continuously captured from fibre optic sensors 24/7 along the entire length of the pipeline.

Figure 4 Advanced control and monitoring

The RPS software utilises advanced algorithms, developed based on actual pipeline events, to provide operators and maintenance personnel with pending threats such as the formation of hot and cold spots, time-to-freeze prediction, and location of pipeline plugs.

This unprecedented access to pipeline performance trends provides rich, actionable data so that maintenance staff can keep pipelines operating safely and efficiently.

Case study and real-world application

Gulf Coast US refinery conversion to renewable diesel requires 1.6 km (1 mile) underground feedstock pipeline

In this unique refinery conversion challenge, chicken fat and oil are feedstocks delivered by rail car to the refinery at a rail unloading terminal that is 1.6 km away from the refinery. Routing of the heated transfer pipeline required most of the line to be underground at depths ranging from 3m to 30m. The owners of this project had significant civil and mechanical challenges designing and planning for the construction of an underground heated line to deliver chicken fat from the rail terminal to the refinery. The chicken fat and oil must be maintained at a process temperature of 120°F (50°C) to keep them in liquid form.

The customer's mission-critical objective for the heat management solution included finding the optimal heated pipeline system design for this project that would keep critical processes running under all scenarios. Additionally, engineering solutions were provided in response to contractor challenges for construction and the future reliable operation of this underground heated line.

Raychem engineers specialise in longline heated pipeline applications that address solutions where power distribution is limited in supply. These experts determined that a STS was the ideal solution for this project (see **Figure 5**) because they could bundle several adjacent technologies for optimum heat management system performance, such as:

- STS heating with a single power connection at one end of the pipeline.

Figure 5 STS longline heated pipeline

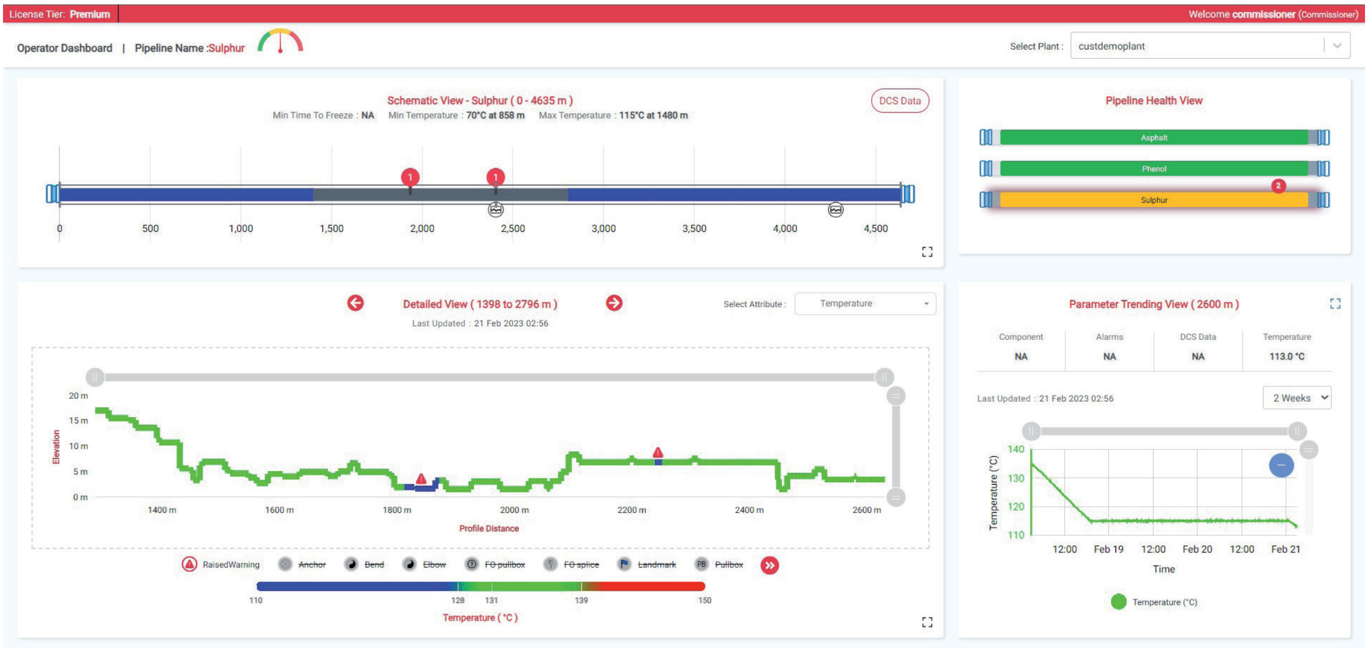

Figure 6 Raychem Pipeline Supervisor DTS fibre optic technology captures data points along the entire length of the pipeline

- Pre-insulated/prefabricated piping systems that offer superior thermal insulation reliability and underground integrity by providing a homogeneous temperature profile for the entire length of the pipeline.
- Fibre optic DTS to measure the temperature of the underground pipeline every metre along its underground routing.
- Raychem RPS predictive analytics software for comprehensive control and safe management of temperature-critical pipelines.

This key feedstock line was constructed using mostly horizontal directional drilling to install the 1.6 km, pre-insulated, STS heated underground.

The pipeline temperature is monitored every metre along its length using DTS fibre optic technology (see **Figure 6**). Raychem RPS software ensures feedstock flow assurance by monitoring the entire pipeline and providing the real-time data required for operations to confirm that this underground line is functioning as designed.

Conclusion

This case study highlights the challenges the renewable diesel industry faces, not only in processing new feedstocks but also in transporting them to refineries. The energy transition has brought significant attention to biofuels, including biodiesel, renewable diesel, and sustainable aviation fuel (SAF), all of which use similar feedstocks. This creates new challenges for maintaining process temperatures, regardless of delivery methods.

New renewable diesel refineries will integrate HMS into their feedstock handling areas. Retrofitted refineries will need to add HMS to manage feedstocks in areas lacking heat tracing or thermal insulation and may face power distribution challenges. We strongly recommend involving a heat management integrator early in the design process for both new and retrofit renewable diesel projects to ensure the most reliable feedstock HMS possible.

> **“Retrofitted refineries will need to add a heat management system to manage feedstocks in areas lacking heat tracing or thermal insulation and may face power distribution challenges”**

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Explore some of the latest available sustainable technologies

Sanicro 35 from Alleima bridges the gap between stainless steels and nickel alloys

Sanicro 35 has been developed for highly corrosive environments in demanding industries like chemicals and refining. It also supports 'green' technologies such as chemical recycling and renewable fuel production. It bridges the corrosion resistance gap between super austenitic stainless steel grades and more expensive high nickel alloys, making it an attractive upgrade material. Its chemical composition is shown below:

Sanicro 35 chemical composition (nominal) %

C	Mn	P	S	Si	Cr	Ni
0.030	1.2	0.030	0.020	0.5	27	35

Mo	Cu	N	Fe
6.5	0.4	0.3	Remainder

Sanicro 35 has very high mechanical strength compared to other super austenitic and nickel base alloys. The yield strength for heat exchanger and hydraulic and instrumentation (H&I) tubing is 425 MPa (62 ksi). In addition, it has high ductility, resulting in good cold forming properties.

Localised corrosion

Sanicro 35 has excellent pitting corrosion resistance with a PREN[1] ≈ 52, making it suitable for applications where chlorides are present. Its pitting corrosion resistance compared to other Alleima grades, using a modified ASTM G150 test, is shown in **Figure 1**. A comparison of Sanicro 35 and Alloy 625 using another slightly modified ASTM G150 test method is shown in **Figure 2**. The grade also exhibits good crevice corrosion resistance, and in ASTM G48 testing, it performs better than Alloy 625 and is at least on par with Alloy C-276 (see **Figure 3**).

Environmental-induced cracking

Chloride stress corrosion cracking (Cl-SCC) can easily lead to catastrophic failures if a pressurised shell or pipe cracks and releases process fluids into the environment. Several Cl-SCC tests have shown that Sanicro 35 has a very high resistance towards this corrosion mechanism.

General corrosion

Sanicro 35 has shown high corrosion resistance in caustic environments and high resistance towards sulphuric acid, making it suitable for a number of applications within the chemical process industry. In organic acids, it is beneficial with high chromium

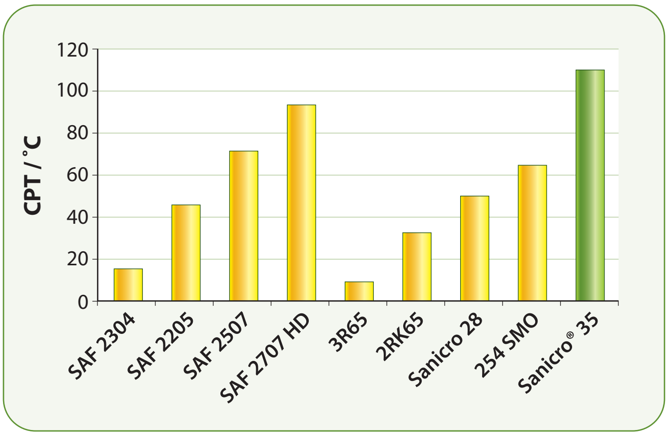

Figure 1 Comparison of pitting corrosion resistance between Sanicro 35 and other Alleima grades. Test according to ASTM G150 with 3 M $MgCl_2$ as test solution

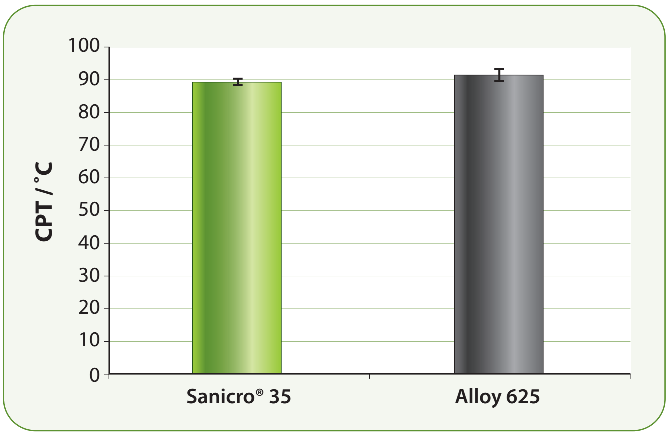

Figure 2 Comparison of pitting corrosion resistance between Sanicro 35 and Alloy 625. Test according to ASTM G150 with 4.5 M $MgCl_2$ at pH = 5 as the test solution

Sanicro 35 has shown high corrosion resistance in caustic environments

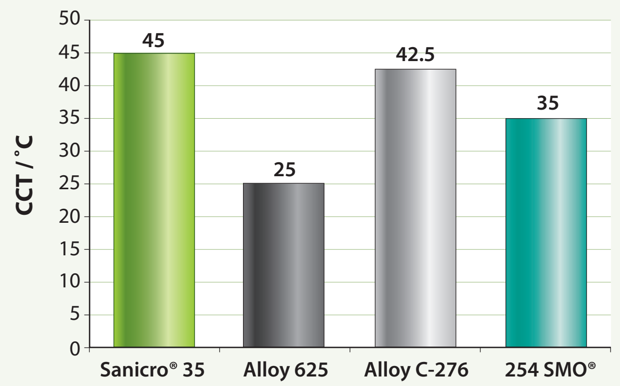

Figure 3 Results from crevice corrosion testing of Sanicro 35 and competing alloys according to ASTM G48 Method F

and molybdenum content, making Sanicro 35 an excellent material for many petrochemical applications. Combined with excellent pitting corrosion resistance, it is also suitable for environments with organic acids contaminated by halides such as chlorides and bromides.

For refineries and renewable fuels

Sanicro 35 has great resistance to ammonium chloride corrosion, and in laboratory testing, it has shown similar performance to Alloy 625. This makes it a good option for overhead condensers in refineries.

In hydrotreater plant heat exchangers, stabilised 304 grades TP321 and TP347 can suffer corrosion and cracking due to long-term build-up of ammonium chloride deposits. The standard solution has been to upgrade the tubes to Alloy 625, but Sanicro 35 can offer a cost-effective alternative to the nickel base alloy.

Hydrotreater plants processing renewable feedstock use Alloy 625 extensively due to ammonium chloride deposits or high-temperature, acidic water phases containing chlorides. Advanced laboratory tests have shown that Sanicro 35 is resistant to these kinds of environments and, therefore, offers a cost-efficient alternative to Alloy 625.

For hydrotreater reactor effluent air coolers (REACs), ammonium bisulphide corrosion is commonly the main concern. However, in some cases, the process stream can also contain high amounts of chlorides. In such cases, Sanicro 35 offers a cost-effective alternative to the standard solution of using Alloy 625.

The grade's high chromium and molybdenum content makes it resistant to high TAN feedstocks. It is, therefore, also suitable for several waste-to-hydrocarbon processes, and has, in several pilot and demo plants, outperformed Alloy 625 and other nickel base alloys.

Offshore, marine, and seawater applications

Sanicro 35 has excellent resistance towards offshore marine environments and sour service. It is, therefore, considered a good alternative to Alloy 625 when sour service resistance is required in H&I systems.

Thanks to its fully austenitic microstructure, it is not susceptible to hydrogen-induced stress cracking (HISC). The grade is, therefore, considered a good alternative to precipitation hardened nickel base fasteners in offshore environments.

In service and advanced laboratory testing, it has shown excellent resistance towards chlorinated seawater. The grade is, therefore, a good material for seawater-cooled heat exchangers.

Moving industry forward

Sanicro 35 bridges the properties gap between super austenitic steel grades and more expensive high nickel alloys for the chemical, petrochemical, and refinery industries sectors. Its excellent corrosion resistance and mechanical properties make it an interesting and cost-saving alternative for many applications where nickel base alloys are the traditional material solutions.

1 PREN = %Cr+3.3×(%Mo+0.5×%W)+16×%N

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